HILL MICHAEL
STRATEGIC ENGINEERING

Report to:

AEMC

Development of Transmission Reliability Standards for Generators

www.hmac.com.au

Head Office:
Level 3, Bowman House
276 Edward St, Brisbane Qld 4000
GPO Box 3195, Brisbane Qld 4001
Australia

p/ +61 (0) 7 3236 4244
f/ +61 (0) 7 3236 4266

HILL MICHAEL

- Cairns
- Townsville
- Brisbane
- Canberra
- Melbourne
- Launceston

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Executive Summary

This report has been prepared for the Australian Energy Market Commission (AEMC) following a conceptual investigation to develop a model to express Transmission Reliability Standards for Generators (TRS-G).

The two key issues driving the consideration of a TRS-G model both relate to a need to provide generators with certainty in network access arrangements in order to improve the efficiency of the market. These issues are:

- liquidity constraints resulting from uncertainty about generation dispatch
- investment distortions due to the complexity in assessing network access risk, resulting in inflated risk premiums or deferred investment.

The investigation and assessment undertaken in preparation of this report focused on improving investment and market activity by addressing these two issues. This report does not include any consideration of the magnitude of market cost resulting from these drivers, alternatives to a TRS-G, or the underlying merit of addressing them.

In seeking to identify and assess potential models for expressing TRS-G, three core characteristics were considered:

i. Metric; being a value (or values) that reflect a level of reliability.

ii. Field of application; being the area or point over which the metric would be applied and assessed (i.e. nodal or zonal and, if zonal, over what area).

iii. Modelling assumptions; being the approach to modelling, assessing and planning the system to meet the TRS-G (i.e. deterministic or probabilistic).

Hill Michael's assessment, findings and recommendations in this report relate to how effective each model is likely to be in addressing the drivers of certainty in network access for generators noted above, as well as the following desirable attributes:

- practical to implement
- able to be measured to assess current (existing) levels
- able to be implemented to a definitive target level.

Hill Michael's investigation has identified and evaluated four alternative approaches for the metric:

- Option 1: capacity (expressed as MW)
- Option 2: time (expressed as definitive time or % of time)
- Option 3: energy (expressed as MWh)
- Option 4 - capacity and energy combined (expressed as a combination of MW and MWh).

The investigation of these options considered a range of issues in relation to how effective each option would be in achieving the objectives of improved contracting liquidity and levels of risk premium for generator output, and reduced complexity, resulting in a lowering of cost-of-capital (risk) associated with investment.

The effectiveness of each model for expressing TRS-G was assessed in the context of the National Electricity Objective (NEO); transmission planning, network operation, generation investment, trading and contracting in the National Electricity Market (NEM);,and other government policy. In particular, the practicality of network planning and investment was given significant weight in the findings and recommendations.

With regard to the most appropriate metric, Hill Michael identified a combined capacity and energy metric (option 4 above) as the preferred option. This recommendation is based on the metric's strong relationship to overall reliability and congestion at peak periods, competitive neutrality between different types of generators, and least risk of inefficient investment, notwithstanding the fact that it requires a greater level of effort to implement.

This metric could be adopted with the following modelling assumptions:

- an energy demand profile based upon 10% PoE maximum demand conditions, focused on peak demand period[1]
- N-1 network contingencies being satisfied
- all generators available, but scaled to allow for the most likely available capacity
- generator bids at short run marginal cost (SRMC).

Assessments would be carried out over typical transmission planning horizons (e.g. as for application of load reliability standards).

Given the imperatives of addressing generation investment and trading/contracting activities, it is likely that the most effective field of application will be nodal. A TRS-G model that exists at a specific connection point to the shared network will provide the strongest basis for removing uncertainty in investment and contracting, although it is acknowledged that further detailed investigation may determine that this approach will involve significant cost to the market.

The conceptual investigation undertaken for this report has sought to provide a basis for framing further assessment and discussion in relation to employment of TRS-G to achieve greater certainty of access to the network for generators, and improve the efficiency of the market. This report includes consideration of the relevant technical,

[1] Peak demand period could be defined on a seasonal (or shorter or longer) basis which captures the maximum demand in a year. To establish the most appropriate definition would require detailed investigation and analysis, which was not included in the scope of this assignment.

regulatory and commercial issues, with a particular focus on the practical implications for transmission network planning, operation and investment of a TRS-G model. Further investigation and consultation with a range of stakeholders, including AEMO and TNSPs would be required to more fully assess various aspects of the preferred TRS-G model option identified in this report and its alternatives.

Specifically, any further investigation should consider:

- the relative level of complexity and practicality of implementation, as compared to a simpler metric consisting of capacity (i.e. option 1 or option 3)
- the relative level of effort, transparency and accuracy of applying more complex modelling assumptions
- the ability to define a suitable zone that would minimise the drawbacks of the preferred option.

Complementing the core report and the consideration of potential TRS-G models is a research summary of the network access regimes for generators in other markets around the world. This investigation aimed to provide an international context to the Australian NEM and the other aspects of this report, but did not seek to identify the best approach.

Climate change and the policies likely to be implemented in response to it have been considered in this report, particularly in relation to the likely change in generation mix. Given the conceptual nature of this report and universal nature of network access issues, it is considered that current climate change policies would not have any specific implications that would change the underlying findings of this investigation.

Contents

1 Background

The AEMC is currently conducting a review of the NEM transmission framework structured around five key themes:

- access
- network charging
- congestion
- planning
- connection

Under the 'access' theme a key issue for consideration is the level of certainty or 'firmness' of network access provided to generators. The underlying driver for addressing this issue is to ensure investment and market (trading) efficiency is maximised.

Some stakeholders have identified the fact that generators do not receive a defined standard of access to the market a significant issue of concern, resulting in inefficiencies, a lack of certainty for new investments, and reduced liquidity in contract markets.

The objective of the standard is to define physical access in terms of the minimum level of ability to export (or maximum level of restriction to export), expressed in a manner that allows generators to make informed and efficient judgements about investment and operation of their generating plant.

This standard is analogous to some degree to existing transmission reliability standards for load that exist in different regions within the NEM.

Hill Michael was engaged by the AEMC to provide options for a model that could express a transmission reliability standard in accordance with the scope of work in the AEMC request for proposal (RFP) document.

The findings of our conceptual investigations are outlined in this report.

2 Assignment Objectives

The objectives of this assignment were to:

- define up to four possible options for a TRS-G model within the context of this assignment
- advise on the material considerations for how these different models could be implemented
- provide consideration of the benefits and challenges of these models
- identify a preferred option, if appropriate.

Importantly, the focus of Hill Michael's advice is on the technical aspects of implementing the model, that is, how the standard can be applied to determine whether existing transmission capacity is sufficient to meet the standard, and the level of additional transmission capacity required to maintain compliance in the future, based on the forecast growth in demand as well as forecast network and generation developments.

This assignment did not include consideration of whether transmission reliability standards for generation as a proposition should be implemented, or other regulatory and commercial matters associated with implementing such a standard (e.g. how costs will be recovered, or which parties will be required to contribute to these costs, etc.). We understand that the AEMC will be considering these aspects separately[2].

Consistent with the AEMC RFP, important considerations for the model options are that they should be:

- practical to implement
- able to be measured to assess current levels
- able to be implemented to define target level

In addition to the above considerations, Hill Michael believes that a critical attribute of the model will be its ability to be applied such that the level of compliance with the standard can be reasonably forecast.

This is necessary for augmentations to transmission capacity for compliance purposes to be planned and implemented by a TNSP with sufficient lead time.

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[2] The AEMC is also considering alternatives to transmission reliability standards for generation to address potential inefficiencies identified by stakeholders.

Other important considerations for the model identified in the AEMC RFP include:

- whether the model form may favour, or be biased against, existing generators or a small number of existing generators, or new entrants — or how it could be implemented in order to reduce this
- how higher or lower standards could be allowed for within the model

3 Guiding Principles

Following discussions with AEMC, the following clarifying principles were established to guide the conceptual development and evaluation of model options.

3.1 Physical-based standard

The assignment requires consideration of a physical-based access standard rather than a financial-based standard. We understand that financial-based access mechanisms are being considered separately in another AEMC work stream.

3.2 Type of standard

As discussed further in Section 4.3, there is a large number of metrics that may be applicable when measuring congestion in a transmission network. The metric options discussed here are those most relevant to transmission investment planning, and not the broader issue of congestion management. This means that the selected metrics relate to network capacity requirements under typical peak demand conditions, rather than a TNSP's operational activities[3].

3.3 Certainty of access provided to individual generators

As noted in Section 1, the key driver for considering a TRS-G model is to provide generators with a level of certainty in terms of the physical access to the transmission network and the market it provides. Therefore, the primary objective of the standard should be to provide certainty of access for individual generators, rather than at the aggregate or system-wide level.

3.4 Simplicity and transparency of the standard

As discussed further in Sections 4 and 5, there are a range of assumptions that must be made to define how a specific metric is to be measured. In defining the most appropriate assumptions, there is a trade-off between the simplicity and transparency of implementing the standard with complexity and accuracy. Obviously, the model must not be simpler than necessary, but the benefits of increased accuracy and reduced transparency need to be carefully considered.

[3] Such metrics would be more useful for measuring day-to-day congestion levels, and therefore could be used within incentive mechanisms geared to influence the operational activities of TNSPs (e.g. transmission outage planning and fault response).

4 Contextual Consideration

This section examines a number of contextual considerations that are helpful in understanding the key concepts that have guided our review and deliberations.

4.1 Definitions

An important requirement of this assignment was to clearly define the different components under consideration and establish the terminology that would be used. The following definitions were established by Hill Michael to provide a context for the review and this report.

- **Framework:** The term 'framework' is not used to describe any output of this assignment. Instead it is reserved for the AEMC's activity of conducting a review of the NEM transmission framework, as noted in Section 1.
- **Standard:** A detailed requirement, including the compliance obligations and assumptions that must be adhered to in order to measure or forecast compliance. In the interests of simplicity, a transmission reliability standard for generation would be similar to the transmission reliability standard for loads. For planning purposes, the overall specification of such a standard is often referred to as the 'planning criteria'.
- **Model:** A model is the mechanism for introducing and applying a transmission reliability standard for generators. Importantly, a preferred model would be selected based on its alignment with defined objective(s).
  In terms of this assignment, a model comprises:
  - defining components (or attributes) of a standard (as discussed in Section 5); and
  - the process to facilitate the introduction and application of the standard.

4.2 Components of a model

To develop options, Hill Michael considered the transmission reliability standard to be specified in terms of three main components:

- The **metric**

  The metric is the measurement used to gauge the level of network access (i.e. reliability). The standard will be expressed through this metric. In the context of these standards, this metric should define the maximum allowable level of constrained generation (or minimum allowable level of unconstrained generation) due to transmission network limitations.

- The **zone** of the metric

  The zone of the metric is the set of system components covered by the standard. For example, this may be the area of the transmission network over which the metric will be evaluated, and potentially specified (if it were to be different across zones); which could range from a system-level standard, regional-level standard, a zone within a region, an individual node or generator.

- The **modelling assumptions**

  The modelling assumptions are the set of parameters or criteria that define how the metric must be measured to assess compliance. The ability to produce forecasts of compliance with the standard is critical for investment planning, and modelling assumptions define the methodology by which these forecasts must be prepared. Clear and complete modelling assumptions are critical to the application of a transparent standard[4].

  It is also important to understand that the actual level of reliability provided through the standard is intrinsically related to the modelling assumptions. As such, the standard of access defined by the metric has to be appreciated through the modelling assumptions. That is to say, the same metric (e.g. 99% unconstrained generation) can produce significantly different actual levels of access reliability if the modelling assumptions are different[5].

  Another consequence of this fact is that any measurement of past or current levels of a metric should employ an equivalent modelling exercise, rather than an analysis of past outcomes using the NEM Dispatch Engine. For example, it our understanding that the majority of constrained generation that has occurred historically is due to either the unusual bidding practices of generators, unusual network outage circumstances, or the influence of market contracting strategy — none of which are likely to be allowed for within the modelling assumptions[6].

  The required modelling assumptions generally relate to the planning approach adopted, which can be considered as either deterministic or probabilistic.

  The **deterministic** approach is simpler in its application than the probabilistic approach, and is more often applied by TNSPs in the NEM and internationally. This approach normally defines a limited set of conditions for which compliance can be assessed. These conditions are normally set to represent 'typical' worst case conditions, such that if compliance is achieved

[4] The need for modelling assumptions is just as relevant to transmission reliability standards for generation as it is for similar load standards. Importantly, the matters that the modelling assumption must cover are also similar between these two forms.

[5] This principle applies to both transmission reliability standards and load standards.

[6] It is also worth noting that this point relates to our guiding principle that the focus of the standard should be investment planning not congestion management.

under these conditions then compliance for the majority of time should be ensured. The most obvious example are the security of supply (or design redundancy) standards often used for load, of which the n-1 standard is an example.

The **probabilistic** approach attempts to estimate the *expected* measure of the metric, accounting for all (or at least most) eventualities. To calculate the expected measure of the metric, it attempts to simulate the actual operation and condition of the transmission network and market, allowing for the most probable events, including network and generation outages, and different demand conditions. As this approach focuses on the expected measure of the metric, it is well suited to metrics whose function is to reflect the long-term average reliability[7].

In addition to the components listed above, the model definition would also establish a number of factors associated with the implementation of the standards, including:

- how the standard (or set of standards) would be introduced (e.g. how the standards should be set)
- how the standard would be applied (e.g. how the network would be planned, how new entrants would be accommodated, how enhanced standards could be achieved)
- how or whether that standard should affect the operation of the market or system.

4.3 Important differences in load and generation characteristics

In order to fully appreciate the options that were considered within this review (see Section 5) it is necessary to understand the different characteristics of load and generation.

Generally, the makeup of the load at a transmission node can be assumed to be relatively homogenous, due to the aggregation of a multitude of individual customer demands which are in turn made up of a small set of demand types (e.g. residential, commercial, industrial, agricultural). Moreover, in broad terms, the customer mix does not change with the assumed demand level. This means that, in order to allow for the economic value associated with the access, the load-related standards need only reflect the level of load; commensurate with the expected level of reliability (i.e. as the level of load increases the reliability of the supply via the network should increase).

[7] It is also relatively simple to extend this approach to cost-benefit analysis by assigning an economic value to the calculated reliability, as occurs in Victoria. For example, where the expected energy not served is calculated, a value can be placed on this energy (e.g. the value of customer reliability); and where expected constrained generation output is calculated, the value can be derived based on the bidding and market clearing assumptions.

At its simplest level, this means that a deterministic standard can be used as it will impose more onerous modelling assumptions as the level of load increase (i.e. moving from an n-level standard to n-1 and then to n-2 as the level of load increases). Furthermore, a relatively simple set of modelling assumptions and an objective test can be specified to measure compliance. As such, provided the standard is well defined via the modelling assumptions, there should be a relatively high level of transparency for any planning decisions based on the application of these standards[8].

Generation has a number of different characteristics to load that are relevant when considering the most appropriate standard and its applications.

Firstly, the time that specific types of generation require access is related to the demand level and the type of generation (e.g. base load, intermediate or peaking plant). Furthermore, some generators have limited control over when they can generate or at what output (e.g. in the case of wind turbine generation). For these types of generation, there is limited certainty as to what level of access is needed, and when.

Secondly, normally there will not be a significant mix of generators at a node, or even across a region. Therefore, a far broader range of economic values associated with reliability of access could be assigned for specific nodes or zones. This may mean that the reliability required is as much a function of the generator type(s) captured by the standard as their level of capacity.

This suggests that the ideal standard may need to adequately reflect the type of generation and when the constraint may occur. For example, a metric that defined the maximum level of constrained time per year could have a far greater effect on the level of allowable constraint of a peaking plant (e.g. open cycle gas turbine) than a base load generator (e.g. coal), due to the far less frequent and shorter operating periods of peaking plant.

It could also be argued that certainty in the level of constrained generation and the relationship with time (i.e. price), rather than certainty in the level of access, would be most beneficial to generation investment decision-making.

Both of these issues suggest that a multi-dimensional metric that reflects differing levels of allowable constraint over different timeframes (e.g. off-peak, on-peak) may be more beneficial.

That said, as noted previously, we have tried not to develop planning metrics that may be significantly influenced by operational actions; these can be best managed

[8] Please note, this should not be interpreted as our agreeing (or not agreeing) that there is a high of transparency provided via the specification of current transmission reliability standards for load in the NEM.

through congestion incentive schemes. For example, network congestion in off-peak periods is far more likely to be driven by outage planning considerations. Therefore, the standard and the metrics we have considered focus on peak demand conditions, which will reflect the most onerous network and pricing conditions under normal circumstances. This has been an important consideration in the development of the guiding principles discussed in Section 3.

The above differences also have a significant influence on the analysis required to plan to the standard. Determining the level of constrained generation due to network congestion, even for a single point in time, will require some form of market simulation. Therefore, the modelling assumptions that define the appropriate generation dispatch are likely to be critical to the specification of the standard. This also means that the level of analysis required to plan to these standards is greater than that required for equivalent load standards. That said, the form of market modelling required should be no more complex — and most likely simpler — to that already required to assess generation constraints due to network congestion via the existing market benefits test in the regulatory investment test for transmission (RIT-T).

Given this additional complexity, in considering the most appropriate modelling assumptions necessary to specify the standard, we have erred on the side of simplicity to ensure transparency can be maintained.

Hill Michael is of the view that the standard should be set to provide a minimum level of transmission reliability, which is cognisant of these simplifying assumptions. This would still provide greater certainty to generators than exists currently. Moreover, a higher level of transmission reliability could still be justified, via more complex modelling assumptions, but this would need to occur through the existing market benefits provisions of the RIT-T or, alternatively, generators specifically requesting an enhanced standard.

4.4 Criteria for evaluation of model options

The AEMC RFP sets out a number of factors to be considered when assessing benefits and challenges of the model options. In addition to the forms of the model discussed previously, this covers:

- relative complexity and cost of implementing such standards
- ability to accurately measure the existing performance across zones
- ability to accurately forecast future performance to the standards and plan additional transmission capacity requirements
- potential cost of transmission investment
- ability of generators to adopt lower or higher standards
- implications for the rights and obligations of new entrants

- creation of a 'level playing field' for generators and potential for a minority of generators to bear the majority of congestion
- interaction with existing transmission reliability standards for load.

Based on the above factors and a number of other considerations we believe to be important, the evaluation criteria can be classified according to the following two primary categories, with a number of secondary categories.

Ease of implementation

This evaluation category involves consideration of matters associated with implementing the standard, including its introduction and ongoing application.

Three specific evaluation criteria would be:

i. Transparency and ability to be audited (i.e. the standard and its application can be readily understood, monitored and TNSP investment decisions evaluated by relevant stakeholders).
ii. Ease (including cost) of introduction, as well as any transitional issues, and includes the ability to measure the existing performance to set the initial standard.
iii. Ease (including cost) to apply, specifically the year-on-year application costs to TNSPs. Also included would be consideration of processes currently applied by TNSPs to plan their networks

Achievement of objectives

This evaluation category involves consideration of whether the standard will achieve its aims, specifically in terms of providing a defined level of access to generation, whether this access is unbiased between generators (both existing and new entrants) and whether the application of the standard will lead to economically efficient outcomes. Five specific evaluation criteria would be:

i. Provision of a defined level of service in terms of reliability of access to the market.
ii. Consistency in the standard of access to generators (e.g. between similar zones or nodes).
iii. Unbiased between the various parties within a standards zone (i.e. between generators within the zone, existing and new).
iv. Reduction in the risk of inefficient outcomes in terms of transmission investment.
v. Ability to define higher or lower level of access.

5 Options Considered

5.1 Reliability metric

Four options for the reliability metric have been considered to be most suited to a TRS-G model, noting the guiding principles defined in Section 3 and the contextual matters discussed in Section 4[9].

Within each of these options there is also a range of alternatives. These options are outlined in Table 1.

[9] It should be noted that the focus of this assignment was to identify a number of possible of options and assess these on a relative merit basis (refer Section 2). Consequently, the option of maintaining the status quo has not been included in the analysis.

Table 1 - Options for reliability metric

Metric	Comments
Option 1: **Capacity-based metric**	The metric would define the maximum level of allowable constrained capacity (or minimum level of unconstrained capacity) under a specific set of conditions, which are defined through the modelling assumptions. This metric would not directly define a level of reliability, although it would still allow the level of access to be specified. (Note: This is the metric defined by both LYMMCo and International Power[10]).
Option 2: **Time-based metric** (This is analogous to the load related reliability metric, SAIDI, which is used in distribution networks.)	The metric would define the maximum time of constrained generation (or minimum time of unconstrained generation) under a specific set of conditions, which are defined through the modelling assumptions. This metric would not distinguish between the scale of the generators constrained (i.e. generator capacity), but rather it would only reflect the time of the constraint. For example, where a network limitation resulted in two generators being constrained by different MW output levels but the same duration, each would contribute the same proportion to the measure. The modelling assumptions would need to define the conditions and period of each year[11] over which the metric would be measured.
Option 3: **Energy-based metric** (This is analogous to the load reliability metric, energy not served, which is used in probabilistic planning approaches for both the transmission and distribution network.)	The metric would define the maximum amount of constrained energy (or minimum amount of unconstrained energy) under a specific set of conditions, which are defined through the modelling assumptions. This metric would distinguish between the scale of the generators and their level of constrained energy. For example, for the same conditions given above, each generator would contribute to the measure in proportion to its MWh of constrained generation. The modelling assumptions would need to define the conditions and period of each year over which the metric would be measured.
Option 4: **Capacity- and energy-based combined metric**	The metric would include two components, covering the capacity and energy metrics defined above. A breach of either component would result in non-compliance to the standard (as opposed to the requirement to breach both components to be considered non-compliant). This metric would distinguish between the scale of the generators, their level of constrained energy, and the generation type (i.e. peaking or base load). The modelling assumptions would need to define the conditions and period of each year over which the metric would be measured.

[10] Ref: LYMMCo and International Power submissions to AEMC Transmission Frameworks Review

Ease of implementation

We do not believe there to be any major difference between the metrics in terms of the ease of implementation. This is mainly due to the fact that such differences relate more to the planning approach and modelling assumptions. In this regard, all metrics will require some level of market modelling to calculate the level of constrained generation, whether this is at a specific point in time (i.e. the capacity metric) or over a duration (i.e. all other metrics). Such analysis should be able to be used to calculate any of the metrics described in Table 1.

Certainly the analysis associated with the capacity metric could likely be simplified to some degree, making this the easiest metric to implement, however the advantage this would provide may not be significant.

Conversely, the combined capacity and energy metric is likely to be slightly more onerous to introduce as this will require more analysis and consideration to define the appropriate levels for the two different components.

Achievement of objectives

An assessment of the above metrics against the standard objectives outlined previously in Section 4.4 of this report needs to include consideration of different generator types, as there are broad differences between metrics with regard to their ability to achieve those objectives.

This is mainly due to how the four metrics may impose different levels of constrained generation for different types and sizes of generation. Critically, depending on the metric chosen, the implications on the peak level of constrained capacity or total level of constrained energy could differ between generators operating under the same standard. This may advantage some generators.

To explain these differences in more detail, consider the following simplified examples.

Figure 1 shows the output from two idealised generators: one base load and one peaking type. The diagram shows the duration that the output capacity occurs. Importantly, energy is represented by coloured areas on the diagram (i.e. capacity x duration).

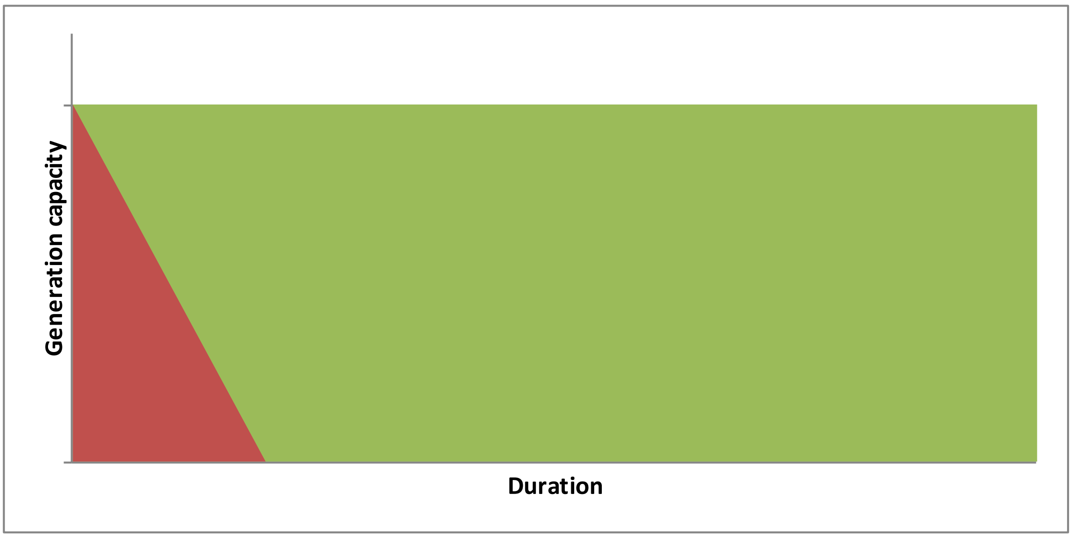

Figure 1 - Comparative outputs from base load (green) and peaking plant (red) generation types

Figure 2 below shows how the same capacity metric will affect the allowable level of constrained generation for each generator — the lighter shade represents the level of constrained generation. As can be seen from this diagram, the maximum constrained capacity is equivalent between the two generators. However, the base load plant would suffer a far greater level of constrained energy.

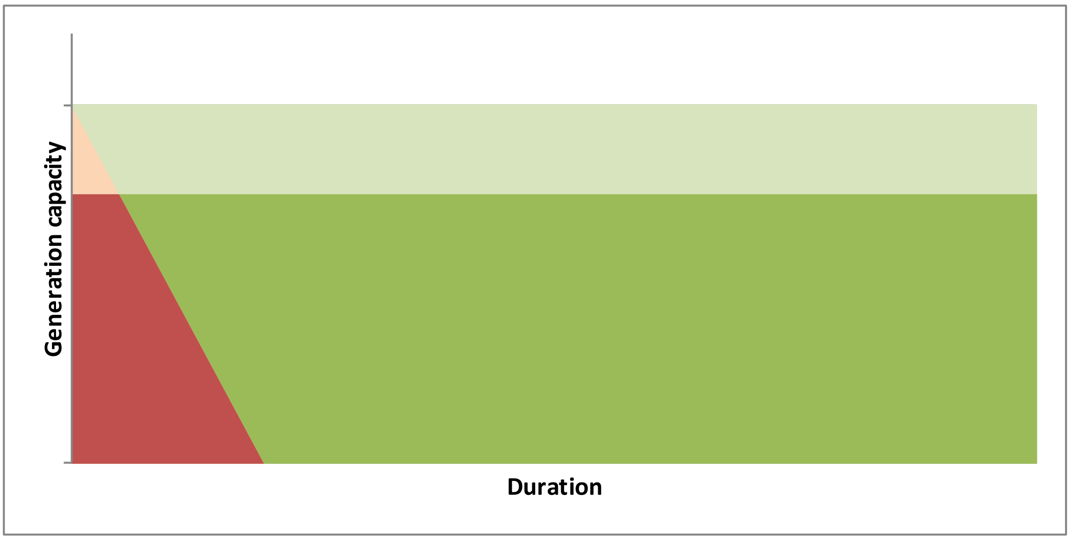

Figure 2 - Comparative impact of equivalent capacity metric on base load (green) and peaking plant (red) generator types

Turning now to the energy metric, Figure 3 below shows how an equivalent metric will affect the allowable level of constrained generation for these two generators. The figure demonstrates that, although the energy constrained is equivalent between the two generators (as a percentage of the generator's unconstrained output), the peaking plant would suffer a far greater level of constrained capacity.

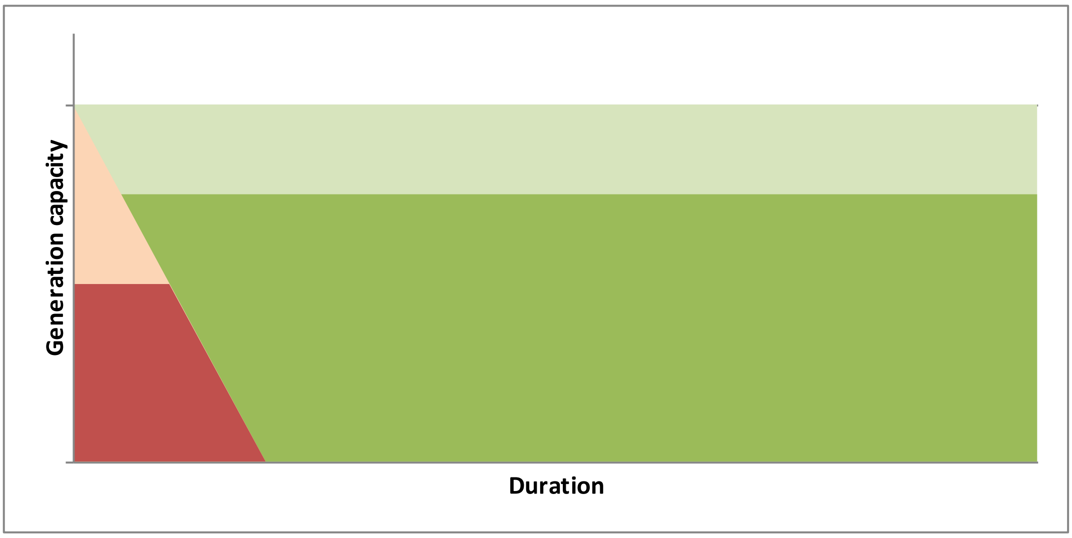

Figure 3 - Comparative impact of equivalent energy metric on base load (green) and peaking (red) plant generator types

With regard to the time metric, this could have a far greater impact on peaking plant both in terms of energy constrained and peak capacity constrained.

These simplified examples highlight the various advantages and disadvantages of the four options.

The capacity-based metric would have the weakest relationship to overall reliability of access, but a strong relationship to congestion at the peak demand condition. This would tend to favour peaking plant.

The time-based metric would also have a weak relationship to both overall reliability and congestion at the peak demand. Furthermore, a time-based metric would not differentiate between the scale of generation constrained.

Additionally, it would appear that both the capacity and time-based metrics would pose greater risks of inefficient transmission investment, due to these limitations.

The energy-based metric would have a much more explicit relationship with access reliability, but a potentially weaker relationship with congestion at peak demand. This would tend to favour base load generation.

The combined capacity and energy-based metric, on the other hand, could be set to address both the worst case level of access at peak demand (in terms of the capacity component) plus the overall level of access reliability (in terms of the energy component). Appropriate settings should be able to be determined to balance the reliability of access provided to both base load and peaking generation.

With regard to the ability to achieve consistency between zones and the ability to define enhanced standards, we do not consider there to be any significant differences between the metrics.

Overall

Based on this analysis, we consider that the combined energy and capacity-based metric to be the preferred option for the reliability metric.

5.2 Zonal or nodal

Whether a zonal[12] or nodal[13] type standard should be applied depends on a number of factors — particularly whether an appropriate zone can be defined.

With regard to the ease of implementation, we do not consider there to be a significant difference in transparency between the two alternatives. The nodal standard, however, will require more effort to apply year-on-year as there will be a greater number of standards to monitor, test and plan to.

Conversely, the nodal option has a number of advantages over the zonal approach with regard to the achievement of the objective. The nodal option should more explicitly define the level of access a generator should be provided. The zonal approach will only reflect an overall level of access across a group of generators.

Related to this issue, the zonal approach may not maintain competitive neutrality, whereby a few generators may account for the majority of congestion in a zone[14].

Under a worst case outcome, this could mean that a small generator could have all of its capacity constrained, but still not affect the measurement of the metric sufficiently to cause non-compliance. These disadvantages in the zonal option would reduce individual generators' level of certainty of access, thereby increasing their risk costs.

The nodal approach also allows enhanced access levels to individual generators to be explicitly defined via enhanced standards. This would not be the case for a zonal standard, where some other mechanism would be required in addition to the standard to ensure that enhanced access is provided.

The nodal option does have disadvantages over the zonal approach with regard to consistency. In this regard, Hill Michael considers it less likely that a consistent set of standards between nodes will be able to be determined.

Furthermore, the zonal standard may be less likely to favour incumbent generators. This is because the standard will be set across a group of generators and, as such, constraints on any individual generators within that group should be less sensitive to the overall metric. Therefore, in the case of a new entrant, it would be less likely that

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[12] Relating to a 'zone' (defined for the purposes of this report as an area of generation in the NEM which is less than a NEM region and may be the same or different to an ANTS zone as defined by AEMO.

[13] Relating to a 'node' (i.e. a connection point to the network in the NEM).

[14] This point was noted in the LYMMCo and International Power submissions to AEMC Transmission Frameworks Review.

any constraints their entry causes for incumbent generators will result in a breach of a zonal standard[15]. However, it is worth noting that this advantage of a zonal metric is linked to the disadvantage discussed previously of potentially treating some generators unfavourably.

It may be possible to mitigate many of the zonal disadvantages discussed here by ensuring that the zone is well designed. Furthermore, provided suitable zones can be defined, the advantages of the zonal metric may outweigh its disadvantages.

We note that the LYMMCo submission indicates that a zone somewhere between the ANTS zones and the nodes may be appropriate, and we would broadly agree with this position. However, having considered this matter at a conceptual level, we believe that more quantitative analysis is required to resolve this issue fully, which is outside the scope of this assignment.

In the absence of this analysis, we consider it reasonable to assume that the nodal approach is the most appropriate, as this provides more certainty in the level of access received by individual generators — one of the guiding principles discussed in Section 3.

However, as discussed previously and as noted in the concluding comments in Section 7 we believe this view should be subject to further analysis. Ultimately, AEMC's final decision on this matter will need to take into consideration what it ultimately wishes to achieve through the TRS-G and the relationship with other elements of its framework review. On this matter, it worth noting that a combined zonal and nodal standard could be applied if deemed appropriate in terms of balancing certainty to generators with the overall reliability of access to the market.

5.3 Deterministic or probabilistic and the modelling assumptions

The deterministic and probabilistic planning approaches, including the differences between these approaches, are discussed in Section 4.2 of this report.

The two approaches involve a trade-off between the ease of implementation and the achievement of the objectives.

The deterministic approach should provide a more transparent and auditable standard[16]. The deterministic approach should also be easier to implement than a probabilistic approach, as the analysis associated with a probabilistic standard would be more challenging as it requires a more sophisticated skill set and effort.

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[15] For example, assume a particular zone contains 10 equivalent generators. A new entrant may cause an incumbent generator to have its output constrained by *x*%, but this would only be an increase 0.1*x*% for the group. (Note that this assumes that the zonal standard would not be set such that it was less onerous than the equivalent set of nodal standards.)

[16] It should be noted that this difference could be reduced by providing sufficient specification in the definition of the modelling assumptions for the probabilistic approach.

On the other hand, a probabilistic approach would provide greater benefits in terms of achieving the objective, particularly with regard to more accurately reflecting true reliability and reducing the risk of inefficient transmission investment.

Given that only one region of the NEM presently uses a full probabilistic planning approach to model the network (Victoria), and based on our understanding that it is unlikely that other regions will adopt such practices in the foreseeable future, we consider that the benefits of a deterministic approach in this regard outweigh its limitations. As such, we recommend adopting a deterministic type standard in terms of network modelling.

It is, however, more usual practice to perform probabilistic market modelling (e.g. modelling of generation planned and forced outages) when assessing network investment that relates to congestion. Therefore, we consider it reasonable to assume that credible options for the standard would allow for the probabilistic analysis of the market.

Without undertaking some numerical analysis — something not within the scope of this review — it is difficult to say with any certainty whether the increased accuracy from such probabilistic market modelling would warrant the increased complexity and reduced transparency. Certainly, the probabilistic market modelling would require the assumptions associated with specifying outage rates to be clearly defined, which could lead to a greater risk of outcomes being disputed — although the existing approach applied by AEMO for its National Transmission Network Development Plan (NTNDP) could be employed to reduce this impact.

On balance, given the inherent simplifications occurring through the deterministic approach to model the network, we consider the full deterministic approach to both the network and market modelling to be the preferred option, unless further quantitative evaluation indicates that the greater accuracy achieved via the alternative is material.

Turning to the specific network and market modelling assumptions, we consider that a relatively simple set of conditions should be used, unless more rigorous analysis proves that the benefits of a more complex set of assumptions justifies their inclusion in the standard.

Although greater accuracy could be achieved by specifying more complex conditions and different scenarios (e.g. future demand profiles, network and generation outages, bidding approaches and generation development plans); as the complexity increases, the transparency of transmission investment decisions is reduced — possibly to a significant degree.

The important point here is that the test for compliance needs to be defined in a clear and objective way. If too many conditions and scenarios need to be investigated, then compliance to a standard becomes vague, and other quantitative risk-based approaches (e.g. the market benefits test in the RIT-T) would offer a more appropriate analysis framework.

Given this and the contextual matters discussed in Section 4, we have identified the following modelling assumptions (see Table 2).

Table 2 - Recommended modelling assumptions

Assumptions	Comments
Demand	The demand assumptions should to be aligned to the TNSP planning tasks, and therefore the demand profile should be based on the 10%, 50% or 90% PoE maximum demand. A profile based on the 50% PoE maximum demand would provide typical congestion conditions faced by generators (i.e. congestion no worse than this for one in every two years). However, this would result in uncertainty to the level of congestion under more onerous peak demand conditions. Therefore, the regional 10% PoE condition may be more appropriate in terms of providing greater certainty to generators, noting that the standard of reliability set by the metric can be tailored to allow for the likelihood of the 10% PoE conditions. An alternative would to use a probability weighted average based upon the three PoE scenarios — or even other maximum demand scenarios (e.g. system peak). However, as discussed previously in regard to simplicity, we consider that further quantitative analysis would be required to justify this increase in complexity.
Network assumptions	To align with the security obligations on system operations, an n-1 condition should be a minimum for the meshed transmission network. This would allow for credible contingencies covering single line and transformer outages. Network limitations and equipment ratings would need to cover those applicable to the network and existing planning assumptions associated with load reliability. An n-2 type condition could be an alternative, particularly for large generation levels, but it is not clear whether the additional complexity required to assess these contingent conditions is worthwhile. Given that the probability of these conditions is much lower (albeit that the consequence is likely to be much higher), in the absence of compelling analysis to support these more extreme assumptions, we would not recommend that these form part of the standard. In special circumstances where these conditions may be material, they could still be assessed outside the standard, under the existing market benefits test.
Generation dispatch assumptions	As discussed previously, we consider that a deterministic approach should be considered for assessing generation dispatch and the level of constrained generation. Such market modelling would use a demand profile based on the 10% PoE conditions. For simplicity, and to provide certainty to generators, the dispatch could be prepared based on SRMC bidding, as developed by AEMO for its NDTDP, assuming all generation is available. Furthermore, assumptions would need to be defined to ensure that intermittent generation capacity was suitably scaled to allow for the most likely capacity available (e.g. generation types such as wind would require some form of capacity scaling). Alternative forms of bidding could be considered (as is prescribed in the RIT-T); however, as noted previously, it would be necessary to define a simple test within the standard to allow the different bidding approaches to be combined in order to assess compliance in a transparent way. Even if these alternatives are not allowed within the standard, they could still be accessed via the full market benefits test of the RIT-T.

5.4 Summary of evaluation of model options

Please refer to Appendix 2 for a summary of the evaluation of the various model options.

5.5 Respondent stakeholder model options

Two models were proposed by two generators, LYMMCo and International Power, as part of the consultation process associated with the AEMC's Transmission Frameworks Review.

These two models are considered in the context of the key attributes, components and assumptions set out in Section 4.

5.5.1 LYMMCo

Table 3 - LYMMCo model summary

Metric	The metric is defined as x%, however it is not clear what the 'x' relates to. It states: '[a]ll generators will have a registered capacity in MW as part of their connection agreements. … The network expansion that would be required to transmit this capacity x% congestion-free within the 'defined zone' ...'. This suggests it may be an explicit reliability metric such as percentage of time of constrained generation.
Zonal or nodal	The model is zonal, however, the zone is not defined. As noted in Section 4, the submission states: '…a level somewhere between the ANTS zones and the node would appear to be appropriate. The work of AEMO in examining the national flow path may lead to a number of appropriate zones, likely in excess of the number of ANTS zones.'
Modelling assumptions	The LYMMCo submission acknowledges that the metric is related to the modelling assumptions, but does not provide a definitive set of assumptions. It does however appear to indicate that a deterministic approach is assumed, and provides an example of what the assumptions could be: • Generation dispatch – it is not clear, but appears to be all generation available and economic dispatch. • Demand – 10% PoE maximum demand, however it is not clear whether this is system, regional or zonal. • Network – n-1, which we assume must mean a single credible contingency (e.g. a single transformer or single circuit).

The LYMMCo submission notes a number of matters associated with the implementation, as follows:

- For existing generators, their level of access would be defined via their registered capacity. For generators where this is already defined in their existing connection agreements, registered capacity would be maintained. For other generators, registered capacity to would be set based on their historical access level. It is worth noting that this may affect the setting of the standard in each zone, and whether a consistent standard can be achieved between zones.

- New entrants (or existing generators requiring increased capacity) would be able to register capacity up to the limit set by standard. In cases where their registered capacity would breach the standard, the generator would need to accept that this additional level of registered capacity cannot be met until a transmission augmentation is in place, or a suitable existing generator is retired[17].

It is not clear from the submission how enhanced standards would be achieved.

5.5.2 International Power

Table 4 - International Power model summary

Metric	There is a capacity metric defined as x MW (i.e. x MW should be unconstrained under the modelling assumptions).
Zonal or nodal	The model is nodal — essentially the standard applies to each generator.
Modelling assumptions	The International Power submission acknowledges that the metric is related to the modelling assumptions, but does not provide a definitive set of assumptions. It is clear that this is following a deterministic approach, using n-1 or n-2 network conditions. However, the relevant generation dispatch assumptions, required to undertake this assessment, are not discussed.

The International Power submission notes a number of matters associated with the implementation, as follows:

- The International Power submission discusses an 'elective' standard, whereby the generator can nominate their registered capacity, which defines the level of access it must be provided under the modelling assumptions.
- The submission also includes some operational considerations, so that when congestion occurs, generators must reduce their available generation to their registered capacity level.
- Enhanced access is achieved by a generator nominating a more onerous set of modelling assumptions. The example given is a move from an n-1 condition to an n-2 condition.

It is not clear from the submission how the initial standard would be set-up, particularly in circumstances where generators are already exposed to congestion. It is also not clear how the enhanced standard would by applied through the dispatch process.

[17] The submission notes that such a retirement could be incentivised via payments from the new generator.

5.6 Transmission reliability standards review

As part of this assignment, Hill Michael undertook a limited review of selected electricity markets to determine whether there were existing transmission reliability standards that were relevant to the development of a TRS-G model for this assignment.

Hill Michael has undertaken a review of publicly available information for Ofgem in Great Britain; Alberta in Canada; Pennsylvania Jersey Maryland (PJM) in the US; and Western Australian Energy Market (WEM) in Western Australia.

Please refer to Appendix 3 for research notes and a summary table of the findings.

5.6.1 Ofgem, Great Britain

The current regulatory regime in Great Britain allows a certain level of congestion, described as a ‘connect and manage’ model.

Under this arrangement, generators request a desired level of access. The generators can connect to the grid — once the required connection works are complete — with shared network to be completed at a later date, as determined by the transmission authority.

This has provided quicker access to the market for generators wanting to connect, compared to the previous regime where generators had to wait until shared network augmentation works were completed to facilitate access of full capacity to the market. The access model is implemented at a nodal level on the basis of the access level sought by the generator. The connect and manage model is transparent, as the criteria for providing access is set out in the prescribed planning criteria.[18]

5.6.2 PJM, United States

PJM’s approach to assessment of reliability for generation is driven by system requirements, rather than the requirement or intention to provide a certain level of firm access to the generators. The generators may secure firm allocation of supply through financial transmission rights. There is no obligation on the part of PJM to provide firm allocation of capacity to connecting generators.

PJM has developed metrics to assess reliability of supply to load, referred to as the ‘deliverability test’. The metrics used in the deliverability test are a combination of power transfer (MW) and energy transfer (MWh). These metrics are evaluated in a

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[18] Source: National Electricity Transmission System Security and Quality of Supply Standard, version 2.1, March 7, 2011.

Section 4 of this document presents the planning criteria for the Main Interconnected Transmission System (MITS). The MITS is designed to standards specified in this chapter; the MITS can be designed to higher standards, provided the higher standards can be economically justified. Guidance on economic justification for planning the MITS is given in Appendix E.

combination of zones, sub-zones and geographic areas suitable for technical analysis.

The form of the metrics used by PJM is similar to that proposed in this paper. However, PJM's assessment is system-driven, whereas the intention of the model options considered in this report is to provide individual generators with greater level of certainty of access, through a reliability standard applied on a nodal basis.

5.6.3 Alberta, Canada

Alberta plans its transmission on the basis of energy transferred; there is a performance target for the grid of 100% energy transfer under normal conditions that requires that all anticipated in-merit generation to be capable of being dispatched without constraint.

The metric used in Alberta is energy transfer (MWh) and the measure of congestion is at a system level. There is no explicit mechanism for generators to request firm access. The incentive to provide firm access for the transmission authority stems from the requirement to compensate generators that are unable to deliver their energy to the market due to transmission congestion.

5.6.4 Western Australia

The current requirement in Western Australia to plan transmission for n-1 conditions under all generation scenarios means that, in principle, new generators are not able to access the market until the required shared network augmentation works have been completed.

It appears that the current planning requirement may have led to over-investment in transmission. It has also resulted in the decision to employ run-back schemes for certain generators as a way of facilitating earlier access to the market.

For example, generators with lower capacity factors, such as wind farms, require transmission investment to cater for maximum output generation scenarios, however these wind farms may not be operating at full output, leading to inefficient investment in the network.

6 Implementation of Preferred Option (Option 4 with Nodal Approach)

The following section provides further commentary on important matters associated with the implementation of such a standard, namely:

- assessing compliance to the standard
- accommodating new entrants
- interaction of existing load-driven transmission planning, including transmission reliability standards for load.

6.1 Assessing compliance to the standard

As discussed in Section 5.1, we do not consider that the effort to implement these standards should differ greatly between the various metric options, but the effort will increase as more complex modelling assumptions are allowed for within the standard.

That said we believe that the notional form of analysis should not generally change, involving some form of network and market modelling to assess whether compliance would be breached in the future.

To aid in the appreciation of this analysis, Table 5 provides an overview of the basic analysis steps we consider that a TNSP would need to undertake in order to assess compliance with TRS-G for a new entrant at the proposed time of connection.

Table 5 - Steps for assessing TRS-G compliance

Step 1	Determine the appropriate inputs to reflect: • demand conditions (e.g. the forecast profile for the 10% PoE maximum demand) • network model (e.g. the transmission network reflecting the time of connection) • market model assumptions (e.g. SRMC for each generator and capacity scales, outage rates if applicable).
Step 2	Undertake an unconstrained market simulation to determine the unconstrained dispatch of generation.
Step 3	Undertake network modelling using the dispatch patterns provided by the market simulation to determine whether any network limitations will be breached under n-1 contingency conditions. Such analysis may include load flow and stability analysis, if necessary. These studies should be very similar to the power system studies TNSPs will be required to undertake as part of their normal annual planning process.
Step 4	Assuming a constraint has been determined and it is clear that a breach of a standard may occur over the planning horizon, undertake further power system studies to develop the appropriate constraint equations for the market modelling software. Note that it may well be the case that appropriate constraint equations are already available, and if so, this step may not be required.
Step 5	Rerun the market simulation, allowing for the constraint equations developed in step 4.
Step 6	Calculate the maximum constrained capacity and level of constrained energy from the outputs of the market simulation.
Step 7	Determine whether these levels still achieve compliance with the standard.
Step 8	Assuming a standard has been breached, further planning studies will be required to determine the amount of additional network capacity required, and least cost option for providing this capacity, to ensure compliance with the standard will be maintained. See Section 6.3 for further discussion of the interaction with transmission reliability standards for load.

It is worth noting that the forms of analysis discussed in Table 5 should not differ greatly from that required to undertake market benefits analysis under the existing rules (i.e. requiring a mix of market and network modelling). Nevertheless, given that the shared network will need to be augmented for a breach of a standard, it will be important to integrate the planning of the capacity upgrade within the normal planning processes to ensure the efficient development of the network. The interaction of these standards with load standards discussed further in Section 6.3.

6.2 New entrants

Accommodating new generation entrants through a TRS-G model may result in two main challenges:

- the approach for dealing with multiple prospective new entrants prior to firm commitment to connect
- the approach for dealing new entrants following a firm commitment to connect.

These two matters are discussed in the following sections.

6.2.1 Multiple prospective new entrants

The first challenge concerns the approach for dealing with multiple prospective new entrants making enquires as to the costs associated with connection. This matter is not new, and effects current planning requirements of the TNSP. Nevertheless, it appears that the TNSP's obligations to plan to the TRS-G will make this task more difficult.

For example, there may be circumstances where two generators are making enquires where either one will result in a breach of the specific standard, but the required project may differ depending on whether one or two connect; or neither will result in a breach on their own but together a breach will occur.

Under the existing arrangements, the onus is on the prospective generator to assess the likely level of constraint, accounting for its knowledge of other prospective developments and the TNSP's stated plans. The TNSP may be involved in this analysis, but does not have to disclose the other party's plans. In effect, the TNSP is concerned with the shallow connection costs.

Under a TRS-G regime, it may be more difficult to plan under these circumstances as a TNSP will need to determine the appropriate shared network augmentations required to avoid a breach of the TRS-G. Informing individual parties of these augmentations may require other prospective connections to be disclosed also. However, for commercial reasons, the TNSP is likely to be bound by confidential obligations involving the various parties, making such discussions difficult.

Under worst case conditions, were each prospective new entrant to be considered separately, this may mean that the transmission works (or connection costs) attributable to a new generator could be highly variable, depending on the time it makes a commitment to connect (i.e. if it is first or last to make a decision). It could also be that inefficient transmission developments occur, due to the 'piecemeal' nature of the developments. Mechanisms to deal with this issue were outside the scope of this review, being mainly regulatory and legal in nature.

6.2.2 New entrants following commitment to connect

The second challenge concerns the approach to deal with an anticipated breach of a standard that may result from a new entrant connecting at a specific location. This issue is foreshadowed in the AEMC directions paper[19] and largely relates to differences in lead times that can occur between generation developments and transmission developments. In this regard, the time between a generator making a firm commitment to develop, and the time taken to enter service is potentially much

[19] Pg 29 and 30 of the AEMC directions paper.

shorter than the time it takes the TNSP to plan and develop a major augmentation following this commitment[20].

This poses a challenge for planning to a TRS-G as the generator may be in a position to connect prior to the transmission augmentation required to ensure compliance with the TRS-G is in service.

Table details the four options that could be applied to allow for these circumstances.

Table 6 - Options for managing transmission augmentations for new connections

Option 1	No connection allowed until transmission augmentation is in service (or a suitable generator retirement occurs).
Option 2	Connection allowed, but at reduced output to ensure compliance until transmission augmentation is in service (or a suitable generator retirement occurs).
Option 3	Connection allowed, with duration defined to achieve compliance.
Option 4	Transmission network planned to comply to agreed generation development scenario(s).

The first two options have the advantage of protecting access certainty, at least for incumbent generators, with access certainty being a guiding principle of the standard. Conversely, the third option provides greater certainty of access to the new entrant. This advantage in access certainty for one party is likely to be at the expense of the certainty provided to the other party. Given the fact that new entrants have more information on incumbents than the reverse, option 3 may pose a greater overall disadvantage in this regard.

Furthermore, this lack of certainty also relates to the possibility of delays in the timing of the transmission augmentation. Such delays could result from the TNSPs actions, but they could also relate to matters beyond the TNSP's control, such as disputes in the TNSP development plans raised by the incumbent or new generators (depending on which party may gain from the delay). That said the probability of such delays could be minimised through the use of appropriate incentive mechanisms for the TNSP, and a robust planning and dispute resolution process.

The second option would be more complex to implement as operational rules may need to be set up in the NEM Dispatch Engine to control when a generator's output should be restricted. However, we consider that such a mechanism would not be overly complex to achieve, and that this additional complexity is not significant enough to outweigh the advantages of allowing immediate connection with reduced

[20] For example, a peaking plant may have a lead time in the order of two years, but a major transmission line development may require up to five years.

access. It is also worth noting that such an operational mechanism was discussed in the LYMMCo submission to the AEMC framework review.

The fourth option would provide a moderate level of access certainty to all parties as there would be a greater likelihood that capacity would be added in anticipation of the new entrant. Although, in certain circumstances (e.g. when the assumed development scenario differs from the actual outcomes) reduced access for specific generators (incumbent and new) could still occur. In these circumstances it may be the case that one of the other three options must still be implemented to regain compliance. It would also appear that such an approach would be far more likely to lead to unneeded capacity being developed or developed early, the cost of which would most likely need to be covered by load customers. As such, the advantages of this option are most likely outweighed by the disadvantages.

Based on the above, there does not appear to be a clear preferred solution from a technical perspective. However, option 2 may well strike the best balance between incumbents and new entrants. However, any final decision on this matter is likely to require more detailed consideration by the AEMC, particularly the risks to the various parties, how these risks would affect their costs, and how they can be minimised.

6.3 Interaction with transmission reliability standards for load

Within the meshed transmission system, operation to ensure a network limitation is not breached (e.g. the thermal rating of a line) can often result in both load shedding and constrained generation.

Given transmission reliability standards for load concern the allowable level of load shedding, and standards for generation concern the allowable level of constrained generation, there is obviously the potential for some interaction when planning to ensure compliance to the two standards — or even the market-based approach applied in Victoria.

In appreciating the implication of this, it is important to understand that planning the development of the transmission network to various standards (or obligations) is normal practice for a TNSP, and often there will be some overlap between future network needs driven by different standards. For this reason the transmission network is planned over a relatively long planning horizon. In this way, future breaches of any standard can be determined over the planning horizon, so that an optimal development plan can be prepared to ensure compliance is maintained.

We see no reason that the introduction of a TRS-G model should result in issues relating to the interaction with TRS for load that cannot be resolved through the current planning processes.

For example, consider the case where there are two different network limitations for which future demand and generation developments will result in the same generator being constrained and involuntary load shedding at a single load centre, under n-1 and peak demand conditions.

It is often the case that a TRS for load will be breached at different times due to the different network limitations. The planning task aims to ensure the network development selected is optimised with any potential future breaches — and with the value of constrained generation if relevant — to ensure compliance is maintained. This can mean that the timing is set by the first breach of the standard, but the optimal additional transmission capacity may be the capacity required to relieve both network limitations, as well as reduce the level of constrained generation.

In the case of TRS-G, this simply becomes another planning criteria that the need, timing and solution would be assessed against. Using the example above, assuming that the breach of the generation standard occurred after the load, then it may be that the optimal additional capacity required to ensure compliance with the load standard is still sufficient to ensure compliance with the generation standards. Alternatively, if the breach of the generation standard occurs first, then the optimal additional capacity may be sufficient to allow for the future breach(es) of the load standard. In other cases, a more piecemeal solution may be optimal.

We believe that analysis of these interactions will be guided to an extent by the cost allocation principles applicable to TRS-G. For example, assuming that the customers will be allocated the costs associated with any additional capacity that provides them with a net benefit under the existing RIT-T, the costs attributable to the generator may be only the ‘brought forward’ costs of the load-only-related development plans, minus any additional net benefits due to the development.

It is worth noting that, although we do not consider there to be major technical issues associated with undertaking this type of analysis, there may well be increased levels of oversight and negotiation on the planned developments by generators aimed at minimising costs allocated to them. This may require increased oversight by other parties to ensure customers are not unfairly treated in this regard.

7 Conclusions

Based on the information and conceptual analysis contained within the scope of this assignment date, our preferred model option is:

- a nodal standard
- based upon a combined energy metric (i.e. a maximum level of constrained energy specified as a percentage of total energy output) and a capacity metric (e.g. peak demand)
- to be measured, assuming:
  - a demand profile based on 10% PoE maximum demand conditions, focused on the peak demand period
  - n-1 network contingencies
  - all generators available, but scaled to allow for the most likely available capacity
  - SRMC bidding.

Assessment would be carried out over typical transmission planning horizons (e.g. as for application of load reliability standards).

Given our assignment is only conceptual and no quantitative analysis has been performed, we still consider that alternatives may be found to be the preferred options.

In particular, this relates to:

- whether a simplified approach to the market modelling could be determined such that a capacity metric may be more suitable
- whether a zonal standard may be more appropriate and, if so, what this zone should be
- whether more complex modelling assumptions should be defined to allow for the modelling of planned and forced generator outages, different bidding approaches and alternative demand scenarios.

The final decision on the option, and the detailed specification of the standard, may not be possible without considering these matters within the context of an evaluation of the different options to address access (including the option of maintaining the status quo), and the relationship of this approach with other matters under review, particularly congestion management and transmission planning.

For example, deciding the best value for setting the standard (and the relationship this will have to the specific modelling assumptions) will require some rigorous analysis and potentially include power system and market modelling over at least a 10-year horizon under a range of network, demand and supply development scenarios in order to fully appreciate the likely level of transmission investment needed to maintain compliance with a standard.

It is also important to note that, in appreciating this advice in the context of existing TRS for load, future compliance will need to be assessed in the context of uncertainty in future generation developments. It may be unavoidable that some form of scenario analysis will be required to address this matter.

Such analysis is not a difficult task to undertake, and is part of the existing processes used to undertake market benefits analysis under the RIT-T. However, the task of defining how this must be undertaken in the context of deterministic standards such that a simple compliance test can be performed is not trivial, and it is unlikely that planning to TRS for generation can be as transparent as planning to TRS for load[21].

Finally, it is worth stressing that the suitability of such standards to the task required (including the ability to reduce the risk of inefficient transmission investment and allow transmission augmentation costs to be appropriately allocated) is strongly related to other considerations, particularly congestion management and associated incentive schemes, general transmission planning arrangements and the overall regulatory framework. For example, the model should not result in augmentations becoming a de facto method of reducing congestion when operational considerations may well provide a more efficient approach.

It is noted that the extent of the improvement in these factors will drive the approach to a TRS-G model, as the pursuit of a full and unconstrained market will lead to a different TRS–G model than if the objective is to create a marginal improvement in liquidity and investment certainty.

It is also noted that government policy, particularly in relation to carbon pricing and the Renewable Energy Target (RET), will result in changes in generation mix over time, and this will require further consideration in future detailed assessments of the TRS-G.

Although we have discussed some contextual issues relevant to the introduction of such standards to guide our development and evaluation of options, these broader considerations were not part of the scope of this assignment. Additionally, the time constraints on this assignment were not sufficient to allow these matters to be given any significant consideration. Consequently, the AEMC must not assume that the discussions of these matters within this report constitute a thorough and complete review, and we expect that any full evaluation will require detailed research and analysis.

[21] When assessing compliance for load standards, scenario and sensitivity analysis is often not included (or at least reduced) through appropriately defined modelling assumptions. This allows a relatively transparent compliance test to be defined. In our experience, it is when assumptions of this nature are not appropriately specified within the TRS for load, there is a lack of transparency in their application.

Appendix 1 – Glossary

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
ANTS	Annual National Transmission Statement
ERA	Economic Regulation Authority
ISO	Independent System Operator
LYMMCo	Loy Yang Marketing Management Company
NEM	National Electricity Market
NEO	National Electricity Objective
NDTDP	National Transmission Network Development Plan
Ofgem	Office of Gas and Electricity Markets
PJM	Pennsylvania Jersey Maryland
PoE	Probability of exceedance
RET	Renewable Energy Target
RIT-T	Regulatory Investment Test for Transmission
SRMC	Short Run Marginal Cost
TNSP	Transmission Network Service Provider
TRS	transmission reliability standards
TRS-G	transmission reliability standards for generators
WEM	Western Australian Energy Market

Appendix 2 - Summary of Evaluation of Model Options

This appendix summarises the evaluation of the various model options, discussed in more detail in Section 5. The summary is presented in the form of two tables; Table 7 compares the four metric options Hill Michael has developed against the evaluation criteria defined in Section 4.4, while Table 8 compares the zonal or nodal model options against the evaluation criteria.

In the two tables, each option is ranked against the individual evaluation criteria in terms of highest and lowest, where *highest* reflects our view that the option presents the greatest benefits and *lowest* reflects our view of that the option presents the greatest challenges.

Table 7 - Evaluation matrix for metric options

	Metric			
Evaluation criteria	**Capacity**	**Time**	**Energy**	**Energy + Capacity**
Ease of implementation				
Transparency	Similar level of transparency			
Ease of introduction	Similar effort to introduce			*Lowest* Greatest level of effort to introduce as two parameters will need to be determined, but unlikely to be significant additional effort.
Ease of application	*Highest* Least effort to apply, but unlikely to be significant.	Similar effort to apply		
Achievement of objectives				
Provide reliability of access	*Moderate* Weak relationship to overall reliability, but strong at peak period.	*Lowest* Moderate relationship to overall reliability, but weak at peak period.	*Moderate* Strong relationship to overall reliability, but weak at peak period.	*Highest* Strong relationship to overall reliability and congestion at peak period.
Consistency of standard	No difference in consistency			
Unbiased between generators	*Moderate* Moderate correlation to scale of generation, but may favour base load plant.	*Lowest* Poor correlation to scale of constrained generation.	*Moderate* Good correlation to scale of constrained generation, but may favour peaking plant.	*Highest* Minimises biases between different types of generators
Risk of inefficient network investment	*Moderate* Moderate risk of inefficient network investment.	*Lowest* Highest risk of inefficient network investment.	*Moderate* Moderate risk of inefficient network investment.	*Highest* Least risk of inefficient network investment.
Ability to define higher or lower standards	No difference in ability to define higher or lower standards			

Table 8 - Evaluation matrix for zonal or nodal options

	Form of standard	
Evaluation criteria	**Zonal**	**Nodal**
Ease of implementation		
Transparency	Similar level of transparency	
Ease of introduction	*Highest* The lower number of standards is likely to result in less effort to introduce	*Lowest* The greater number of standards is likely to result in more effort to introduce
Ease of application	*Highest* The lower number of standards is likely to result in less effort to apply.	*Lowest* The greater number of standards is likely to result in more effort to apply.
Achievement of objectives		
Provide reliability of access	*Lowest* Less certainty of access for individual generators, as it will only reflect aggregate levels of access across all generators within a zone.	*Highest* Should provide a defined level of reliability of access for individual generators.
Consistency of standard	*Highest*	*Lowest* Greater possibility that a consistent set of standards cannot be achieved.
Unbiased between generators	*Lowest* Possibility that only a small proportion of generators within the zone may suffer the majority of congestions. Also, smaller generators may suffer very high congestion relative to their size. On the other hand, compliance may be less sensitive to new entrants.	*Highest* Minimises biases between different types of generators
Risk of inefficient network investment	No significant difference	
Ability to define higher or lower standards	*Lowest* It will not be possible to define higher or lower standards for individual generators directly through the standard.	*Highest* Should explicitly allow generators to elect higher or lower standards of access reliability.

Appendix 3 – Review of TRS in National and International Context

Research Notes and Summary Table

The following research notes are provided for background information, based on Hill Michael's high-level investigation and information available in the public domain. This review of other jurisdictions should be read as informal research, and while materially accurate only aims to provide a general overview and comment of alternative approaches to managing access to the network and market for generators.

Great Britain (The region governed by Ofgem)

The previous regime of transmission access for new generators in Great Britain had been governed under an 'invest then connect' (I&C) regime, whereby new generators are required to wait until wider network reinforcements are completed in order to meet planning criteria before being permitted to export electricity onto the grid. Network access has also typically been granted on a 'first come, first served' basis, whereby generators in constrained regions must 'queue' for access based on the date at which they first applied for connection. This created a large timeframe for delays for connection of generators until augmentation to provide unconstrained access was completed. This was replaced by a 'connect and manage' (C&M) regime in 2010 which provides generators with firm access (full or partial) on the basis of MW capacity with generators paying an access payment. The nature of the firm access seeks to provide firm revenue access, rather than guaranteed dispatch of energy. This means that in the event that a generator's export is constrained down, it will receive compensation equal to its bid price in the Balancing Mechanism. The generators are compensated via a bid system if firm access has been secured and the generator is constrained off. It is envisaged that system operator having to compensate generators for constraint costs will incentivise the system operator to operate efficiently.

The government, based on a study[22] of congestion costs, has determined that the cost of additional transmission infrastructure will be in excess of the long-term congestion costs if transmission infrastructure is not built. In the short term, the cost of the C&M scheme will increase the cost of constraints but defer the cost of augmentation.

The congestion costs due to the previous I&C and the current C&M regime were simulated. The two scenarios for congestion costs simulation are:

- the I&C regime in which new generators are only connected once the grid is fully capable of accommodating them via both local and wider network reinforcements
- the C&M Socialised regime, an enduring version of the current Interim C&M arrangements, in which new generators are connected as soon as their local works can be completed and any constraint costs they impose on the network are socialised across all users.

I&C minimises constraint costs, thus reducing costs to consumers, but at the same time delays the connection of new generation which is necessary to deliver the government's renewable energy targets. The C&M Socialised model delivers accelerated connections at the cost of increased network congestion and constraint costs, although with an offsetting benefit in terms of reduced

[22] Improving Grid Access – A report for the Department of Energy and Climate Change (URN 10D/549) – issued by Redpoint, February 2010.

wholesale costs. The other models considered would generally lead to outcomes that are intermediate between the two regimes.

National Grid has a set of criteria[23] to assess when and if the works are required and this will take into account avoiding excessive constraint costs. The National Electricity Transmission System Security & Quality of Supply Standard (SQSS). The SQSS is the main standard used to plan and operate the onshore and offshore transmission systems. The set of criteria will ensure that only generators with a reasonable chance of being dispatched will be offered firm access.

C&M means that a generator can connect once its 'enabling' (i.e. local) works are complete, with 'wider' (deep augmentation) works completed at a later date. The [24]criteria for determining the extent of 'enabling works' are based on a subset of Chapter 2 of the SQSS and the wider deep augmentation works criteria are covered in Chapter 4 and Appendix E.

The transmission company will deliver the reliability criteria set out as part of its licence obligation, however OFGEM has the provision to provide exemptions for a level of transmission service higher or lower than what is set out in the deterministic rule in the planning criteria. This derogation is probably to balance the requirement of over/under investment in the system and to take into account atypical scenarios where this consideration is required.

There are two major weaknesses of this C&M model; one is that market power can be exercised by generators depending on their relative contribution to a constraint. The second is that the scheme does not distinguish between access provisions for peaking generators and base load generators. The combined power transfer (MW) and energy (MWh) proposed in this paper may be able to address the distinction between base load and intermittent or peaking generation better.

Pennsylvania Jersey Maryland (PJM)

PJM provides a system which manages access for generators through the planning criteria. The PJM system provides more explicit guidance than the Great Britain market providers to the generators as to where they can connect by mandating that unless a generator passes the generator deliverability test, the generator is not entitled to revenue from PJM's capacity market. The deliverability test guarantees a generator the status of a 'certified' capacity resource[25] with respect to the installed capacity obligations imposed under the Reliability Assurance Agreement. Deliverability ensures that PJM can be operated within applicable reliability criteria and, guarantees within those criteria that regional load will receive energy, with no guarantee as to price, from the aggregate of capacity resources available to PJM.

A brief description of deliverability test for generators and loads is given below.

<u>Generation Deliverability Analysis</u>

The generation deliverability tests the ability of an electrical area to export capacity resources to the remainder of PJM. This would require that each electrical area be able to export its capacity, at a minimum, during periods of peak load.

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[23] National Electricity Transmission System Security and Quality of Supply Standard, Version 2.1, March 7 2011.

[24] Section 13.1 & 13.2 - Improving Grid Access – Department of Energy and Climate Change (URN 10D/723), issued 27 July 2010.

[25]A certified capacity resource is eligible to receive installed capacity market revenues, PJM requires that the generator has to contribute positively to the deliverability test in order to receive capacity market payments.

Deliverability, from the perspective of individual generator resources, ensures that, under normal system conditions, if capacity resources are available and called on, their ability to provide energy to the system at peak load will not be limited by the dispatch of other certified capacity resources. This test does not guarantee that a given resource will be chosen to produce energy at any given system load condition. Rather, its purpose is to demonstrate that the installed capacity in any electrical area can be run simultaneously, at peak load, and that the excess energy above load in that electrical area can be exported to the remainder of PJM. Unless the generator is able to meet the deliverability test, the generator is not entitled to capacity payments.

Load Deliverability Analysis

The metrics used to measure the deliverability capability are the Capacity Emergency Transfer Limits (CETL) and the Capacity Emergency Transfer Objectives (CETO). PJM has developed testing methodologies to verify compliance with each of these deliverability requirements.

A CETO represents the amount of energy that a given sub-area must be able to import in order to remain a certain reliability level. A CETL represents the ability of the transmission system to support deliveries of energy to an electrical sub-area experiencing such a capacity emergency. Providing that the CETL for a given area exceeds the CETO for that area, the test is passed and, on a probabilistic level, the area will be able to import sufficient energy during emergencies. The transmission system is tested at a reliability level so that the transmission risk does not appreciably diminish the overall reliability target PJM. The metrics are evaluated in a combination of zones, sub-zones and geographic areas.

Failure of deliverability tests is one of the triggers to the expansion planning process. Failure of deliverability tests brings at least two different possible consequences. When evaluating a new generation, if the addition of the resource will cause a deliverability deficiency then the new generator cannot be granted full capacity credit until system upgrades are completed to correct the deficiency. Failure of deliverability tests may result in a sub-area being unable to receive full capacity credit for remote capacity resources delivered to that sub-area.

The weakness of this system lack of deliverability in a region can lead to creating smaller and less competitive local areas which can significantly raise costs to customers and undermine the reliability of the network. Lack of deliverability can also prohibit remote generation sources from being used to serve load throughout a region.

The combination of power transfer (MW) and energy (MWh) is the closest to the system proposed in this paper. The key difference is that, for the proposed model in this report, generation receives firmer access on a nodal basis, with the aim to provide assurance to generators of being able to get their capacity and energy to the market, whereas the PJM model is driven by the requirement to provide system security and reliability. The deliverability metrics are based on zones, sub-zones or other areas developed to suit technical transmission planning analysis in PJM and not specifically on a nodal basis for individual generator connection points.

Alberta, Canada

[26]Alberta's Independent System Operator (ISO) plans its transmission on the basis of energy transferred. The target performance for the grid is to achieve 100% energy transfer under normal conditions (100% of the time, transmission of all anticipated in-merit electric energy referred to in section 17(c) of the Act [27]) and 95% transfer during contingency conditions. The Alberta transmission system measures congestion at a system level, which is different from providing firm access for specific generators on a nodal basis.

The open access transmission structure in Alberta consists of an implicit system that requires the ISO to proactively plan transmission development to achieve this result of 'congestion-free' transmission. The ISO will be required to ensure that the transmission system is appropriately reinforced so that under normal operating conditions (i.e. all transmission facilities in service) all in-merit generation can be dispatched and virtually all economic wholesale transactions may be realized without congestion or constraints.

The disadvantage of the planning criterion is that it is likely that there will be demand for transmission expansion for which the costs outweigh the benefits, which may result in a transmission system that has an inefficient mix of generation and transmission, leading to a higher-than-necessary cost of delivered electricity.

Western Australian Energy Market (WEM)

Western Australia provides mandated firm transmission allocation on the basis of installed capacity (MW) of generators. The Technical Rules[28] in the WEM stipulate that the transmission system must provide unconstrained access to generation. Therefore, transmission capacity planning is undertaken with all generation in a given area being run at full output, including generators with intermittent output and low capacity factors.

The requirement to plan transmission for n-1 conditions under *all* generation scenarios means that there is a likelihood of compliance breach if generators connect prior to deep augmentation works being completed by the transmission entity to provide congestion free access. The deep augmentation costs are funded by the generation proponent. The generators often do not wish to pay for unconstrained access, as there can be a first mover disadvantage[29], so the practical solution to maintain compliance and allow the connecting parties to reduce connection costs has been to implement run-back schemes or constrain output until works are complete.

Shared Transmission investment has to be justified under an economic test[30]. The generator proponent funds the difference in cost between the economic outcome and the cost of the proposed augmentation.

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[26] Refer to section 15(1) – Part 3 Electric Utilities Act – Transmission Regulation Alberta Regulation 86/2007 – Province of Alberta.

[27] Section 17(c) of the Electric Utilities Act was unable to be located.

[28] Technical Rules – Western Power - Issued 26 April 2007. (Note: The clauses refer to refer to any generation scenario or any credible generation scenario under the network performance of the grid clauses 2.3.7.1a, N-1 criteria for planning 2.5.2.2b and 2.2.11b of the Technical Rules).

[29] There is some rebate available to the first mover of the amount of difference between the outcome of an economic test and the capital augmentation cost if the long term economic efficiency is proved or if other participants share the benefit of the connection in the future.

[30] New Facilities Investment Test (NFIT)

In the WEM, if a generator is unable to access the market due to transmission constraints, the constrained generators are compensated for the opportunity cost.

The Economic Regulation Authority (ERA) in Western Australia has an ex-post system of revenue reset for investment, which means that there is a high risk for the transmission company if assets are stranded, therefore the transmission asset owner will not take the risk of broad augmentation without guaranteed connection.

The theory of unconstrained access in Western Australia was to ensure that an isolated power system such as Western Australia can securely meet load with minimal generation. A second reason was that generally, it is cheaper to overinvest in transmission rather than invest in generation, particularly due to potential fuel constraints/costs. The majority of the generation in Western Australia is coal or gas with renewable generation being added to the mix recently.

The present queuing system[31] for connection in Western Australia requires that generator connection be assessed in the merit-order they had requested connection, which is not necessarily in the order of timeframe requested. In addition, generation with existing connection access has rights to the capacity even if the generators have been de-commissioned. The connection access can also be transferred by proponents of generation development to other parties at any stage.

There are a number of issues for generation access that has prompted a pre-feasibility stage review of the current transmission planning regime in Western Australia. The drivers for this review are:

- Possible overinvestment in networks
- High level of wind penetration in the network
- Disincentive for new generation entrants into the market due to the deep augmentation costs, which is compounded by the fact that existing generation can re-build or hold onto its unconstrained access as long as access charges are being paid
- Number of run-back schemes with potential to create conflict in control for the system operator and compromise the security/reliability of the system.

[31] Applications and Queuing Policy – Western Power

Table 3.1 - Summary table

Transmission Entity	Regulator	Reference	Relevant Criteria	Notes
Western Australia - Western Power, Australia	Economic Regulation Authority (ERA)	Electricity Industry (Network Quality and Reliability of Supply) Code 2005. Technical Rules – Western Power - Issued 26 April 2007.	N-0, N-1, N-1-1 criteria, customer/load security supply must be maintained and load shedding avoided at any load level and for **any** generation schedule Technical Rules – Western Power - Issued 26 April 2007. *(Note: The clauses refer to refer to any generation scenario or any credible generation scenario under the network performance of the grid clauses 2.3.7.1a, N-1 criteria for planning 2.5.2.2b and 2.2.11b of the Technical Rules).*	Although not explicit in Western Australia's Access Code or the Technical Rules, the Technical Rules stipulate that N-1 criterion (*clause 2.5.2.2b)* has to be maintained under all generation scenarios. Unconstrained access to all generation based on installed capacity (MW) and on a nodal basis. Generators are compensated for being constrained off due to transmission congestion unless there is an agreement or through run-back schemes.
Alberta - AESO, Canada	Alberta Utilities Commission (AUC)	ELECTRIC UTILITIES ACT TRANSMISSION REGULATION, 2007 (http://www.aeso.ca/transmission/8875.html)	Refer to Section 15(1) – Part 3 Electric Utilities Act – Transmission Regulation Alberta Regulation 86/2007 – Province of Alberta. (e) taking into consideration the characteristics and expected availability of generating units, plan a transmission system that (i) is sufficiently robust so that 100% of the time, transmission of all anticipated in-merit electric energy referred to in Section 17(c) of the Act can occur when all transmission facilities are in service, and (ii) is adequate so that, on an annual basis, and at least 95% of the time, transmission of all anticipated in-merit electric energy referred to in Section 17(c) of the Act can occur when operating (f) "make arrangements for the expansion or enhancement of the transmission system so that, under normal operating conditions, all anticipated in-merit electricity referred to in clause (e)(i) and (ii) can be dispatched without constraint"	Source: NERC/WECC Planning Standards - NERC Planning Standards with additional requirements specific to the WECC There are no explicit transmission rights for the generator, however the planning guidelines are explicit in the requirement in planning for an unconstrained network. Hill Michael is not aware of any firm rights issued to generators.

Transmission Entity	Regulator	Reference	Relevant Criteria	Notes
Great Britain – National Grid	Office of Gas and Electricity Markets (OFGEM)	Transmission System Security and Quality of Supply Standard, Version 2.1, March 2011. Section 13.1 & 13.2 - Improving Grid Access – Department of Energy and Climate Change (URN 10D/723) Issued 27 July 2010.	The National Electricity Transmission System Security & Quality of Supply Standard (SQSS). The SQSS is the main standard used to plan and operate the onshore and offshore transmission systems. The set of criteria will ensure that only generators with a reasonable chance of being dispatched will be offered firm access.	Generation can seek firm capacity allocation up to the desired level of installed capacity. Capacity is allocated on the basis of power transfer on a nodal basis.
PJM, United States	NERC/FERC	Manual 14B: PJM Region Transmission Planning Process Section 2: Regional Transmission Expansion Plan Process Revision 17 13 April 2011	**2.3.9 Generation Deliverability Analysis** The generator deliverability test for the reliability analysis ensures that, consistent with the load deliverability single contingency testing procedure, the transmission system is capable of delivering the aggregate system generating capacity at peak load with all firm transmission service modelled. The procedure ensures sufficient transmission capability in all areas of the system to export an amount of generation capacity at least equal to the amount of certified capacity resources in each area.	PJM has developed deliverability metrics in terms of energy transfer for load and generation. *The metrics are evaluated in a combination of zones, sub-zones and geographic areas.*