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13 August 2009

Dr John Tamblyn
Chairman
Australia Energy Market Commission
Level 5, 201 Elizabeth Street,
SYDNEY NSW 2000

By email to submissions@aemc.gov.au

Dear Dr. Tamblyn,

AEMC Draft Report on Review of National Framework for Electricity Distribution Network Planning and Expansion

EnergyAustralia welcomes the opportunity to respond to the Australian Energy Market Commission (AEMC) Draft Report for the Review of National Framework for Electricity Distribution Network Planning and Expansion ('the Review').

EnergyAustralia agrees that there is a need to ensure efficient network planning and development by distributors across all regions of the national electricity market and, by doing so, also ensure a level playing field for non-network alternatives. Whilst robust economic assessment of alternatives, information transparency and inclusion of all interested participants are important aspects of achieving these aims, the resulting national framework also needs to be efficient and proportionate.

This submission is in two parts. Firstly, EnergyAustralia provides comments on the key aspects of AEMC's recommendations, namely the:

- annual planning process and requirements for a Demand Side Participation Strategy;
- proposed scope of the Distribution Annual Planning Report (DAPR);
- regulatory investment test for distribution investments; and
- arrangements for transitioning from jurisdictional arrangements to a national framework.

On the other two key aspects of AEMC's recommendations, being proposals for a dispute resolution regime and recommended areas of further reform, EnergyAustralia endorses the material contained within the Energy Networks Association(ENA) submission.

The second part of the submission provides a marked up version of the AEMC's draft Framework Specifications indicating the changes considered necessary to address the concerns we have raised.

Should you have any questions in relation to this submission please contact Ms Catherine O'Neill on 02 9269 4171.

Yours sincerely

Trevor Armstrong
Executive General Manager – System Planning and Regulation

Attachments
1. Comments on aspects of AEMC's recommendations
2. Draft Framework Specification – Annual Planning Process and Reporting Requirements
3. Draft Framework Specifications – Regulatory Investment Test for Distribution and Dispute Resolution Process

Attachment 1 - Comments on aspects of AEMC's recommendations

1. Transitional Arrangements

It is noted that the AEMC anticipates that the existing jurisdictional planning and reporting arrangements will fall away when the Framework for Distribution Network Planning and Expansion is incorporated into the Rules. The AEMC does not intend that DNSPs' be subject to regulation by more than one regulator at a time for the same activities.

We submit that there needs to be a sufficient period provided for the transition to and implementation of the new Framework.

It is also important to take account of the timing of existing reporting obligations that apply in the various jurisdictions. EnergyAustralia is currently required to report on many of the matters contained in the proposed new Framework in an Annual Electricity System Development Review report each June. EnergyAustralia requests that transitional arrangements ensure that DNSPs are not required to provide both the jurisdictional report as well as a DAPR report in the same year.

2. Annual Planning Process

2.1. Requirements of an Annual Planning process

> *The Annual Planning Process shall require [DNSPs] to, as a minimum, prepare forecasts, ….[and] identify system limitations on its network*[1]……

In the preparation of demand forecasts EnergyAustralia includes projects for major connection points, zone substations and other sub-transmission assets that are already committed and have already been subject to the regulatory investment test – distribution (RIT-D).

EnergyAustralia proposes that the draft Framework Specification should reflect this practicality and editorial changes are proposed to A.3(a)(i) and included in Attachment 2.

> *The annual planning process shall require each DNSP to prepare forecasts to the best of its ability, of maximum demands for distribution feeders…..and at a system level*[2]….

As part of the planning process "forecasts for the network as a whole" play no role. Hence EnergyAustralia queries the inclusion of this requirement in both the planning process and the planning report.

As a way of explanation, from a process point of view, planning the efficient operation and economical capital expansion of an electrical system involves anticipating future electricity demand, and *where* and when network augmentation will be needed. Such information is provided by a spatial load forecast, where demand location is one of the chief elements. Hence overall system capacity/load is not relevant to distribution system planning and, as such, EnergyAustralia suggests the removal of this requirement from the draft Framework Specification (Reference: A.3(a)(i) and A.6(b)(iii)).

EnergyAustralia also questions the drafting of requirements for distribution businesses to prepare demand forecasts, <u>to the best of its ability</u>. We concur with the AEMC's decision that no specific provisions are to be included in the Rules to stipulate how DNSPs should model the future and determine such forecasts. We also agree that DNSPs are better placed to determine how to plan and that incentives and obligations currently do exist for DNSPs to plan accurately.

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[1] AEMC, Draft Report for the Review of National Framework for Electricity Distribution Network Planning and Expansion ('Draft Report'), p.12.

[2] AEMC, Draft Report, p.12.

Placing detailed requirements on forecasting in the NER would also not be consistent with the principle of ensuring that the national framework is proportionate.

EnergyAustralia believes that the forecasting process at each level of the system should be appropriate and proportionate to the purpose of the forecast. EnergyAustralia supports the intent to not overly prescribe the forecasting process, however we are concerned that the use of the words “to the best of its ability” could be a source of dispute in regards to the approach taken in forecasting. In particular it implies disproportionate effort be required in forecasting, particularly at a distribution level, where demand growth is driven by the actions of individual customers which can not be accurately forecast more than 1-2 years in advance. It should be noted that the present planning process for distribution feeders does not involve annual forecasting for each section of distribution feeder (more than 30,000 sections of feeder) but instead is carried out on a cyclic basis every few years. This is a pragmatic and efficient approach. For this reason we suggest that the phrase is removed to avoid the forecasting process undertaken by DNSPs for distribution feeders being challenged as not being performed “to the best of its ability”. This proposed change has been made in Attachment 2, Indicative Framework reference A.3(a)(i).

….DNSPs would be required to prepare forecasts……after considering the level of embedded generation[3]*…*

Whilst recognising the intent of the proposed requirement to consider the level of embedded generation connected to the network in the preparation of forecasts, EnergyAustralia considers that the accuracy regarding the level of embedded generation for non-scheduled and unregistered generation including small-scale solar cells is low. Consequently, the availability of renewable energy is difficult to forecast. The intermittent nature of renewable forms of energy (such as wind and solar), means that it is difficult to accurately forecast the extent of generation at time of peak demand and cannot be relied upon to supply system demand. Hence this form of generation can not be relied on to defer network investment, as the contribution of this form of embedded generation at times of peak demand is not necessarily correlated. EnergyAustralia proposes a small amendment to clause A.3(a)(i)(3) of the Indicative Framework to reflect these practicalities.

[3] AEMC, Draft Report, p.12

2.2. Demand Side Engagement Strategy

Each DNSP would be required to use reasonable endeavours to engage with non-network proponents and consider non-network alternatives.[4]

EnergyAustralia supports a planning framework that requires consideration of non-network alternatives and concur that engaging with non-network proponents as soon as possible in the planning process could aid in identifying or developing these alternatives.

However, we are concerned that the assessment of whether 'reasonable endeavours' have taken place is a likely source of disagreement between DNSPs, the proponents of non-network solutions and possibly the AER. A DNSP cannot force engagement to occur, however, a DNSP can implement processes to enable engagement. As such, the obligation upon the DNSP should be to implement processes to enable engagement, essentially through a Demand Side Engagement Strategy. Hence, EnergyAustralia proposes the removal of the term "reasonable endeavours" and we have made this proposed change in draft Framework Specification reference A.3(d) included as Attachment 2.

DNSPs would also be required to establish and implement a Demand Side Engagement Strategy.[5]

In principle, the proposal contained in the Draft Report for a Demand Side Engagement Strategy is similar to EnergyAustralia's existing processes and as such can continue to operate with and complement other existing regulatory and commercial drivers.

However, some aspects of the required content of the *Demand Side Engagement Facilitation Process* document are difficult to provide in a meaningful or useful way, and in some cases can only be provided on a project basis. We provide more comments on this in response to the AEMC request below.

The AEMC seeks comments on whether the proposed content of the facilitation process document provides useful information and can be provided by DNSPs at reasonable cost.[6]

EnergyAustralia supports, in principle, the proposal for a Demand Side Engagement Strategy. Some aspects of the proposed content of the Facilitation Process document are difficult to provide in a meaningful or useful way and, as such, are overly prescriptive. These include the requirements to set out:

1. The process for negotiation with non-network proponents to develop potential solutions (Reference A.4(b)(iii));
2. Information required in proposals by non-network proponents (Reference A.4(b)(iv));
3. Criteria a proponent should meet or consider in any proposals (Reference A.4(b)(v)); and
4. Applicable incentive payment schemes and principles for developing payment levels (Reference A.4(b)(vi) and (vii)).

Process for negotiation with non-network proponents to develop potential solutions

We consider that it is possible to describe the process for negotiation with non-network proponents to develop potential solutions (clause 4(b)(iii)) in general terms in a *Demand Side Engagement Facilitation Process* document.

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[4] AEMC, Draft Report, p.14.
[5] AEMC, Draft Report, p.14.
[6] AEMC, Draft Report, p.15.

However, our experience has shown that the optimal method for procurement of non-network options can differ depending on the specific nature of network requirements. To allow an appropriate level of flexibility, EnergyAustralia considers that the Facilitation Process document should outline the process for engagement with non-network proponents in the development of potential solutions . Any detailed description of this process will be contained in the *Project Specification Report* stage (or any other document the DNSP publishes to consult with non-network proponents).

Information and criteria

EnergyAustralia does currently publish the information outlined in points 2 and 3 above. This material is published when the individual project specific documentation is published. This enables interested parties to identify alternative investment options or develop those so far considered by the DNSP. EnergyAustralia believes that because the information required in proposals by non-network proponents and the criteria any proposal must meet varies for each identified need, it is only possible to make very general statements about these aspects in the overarching Facilitation Process document.

Incentive payments

For similar reasons, only a very high level of information can be provided on payment arrangements. Payment arrangements are derived on a case-by-case basis from the estimated total cost of the preferred supply side option which is only determined once the options and cost analysis is complete. In fact, given that the aim of the network planning process is to seek out least-cost solutions, it is likely to be commercially imprudent to publish payment levels prior to receipt of proposals from non-network proponents.

We note the AEMC's views that these four aspects of the facilitation process document (outlined above) "would form the key components that non-network proponents would consider in preparing proposals".[7] EnergyAustralia contests that the information that is required to be included in the *Project Specification Report* by DNSPs (or any alternative DNSP project specific document or process used by DNSPs to aid in the identification and development of non-network alternatives) would in fact be the key component for consideration. Hence it is appropriate that the information contained in the process document be only included if useful or is available and kept at a high level.

EnergyAustralia proposes amendments to Clause A.4(b)(iii), (iv), (v) (vi) and (vii) to reflect these practicalities.

The AEMC seek comments on whether explicit protocols for the Demand Side Engagement Facilitation Process Document would be beneficial.[8]

As part of the Terms of Reference for the Review, the MCE required that the Review address a perceived failure by distribution businesses to consider non-network alternatives when making augmentation investment decisions.

EnergyAustralia does not dispute that the NER should provide a framework that requires a thorough and transparent consideration of Demand Management (DM) and other non-network options.

However, EnergyAustralia does not believe that the Rules should prescribe how investigations should be carried out. The reason for this view is that opportunities for non-network solutions

[7] AEMC, Draft Report, p.16.
[8] AEMC, Draft Report, p.16.

vary with circumstances and overly prescriptive obligations on distributors are not the best mechanism for encouraging the development of efficient non-network solutions.

EnergyAustralia considers that an efficient planning regime should result in DNSPs developing processes that are effective in terms of DM delivery and are cost-effective. The obligations placed on distributors should avoid requiring an unnecessary use of resources in circumstances that are least likely to provide non-network options. The less prescriptive approach, allows the development of a wider range of non-network alternatives at lower cost than would otherwise be achieved.

2.3. Joint Planning requirements

The Regulatory Investment Test for Transmission (RIT-T) should be applied to any investments identified through the joint planning process that affect both the transmission and distribution networks.[9]

The reasoning provided for this approach proposed by the AEMC is that the RIT-T requires "more rigorous reporting, consultation and assessment requirements" whereas DNSPs "have greater flexibility and discretion under the RIT-D", being required only to quantify any applicable market benefits where the DNSP considers it is appropriate to do so.

EnergyAustralia supports the flexibility proposed in the RIT-D to quantify any applicable market benefits where the DNSP considers it is appropriate to do so. Most of a DNSP's investments are driven by requirements to meet jurisdictional reliability standards and significant market benefits are unlikely. The same circumstances arise for transmission investments required to ensure that a distribution network meets the minimum power system security and reliability standards or to replace distribution assets. In contrast to the AEMC's position, EnergyAustralia considers that the Distribution Test should apply to transmission investments required to meet distribution objectives and the Transmission Test should be preserved for projects requiring joint planning where there is some likelihood that the augmentation will influence main transmission network and interconnector flows and thus have a material market effect.

If the proposal contained within the Draft Report is retained, there will be a difference in the cost threshold applied to the two regulatory investment tests; $2 million for the RIT-D and $5 million for the RIT-T. To address this issue, the AEMC has proposed that joint investments should be subject to the RIT-T threshold, which is currently $5 million.

EnergyAustralia is unclear about the following statement "for joint investments between $2 and $5 million, the RIT-T would still need to be carried out, however the projects would be exempt from the project specification and draft project assessment reporting requirements".[10] The RIT-D and RIT-T both comprise processes which culminate in an economic assessment. EnergyAustralia considers that if a decision is made that all transmission projects should be assessed by the transmission economic assessment process then the entire transmission process and thresholds should apply. EnergyAustralia does not believe a hybrid process involving parts of the transmission and distribution process is appropriate.

[9] AEMC, Draft Report, p.21.
[10] AEMC, Draft Report, footnote 82, p.77

3. Distribution Annual Planning Report (DAPR)

3.1. Objectives of the Annual Reporting

In outlining the purpose of the DAPR, the AEMC states that Regulators could use the information contained in the Annual Planning Report to understand the activities undertaken by distribution businesses.[11] The AEMC also considers that the annual reporting process could provide regulators with updated information on a more frequent basis and that this could assist the AER's five-year revenue determination processes. Further by publishing forecast information each year, the AER would have access to information on a more regular basis.[12] .

EnergyAustralia challenges this objective or purpose for the DAPR on the basis that the 5 year review carried out by the AER is extremely comprehensive and goes far beyond the depth of information presented in a DAPR. In addition, the AER requires DNSPs to provide annual information with respect to performance which includes data (some of a confidential nature) substantially in excess of the information which could be provided in a public planning document. As demonstrated by the consultation process commenced by the AER, the AER intends to publish a regulatory information order (RIO) under the NEL[13] setting out a nationally consistent framework for annual information reporting by DNSPs and the types of information requested are far in advance of the DAPR.

Whilst EnergyAustralia agrees that some planning data should be made available publicly to provide transparency and to inform demand side proponents and other interested parties, there is no justification for the AEMC to require publication of data for the AER. Any such public information will inevitably will not be in the content or format required by the AER and will unnecessarily duplicate information provided to the AER in accordance with the RIO. The AEMC's proposal on this matter is not effective or efficient.

3.2. Contents of report

> *The scope of the Distribution Annual Planning Report (DAPR) is limited to direct control services and system limitations affecting the power system and any significant investments in metering system. The scope of the planning report is proposed to extend to primary distribution feeders on an exception basis.[14]*

EnergyAustralia questions the inclusion of investments in metering systems in the distribution annual planning report. Given the objectives of the DAPR, EnergyAustralia considers that the inclusion of investment in metering systems in this report is not necessary or useful. EnergyAustralia's views on the inclusion of information on primary distribution feeders is included below.

> *The DAPR must set out information on…….[distribution lines 11kV or greater] that have exceeded in the current year or is forecast to exceed within the next two years, 100 per cent of the normal cyclic operation under normal operating conditions[15]…..*

There are difficulties in providing this data on an annual basis due to the volume of assets in this asset class and the process used in forecasting demand for Medium Voltage (MV)[16]

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[11] AEMC, Draft Report, p.26

[12] AEMC, Draft Report pgs. 26 and 29

[13] The power to make a regulatory information order (RIO) is conferred on the AER by Part 3 of the NEL, Section 28

[14] AMEC, Draft Report, pp. 27-28

[15] AEMC, Draft Report, p.29.

[16] The Medium Voltage (MV) network operates at voltages of 22 and 11kV and in some instances at 33kV. The low voltage network operates at a voltage of 415/220V (three/single phase).

feeders. As discussed in previous submissions, compared to the sub transmission network there is a vastly greater number of individual assets within the medium and low voltage system – in EnergyAustralia's case there are more that 30,000 sections of MV feeders connecting more than 29,000 distribution substations.

As the planning process must consider the loads and ratings of the numerous sections of each MV feeder supplying each distribution substation, the present planning processes do not involve annual forecasting and assessment of the need for augmentation. Instead, a review of MV feeders is carried out on a cyclical basis every few years. This is a pragmatic and efficient approach. Provision of the AEMC proposed data on emerging distribution constraints will require EnergyAustralia to carry out significant additional system modelling. This will only lead to greater costs with few benefits.

Also, the lead times for these types of projects are generally quite short (~12 months). Augmentation is often driven by the electricity requirements of one or two customers, and as such it is often not possible to accurately forecast the timing for constraints of such infrastructure more than 1-2 years in advance. For these reasons, EnergyAustralia considers that if information is contained in the Annual Planning report on distribution feeders, it should be limited to feeders which have exceeded their cyclic rating.

Where an estimated reduction in load would defer a forecast limitation the DAPR must include ………the relevant connection points at which a load reduction should occur.[17]

Energy Australia is also concerned about the requirement to identify within the DAPR the connection points at which an estimated load reduction may occur (draft Framework Specification reference: A.6(c)(v)(2)). The sub transmission assets within a distribution network are generally used to supply the MV level of the DNSP's network and are not linked to connection points as defined by the NER. A zone substation would typically supply thousands of customers and it is not possible to supply details of connection points supplied from such assets. Some clarification or redrafting of the requirements is required.

The DAPR must set out information on system limitations, including identification of system limitations where the limitation is caused by the requirement for asset replacement or refurbishment [18]

EnergyAustralia's replacement and refurbishment expenditure for the next five years is approximately $3 billion. Considering the principles for the Review as well as the purpose and objectives of the DAPR, such as proportionality, EnergyAustralia proposes a threshold to be set above which the information on system limitations "caused by requirements for asset replacement or refurbishment" is included in the DAPR. EnergyAustralia recommends this threshold should be the same as the RIT-D threshold. Without such a threshold the amount of reporting information required to be included in the DAPR on asset replacement and refurbishment will be substantial with little, if any, value.

As a drafting matter, Clauses A.6(b)(ii) and (iii) on forecasting requirements could be clarified to better reflect the process of forecasting capacity, forecasting demand and identifying constraints. EnergyAustralia proposes some editorial changes and these are included in Attachment 2.

3.3. Definition of sub transmission assets and primary distribution feeder

[17] AMEC, Draft Report, pp. 27-28, Draft Framework Specification reference A.6(d)(vii)(2), p80.

[18] AMEC, Draft Report, Draft Framework Specification reference A.6(d)(i)), p.80.

The AEMC proposed definition for sub-transmission assets as currently drafted can inadvertently include some distribution substations. This is because there are some substations that have a primary voltage of 33kV with a secondary voltage at low voltages. For this reason EnergyAustralia proposes an alternative definition to insure the correct assets are captured in the definition of sub transmission assets.

> Definition: *Sub transmission assets* include *substations* connected with primary voltages of 132, 66 and 33kV and secondary voltages of 11kV or greater together with the 132, 66 and 33kV cables, lines and switching stations which supply these substations and is not a *transmission* asset.

The AEMC definition for primary distribution feeder is a distribution line 11kV or greater. To remove any confusion, EnergyAustralia suggests that the definition also needs to be altered to exclude any sub transmission assets. EnergyAustralia operates some 5kV feeders in its network area.

3.4. Timeframes and the impact of requirement for CEO and Director (or Company Secretary) certifying the Annual Planning report

AEMC seeks comments on whether the publication date of 31 December is appropriate.[19]

The annual planning process considers summer and winter load forecasts which are updated after each season. As EnergyAustralia's system comprises a mixture of both summer and winter peaking networks, system limitations must be reviewed for both seasons. The timing of the reviews are dependent on the availability of updated summer and winter forecasts, and hence the outcomes of reviews occur at different times. Variation to timing of the DAPR will alter the currency of analysis contained in the review for summer and winter forecasts.

It should be noted that after the end of each peak season period (summer or winter) it takes some months for the data to be verified and analysed and forecasts prepared. Analysis of the system performance is then required which involves substantial load flow modelling and analysis of potential solutions. Data will then need to be assembled into a DAPR. The requirements of the DAPR to be certified by CEO and Director/Company Secretary will require an external audit. The combination of all of these processes means that a publishing date by 31st December will result in the use of the forecast data based on the previous year's peak demand. The report would include RIT-D and reliability reports to the end of June.

3.5. Duplication with existing reporting requirements

As currently drafted the DAPR is required to provide information on performance standards and compliance such as reliability and quality of supply standards, as well as asset management methodologies.

The reporting and publication date of the DAPR does not align with the publishing of the performance and compliance information required by jurisdictional regulators or the Australian Energy Regulator. Also, consistent with the objectives of the AEMC review, the DAPR should not replicate information which is reporting in other documents or examined in other regulatory processes. Rather the DAPR should if necessary contain references to the locations where the latest material may be accessed. EnergyAustralia has marked up amendments to the Indicative Frameworks (A.6(j) and (k)) to reflect this position.

[19] AEMC, Draft Report, p.18.

A high level of information on….quality of supply standards should be included in the DAPR. This would include qualitative assessments of the performance of the network and any areas where the relevant standards were not met.[20]

Not withstanding comments made about the appropriateness and duplication of information on performance standards and compliance in the DAPR, the requirements in relation to quality of supply are above those currently performed as part of business processes.

The standards for quality of supply are provided in the Rules, are high level targets and as such it is difficult to demonstrate compliance. For example within schedule 5.1a of the NER which establishes system standard, S5.1 a 4 specifies power frequency voltage levels, and S5.1a 7 covers voltage unbalance limits at connection points. EnergyAustralia has in excess of 1.5 million connection points. Whilst EnergyAustralia may sample quality of supply characteristics as part of a small monitoring program or in response to concerns about aspects of supply quality, this information does not provide a comprehensive view of compliance with quality of supply standards. Unless there is a review undertaken on existing requirements in relation to quality of supply, this obligation as currently drafted is not appropriate and in fact goes well beyond that commonly required by the Rules.

3.6. Development of regional development plans

The AEMC seeks comments on whether the national framework should include a requirement for DNSPs to develop regional development plans.[21]

Whilst DNSPs may identify the location of *system limitations*, EnergyAustralia considers the publishing of regional development plans should be a matter for distribution businesses. The relevance of Regional plans to a DNSPs Investment management processes will vary with the circumstances and internal processes. Whilst presently EnergyAustralia does periodically prepared regional plans, this methodology may not be appropriate for all businesses and it is considered inappropriate that this methodology should be mandatory. Given the objectives of the national framework and the material proposed to already be available in the DAPR, which should detail all material investments, it is unclear what benefit the publication of such plans would serve.

4. Regulatory Investment Test for Distribution (RIT-D)

4.1. Scope of Projects Subject to RIT-D

The RIT-D would not apply to urgent and unforeseen investments, negotiated services, replacements and connection services or where the proposed investments have been identified through joint planning process.[22]

For reasons as outlined in EnergyAustralia's previous two submissions, EnergyAustralia agrees that the classes of investment identified by the AEMC above should remain exempt from the RIT-D, with the exception of jointly planned investments, which is discussed in Section 2.3.

In the event that no prior engagement with stakeholders had taken place, the RIT-D process proposed by the AEMC spans a period which would take a minimum of 8 – 9 months. In the

[20] AEMC, Draft Report, p.34.
[21] AEMC, Draft Report, p.107
[22] AEMC, Draft Report, p.37.

case of investments of an urgent or unforeseen nature, prior engagement with stakeholders is unlikely. Hence, due to the length of the process, it is necessary that investments required to be operational within 12 months are considered “urgent or unforeseen”. This proposed change has been made to Indicative Framework B.2(c)(i) contained in Attachment 3.

The AEMC seek comments on the proposal to exclude primary distribution feeders from the RIT-D.[23]

EnergyAustralia supports the exclusion of primary distribution feeders from the RIT-D process.

The impacts of these investment projects are very localised and are generally required in short timeframes. Primary distribution feeders are often customer-driven requirements and are generally unlikely to have non-network alternatives.

A DNSP must apply the RIT-D as part of the consideration of any distribution investment,…except in circumstances where the estimated capital cost of the most expensive option, <u>which is economical and technically feasible</u> is less than $2 million.[24]

EnergyAustralia considers the proposed threshold for the RIT-D process is too low. Such a proposal would result in a significant administrative burden on DNSPs. In addition the use of the terminology the “most expensive option which is economically and technically” creates the scenario where all but the cheapest investments (substantially less that $2 million) would be subject to the RIT-D process.

The ENA submission provides substantive material explaining the concerns regarding these two aspects. EnergyAustralia supports the position contained within the ENA submission on this matter.

4.2. Specification Threshold Test

Under the STT, DNSPs would be required to assess ……the material potential for the identified need to adversely impact on the quality of the service experience by end customers.

Most, if not all, augmentation investments undertaken by EnergyAustralia are to meet jurisdictional reliability/planning standards. The jurisdictional requirements for such projects were specifically intended to address emerging quality of service issues . Under the present drafting in Framework Specification, reference B.6, all augmentation projects would require a project specification report because the identified need for all such projects would have a material impact on quality of service. Contrary to this drafting, EnergyAustralia understands the AEMC intended this clause to require DNSPs to assess whether the planned investment to address the identified need (i.e. the solution) does not adversely impact on the quality of the service experienced by end customers. EnergyAustralia has made suggested amendments to the draft Framework Specification to reflect this intent (reference B.6(b)(iii), B.7(a)(ii) and B.7(c)(iii)(2).

AEMC seeks stakeholder comments on whether prescription is required in the Rules regarding the actions that DNSPs must have undertaken to qualify for accelerated consultation on their project specification reports. An alternative to greater prescription in the Rules would be to provide the AER with greater discretion in its development of the RIT-D Application Guidelines

[23] AEMC, Draft Report, p.48.
[24] AEMC, Draft Report, p.87.

to determine the appropriate actions DNSPs must undertake to comply with the Rules requirements for accelerated consultation.[25]

The AEMC provides for an opportunity for DNSPs to consult under an accelerated consultation period on the project specification reports if DNSPs have undertaken prior engagement with non-network proponents.

Whilst EnergyAustralia acknowledges the AEMC's objective to incentivise DNSPs to proactively engage with non-network proponents by providing the opportunity for accelerated consultation, we question whether it does actually "place a complementary responsibility on non-network proponents to put forward proposals and engage proactively with the DNSPs on an ongoing basis".

EnergyAustralia considers that provided DNSPs:

- engage with non-network proponents consistent with its *Demand Side Engagement Strategy* on the identified need for the investment;
- respond to any enquiry by non-network proponents; and
- comply with requirements of the DAPR and STT,

prior to publishing the Project Specification Report, then sufficient prior engagement would be deemed to have taken place. Unless this is the case, any "interested party" that had not been individually consulted in relation to the proposal would be able to raise a dispute.

Guidelines should only be developed to assist in understanding substantive obligations and the way in which such obligations can be met. EnergyAustralia considers the above outcome can be achieved in the Rules.

4.3. Quantification of costs and any applicable market benefits where appropriate

The RIT-D would involve.....consideration of applicable market benefits and costs for each credible option, to determine the preferred option. DNSPs would be required to quantify all applicable costs, but would have the discretion to quantify any applicable market benefits.[26]

As outlined previously, it is unusual for augmentation projects within distribution networks to involve market benefits which are material. EnergyAustralia firmly supports the AEMC's proposal that DNSPs would be required to consider the potential for market benefits but would be provided with the option to quantify any applicable market benefits where they consider it appropriate to do so.

The purpose of the RIT-D is to identify the credible option that maximises the present value of net economic benefits to all those who produce, consume and transport electricity in the market (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit where the identified need is for reliability corrective action. [27]

Distribution investment related to the refurbishment or replacement of existing assets where it is not intended to augment the distribution network, is exempt from the RIT-D. Where refurbishment or replacement expenditure also results in augmentation to the network and the augmentation component cost is $2 million or greater, the augmentation component is subject to RIT-D.

[25] AEMC, Draft Report, p.54.
[26] AEMC, Draft Report, p.37.
[27] AEMC, Draft Report, p.86.

Whilst EnergyAustralia does not contend that the augmentation component should not be subject to RIT-D, EnergyAustralia considers that there must also be the ability for these projects to have a negative net economic benefit.

For example, some projects driven by replacement/refurbishment requirements cost in the order of $150 million. It is not unusual for these types of projects to have an augmentation component costing more than $2 million. If the augmentation components of these projects were unable to have a negative net economic benefit, as is proposed for 'pure' augmentation projects, they could be excluded as an option. EnergyAustralia considers this to be an unintended effect of the current drafting. A minor amendment to Indicative Framework B.1.(c) would remove this consequence and is indicated in Attachment 3.

The RIT-D must be based upon a cost-benefit analysis of the future that is to include an assessment of reasonable scenarios of future supply and demand if each credible option were implemented compared to the situation where no option is implemented.[28]

Distribution planning does not generally require the identification of alternative scenarios of demand growth and development which is characteristic of transmission developments. The requirement for a RIT-D to develop and consider alternative scenarios is considered to be inappropriate and disproportionate to the outcomes of such analysis.

For distribution planning perspective it is more appropriate to take a sensitivity analysis approach to demand forecasts and therefore EnergyAustralia recommends an amendment to clause to B.1(j)(i) of the draft Framework Specification to reflect the use of this approach.

5. Dispute Resolution

The ENA submission provides material on Dispute Resolution and raises some concerns with regards to the scope of the process and the parties who may raise a dispute. EnergyAustralia supports the position contained within the ENA submission on this matter.

6. Areas of further reform

The ENA submission provides comment on the areas the AEMC suggests could benefit from further review including the process for determining jurisdictional reliability standards, target setting and measuring of reliability performance, and asset management practices and reporting.

EnergyAustralia supports the position contained within the ENA submission on this matter.

[28] AEMC, Draft Report, p.87.

EnergyAustralia Attachment 2

A Draft Framework Specification - Annual Planning Process and Reporting

The purpose of these specifications is to explain in detail, the regulatory requirements for the proposed annual planning process and reporting requirements under the national framework, as set out in the draft recommendations. The specifications are not draft Rules and should not be interpreted as such.

Key for Markups
Text in red: EnergyAustralia's suggested deletions
Text in blue: EnergyAustralia's suggested additions
Highlighted yellow: EA's comments

Definitions

Existing definitions in the Rules have been italicised in these specifications. In addition, a number of new terms for the national framework have also been italicised. Outlined below are the new terms that have been included in these specifications and an accompanying proposed definition for each new term.

asset management

The development and implementation of plans and processes, encompassing management, financial, consumer, engineering, information technology and other business inputs to ensure assets achieve the expected level of performance and minimise costs to consumers over the expected life cycle of the assets.[80]

joint network investment

An investment identified under clause 3(b) which affects both a *transmission network* and *distribution network* or an investment which would require action by the *Transmission Network Service Provider* and the *Distribution Network Service Provider*.

primary distribution feeder

Distribution line 11kV or greater.

sub transmission asset

includes *substations* ~~or switching station~~ connected with ~~a~~ primary voltages of 132, 66 and 33kV ~~or greater~~ and secondary voltages of 11kV or greater together with the 132, 66 and 33kV cables and lines which supply these substations and is not a *transmission* asset.

[80] Gives consideration to the discussions on asset management in *Electricity Distribution Business Asset Management Plans and Consumer Engagement: Best Practice Recommendations*, prepared for Commerce Commission NZ by Parsons Brinckerhoff Associates, April 2005.

system limitation

A limitation on the *transmission network* and/or *distribution network* as identified under clause 2(b) or clause 6(d) of this specification. [Reference 2(b) seems to be incorrect. Should this be 3(a)?]

1. Objectives of the Annual Planning Process and Reporting

The objectives of the Annual Planning Process and Reporting are to:

(a) provide a clearly defined and efficient planning process which provides certainty in relation to the approval of network expansion and augmentation to maintain the security and reliability of the electricity supply to consumers;

(b) ensure efficient development of the network, including to ensure that non-network alternatives are considered in a neutral manner;

(c) provide appropriate information transparency;

(d) ensure a level playing field for all regions in terms of attracting investment and promoting more efficient decisions;

(e) ensure that network users understand how the timing and location of connections might affect capability of the network and the need for augmentations; and

(f) reduce the regulatory compliance burden for participants operating in more than one region in the NEM.

2. Scope of the Annual Planning Process

(a) Each *Distribution Network Service Provider* shall carry out an annual planning process analysing the expected future operation of its *network* over a minimum forward planning period.

(b) The minimum forward planning period for the purpose of the annual planning process is 5 years for *distribution* and *sub transmission networks* and 10 years for *transmission networks*.

(c) The annual planning process shall apply to all *distribution network* assets and activities undertaken that would be expected to have a material impact on the *distribution networks* and *sub transmission networks* in the forward planning period (which would include negotiated services and replacement activities).

3. Requirements of the Annual Planning Process

(a) The Annual Planning Process shall require each *Distribution Network Service Provider*, for its *network*, to at a minimum:

(i) prepare forecasts~~, to the best of its ability,~~ of maximum demands for ~~distribution feeders,~~ sub-transmission substations, zone substations and for distribution feeders~~, and at a system level~~ having consideration of;

1. number of customer connections at each level of the ~~a~~ system ~~level~~;

2. energy consumption at a system level;

3. estimated level of embedded generation [This may be difficult to estimate, given the proliferation of small scale generation including PV. It is unclear what benefit would be obtained from this when network planning is to meet or manage the net demand];

4. committed projects that have been subject to the RIT-D and RIT-T;

(ii) based on the outcomes of the forecasts in clause 3(a)(i), identify *system limitations*[81] on its *network*;

(iii) identify the need for investments and options available to address the *system limitations*, and to carry out the requirements of the *Regulatory Investment Test for Distribution* or the *Regulatory Investment Test for Transmission* and the *Demand Side Engagement Strategy* where appropriate;

(iv) undertake the annual planning process in a manner which is consistent with its *asset management* policies; and

(v) take into account any other jurisdictional specific requirements.

(b) The Annual Planning Process shall require each *Distribution Network Service Provider* to undertake joint planning with each *Transmission Network Service Provider* of the *transmission networks* to which the *Distribution Network Service Provider's distribution networks* are connected.

(i) The joint planning will require the *Transmission Network Service Provider* and the *Distribution Network Service Providers* to meet on a regular and as required basis to assess the adequacy of existing transmission-distribution connection points over the next five years and to undertake joint planning of proposals which relate to both networks.

(ii) The parties shall use best endeavours to work together to ensure efficient planning outcomes and to identify the most efficient investments.

(iii) The joint planning will identify any system limitations that will affect both the *transmission networks* and *distribution networks* or will require coordination by both the *Distribution Network Service Provider* and *Transmission Network Service Provider* to undertake action to address a *system limitation*.

(iv) Where the necessity for augmentation or a non-network alternative is identified by the process under this clause, the *Network Service Providers*:

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81 "System limitation" is defined in accordance with the provisions in clause 7.d. [Should this be 6(d)?]

1. must jointly determine plans that can be considered by relevant *Registered Participants*, *AEMO* and *interested parties*;

2. must carry out the *Regulatory Investment Test for Distribution* ~~*Transmission*~~ for the options identified unless there is some likelihood that the augmentation will influence main transmission network and interconnector flows or have a material market effect;[82] and

3. may agree on a lead party to be responsible for carrying out the *Regulatory Investment Test for Transmission*. In this case, the other parties will be deemed to have discharged their obligations to undertake the relevant *Regulatory Investment Test* in response to the identified need for investment.

(c) The Annual Planning Process shall require *Distribution Network Service Providers* to meet regularly to undertake joint planning with other *Distribution Network Service Providers* where there is a requirement to do so to consider any augmentation or non-network alternative that affects more than one *distribution network*.

(d) The Annual Planning Process shall require each *Distribution Network Service Provider* to ~~use reasonable endeavours to~~ engage with non-network proponents and consider non-network alternatives. This shall include the requirement for each *Distribution Network Service Provider* to implement a *Demand Side Engagement Strategy*.

4. Demand Side Engagement Strategy[83]

(a) The objective of the *Demand Side Engagement Strategy* is to provide transparency regarding the consideration and assessment of non-network solutions by *Distribution Network Service Providers*. This would encourage the engagement of non-network proponents in network planning and streamline the development process to improve efficiency and provide certainty over the recovery of investments.

(b) Each *Distribution Network Service Provider* must prepare and make available a *Demand Side Engagement Facilitation Process* document which shall set out at a minimum:

(i) the process which the *Distribution Network Service Provider* follows to develop, investigate, assess and report on potential non-network solutions;

(ii) the process with which the *Distribution Network Service Provider* follows to engage and consult with potential non-network

82 ~~As~~ the RIT-T would apply~~,~~ in these cases ~~joint investments would be subject to the RIT-T threshold, which is currently $5m. For joint investments between $2 and $5m, the RIT-T would still need to be carried out but the projects would be exempt from the specification and draft report requirements~~.

83 The Demand Side Engagement Strategy replaces the "Non-network Strategy" discussed in the Workshop Paper.

proponents to determine their level of interest and ability to participate in the development process;

(iii) an outline of the process with which the *Distribution Network Service Provider* follows to engage ~~negotiate~~ with non-network proponents to further develop ~~a~~ potential solutions;

~~(iv) an outline of the information a non-network proponent is to include in a non-network solution proposal;~~

~~(v) an outline of the criteria that a potential non-network proponent should meet or consider in any offers or proposals;~~

(vi) ~~an outline of the principles that the *Distribution Network Service Provider* considers in developing the payment levels for non-network solutions;~~

(vii) ~~a reference to any applicable incentive payment schemes for the implementation of non-network solutions and whether any specific criteria is applied by the *Distribution Network Service Provider* in its application and assessment of the scheme~~; [These details cannot be meaningfully provided in the process document as they will be project and site specific. They should be included in the project specific document.]

(viii) the applicable performance incentives or standards that the Distribution Network Provider is required to meet and the proposed treatment of changes in performance or standards attributable to a non-network proponent;

(ix) sources of relevant, publicly available information that non-network proponents may access;

(x) how non-network proponents may contact the *Distribution Network Service Provider* to request additional information or register as an interested party;

(xi) the process, including the information that would be provided, for updating the parties registered on the *Register of Interested Parties*;

(xii) the *Distribution Network Service Provider's* contact details; and

(xiii) the methodology to be used for determining *avoided Customer TUOS charges*, in accordance with clause 5.5 and clause 5.6.2(k1) of the *Rules*.

(c) The *Demand Side Engagement Facilitation Process* document shall be published by 31 December 2010.

(d) The *Distribution Network Service Provider* shall review its *Demand Side Engagement Facilitation Process document* at least once every three years.

(e) Each *Distribution Network Service Provider* must ~~establish and maintain a public database of non-network proposals and/or case studies that demonstrate the economic assessments~~ publish on its web site the outcome of *non*-network screening tests and investigations undertaken by the *Distribution*

Network Service Provider in its consideration of non-network proposals.[84] In selecting items to be published in the database, the *Distribution Network Service Provider* shall not breach any confidentiality provisions or publish any information that is commercially sensitive.

(f) Each *Distribution Network Service Provider* must establish and maintain a *Register of Interested Parties* for those parties wishing to be advised of developments relating to specific constraints.

5. Distribution Annual Planning Report

(a) By 31 December each year, each *Distribution Network Service Provider* must publish, and make available to interested parties, the *Distribution Annual Planning Report* setting out the outcomes from carrying out the annual planning process for the forward planning period beginning 1 January the following year.

(b) Within two months following the publication of the *Distribution Annual Planning Report*, the *Distribution Network Service Provider* must conduct a public forum on the *Distribution Annual Planning Report*.

(c) The *Distribution Annual Planning Report* must be certified by the Chief Executive Officer, and a Director or Company Secretary of the *Distribution Network Service Provider* that:

(i) the *Distribution Annual Planning Report* meets the *Distribution Network Service Provider's* obligations under the *Rules* and any other applicable *regulatory instruments*; and

(ii) the *Distribution Annual Planning Report* accurately represents the relevant policies of the *Distribution Network Service Provider*.

(d) The scope of *Distribution Annual Planning Report* is limited to *direct control services* and *system limitations* affecting the *power system* ~~[and any significant investments in metering systems]~~ only.

6. Contents of the Distribution Annual Planning Report

The *Distribution Annual Planning Report* must set out information on the following:

(a) *Distribution Network Service Provider* and *network*, including:

(i) description of the *network*;

(ii) description of the operating environment;

(iii) summary information of the number and types of assets ~~and the number of each type of asset~~;

(iv) planning methodology used, including the methodology used to identify the need for investments and the assumptions applied; and

[84] The database should include examples of proposals that were successful as well as examples of proposals that were not successful.

(v) analysis and explanation of any aspects of the *Distribution Annual Planning Report* that has changed significantly from previous results (e.g. changes in forecast load);

(b) Forecasts for the forward planning period, including at a minimum:

(i) description of the forecasting methodology used; sources of input information; and the assumptions applied;

(ii) capacity forecasts for ~~the network as a whole;~~ major connection points (including any transmission connection points)~~; zone substations;~~ and *sub-transmission assets*; including~~: 1. total capacity; 2.~~ firm delivery capacity for ~~(~~summer and winter~~)~~;

Commentary: Planning the efficient operation and economical capital expansion of an electrical system involves anticipating future electricity demand, and *where* and when expanded capacity will be needed. Forecasts for the network as a whole is not relevant to distribution system planning process. Sub-transmission assets is a defined term (should be italicised) and zone substations is a duplication of the definition.

(iii) Demand ~~load~~ forecasts for ~~the network as a whole;~~ major connection points (including any transmission connection points)~~;~~ and ~~zone substations;~~ *sub-transmission assets*; including:

1. peak load (summer and winter);
2. power factor at time of peak load;
3. load sharing/load transfer capabilities including transmission interface capacity; and
4. level of embedded generation;

(iv) forecasts of future connection points and zone substations, including location, future loadings, and estimated timing (month, year) of the connections;

(v) forecasts of reliability targets at a system level and by feeder categories or reference to relevant jurisdictional or AER requirements; and [To avoid the duplication of jurisdictional planning reports and the AER's STPIS targets]

(vi) forecasts of any factors that may have a major affect on the *network*, including factors affecting:

1. fault levels;
2. voltage levels;
3. other system security requirements; and
4. ageing and potentially unreliable assets;

(c) *Primary distribution feeders* that have exceeded~~, in the current year or is forecast to exceed in the next 2 years,~~ 100% of its normal cyclic rating (summer or winter) under normal operating conditions and identify:

(i) the location of the primary distribution feeder;

(ii) the extent of overload experienced in the current year;

(iii) the forecast load in the next 2 years and the extent the forecast load would exceed the normal cyclic rating (summer or winter); and

(iv) any potential solutions being considered by the DNSP to address the overload; and

(v) where an estimated reduction in forecast load would defer a forecast overload for a period of 12 months, include:[85]

1. the year and month in which the overload (the *system limitation*) is forecast to occur;

~~2. the relevant connection points at which the estimated reduction in forecast load may occur;~~

3. the estimated reduction in forecast load in MW needed;

(d) *System limitations* ~~and network transfer capability~~, including at a minimum:

(i) identifying any system limitations for sub transmission assets and zone substations where the limitation may be caused by one or more of the following factors:

1. forecast load exceeding system capability; in which case identify: the extent of the overload; frequency of overload; duration of overload; power factor at time of peak load;

2. the requirement for asset replacement or refurbishment where the estimated cost exceeds $2million;

3. the requirement for system security or reliability improvement;

4. design fault levels being exceeded;

5. the requirement for voltage regulation;

6. the requirement to meet SAIDI and SAIFI or any other regulatory obligations;

(ii) the location and estimated timing (month, year) of the system limitation;

(iii) analysis of any potential load transfer capability between supply points that may decrease the impact of the system limitation or defer the requirement for investment;

(iv) impact of the system limitation, if any, on the capacity at the transmission connection points;

(v) discussion of the potential solutions that may address the system limitation in the forward planning period, if a solution is required;

[85] This clause is consistent with the clause introduced under the National Electricity Amendment (Demand Management) Rule 2009 No. 11. Additional information on this Rule change may be found at www.aemc.gov.au.

(vi) other jurisdictional requirements[86]; and

(vii) where an estimated reduction in forecast load would defer a forecast system limitation for a period of 12 months, include:[87]

1. the year and month in which a system limitation is forecast to occur (as required under (ii) above);
2. ~~the relevant connection points at which the estimated reduction in forecast load may occur~~;
3. the estimated reduction in forecast load in MW needed;

(e) Provide a summary of each proposed *new distribution network investment* for which the *Regulatory Investment Test for Distribution* has been completed or is in progress since the last DAPR, which may include:

(i) a summary of the outcomes or progress of the *Regulatory Investment Test for Distribution* including any consultation undertaken under the *Demand Side Engagement Strategy* or any other consultation on the investment;

(ii) a description of the investment required and how it will alleviate the system limitation;

(iii) estimated timing (month, year) of the investment [Commencement or completion?];

(iv) the estimated total capitalised expenditure;

(v) a summary of any other options considered and, if the *Regulatory Investment Test for Distribution* is in progress, the *Distribution Network Service Provider's* preferred option and the reasons for selecting the preferred option; [These details would be included in the RIT-D for those that have been completed. For those where the RIT-D has commenced but not completed, the DNSP would only be able to provide such information where practicable.]

(vi) any factors that may result in the investment requirements (or preferred option) being altered; and

(vii) any impacts on network users, including any potential material impacts on connection charges and distribution use of system charges that may be estimated;

(f) For each identified system limitation which will require a *Regulatory Investment Test for Distribution* an estimation of the date when the business intend to commence the *Regulatory Investment Test for Distribution*;

(g) For all committed projects with an estimated total capital cost of $2m or more that are urgent and unforseen projects, or refurbishment or replacement projects provide:

86 e.g. worst performing feeder analysis required in QLD.

87 This clause is consistent with the clause introduced under the National Electricity Amendment (Demand Management) Rule 2009 No. 11. Additional information on this Rule change may be found at www.aemc.gov.au.

(i) a brief description of the project, including location;

(ii) the date or estimated time (month, year) the investment was or would become operational;

(iii) the purpose of the investment;

(iv) the total capital cost of the investment; and

(v) an explanation of the ranking of any reasonable credible options to the committed project which are being or have been considered by the *Distribution Network Service Provider*. These alternatives could include, but are not limited to, generation options, demand side options, and options involving other *distribution* or *transmission networks*.

(h) Joint planning undertaken with the *Transmission Network Service Provider*, including:[88]

(i) a summary of the process and methodology used by the *Network Service Providers* to undertake joint planning;

(ii) any planned *joint network investments*; and

(iii) where additional information on the joint planning and *joint network investments* may be obtained;

(i) Joint planning undertaken with other *Distribution Network Service Providers* where applicable, including:

(i) a summary of the process and methodology used by the *Distribution Network Service Providers* to undertake joint planning;

(ii) any planned investments that have been discussed through this process, including estimated capital costs and estimated timing (month, year) of the investment; and

(iii) where additional information on the investments may be obtained.

(j) Performance of the *network*, including a summary description of, or reference to the:[89]

(i) *reliability standards* that apply, including the relevant codes, standards and guidelines;

(ii) the *quality of supply standards* that apply, including the relevant codes, standards and guidelines;

[88] It is noted that there may be changes to the provisions in the Rules governing TNSP planning requirements. These provisions will need to be reviewed and reconciled for consistency.

[89] The potential benefits of including the information in the planning report is to provide transparency, clarity and context for the system limitation and investment requirements. If the information is reported elsewhere, it could potentially be replicated here at limited additional cost. However, it is noted that different timing requirements for reporting may impact the replication of information.

(iii) performance of the *distribution network* against the *reliability* and *quality of supply standards* for the preceding year or reference to jurisdictional or AER reports; and

(iv) qualitative assessment of how the *Distribution Network Service Provider* has complied with the applicable standards; its processes to ensure compliance; and a description of any areas of the standards that were not met in the preceding year and the corrective action taken.

(k) Asset Management:

(i) Summary of any *asset management* strategy employed by the *Distribution Network Service Provider* system or reference to jurisdictional reports;

(ii) ~~summary of any issues that may impact on the *system limitations* identified in the *Distribution Annual Planning Report* that has been identified through carrying out *asset management*; and;~~ [Duplication of asset management practices which are covered by comprehensive jurisdictional requirements.]

(iii) information about where further information on the *asset management* strategy and methodology adopted by the *Distribution Network Service Provider* may be obtained.

(l) Any other information as required by the relevant jurisdiction.

B Draft Framework Specifications- Regulatory Investment Test for Distribution and Dispute Resolution Process

The purpose of these specifications is to explain in detail, the regulatory requirements for the proposed RIT-D and dispute resolution process under the national framework, as set out in the draft recommendations. The specifications are not draft Rules and should not be interpreted as such.

Definitions

Existing definitions in the Rules have been italicised in these specifications. In addition, a number of proposed new terms for the national framework have also been italicised. Outlined below are the new terms that have been included in these specifications and an accompanying proposed definition for each new term.

draft project assessment report

The report prepared by a *Distribution Network Service Provider* under section 8.

final project assessment report

The report prepared by a *Distribution Network Service Provider* under section 10.

project specification report

The report prepared by a *Distribution Network Service Provider* under section 7.

Regulatory Investment Test for Distribution

The test developed and published by the AER under section 1, as in force from time to time, and includes amendments made under section 12.

Regulatory Investment Test for Distribution Application Guidelines

The guidelines developed and published by the AER under section 12, as in force from time to time, and includes amendments made under section 12.

Specification Threshold Test

The test undertaken by a *Distribution Network Service Provider* under section 6.

specification threshold test report

The report prepared by a *Distribution Network Service Provider* under section 6(c)(ii).

In addition, a number of terms have been defined in the Rules for the new RIT-T[90] which are proposed to be amended to also refer to investments considered under the RIT-D. These terms include:

cost threshold

cost threshold determination

cost threshold review

credible option

dispute notice

identified need

preferred option

reliability corrective action

1. Objectives of the Regulatory Investments Test for Distribution

(a) The *AER* must develop and publish the *Regulatory Investment Test for Distribution* in accordance with the *distribution consultation procedure*.

(b) The purpose of the *Regulatory Investment Test for Distribution* is to identify the *credible option* that maximises the present value of net economic benefits to all those who produce, consume and transport electricity in the *market* (the *preferred option*).

(c) For the avoidance of doubt, a *preferred option* may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for *reliability corrective action* [Needs to accommodate a negative net economic benefit for primarily replacement/refurbishment driven investments that have an augmentation component >$2million.]

(d) This should not prevent a *Distribution Network Service Provider* from applying a value of *unserved energy* (probabilistic planning) approach to the project assessment if it wishes to do so.

(e) The *Regulatory Investment Test for Distribution* will involve a consideration of both costs and benefits associated with all of the *credible options.*

(f) Market benefits may be quantified by the *Distribution Network Service Provider* under the *Regulatory Investment Test for Distribution* where the *Distribution Network Service Provider* considers it appropriate to do so.

[90] AEMC, 2009, National Electricity Amendment (Regulatory Investment Test for Transmission) Rule 2009 No. 15, 25 June 2009.

(g) The *Regulatory Investment Test for Distribution* shall comprise three sequential stages: a *Specification Threshold Test* stage; a project specification stage; and a project assessment stage.

(h) The extent of consultation and the nature of assessment required will vary depending upon the specific characteristics of the identified need in question. This will be achieved through a combination of cost thresholds and the *Specification Threshold Test.*

(i) The *Regulatory Investment Test for Distribution* should permit the single assessment of an integrated set of related and similar *distribution* investments.

(j) The *Regulatory Investment Test for Distribution* must:

(i) be based upon a cost-benefit analysis of the future which may ~~that is to~~ include a sensitivity test or an assessment of reasonable scenarios of future supply and demand if each *credible option* were implemented compared to the situation where no option is implemented [EnergyAustralia does not prepare forecast scenarios for distribution but instead would make an assessment from a single point forecast of the likely range of demand growth];

(ii) not require the level of analysis to be disproportionate to the scale and likely impact of each of the *credible options* being considered; and

(iii) be capable of being applied in a predictable, transparent and consistent manner.

2. Scope of Projects Subject to the Regulatory Investment Test for Distribution

(a) A *Distribution Network Service Provider* must apply the *Regulatory Investment Test for Distribution* as part of the consideration of any new *distribution* investment, where the purpose of the *distribution* investment is to augment a *distribution* network, except in circumstances where:

(i) the proposed investment is required to address an urgent and unforeseen *network* issue that would otherwise put at risk the *reliability* of the *distribution network* as described in section 2c);

(ii) the estimated capital cost of the most expensive investment option, which is economically and technically feasible is less than $[2] million (as varied in accordance with a *cost threshold determination*);

(iii) the proposed investment is designed to ensure that a *transmission network* meets the level required by the minimum *power system security and reliability standards*. For the avoidance of doubt, such investments shall be assessed under the *Regulatory Investment Test for Transmission;*

(iv) The need for the proposed investment has been identified through a joint planning process between a *Distribution Network Service Provider* and a *Transmission Network Service Provider*;

(v) The cost of the proposed investment is to be fully recovered through charges in relation to *negotiated distribution services, alternative control services,* or unclassified *distribution services*;

(vi) The proposed investment will be a *connection asset*, which will not be part of the *Distribution Network Service Provider's* shared *distribution network*;

(vii) [The proposed investment is designed to address a *network* issue on a *primary distribution feeder*];

(viii) The *distribution* investment is related to the refurbishment or replacement of existing assets and is not intended to *augment* the *distribution network*; or

(ix) The refurbishment or replacement expenditure also results in an *augmentation* to the *network*, and the estimated capital cost for the *augmentation* component of the *distribution investment* is less than $[2] million (as varied in accordance with a *cost threshold determination)*, as allocated by the *Distribution Network Service Provider* in accordance with recognised *cost allocation methods* and any applicable *AER* guidelines.

(b) If the proposed *distribution* investment is to be provided as a *dual function asset,* the proposed investment shall be assessed under the *Regulatory Investment Test for Distribution.*

(c) For the purposes of section 2(a)(i), a proposed investment will be required to address an urgent and unforeseen *network* issue that would otherwise put at risk the *reliability* of the *distribution network* if:

(i) the proposed investment is required to be operational within ~~6~~ 9 months of the *Distribution Network Service Provider* identifying the *identified need*; and

(ii) the event or circumstances causing the *identified need* was not reasonably foreseeable by, and was beyond the reasonable control of, the *Distribution Network Service Provider*; and

(iii) a failure to address the *identified need* is likely to materially adversely affect the *reliability* and *secure operating state* of the *distribution network*.

(d) A *Distribution Network Service Provider* must not treat different parts of an integrated set of related and similar proposed investments to an *identified need* as distinct and separate options for the purposes of determining whether the *Regulatory Investment Test for Distribution* applies to each of those distribution investments.

3. Application of the Regulatory Investment Test for Distribution – Identification of a credible options

(a) A *credible option* is an option (or group of options) that:

(i) addresses the *identified need*;

(ii) is (or are) economically and technically feasible;

(iii) can be implemented in sufficient time to meet the *identified need*;

(iv) complies with recognised industry standards for operational and safety requirements to connect to a *distribution* network; and

(v) is (or are) identified as a *credible option* in accordance with section 3(b).

(b) In applying the *Regulatory Investment Test for Distribution*, a *Distribution Network Service Provider* must consider, in relation to a proposed *distribution investment* to address an *identified need*, other than those described in sections 2(a)(i)-(ix), all options that could reasonably be classified as *credible options*, taking into account:

(i) energy source;

(ii) technology;

(iii) ownership;

(iv) whether it is a network or non-network option;

(v) whether the *credible* option is intended to be regulated;

(vi) whether the *credible option* has a proponent; and

(vii) any other factor the *Distribution Network Service Provider* reasonably considers should be taken into account.

(c) The absence of a proponent does not exclude a *distribution* investment option from being considered a *credible option*

4. Application of the Regulatory Investment Test for Distribution – Consideration of Market Benefits and Costs

(a) The *Regulatory Investment Test for Distribution* must require *Distribution Network Service Providers* to consider the following classes of market benefits that could be delivered by each *credible option*:

(i) changes in voluntary *load* curtailment;

(ii) changes in involuntary *load shedding* and customer interruptions caused by *network* outages, using a reasonable forecast of the value of electricity to consumers;

(iii) changes in costs for parties', other than *Distribution Network Service Provider* due to:

1. differences in the timing of new plant;
2. differences in capital costs; and
3. differences in the operational and maintenance costs.

(iv) differences in the timing of *distribution* investments;

(v) changes in the transfer capability in the dispatch of *embedded generating units*;

(vi) any additional option value (where this value has not already been included in the other classes or market benefits) gained or foregone from implementing the *credible option* with respect to the likely future investment needs of the *market*;

(vii) changes in *electrical energy losses*; and

(viii) any other market benefits that are determined to be relevant by the Distribution Network Service Provider, as consistent with section 4(f).

(b) *Distribution Network Service Providers* may quantify each applicable class of market benefit outlined in section 4(a) in respect to each *credible option*, where the *Distribution Network Service Provider* considers that any applicable market benefits may be material or where it considers the quantification of market benefits may alter the selection of the *preferred option*.

(c) With respect to the classes of market benefits outlined in sections 4(a)(i) and (ii), if the *credible option* is for *reliability corrective action*, the consideration and quantification assessment of these classes of market benefits will only apply insofar as the market benefits delivered by the *credible option* exceeds the minimum standards required for *reliability corrective action*. [Needs to accommodate replacement projects primarily replacement/refurbishment driven investments that have an augmentation component >$2million.]

(d) The *Regulatory Investment Test for Distribution* must require *Distribution Network Service Providers* to consider the following classes of costs that could be delivered by each *credible option*:

(i) costs incurred in constructing or providing the *credible option*;

(ii) operating and maintenance costs over the operating life of the *credible option*;

(iii) the cost of complying with laws, regulations and applicable administrative requirements in relation to the construction and operation of the *credible option*; and

(iv) any other costs that have been determined to be relevant by the *Distribution Network Service Provider,* as consistent with section 4(f).

(e) The *Regulatory Investment Test for Distribution* must include a quantification of all classes of costs outlined in section 4(d) for each *credible option*, unless the *Distribution Network Service Provider* provides an explanation in its *draft project assessment report* and *final project assessment report* which outlines why a particular class of cost is not expected to apply to a *credible option.*

(f) Any cost or market benefit which cannot be measured as a cost or market benefit to *Generators*, *Distribution Network Service Provider*s, *Transmission Network Service Providers*, *Market Customers*, and consumers of electricity may not be included in any analysis under the *Regulatory Investment Test for Distribution*.

(g) Any judgement by a *Distribution Network Service Provider* of whether a particular class of market benefit or cost applies to a *credible option* must be exercised in a manner which is objective and have regard to any submissions received on the *project specification report* and/or the *draft project assessment report*.

(h) The *Regulatory Investment Test for Distribution* shall, as a minimum, list or specify:

(i) the method or methods permitted for estimating the magnitude of the different classes of market benefits;

(ii) the method or methods permitted for estimating the magnitude of the different classes of costs;

(iii) the appropriate method and value for specific inputs, where relevant, for determining the discount rate(s) to be applied;

(iv) specify that a sensitivity analysis is required of any modelling relating to the cost-benefit analysis; and

(v) reflect that the *credible option* that maximises the present value of net economic benefit to all those who produce, consume or transport electricity in the *market* may, in some circumstances, be a negative net economic benefit (that is, a net economic cost) where the identified need is for *reliability corrective action* or where the *Distribution Network Service Provider* does not quantify market benefits during the project assessment process.

5. Review of Costs Thresholds

(a) Every 3 years (or shorter for the first review) the *AER* must undertake a review (the *cost threshold review*) of the changes in the input costs used to calculate the estimated capital costs in relation to investments subject to the *Regulatory Investment Test for Distribution* and the *cost threshold* for refurbishment, replacement, and urgent and unforeseen investments subject to the *Distribution Annual Planning Report*, for the purposes of determining whether the amounts (each *cost threshold*) needs to be changed to maintain the appropriateness of the *cost thresholds* over time by adjusting those *cost thresholds* to reflect any increase or decrease in the input costs since:

(i) [insert commencement date of Rule] in respect of the first *cost threshold review;* and

(ii) the date of the previous review in respect of every subsequent *cost threshold review.*

(b) Each c*ost threshold review* is to be commenced by the *AER* on 31 July of the relevant year.

(c) The AER must initiate its first *cost threshold review* in 2012.

(d) Within 6 weeks following the commencement of a *cost threshold review*, the *AER* must publish a draft determination outlining:

(i) whether the *AER* has formed the view that any of the *cost thresholds* need to be amended to reflect increases or decreases in the input costs to ensure that the appropriateness of the *cost thresholds* is maintained over time;

(ii) its reasons for determining whether the *cost thresholds* need to be varied to reflect increases or decreases in the input costs;

(iii) if there is to be a variation in a *cost threshold*, the amount of the new *cost threshold* and the date the new *cost threshold* will take effect; and

(iv) its reasons for determining the amount of the new *cost threshold*.

(e) At the same time as it publishes the draft determination under section 5(d), the *AER* must publish a notice seeking submissions on the draft determination and which specifies the period within which written submissions can be made (the *cost threshold consultation period)* which must be within 5 weeks from the date of the notice.

(f) The *AER* must consider any written submissions received during the *cost threshold consultation period* in making its final determination in respect of the matters outlined in section 5(d).

(g) This final determination must be made and published by the *AER* within 5 weeks following the end of the cost threshold consultation period (the *cost threshold determination*)

(h) The *AER* shall undertake its *cost threshold review* for the *Regulatory Investment Test for Distribution* at the same time it undertakes its *cost threshold review* for the *Regulatory Investment Test for Transmission.*

6. Regulatory Investment Test for Distribution Process- Specification Threshold Test stage

(a) The *Specification Threshold Test* stage shall be initiated by a *Distribution Network Service Provider's* assessment of an *identified need* for a proposed investment against the *Specification Threshold Test*.

(b) In undertaking the *Specification Threshold Test*, the *Distribution Network Service Provider* must assess the:

(i) reasons (*identified need*) for the proposed investment, including the assumptions used in identifying the *identified need*;

(ii) the material potential for the use of non-network options either to defer or remove the need for the proposed investment to address the *identified need*; and

(iii) the material potential for the proposed investment to address *identified need* have an adverse impact on the quality of service experienced by end use customers, including:

1. estimated changes in voluntary *load* curtailment by end use customers; and

2. estimated changes in involuntary *load* shedding and customer interruptions caused by *network* outages.

(c) If after undertaking the *Specification Threshold Test* the *Distribution Network Service Provider* determines that:

(i) the identified need has:

1. no material potential for non-network options either to defer or remove the need for the proposed investment to address the *identified need*; and

2. no material potential to impact adversely on the quality of service experienced by end use customers,

then the *Distribution Network Service Provider*:

(ii) must publish a *Specification Threshold Test report* on its website which outlines its assessment against the *Specification Threshold Test* and the methodologies and assumptions used to make this assessment, as soon as practicable after the completion of the assessment. The *Specification Threshold Test report* must also be circulated to the *Distribution Network Service Provider's Register of Interested Parties* within 5 business days of the publication of the report on the *Distribution Network Service Provider's* website; and

(iii) is not required to publish a *project specification report* in accordance with section 7(d).

7. Regulatory Investment Test for Distribution Process - Project specification stage

(a) The project specification stage shall be initiated by a *Specification Threshold Test* assessment by a Distribution Network Service Provider which determines that:

(i) the identified need has~~: 1. a~~ material potential for non-network options either to defer or remove the need for the proposed investment to address the identified need; or

(ii) ~~2.~~ the proposed investment to address the identified need has a material potential to impact adversely on the quality of service experienced by end use customers.

(b) A *Distribution Network Service Provider* will be required to consult on the *identified need* for the proposed investment through the publication of a *project specification report*.

(c) The *project specification report* must contain the following information:

(i) a description of the *identified need*;

(ii) the assumptions used in identifying the *identified need* (including, in the case of proposed *reliability corrective action*, why the *Distribution Network Service Provider* considers *reliability corrective action* is necessary);

(iii) a summary of the *Distribution Network Service Provider*'s assessment of the *identified need* against the *Specification Threshold Test*, including:

1. the material potential for the use of non-network options either to defer or remove the need for the proposed investment to address the *identified need*;

2. the material potential for the proposed investment to address the *identified need* to impact adversely on the quality of service experienced by end use customers; and

3. the methodology and assumptions used by the *Distribution Network Service Provider* in undertaking the *Specification Threshold Test.*

(iv) the technical characteristics of the *identified need* that a non-network option would be required to deliver, such as:

1. the size of l*oad* reduction or additional supply;

2. location;

3. contribution to *power system security* or *reliability*;

4. maximum permissible contribution to system fault level; and

5. operating profile;

(v) a description of all options. These options can include, but are not limited to, alternative *distribution* options, *generation* options, demand side management, and options involving other *transmission* and *distribution networks* and could include groups of credible options; and

(vi) for each option, the *Distribution Network Service Provider* must provide information on:

1. A technical definition or characteristics of the option;

2. Estimated construction timetable and commissioning date where the option is a *network investment* option; and

3. To the extent practicable, the total indicative capital and operational costs.

(d) The *project specification report* shall be published on the *Distribution Network Service Provider's* website in a timely manner having regard to the ability of interested parties to identify the scope for, and develop, alternative investment options or variants to the proposed investment options.

(e) The *project specification report* must be circulated to the *Distribution Network Service Provider's Register of Interested Parties* within 5 business days of the publication of the report on the *Distribution Network Service Provider's* website.

(f) A *Distribution Network Service Provider* must publish any preliminary or supplementary information ~~where such information is likely to enhance the ability of interested parties to engage constructively in the *project specification report* consultation process~~ in accordance with its Demand Side Engagement Strategy process.

(g) Interested parties must be provided with not less than 6 months to make submissions on each *project specification report*. If the *Distribution Network Service Provider* has:

(i) ~~constructively~~ engaged with non-network proponents ~~through~~ consistent with its *Demand Side Engagement Strategy* on the *identified need* for the investment prior to ~~undertaking the *Specification Threshold Test*~~ publishing the Project Specification Report; and

(ii) sought to identify scope for, and develop, alternative non-network options or variants to the proposed investment options ~~either internally~~

~~or via consultation~~ with *Register of Interested Parties* ~~non-network proponents~~;

then interested parties must be provided with not less than 1 month to make submissions on the *project specification report. Distribution Network Service Provider*s must outline the basis on which it is has adhered to sections 7(g)(i) and (ii) in its *project specification report* if it seeks to consult under this accelerated timeframe.

8. Regulatory Investment Test for Distribution Process – Draft project assessment report

(a) If the *Distribution Network Service Provider* elects to proceed with the proposed investment, within 12 months, or such longer time period as is agreed to in writing by the *AER*, of where relevant, the end of the consultation period on a *project specification report* or the publication by the *Distribution Network Service Provider* of a *Specification Threshold Test report*, the *Distribution Network Service Provider* must publish a *draft project assessment report* on its website.

(b) The *draft project assessment report* must be circulated to the *Distribution Network Service Provider*'s *Register of Interested Parties* within five business days of the publication of the report on the *Distribution Network Service Provider's* website.

(c) The *draft project assessment report* must include the following:

(i) a description of the *identified need* for the investment,

(ii) the assumptions used in identifying the *identified need* (including, in the case of proposed *reliability corrective action*, why the *Distribution Network Service Provider* considers *reliability corrective action* is necessary);

(iii) if applicable, a summary of, and commentary on, the submissions to the *project specification report;*

(iv) a description of each *credible option* assessed;

(v) where relevant, a quantification of each applicable market benefit for each *credible option;*

(vi) a quantification of each applicable cost for each *credible option*, ~~including a breakdown of operating and capital expenditure~~ [EA considers that this should be deleted because the requirements are considered unduly detailed and prescriptive];

(vii) ~~a detailed description of the methodologies used in quantifying each class of cost and market benefit;~~ [EA considers that this should be deleted because the requirements are considered unduly detailed and prescriptive]

(viii) where relevant, the reasons why the *Distribution Network Service Provider* has determined that a class or classes of market benefits or costs do not apply to a *credible option*;

(ix) the results of a net present value analysis of each *credible option* and accompanying explanatory statements regarding the results;

(x) the identification of the proposed *preferred option*; and

(xi) for the proposed *preferred option*, the *Distribution Network Service Provider* must provide:

1. Details of the technical characteristics;

2. The estimated construction timetable and commissioning date;

3. Indicative capital and operational cost; and

4. A statement and accompanying detailed analysis that the *preferred option* satisfies the *Regulatory Investment Test for Distribution.*

(d) The *Distribution Network Service Provider* must seek submissions from *Registered Participants* and *interested parties* on the *preferred option* presented, and the issues addressed, in the *draft project assessment report.*

(e) The consultation period on the *draft project assessment report* must not be less than 30 business days from the publication date of the report.

(f) Within 4 weeks of the end of the consultation period on the *draft project assessment report*, at the request of an *interested party* or a *Registered Participant*, the *Distribution Network Service Provider* must use its best endeavours to meet with the *interested party* if:

(i) having considered all submissions, the *Distribution Network Service Provider*, acting reasonably, considers that the meeting is necessary or desirable; or

(ii) a meeting is requested by two or more *interested parties.*

9. Regulatory Investment Test for Distribution Process – Exemption from the draft project assessment report

(a) A *Distribution Network Service Provider* is exempt from publishing a *draft project assessment report* under section 8(a) if:

(i) the *Distribution Network Service Provider* has published a *Specification Threshold Test report* which determined that:

1. there is:

   a. no material potential for non-network options either to defer or remove the need for the proposed investment to address the *identified need*; and

   b. no material potential for the *identified need* to impact adversely on the quality of service experienced by end use customers; and

(ii) the estimated capital cost of the most expensive investment option which is both economically and technically feasible for meeting the *identified need* is less than $10 million (varied in accordance with a *cost threshold determination*).

10. Regulatory Investment Test for Distribution Process – Final project assessment report

(a) As soon as practicable after the end of the consultation period on the *draft project assessment report*, the *Distribution Network Service Provider* must, having regard to any submissions received on the *draft project assessment report*, publish a *final project assessment report* on its website.

(b) If the proposed investment is exempt from the *draft project assessment report* stage under section 9(a), the *Distribution Network Service Provider* must publish the *final project assessment report* on its website as soon as practicable after the publication of the relevant *Specification Threshold Test report*.

(c) The *final project assessment report* must be circulated to the *Distribution Network Service Provider*'s *Register of Interested Parties* within five business days of the publication of the report on the *Distribution Network Service Provider's* website.

(d) The *final project assessment report* must set out:

(i) the matters detailed in the *draft project assessment report* as required under section 8(c); and

(ii) summarise any submissions received from interested parties on the *draft project assessment report* and the *Distribution Network Service Provider's* response to each such submission.

(e) If the *preferred option* outlined in the *final project assessment report* has an estimated capital cost of $20 million or less, the *Distribution Network Service Provider* may discharge its obligations to publish its *final project assessment report* under sections 10(a) and (b) by including the *final project assessment report* as part of its *Distribution Annual Planning Report*.

(f) The AER shall take into account a *Distribution Network Service Provider's* application of the *Regulatory Investment Test for Distribution* and *final project assessment reports* when considering a *Distribution Network Service Provider's regulatory proposal* under Chapter 6 of the *National Electricity Rules.*

11. Dispute Resolution Process

(a) *Registered Participants*, the *AEMC, Connection Applicants, Intending Participants,* and *interested parties* may, by notice to the *AER*, dispute conclusions made by the *Distribution Network Service Provider* in the final project assessment report in relation to the application of the *Regulatory Investment Test for Distribution*.

(b) A dispute may not be raised in relation to any matters set out in the *final project assessment report* which:

(i) are treated as externalities by the *Regulatory Investment Test for Distribution*; or

(ii) relate to an individual's personal detriment or property rights.

(c) A person disputing a *final project assessment report* must within 30 business days after the publication of the *final project assessment report* or the publication of a *Distribution Annual Planning Report* containing the *final project assessment report:*

(i) give notice of the dispute in writing setting out the grounds for the dispute (the *dispute notice*) with the *AER*; and

(ii) at the same time give a copy of the *dispute notice* to the relevant *Distribution Network Service Provider*.

(d) Within 40 business days after receiving the *dispute notice* or within an additional period of up to 60 business days where the AER notifies interested parties that the additional time is required to make a determination because of the complexity or difficulty of the issues involved, the AER must either:

(i) reject any dispute by written notice to the person who initiated the dispute if the *AER* considers that the grounds for dispute are invalid, misconceived or lacking in substance;

(ii) notify the *Distribution Network Service Provider* that the dispute has been rejected; or

(iii) make and publish a determination, subject to section 11(f):

1. directing the *Distribution Network Service Provider* to amend the matters set out in the *final project assessment report*; or

2. stating that, based on the grounds of the dispute, the *Distribution Network Service Provider* will not be required to amend the *final project assessment report.*

(e) A *Distribution Network Service Provider* must comply with an *AER* determination made under section 11(d)(iii) within a timeframe proposed by the *AER* in its determination.

(f) In making a determination on the dispute, the AER:

(i) must only take into account information and analysis that the *Distribution Network Service Provider* could reasonably be expected to have considered or undertaken at the time that it performed the *Regulatory Investment Test for Distribution*;

(ii) must publish its reasons for making a determination;

(iii) may disregard any matter raised by a party in the dispute that is misconceived or lacking in substance;

(iv) may request further information from a party bringing a dispute, or from the *Distribution Network Service Provider,* in which case the period of time for rejecting a dispute or issuing a determination under section 11(d)(iii) is extended by the time it takes the relevant party to provide the requested further information to the *AER;* and

(v) where making a determination under section 11(d)(iii)(1), must specify a reasonable timeframe for the *Distribution Network Service Provider* to comply with the *AER's* direction to amend the matters set out in the *final project assessment report*.

(g) The *AER* may only make a determination under section 11(d)(iii) to direct the *Distribution Network Service Provider* to amend the matters set out in the *final* p*roject assessment report,* if it determines that:

(i) the *Distribution Network Service Provider* has not correctly applied the *Regulatory Investment Test for Distribution* in accordance with the *Rules*; or

(ii) there was a manifest error in the calculations performed by the *Distribution Network Service Provider* in applying the *Regulatory Investment Test for Distribution*.

(h) A disputing party or the *Distribution Network Service Provider* (as the case may be) must as soon as reasonably practicable provide any information requested under section 11(f)(iv) to the *AER*.

(i) The relevant period of time in which the *AER* must make a determination under section 11(d)(iii) is automatically extended by the period of time taken by the *Distribution Network Service Provider* or a disputing party to provide any additional information requested by the *AER*, provided:

(i) the *AER* makes the request for the additional information at least 7 business days prior to the expiry of the relevant period; and

(ii) the *Distribution Network Service Provider* or the disputing party provides the additional information within 14 business days of receipt of the request.

12. Regulatory Investment Test for Distribution Guidelines

(a) At the same time as the *AER* develops and publishes a proposed *Regulatory Investment Test for Distribution* under the *distribution consultation procedure*, the AER must also develop and publish guidelines for the operation and application of the *Regulatory Investment Test for Distribution* (*the Regulatory Investment Test for Distribution Application Guidelines)* in accordance with the *distribution consultation procedure* and this section.

(b) The *Regulatory Investment Test for Distribution Application Guidelines* must:

(i) give effect to and be consistent with this section;

(ii) provide guidance on:

1. the operation and application of the *Regulatory Investment Test for Distribution*;

2. the process to be followed in applying the *Regulatory Investment Test for Distribution*; and

3. how disputes raised in relation to the application of the *Regulatory Investment Test for Distribution* and its application will be addressed and resolved by the *AER.*

(c) The *Regulatory Investment Test for Distribution Application Guidelines* must provide guidance and worked examples as to:

(i) the acceptable methodologies for undertaking the *Specification Threshold Test;*

(ii) the acceptable methodologies for valuing the costs of an option;

(iii) the suitable modelling periods and approaches to scenarios development;

(iv) what may constitute an externality under the *Regulatory Investment Test for Distribution;*

(v) the acceptable methodologies for valuing the *market* benefits of an option,

(vi) what constitutes a *credible option*;

(vii) the appropriate approach to undertaking a sensitivity analysis;

(viii) the appropriate approaches to assessing uncertainty and risks; and

(ix) when a person is sufficiently committed to a *credible option* to be characterised as a proponent under section 3(c).

(d) The *AER* must develop and publish the revised *Regulatory Investment Test for Distribution* and *Regulatory Investment Test for Distribution Application Guidelines* by [insert date] and there must be a *Regulatory Investment Test for Distribution* and *Regulatory Investment Test for Distribution Application Guidelines* in force at all times after that date.

(e) The *AER* may, from time to time and in accordance with the *distribution consultation procedure*, amend or replace the *Regulatory Investment Test for Distribution* and *Regulatory Investment Test for Distribution Application Guidelines* developed and published under this section, provided that such amendments must be published at the same time.

(f) The *AER* may publish the *Regulatory Investment Test for Distribution*, the *Regulatory Investment Test for Distribution Application Guidelines,* the *Regulatory Investment Test for Transmission* and the *Regulatory Investment Test for Transmission Application Guidelines* in a single document.