A Response to Issues Raised in Submissions on the Draft Report

Submissions on the Draft Report closed on 13 August 2009. In total, 19 submissions were received. In preparing our Final Report, we have taken account of the issues raised in submissions and our considerations have been discussed throughout the report. The following table provides a summary of our responses to specific issues.

	Draft Recommendation	Issue raised in submissions	Commission Response
Engagement of non-network providers			
1.	Each DNSP would be required to use reasonable endeavours to engage with non-network providers and consider non-network alternatives.	Some DNSPs were concerned with how 'reasonable endeavours' would be defined and whether the use of the term would increase the potential for disputes to be raised.[88]	For the avoidance of doubt, this term in relation to the engagement of non-network providers has been deleted so that it is clear that each DNSP would be required to engage with non-network providers and consider non-network alternatives. We note that the term 'reasonable endeavours' is used elsewhere in the Rules.
2.	Each DNSP would be required to establish and implement a Demand Side Engagement Strategy, which is comprised of three parts: i) Facilitation Process Document; ii) Database of proposals and case studies; and	Stakeholders, including some DNSPs, were generally supportive of the Demand Side Engagement Strategy. However, some DNSPs submitted that the processes were too prescriptive and queried the benefits that may be achieved. They believed it may be more effective for AEMO to maintain a register of non-network providers and the database of case studies.[89]	The elements of the Demand Side Engagement Strategy provide transparency in the processes adopted by DNSPs and encourage and provide opportunities for DNSPs to engage with non-network providers. The strategy

88 For example, EnergyAustralia, Submission on the Draft Report, p. 5.

89 For example, submissions on the Draft Report from: ENERGEX, pp. 3-4; Aurora Energy, p. 6.

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	iii) Register of 'interested parties' (the Demand Side Engagement Register).		allows DNSPs to maintain their own operational protocols. Given the proposal to increase the RIT-D threshold, the role of the strategy will be enhanced. DNSPs should maintain the database and Demand Side Engagement Register as the purpose of these requirements are to enhance the relationship between DNSPs and non-network providers.
3.	The Demand Side Engagement Strategy would encourage proactive engagement of non-network providers.	A number of DNSPs submitted that requiring a Demand Side Engagement Strategy to encourage engagement of non-network providers was inconsistent with the AEMC's recommendations under the Demand Side Participation (DSP) Review where it found that DNSPs had private incentives to consider non-network options.[90]	We note that the draft findings under the DSP Review relate to an assessment of incentives under regulated price arrangements.[91] The objective of the Demand Side Engagement Strategy is to provide transparency to the processes utilised by DNSPs to assess non-network opportunities and promote

[90] See, for example, Jemena's submission on the Draft Report, p. 3.

[91] AEMC, *Review of Demand-Side Participation in the National Electricity Market*, Stage 2: Draft Report, 29 April 2009, Sydney, p. viii

	Draft Recommendation	Issue raised in submissions	Commission Response
			the engagement of non-network providers. For these reasons, we do not consider there are any inconsistencies in our findings under the two reviews.
4.	The framework comprises three components – the Demand Side Engagement Strategy, the annual reporting requirements and the RIT-D process.	Aurora Energy submitted that the proposed reporting requirements and engagement obligations under the RIT-D would provide sufficient opportunities to non-network providers without the further need for a Demand Side Engagement Strategy.	We note the purpose of the Demand Side Engagement Strategy is to provide transparency to the processes utilised by DNSPs to assess non-network opportunities and promote the engagement of non-network providers on a day-to-day basis. The strategy supports the information published in the DAPRs and provides for stakeholders to more actively participate in the RIT-D process.

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5.	The Draft Report sought comments on whether guidelines should be established for the implementation of the Demand Side Engagement Strategy.	TEC maintained its support for guidelines to be established as the implementation and delivery of the strategy were important considerations. The ENA noted that protocols may clarify how DNSPs should comply with the strategy and minimise the potential for disputes.[92] However, DNSPs also noted that there should not be further specification of aspects of the strategy.[93]	The Rules should be clear on the requirements for the process. In developing the Demand Side Engagement Strategy we have sought to provide a balance between outlining explicit provisions and allowing DNSPs to adapt processes to the requirements of their stakeholders. We have recommended that the AEMC conduct a review of the national framework in three years and it may be appropriate at that time to consider whether guidelines should be established.
Joint Planning			
6.	Joint planning would require TNSPs and DNSPs to meet on a regular, as required, basis to undertake annual planning. The parties would be required to use best endeavours to work together to achieve efficient planning outcomes and investments.	Some DNSPs submitted that the current joint planning provisions in the Rules were working and did not require changes.	We note that the recommendations did not seek to change the current joint planning obligations. It clarified that the parties would meet and use best endeavours to achieve planning outcomes.

92 ENA, Submission on the Draft Report, p. 9. Also, see for example, ENERGEX, Submission on the Draft Report, p. 2 of Annex A.

93 For example, ETSA, Submission on the Draft Report, p. 2.

	Draft Recommendation	Issue raised in submissions	Commission Response
7.	Investments identified by joint planning (joint investments) would be subject to one regulatory investment test, the RIT-T, in which case the $5m RIT-T threshold would apply. The Draft Report also noted that joint investments between $2m and $5m would also need to be assessed under the RIT-T, however, these investments would be exempt from the project specification and draft project assessment reporting requirements.	A number of DNSPs did not support the application of the RIT-T to all joint investments as some joint investments may have a small transmission component and/or be driven by distribution needs. In these cases, they consider that the RIT-D should apply. In addition, they considered that the recommendation was inconsistent with the RIT-T provisions where transmission investments to meet distribution needs would be assessed under the RIT-D.[94] Some DNSPs submitted that if the RIT-T threshold of $5m is to apply, then the projects below this threshold should not be subject to the RIT-T at all. Some DNSPs also noted there was a lack of clarity as to whether the RIT-T would apply to transmission connection investments.[95]	As the RIT-D threshold has been amended to $5m, no test would apply to joint investments less than $5m. The requirement for transmission-distribution connection investments to be assessed under the RIT-T has been clarified.
8.	The Draft Report sought comments on any specific requirements for joint planning in Victoria.	The Victorian DNSPs raised a number of issues relating to their planning functions compared to those of AEMO. Issues on the definition of prescribed and negotiated transmission services in the Rules transmission network connections were also raised.	This issue is discussed in Chapter 2 and an outline of the issues as reported by stakeholders is provided in Appendix G.
9.	DNSPs will be required to meet regularly, where required, with other DNSPs to jointly plan.	Integral Energy considered there be would be little benefit in having an obligation to meet regularly to undertake joint planning with other DNSPs as these planning events occur very rarely.	We acknowledge that there may be limited joint DNSP investments in some jurisdictions. DNSPs would only be required to meet

94 For example, submission on the Draft Report from: Aurora Energy p. 6; ENA p. 13.

95 For example, Jemena, Submission on the Draft Report, p. 4.

	Draft Recommendation	Issue raised in submissions	Commission Response
			regularly where there is a reason to do so.
Publication of the Distribution Annual Planning Report (DAPR)			
10.	The Draft Report recommended that each DNSP would conduct a public forum on its DAPR within two months of publication.	A number of DNSPs submitted that a public forum should only be required if requested by a "registered non-network proponent".[96] Non-network providers supported the requirement to conduct a public forum.[97] As the draft recommendations require the DAPR to be published by 31 December each year, it was suggested that the two month period should be extended to three months giving consideration to the new year holiday period.	We agree that these suggestions are reasonable and have amended the final recommendations: i) a public forum would only be required if requested by a stakeholder; and ii) if requested, the public forum must be held within 3 months of the DAPR being published.
11.	The DAPR is to be certified by the CEO and a Director or Company Secretary.	DNSPs submitted that this level of certification was excessive as the planning report would be an "operational document" and DNSPs should be allowed to retain their own delegations for approval of the DAPR.[98] Non-network advocates and providers supported the certification process as it would increase confidence for users of the reports.[99]	We consider that certification by the CEO and a Director or Company Secretary would provide confidence in the contents of the DAPR and should be maintained.

96 See for example, ENA's submission on the Draft Report, p. 12.

97 For example, ATA, Submission on the Draft Report, p. 3.

98 For example, Jemena, Submission on the Draft Report, p. 4.

99 For example, TEC, Submission on the Workshop/Workshop Papers, p. 5.

	Draft Recommendation	Issue raised in submissions	Commission Response
DAPR – Reporting Requirements			
12.	Each DNSP would be required to publish a DAPR, which sets out information forecasts, systems limitations and other general information.	The AER considers that the DAPR would provide transparency and accountability to DNSPs' actions and would assist the AER in its regulatory and enforcement roles. It sees merit in producing guidelines for the DAPR to provide for a consistent format and approach across DNSPs.	We consider that the Rules should be clear on the content requirements for the DAPR. The requirement for guidelines could be considered when the AEMC conducts its review of the framework.
13.	The DAPR would include information on potential options to address system limitations, including non-network solutions and forecasts would be prepared giving consideration to the level of embedded generation.	The DPI submitted that the report should cover the DNSPs' expectations of embedded generation and planning efforts should extend to the means of accommodating this to deliver the most efficient outcome in the long term. Non-network providers submitted that additional information should be provided on how the DNSPs have carried out the requirements under the Demand Side Engagement Strategy. TEC submitted that there would be additional reporting on the demand management proposals received and implemented as well as the expenditure on, and savings achieved, implementing demand side options.[100]	We believe our recommendations meet the requirements of the DPI as DNSPs would be required to consider the level of embedded generation in their forecasts, consider non-network solutions to any potential system limitations and also consider non-network options with assessments under the RIT-D. In increasing the RIT-D threshold to $5m, we consider there is merit to add to the reporting requirements so that additional information such as the demand side activities

100 TEC, Submission on the Draft Report, p. 5.

	Draft Recommendation	Issue raised in submissions	Commission Response
			planned by the DNSPs in the forward planning period and any other significant investments (such as investments in "smart" technology) be included.
14.	Identification of the timing of system limitations (month, year) would need to be reported.	Ergon Energy submitted that it currently forecasts the season in which a system limitation would occur and, therefore, would not be able to forecast the exact month.	As forecasts would be subject to a number of variables, we have clarified that the timing of system limitations would be based on the DNSP's best estimate.
15.	System limitations would include situations where investments were required for asset replacement.	ETSA submitted that small asset replacement occurs on an ongoing basis to sub-transmission networks; often for only a few thousand of dollars per unit. For this reason, ETSA submitted that a threshold should only apply to major assets – perhaps a $2m threshold.	The requirements have been clarified to refer to system limitations on sub-transmission lines rather than "sub-transmission assets". We consider that this asset threshold would ensure that only these major assets would be included.
16.	Forecasts of any overloaded primary distribution feeders and the potential solutions being considered by the DNSPs to address the overload.	Some DNSPs have noted that forecasts of primary distribution feeders were generally prepared on a cyclic basis, not annually. In addition, the volume of primary distribution feeders could be quite high for some DNSPs and the lead time on any projects would generally be quite short.	We note that, due to the number of primary distribution feeders and the nature of preparing forecasts for these assets, we have

	Draft Recommendation	Issue raised in submissions	Commission Response
			amended the recommendations to require information on overloaded primary distribution feeders *where they have been identified* by the DNSP.
17.	Where an overloaded primary distribution feeder has been identified, also identify the relevant connection points at which a reduction in load would defer the overload.	ETSA submitted that, in this situation, the connection points would be customer connection points of which there may be thousands.[101]	We have clarified that this information should be provided only if it is identified by the DNSP.
18.	The Draft Report sought comments on whether the DAPR should include regional development plans.	Some DNSPs submitted they consider regional development plans to be outside the requirement of the DAPR and the costs would outweigh any potential benefits. [102] CUAC and TEC submitted regional development plans would be beneficial as they would assist non-network providers in identifying the location of potential non-network investments. The South Australian Government supported the inclusion of regional development plans as they would increase transparency.	Non-network providers and investors would likely benefit significantly from regional development plans as they would enable them to more efficiently identify areas for potential investment. As DNSPs would already identify the location of system limitations summarising the information in a regional development plan should not add significant costs.

101 ETSA, Submission on the Draft Report, p. 11.

102 See for example, ENA's submission on the Draft Report, p. 18.

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19.	The Draft Report sought comments on whether significant investments in smart grids/meters should be captured in the DAPR.	Some DNSPs submitted that investments in these areas would not be directly related to system limitations and therefore should not be included. In addition, the DNSPs considered the issues should be addressed by the MCE through its review on smart meters.[103] Although ETSA supported a high level of reporting on significant investments.[104] CUAC and TEC submitted that it would be important to capture significant investments in this area.[105]	We consider that by requiring the additional information outlined above in relation to non-network initiatives, significant investments in smart grids/metering would be captured. As a qualitative assessment would be provided, impacts on DNSPs would be minimised.
20.	The DAPR should include high level information on reliability and the quality of supply standards and a qualitative assessment of the performance of the network over the previous year where the relevant standards were not met.	EnergyAustralia (EA) submitted that the quality of supply standards in the Rules are at a high level and as such it would be difficult to demonstrate compliance. EA considers that the requirement is not appropriate and goes beyond what is commonly required by the Rules. Some DNSPs did not support the inclusion of asset management information as they considered this was outside the requirements of the Review.[106]	The recommendations require summarised and qualitative information, which we do not consider to be onerous. However, to clarify the provisions, we have amended the requirements to refer to the relevant performance standards. We consider that asset management is an important consideration in the planning process. The DAPR would only require high level

103 For example Ergon Energy's submission on the Draft Report, p. 14.

104 ETSA, Submission on the Draft Report, p. 5.

105 CUAC, Submission on the Draft Report, p. 3; TEC, Submission on the Draft Report, p. 6.

106 For example, ENA's submission on the Draft Report, p. 19.

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			information.
21.	The DAPR would include information on investments that have been, or are in the process of being, assessed under the RIT-D, including information on any potential material impacts on connection charges and distribution use of system charges that may be estimated.	ETSA submitted that connection charges can be very specific to timing and the size and nature of load. It is also expensive and difficult to calculate. It suggests that a threshold be set to only include those projects that will raise the DUOS charge by a significant amount, say 1%.	We note the issues raised by ETSA and consider that the proposed arrangements are consistent with what has been suggested by ETSA as only "material impacts" on the charges would be required and to the extent that they may be estimated.
Regulatory Investment Test for Distribution (RIT-D)			
22.	The Draft Report discussed that the RIT-D would identify the preferred option for network investment which maximises the present value of net economic benefits. Where a proposed investment is required to meet deterministic reliability standards, the preferred option may have a negative net present value.	Some DNSPs submitted that a negative present value (NPV) should also be allowed in other circumstances e.g. to meet a probabilistic reliability standard or other jurisdictional requirements.[107] ETSA considered that the negative net present values should be permitted whenever a DNSP is compelled to resolve a constraint by an external party or agreement and not just by its Schedule 5 obligations. This would also include the DNSP's planning criteria as published in the DAPR as it considered that these have been established to ensure compliance with jurisdictional service standard obligations (e.g. reliability standards).[108]	We note that a negative NPV could result from requirements to meet jurisdictional requirements and have amended the requirements accordingly. This issue is discussed in Chapter 4. With respect to ETSA's comment, this would be a negotiated service which would be exempt from the RIT-D.

107 For example, see submissions on the Draft Report from: ENA, pp. 20-21; EnergyAustralia, p. 14; Ergon Energy, p. 16; Integral Energy, p. 5.

108 ETSA, Submission on the Draft Report, p. 7.

109 EnergyAustralia's submission on the Draft Report, pp. 13-14.

110 ENA's submission on the Draft Report, p. 20.

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		EnergyAustralia considered that there must be the ability for refurbishment or replacement projects, which results in augmentation to the network and the augmentation component cost is $2m or greater, to have a negative net economic benefit. It considered that 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. It proposed an amendment to specification 1(c) to address this.[109] ENA raised a similar point.[110]	With respect to EnergyAustralia and ENA's comments, this issue is discussed in Chapter 4.
23.	The RIT-D would 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.	EnergyAustralia considered that distribution planning does not generally require the identification of alternative scenarios of demand growth and development which is characteristic of transmission developments and would be inappropriate and disproportionate under the RIT-D. It suggested that it is more appropriate to take a sensitivity analysis approach to demand forecasts and recommended an amendment to specification 1(j)(i) to reflect the use of this approach.[111]	We note EnergyAustralia's comments. It is assumed that the AER guidelines would provide guidance on the specific requirements.
24.	The term "capital cost" is used in the RIT-D.	ENERGEX sought clarification on what would be "capital cost". Is it the NPV or the initial capital cost of the augmentation component of a project?[112]	We note the issue raised and consider the references to capital costs are clear in the Rules. This term is also consistent with that of the RIT-T. Further clarification would be a matter for the AER.

111 EnergyAustralia's submission on the Draft Report, p. 14.

112 ENERGEX, Submission on the Draft Report, p. 2 of Annex B.

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25.	A DNSP must consider all options that could reasonably be classified as credible options.	Ergon Energy did not understand the purpose of the criteria under specification 3(b) in identifying a credible option, noting that the current Regulatory Test adopts this set of criteria in requiring the DNSP to consider alternative options without bias.[113] ETSA considered that credible options at this stage of the process should be identified based solely on their ability to address the constraint, economic and technical feasibility and likely availability. It submitted that questions of ownership, energy source, technology etc. are vital but only at the end of the process and then based on commercial negotiation and in the light of evidence brought to light by the RIT-D process. It therefore suggested that specification 3(b) should be deleted.[114]	We note that the provision would provide certainty to non-network providers by setting out the potential options to be considered. This approach is also consistent with that of the RIT-T.
26.	DNSPs would undertake a case by case project assessment process to identify the most economic option when considering network expansions and augmentations. This process is to be triggered using appropriate thresholds.	TEC questioned the likely efficacy of the RIT-D which it considered did not appear to mandate that the DNSP to implement the most efficient investment or prescribe that the investment must be consistent with the estimated costs used in the RIT-D.[115]	We consider TEC's comment would be inconsistent with the Terms of Reference for this Review. We have clarified that the AER would have regard to the RIT-D outcomes in its determination of efficient capex.
27.	The RIT-D threshold would be assessed against the "most expensive	Some DNSPs submitted that assessing the RIT-D threshold against the most expensive option which is technically and	This issue is discussed in

113 Ergon Energy, Submission on the Draft Report, pp. 21-22.

114 ETSA, Submission on the Draft Report, p. 12.

115 TEC, Submission on the Draft Report, pp. 7-8, 10

	Draft Recommendation	Issue raised in submissions	Commission Response
	option which is technically and economically feasible".	economically feasible would not work and would create a significant administrative burden. They requested clarifications on how this would be applied. Some DNSPs suggested that "most likely option" would be a better test.[116] CUAC also recommended for greater clarity on this.[117]	Chapter 4.
28.	The Draft Report outlined that the Regulatory Investment Test for Distribution (RIT-D) would have a threshold of $2m.	Some DNSPs, Grid Australia and the AER submitted that the $2m threshold was too low and supported an increase to $5m. They considered that this would reduce regulatory burden and maintain consistency with the RIT-T. [118] ETSA considered that there have been increases in construction costs (since 2003 when the current ESCOSA Guideline 12 specified a $2m threshold) and that the threshold should be increased to at least $3m in line with inflation or preferable 1% of annual revenue requirement (which is half of the AER's material projects threshold of significant projects of 2%).[119] Non-network providers and advocacy groups supported a threshold that was as low as possible. TEC considered that there was no justification to increase the current regulatory test threshold of $1m. It considered that an explanation needs to be provided on which input costs have increased to justify an increase in the threshold. It proposed that DNSPs should	We have recommended that the RIT-D threshold be amended to $5m. This is discussed in detail in Chapter 4.

116 For example, see submissions on the Draft Report from: Aurora Energy, pp. 8, 10; ENA, pp. 20, 22-23; ENERGEX, pp. 2, 4; Ergon Energy, pp. 14, 16; ETSA, p. 7.

117 CUAC, Submission on the Draft Report, p. 3.

118 For example, see submissions on the Draft Report from: AER, p. 4; Aurora Energy, p. 8; ENA, pp. 20, 23; ENERGEX, p. 2; EnergyAustralia, p. 12; Ergon Energy, p. 17; ETSA, p.7; Grid Australia, p. 2; Integral Energy, pp. 5-6; Jemena, p. 4; Victorian distribution businesses, p. 10.

119 ETSA, Submission on the Draft Report, p. 7.

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		publish standard offers for the procurement of non-network solutions for capital expenditure in excess of $200k.[120]	
29.	The AER would review the RIT-D threshold once every three years.	ENA and Ergon Energy supported the AEMC's proposal for the AER to review the threshold every three years.[121]	We note the submissions received and have retained the requirement for the three year review of the RIT-D threshold.
30.	The RIT-D would involve an initial screening test, project assessment process, and a project specification stage.	ENA considered that the multi-stage approach to the RIT-D is overly complex for application in the distribution planning environment and to the relatively large number of projects which DNSPs carry out.[122] Jemena and Ergon Energy agreed with the ENA's concern on this.[123]	We note that the amendment of the threshold to $5m and the changes to the consultation requirements have simplified the process and addressed a number of concerns raised.
31.	The RIT-D would have an initial screening test, the Specification Threshold Test (STT), to determine whether additional consultation and reporting would be required before the project assessment process.	Integral Energy considered that the STT provides an appropriate degree of discretion.[124] ETSA suggested that if a DNSP considers that the RIT-D is a certainty, due to the size or nature of the project or the obvious potential for demand side management, the DNSP should not be required to undertake a STT.[125] ENA proposed that the requirements of STT could be	We note Integral Energy's comment. We do not agree with ETSA's comment because we consider the STT to be an essential part of the process and provides for transparency in the

120 TEC, Submission on the Draft Report, pp. 7-8.

121 ENA, Submission on the Draft Report, p. 23.

122 ENA, Submission on the Draft Report, p. 20.

123 Submissions on the Draft Report from: Jemena, p. 2; Ergon Energy, p. 6.

124 Integral Energy, Submission on the Draft Report, p. 6

125 ETSA, Submission on the Draft Report, p. 9.

	Draft Recommendation	Issue raised in submissions	Commission Response
	The RIT-D would have an initial screening test, the Specification Threshold Test (STT), to determine whether additional consultation and reporting would be required before the project assessment process.	simplified to be clear that investments required to meet jurisdictional security and reliability standards would not meet the requirements of the STT.[126] Referring to specification 6(c)(ii), Ergon Energy did not support the requirement to publish a STT Report or for the STT process to be subject to the dispute resolution process where an investment does not proceed to the final project assessment stage.[127]	process. We do not agree with ENA's comment because we consider that this assumes no non-network option can address reliability needs. The STT would be triggered if there is potential for non-network solutions. With respect to Ergon Energy's comment, we consider that publication of the STT report provides for transparency. We also consider that the whole RIT-D process would be subject to the dispute resolution process at the end of the RIT-D process rather than during the process to avoid delays during the project.

126 ENA, Submission on the Draft Report, p. 28.

127 Ergon Energy, Submission on the Draft report, pp. 18, 22.

	Draft Recommendation	Issue raised in submissions	Commission Response
32.	The STT would consider whether there was material potential for adverse impacts on the quality of service for end users.	Some DNSPs sought clarification on the intent of the requirement relating to the material potential for the identified need to adversely impact on end users' quality of service.[128] ENA was concerned that it would be very difficult to assess this.[129] ETSA proposed that the specifications 6(b)(iii), 7(a)(i) and 9(a)(i) should be clarified with respect to this.[130] Ergon Energy referred to specification 6(c)(i)(2) in relation to this.[131] ENA and Aurora Energy was concerned that this term could lead to disputes and delays.[132] TEC did not support the STT as it considered that it places an inappropriate level of discretion with DNSPs. It proposed that the ability to avoid the project specification stage of the RIT-D through the demonstration of there being 'no material potential' for non-network solutions should be rejected and the reduced consultation time-frames should be dropped.[133]	We consider that DNSPs should directly consult with any customers who would be adversely impacted from a proposed investment. We have therefore amended the requirements such that such consultation would occur once the preferred option has been identified and specified, which would be outside the RIT-D process. This is discussed in more detail in Chapter 4.
33.	Under the project specification stage DNSPs would be required to consult to request alternative proposals to meet the identified need. If it has demonstrated prior engagement with non-network providers, an	Some DNSPs considered that the RIT-D process was too complicated and suggested that it be simplified by having one consultation period of one month for projects that pass the specification threshold test (instead of a one month or six month consultation period).[134] Some DNSPs also proposed	By increasing the threshold to \$5m, we consider an appropriate balance would be removing the accelerated consultation period under the project specification stage.

128 For example, see submissions on the Draft Report from: Aurora Energy, p. 9; ENA, p.28; Ergon Energy, p. 23; EnergyAustralia, p. 12; Integral Energy, p. 6.

129 ENA, Submission on the Draft Report, p. 28.

130 ETSA, Submission on the Draft Report, pp. 9, 12, 13.

131 Ergon Energy, Submission on the Draft Report, p. 23.

132 Submissions on the Draft Report from: Aurora Energy, p. 9; ENA, p. 28; Integral Energy, p. 6.

133 TEC, Submission on the Draft Report, p. 8.

134 For example, see submissions on the Draft Report from: Aurora Energy, pp. 9-10; ENA, pp. 25-26; Victorian distribution businesses, p. 10.

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	accelerated consultation process would be available.	removing the requirement for projects greater than $20m to publish a separate final report.[135] Some DNSPs were also concerned with how "constructive engagement" or "prior engagement" would be required to qualify for the accelerated consultation process.[136] ENERGEX considered that the six month consultation timeframe and accelerated consultation option should be removed as it was redundant when DNSPs would be required to publish a Demand Side Engagement Facilitation Document and consult with non-network providers as part of a Demand Side Engagement Strategy.[137] CUAC and TEC were concerned that the accelerated consultation process did not take into account the time and resources that non-network providers would require to develop their proposals.[138] TEC also considered that "constructive engagement" was an ambiguous term and was unclear on how DNSPs would qualify for accelerated consultation.[139]	However, we consider that the consultation period should then be four months as opposed to six months. This should also simplify the overall process. This is discussed in more detail in Chapter 4.
34.	The Specification Threshold Test (STT) would determine whether	Ergon Energy considered that the Project Specification Stage should be initiated either where the DNSP has not met the	We note the issue raised. We consider that it is appropriate

135 For example, see submissions on the Draft Report from: Aurora Energy, p. 9; ENA, pp. 25- 26, 29; ENERGEX, p. 3; Ergon Energy, p. 6; Jemena, p. 4; Victorian distribution businesses, p. 10.

136 For example, see submissions on the Draft Report from: Aurora Energy, p. 9; ENA, pp. 26, 29, 31; ENERGEX, p. 3 of Annex A; EnergyAustralia, p. 13; Ergon Energy, p. 18; Integral Energy, p. 7; Victorian distribution businesses, p. 10.

137 ENERGEX, Submission on the Draft Report, pp. 3-4 of cover letter, pp. 3-4 of Annex A.

138 See submissions on the Draft Report from: CUAC, p. 3; TEC, p. 9.

139 TEC, Submission on the Draft Report, p. 9.

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	additional consultation and reporting would be required before the project assessment process.	STT or where the most likely option for addressing the identified need has a capital cost that is greater than $20m.[140]	that the STT would determine whether an initial stage of consultation would be required depending on whether there was potential for non-network options.
35.	In the project specification report, DNSPs would provide information including a description of all investment options to meet the identified need.	Some DNSPs submitted that requiring the DNSP to provide information on any potential non-network alternatives was unnecessary as they should not be required to "second guess" potential non-network solutions.[141] Ergon Energy considered that information on non-network alternatives (including costs and benefits) should be provided by non-network providers in response to the project specification report which the DNSP would assess.[142] ETSA recommended editorial changes to specifications 7(c)(vi)(3) and 7(c)(vi)(2) which related to the project specification report. It also recommended that cost data should only be supplied for network investment options proposed by the DNSP.[143] Integral Energy did not consider it reasonable for DNSPs to be required to provide a description of all investment options to meet the identified need and believed that the project	The DNSPs should provide any information to the extent that is possible to the best of their endeavours. We agree that DNSPs should not be required to "second guess" potential non-network solutions. In relation to any lack of clarity of the content of the project specification report, we consider that this would be addressed in the Rule change process.

140 EnergyAustralia, Submission on the Draft Report, p. 23.

141 For example, see submissions on the Draft Report from: Aurora Energy, p. 8; ENA, pp. 25, 29; ETSA, pp. 9, 13; Integral Energy, p. 6; Victorian distribution businesses, p. 10.

142 EnergyAustralia, Submission on the Draft Report, pp. 23-24.

143 ETSA, Submission on the Draft Report, p. 13.

	Draft Recommendation	Issue raised in submissions	Commission Response
		specification report should only provide information on identified network investment options.[144]	
36.	DNSPs would be required to publish any preliminary or supplementary information where such information is likely to enhance the ability of interested parties to engage constructively on the project specification report.	Ergon Energy and Integral Energy did not support a requirement for DNSPs to publish any preliminary or supplementary information.[145]	We consider that providing preliminary and supplementary information would assist non-network providers and this requirement should remain unchanged.
37.	The absence of a non-network proponent does not exclude a distribution investment option from being considered a credible option.	Ergon Energy considered that it would be difficult to proceed with an option that has no proponent and therefore no certainty over implementation and its ability to meet the identified need.[146]	We consider that one of the objectives of the RIT-D is to provide a level playing field for all potential solutions and to take a technologically neutral approach. Where the best option identified is a non-network solution without a proponent, the framework provides that the next best option may be adopted.

144 Integral Energy, Submission on the Draft Report, p. 6.

145 See submissions on the Draft Report from: Ergon Energy, pp. 21-23; Integral Energy, p. 7.

146 Ergon Energy, Submission on the Draft Report, pp. 21-23.

	Draft Recommendation	Issue raised in submissions	Commission Response
38.	Specific requirements for reporting under the project specification process was outlined.	ETSA considered that the annual deferred augmentation charge, which is the value of any deferral in the network solution, is a major element of interest to demand side management solution providers and has not been included in the reporting requirements.[147]	We agree with this point and have amended the requirements to include this provision. This is clarified in Chapter 4.
39.	If the DNSP 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 the end of the consultation period on a project specification report or the publication by the DNSP of a STT report, the DNSP must publish a draft project assessment report on its website.	Ergon Energy proposed that the DNSP provide AEMO with a copy of its draft project assessment report and publishes this on its website.[148]	We consider that DNSPs should be responsible for publishing the draft project assessment report on its website and notify AEMO of this publication.
40.	The draft project assessment report must include a detailed description of the methodologies used in quantifying each class of cost and market benefit.	Ergon Energy did not support this requirement as it considered this to be inconsistent with the objective of the RIT-D for assessing market benefits to be at the DNSP's discretion.[149]	We agree that DNSPs should be given discretion to assess market benefits where applicable. However, for reasons of transparency, we also consider that there is a need for DNSPs to provide its reasons for determining the class or classes of market costs and benefits.

147 ETSA, Submission on the Draft Report, p. 9.

148 Ergon Energy, Submission on the Draft Report, p. 23.

149 Ergon Energy, Submission on the Draft Report, p. 24.

	Draft Recommendation	Issue raised in submissions	Commission Response
41.	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 DNSP must use its best endeavours to meet with the interested party.	ETSA believed that it would be in the public interest that if an interested party requested a meeting then that meeting should be held. However, it considered the requirement that a meeting would be required only if two parties request the meeting would invite gaming of the regulations and would not deter nuisance requests.[150]	We consider that the parties would only have to meet if it has been requested and consider ETSA's concerns to be a minor risk.
42.	For investments where the preferred solution has an estimated capital cost of $20m or less, DNSPs could publish their final project assessment report as part of their DAPR, where the timing was appropriate.	Some DNSPs did not support the requirement to publish the final report separately if the preferred solution has an estimated capital cost greater than $20m.[151]	We note that a final project assessment report would need to be published in all cases. The provisions provide for the option of publishing the report in the DAPR where the estimated capital costs is less than $20m.
43.	The RIT-D process requires DNSPs to circulate the STT report, project specification report, draft project assessment report and final project assessment report to their Register of Interested Parties within 5 business days of the publication of the report on the DNSPs website.	ETSA suggested that DNSPs should only be required to notify the DNSP's Register of Interested Parties via email of the STT report, project specification report, draft project assessment report and final project assessment report which would be made available on the DNSP's website rather than sending potentially large emails.[152]	We agree with ETSA's comments and have clarified the requirements.

150 ETSA, Submission on the Draft Report, p. 13.

151 See submissions on the Draft Report from: Aurora Energy, pp. 9-10; ENA, p. 27; Ergon Energy, p. 24.

152 ETSA, Submission on the Draft Report, pp. 12-13.

	Draft Recommendation	Issue raised in submissions	Commission Response
44.	For investments that do not pass the STT, DNSPs would publish a report outlining the results of the assessment against the STT requirements.	Some DNSPs believed this report was unnecessary and were concerned with the potential for disputes to be raised.[153]	We consider that the requirement for this report provides for transparency and certainty. If disputes were raised then this would only be raised at the end of the RIT-D process (as opposed to during the process).
45.	Refurbishment or replacement expenditure which also results in an augmentation to the network, where the estimated capital cost for the augmentation component is less than $5m, would be exempted from the RIT-D.	Submissions from NSPs strongly supported the exclusion of replacements from the RIT-D and stated that the RIT-D should only apply to augmentations to a distribution network.[154] The Victorian distribution businesses noted that, in practice, distinguishing between asset replacement and augmentation expenditure would be problematic where old assets are replaced with modern equivalents of a different technology, rating or capacity.[155] TEC considered that exemption for replacement assets should be dropped as non-network solutions can provide an alternative to replacement, just as they can for augmentation projects and should be able to benefit from a transparent RIT-D process.[156]	We note NSPs' support for the exemption of replacement expenditure. With respect to the Victorian distribution businesses' comment, we consider that the draft Rules would clarify this issue. We do not agree with TEC's comment because we consider the exemption of replacement expenditure would be proportionate.

153 For example, see Ergon Energy, Submission on the Draft Report, p. 18.

154 For example, see submissions on the Draft Report from: Aurora Energy, p. 8; ENA, p. 25; ENERGEX, p. 4; Victorian distribution businesses, p. 10.

155 Victorian distribution businesses, Joint submission on the Draft Report, p. 10.

156 TEC, Submission on the Draft Report, p. 8.

	Draft Recommendation	Issue raised in submissions	Commission Response
46.	Only investments required to "augment" a distribution network would be subject to the RIT-D. Investments such as communications and IT systems, would not be subject to the RIT-D.	ENERGEX, Ergon Energy and the Victorian distribution businesses considered that augmentation should not apply to non-system assets and secondary system assets such as IT, communication projects, land acquisition, conduit/duct instalments for future networks, and protection systems.[157] Some DNSPs considered that such expenditure would not be associated with the expansion of the network to meet demand and would not provide opportunities for non-network alternatives.[158] In contrast, Jemena did not support the exclusion of certain network expenditure such as IT and communications equipment investment because it considered such expenditure would be an essential component of smart grid investment in the future and needed to have benefit assigned to it to the extent that the expenditure will form part of a DNSP's regulatory asset base.[159]	We agree with the comments from ENERGEX, Ergon Energy and the Victorian distribution businesses. The definition for distribution investment has been clarified. With respect to Jemena's comment, we consider that information such as IT and communications equipment would be included in the DAPR, but would be exempt from the RIT-D.
47.	A number of distribution investments would be exempt from the RIT-D.	ENA and the Victorian distribution businesses proposed for the exclusion of reliability improvement (STPIS-driven) capital expenditure from the RIT-D.[160]	We do not agree with these comments because this would be a matter for the AER to consider.
48.	The Draft Report sought comments on whether primary distribution feeders should be exempt from the	Some DNSPs supported excluding primary distribution feeders due to the number of projects and the short lead time (less than 12 months) for the majority of such projects.[161]	We have not excluded primary distribution feeders from the RIT-D process given

157 Submissions on the Draft Report from: ENERGEX, p. 4; Ergon Energy, p. 17; Victorian distribution businesses, pp. 10-11.

158 ENERGEX, Submission on the Draft Report, p. 4.

159 Jemena, Submission on the Draft Report, pp. 4-5.

160 See submissions on the Draft Report from: ENA, p. 25; Victorian distribution businesses, p. 11.

	Draft Recommendation	Issue raised in submissions	Commission Response
	RIT-D.	Ergon Energy would only support the inclusion of primary distribution feeders if the capital costs of the project exceeded its proposed RIT-D threshold of $5m.[162] In contrast, ETSA stated that with a proposed increased threshold to $3m it would not be necessary to exclude primary distribution feeders as the bulk of the work would be excluded by the increased threshold.[163]	the increase in the RIT-D threshold to $5m.
49.	"Urgent and unforseen" investments would be excluded from the RIT-D. An investment would be urgent and unforseen if it is required to be operational within six months; the identified need was not reasonably foreseeable by and was not beyond the reasonable control of the DNSP; and failure to address it is likely to materially adversely affect reliability and secure operations.	Some DNSPs submitted that the 6-month period was too short giving consideration to the time required to implement projects.[164] Some DNSPs submitted that 12 months would be appropriate. Some DNSPs also submitted that the definition should be amended such that it refers to projects that are required "to commence" rather than "be operational" within 6 (12) months.[165] TEC suggested that defining "urgent and unforseen" was problematic and were unconvinced that reputational costs would have any bearing against the risk of the exemption being exploited.[166] Ergon Energy considered that a test of foreseeability would be more appropriate (than beyond the reasonable control of the	For consistency with the RIT-T exemption for urgent and unforeseen investments, a similar exemption has been applied under the RIT-D.

161 For example, submissions on the Draft Report from: Aurora Energy, p. 8; ENA, p. 31; EnergyAustralia, p. 12; Integral Energy, p. 6; Victorian distribution businesses, p. 10.

162 Ergon Energy, Submission on Draft Report, p. 17.

163 ETSA, Submission on the Draft Report, pp. 8-9.

164 For example, see submissions on the Draft Report from: ENA, pp. 24-25; Ergon Energy, p. 21.

165 For example, see submissions on the Draft Report from: Aurora Energy, p. 9; ENA, pp. 8, 24-25; EnergyAustralia, p. 11-12; Ergon Energy, p. 21; ETSA, pp. 8, 12.

166 TEC, Submission on the Draft Report, p. 8.

	Draft Recommendation	Issue raised in submissions	Commission Response
		DNSP) as it can be applied against existing and established forecasting and planning processes.[167] ETSA recommended that this requirement should be removed as it considered that the public embarrassment of admitting the failure in the APR should be sufficient punishment without inflicting damage or risk of damage on innocent third parties.[168] Ergon Energy considered that meeting network reliability criteria and achieving a secure operating state should not be subject to a materiality test in the context of addressing an urgent and unforeseen network issue that would otherwise put at risk the reliability of the distribution network.[169]	
50.	The RIT-D would exempt connection assets, which would not be part of the DNSP's shared network.	ETSA submitted that not exempting large customer connections is contradictory as it would: be difficult to identify any connection assets that would not eventually be part of the shared network; defeat the purpose of the exemption; and impact significantly on the ability of a DNSP to act quickly to meet the requirements of customers.[170] It also requested that a new exemption should apply to requests from external parties for connection within a period that does not permit the performance of a RIT-D.[171] ETSA sought clarification on what is negotiated service or a direct service for situations where a new customer connection	We agree with ETSA's comments and consider that all customer connection assets should be exempt. This is addressed in Chapter 4. In relation to ETSA's question about negotiated or a direct service, it would be a negotiated service.

167 Ergon Energy, Submission on the Draft Report, p. 21.

168 ETSA, Submission on the Draft Report, p. 12.

169 Ergon Energy, Submission on the Draft Report, p. 21.

170 ETSA, Submission on the Draft Report, pp. 8-12.

171 ETSA, Submission on the Draft Report, p. 12.

	Draft Recommendation	Issue raised in submissions	Commission Response
		causes an augmentation of the network that is only partly paid for by the customer.[172]	
51.	The RIT-D is an "exclusive" test where a list of assets that are excluded from the test are outlined.	Aurora was concerned with specifying exemptions and the potential for ambiguity and a source for unwarranted dispute and delay. It strongly believed that this should be a list of types of distribution investments that shall be subject to the RIT-D.[173]	To provide for the RIT-D to capture the necessary investments, we consider that an "exclusive" approach would be more suitable.
52.	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 option to decide which market benefits are included.	Most DNSPs generally considered the provisions for market benefits to be adequate.[174] CUAC referred to its previous submission which listed market benefits and how non-market and social benefits may be included.[175] TEC supported a full cost benefit approach and also supported the previous list of items for cost benefit analyses from ATA and CUAC.[176] The Victorian Department of Primary Industries submitted that the list of market benefits should include embedded generation.[177] ETSA considered that embedded generating units should be qualified as either existing or committed.[178]	With respect to CUAC and TEC's comments, we consider that the list that we provided to be sufficient and that the AER would provide further clarification on the applicable market benefits and costs. With respect to DPI's comments, this is addressed in Chapter 4. With respect to ETSA's comment, we consider that the AER would address this

172 ETSA, Submission on the Draft Report, p. 8.
173 Aurora Energy, Submission on the Draft Report, p. 8.
174 For example, submissions on the Draft Report from: Aurora Energy, p. 9; ENERGEX, p. 4 of Annex A; Ergon Energy, p. 19; Integral Energy, p. 7.
175 CUAC, Submission on the Draft Report, p. 4.
176 TEC, Submission on the Draft Report, pp. 9-10.
177 DPI, Submission on the Draft Report, p. 2.
178 ETSA, Submission on the Draft Report, p. 12.

	Draft Recommendation	Issue raised in submissions	Commission Response
	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 option to decide which market benefits are included.	The AER and the NGF both considered that the RIT-T approach to market benefits could be applied to the RIT-D.[179] Ergon Energy did not support a prescriptive process relating to quantifying costs and determining discount rates. It also considered that the application of value to any particular market benefit should be at the DNSP's discretion and not be subject to the dispute resolution process. It suggested that the AER could take into consideration the DNSP's application of the RIT-D and final project assessment reporting when considering regulatory proposals under Chapter 6 of the Rules.[180] ENERGEX considered that DNSPs should be left to assign their own value to each benefit as values differ between jurisdictions.[181]	issue. With respect to the AER and the NGF's comments, we consider that the option approach would be more appropriate as it provides for transparency. This can be assessed in three years' time. We do not agree with Ergon Energy's comments, but agree that the AER should have regard to the project assessment reports. We consider that prescription ensures consistency. We note ENERGEX's comments.

179 For example, submissions on the Draft Report from: AER, p. 4; NGF, p. 1.

180 Ergon Energy, Submission on the Draft Report, pp. 19, 22.

181 ENERGEX, Submission on the Draft Report, p. 4 of Annex A.

	Draft Recommendation	Issue raised in submissions	Commission Response
53.	The AER would publish the proposed RIT-D and the RIT-D Application Guidelines.	ENERGEX proposed that to ensure consistency across DNSPs, the AER should publish (or approve) a standard set of measures (i.e. $/KVA) for the STT test. These measures would be adjusted annually to keep pace with market costs.[182] Ergon Energy proposed for the inclusion of specific examples in the guidelines.[183] ETSA strongly supported the AER providing some examples of the application of the test, including the treatment of DUOS, TUOS and connection charges, and the inclusion of other parties' costs.[184] Integral Energy did not support giving the AER greater discretion in its development of the RIT-D Application Guidelines to determine the appropriate actions DNSPs must undertake.[185] TEC considered that there seemed to be some misalignment between the RIT-D and the AER's revenue determinations where the AEMC is recommending that the AER consider the RIT-D, yet the RIT-D may be done after the revenue determination. It considered that this process would not alone be sufficient to keep DNSPs to be accountable via the AER.[186]	We note the comments from ENERGEX, Ergon Energy, ETSA and Integral Energy, and consider this is a matter for the AER to decide. We note TEC's comments.

182 ENERGEX, Submission on the Draft Report, p. 3 of Annex A.

183 Ergon Energy, Submission on the Draft Report, pp. 9, 19.

184 ETSA, Submission on the Draft Report, p. 9

185 Integral Energy, Submission on the Draft Report, p. 7

186 TEC, Submission on the Draft Report, p. 10.

	Draft Recommendation	Issue raised in submissions	Commission Response
Dispute Resolution			
54.	The process would apply to DNSPs' application of the RIT- D against the requirements in the Rules and cover all stages and decisions made by DNSPs when applying the RIT-D. It would be a compliance review only.	Although some DNSPs supported the dispute resolution process being a compliance review, they were concerned with the clarity of some of the terms used and the implication and potential for disputes that would be created.[187] CUAC submitted that it was comfortable with the process.[188] To reduce ambiguity and potential for disputes which may cause administrative burden and cost, and unnecessary delays, ENA and Jemena proposed that the elements for the dispute resolution process be sufficiently prescribed in the Rules, in the AER guidelines, or within documents prepared by the DNSP and approved by the AER prior to implementation.[189]	We note the issues on clarity and have taken this into consideration in preparing the draft Rules. We note CUAC's comments. In relation to ENA and Jemena's comments, we consider that the draft Rule sufficiently addresses these.
55.	The dispute resolution process would apply to all investments which are subject to the RIT-D.	ENA recommended that the coverage of the dispute resolution process should be limited to an investment where the cost of the recommended option is greater than $5m. If the RIT-D threshold was $2m, the dispute resolution process would extend to all but the smallest investments that DNSPs make and lead to an excessive number of disputes and resources.[190] Jemena supported ENA's proposal.[191] TEC considered that the dispute resolution process should be	We agree with ENA's comments and consider this has been addressed with the increased RIT-D threshold to $5m. We do not agree with TEC's comments, but note that this can be reviewed in three

187 For example, submissions on the Draft Report from: ENA, p. 32; Ergon Energy, p. 19; ETSA, p. 9; Integral Energy, pp. 7-8; Jemena, p. 5; Victorian distribution businesses, pp. 11-12.

188 CUAC, Submission on the Draft Report, p. 4.

189 Submissions on the Draft Report from: ENA, p. 32; Jemena, p. 5.

190 ENA, Submission on the Draft Report, p. 34.

191 Jemena, Submission on the Draft Report, p. 5.

	Draft Recommendation	Issue raised in submissions	Commission Response
		available for non-network solutions over $200,000 as this would be at the level which many non-network solutions would be carried out.[192]	years' time.
56.	The dispute resolution process would not extend to DNSPs' DAPRs.	TEC considered that if DAPRs include reporting on historical data and performance, it would not be appropriate to rule out subjecting DAPRs from the dispute resolution process.[193]	We do not agree with TEC's comments and consider that the DAPR should not be subject to dispute resolution as the DAPR would predominantly focus on forecasts of system limitations.
57.	Disputes could be raised in relation to the DNSP's assessment as to whether an identified need meets the STT.	Ergon Energy considered that the outcome of the STT, where the DNSP has assessed that non-network option is not feasible, should not be subject to the dispute resolution process. It proposed that this assessment would be published in the DAPR and the identified need may have been resolved at the time of publication, which would be subject to compliance monitoring by the AER as part of its Rules enforcement role.[194]	We do not agree with Ergon Energy's comment as we consider that all aspects of the RIT-D process should be covered by the dispute resolution process to provide regulatory discipline and transparency.
58.	Registered Participants, the AEMC, Connection Applicants, Intending Participants and interested parties would be able to raise disputes.	Some DNSPs raised concerns with the ability of interested parties to raise a potentially large number of disputes, including vexatious disputes. To address this, some DNSPs proposed: the inclusion of "non-network proponents (or	We consider that any party which may be impacted by DNSPs' decisions under the RIT-D, including any non-

192 TEC, Submission on the Draft Report, p. 11.

193 TEC, Submission on the Draft Report, p. 11.

194 Ergon Energy, Submission on the Draft Report, pp. 19-20.

	Draft Recommendation	Issue raised in submissions	Commission Response
		participants)"; and/or a new classification under Chapter 2 of the Rules which would be maintained by AEMO.[195] Ergon Energy considered that the AEMC should not be entitled to raise a dispute under the dispute resolution process as the rule maker should not be involved in disputes relating to a DNSP's compliance with the Rules.[196] In contrast, TEC considered that any electricity consumer should be able to contest network investment decisions through the dispute resolution process as it would be electricity consumers who would pay for these investments. They considered the current filters that could be applied to exclude "trouble-making" complaints would be sufficient to ensure that unnecessary resources are not spent defending otherwise legitimate decisions.[197]	network providers and interested parties, should be able to raise a dispute with the AER for resolution. This matter is addressed further in Chapter 5. We note Ergon Energy's comment concerning the inclusion of the AEMC. The AEMC has been included as it is consistent with the RIT-T approach.
59.	Disputes should be raised with the AER in writing within 30 business days after the publication of DNSPs' final project assessment reports or the publication of DNSPs' DAPRs, containing their final project assessment reports.	Some DNSPs considered the 30 day deadline for raising disputes to be reasonable.[198]	We note the comments.
60.	The AER would either reject the dispute or make a determination on	Some DNSPs were concerned that an initiation of a dispute would lead to a delay of over four months in completing a	We consider that the DNSP should risk manage for a

195 For example, see submissions on the Draft Report from: ENA, pp. 32-33; ENERGEX, p. 3 of the Cover Letter, p. 4 of Annex A; EnergyAustralia, p. 14; Ergon Energy, pp. 8, 20; Integral Energy, p. 8; Jemena, p. 3; Victorian distribution businesses, p. 11.

196 Ergon Energy, Submission on the Draft Report, pp. 8, 20.

197 TEC, Submission on the Draft Report, p. 11.

198 Submissions on the Draft Report from: ENA, p. 34; Ergon Energy, p. 20.

	Draft Recommendation	Issue raised in submissions	Commission Response
	the dispute within 40-100 business days of receiving the dispute notice, depending on the complexity of the dispute.	project, which could potentially force a DNSP to undertake urgent remedial action to avert a supply constraint and customer supply interruptions.[199] ETSA considered the timeframes were acceptable, provided that the AER is given the power to impose a deadline date on the furnishing of additional information in order to avoid one party or the other from delaying the determination indefinitely.[200] Ergon Energy submitted that the timeframe for a DNSP to amend its final project assessment report must be reasonable.[201]	potential dispute resolution process to arise in their planning processes. We agree with ETSA's comments. We note Ergon Energy's comments.
61.	The AER can only be able to make a determination to direct the DNSP to amend its final project assessment report if the DNSP: has not correctly applied the RIT-D in accordance with the Rules; or has made a manifest error in its calculations.	Ergon Energy agreed with the proposed role for the AER but considered that a positive obligation must be placed on the AER to provide detailed reasons for making a determination.[202] ENA did not believe that it would be appropriate for the AER to be given the responsibility to make a determination to direct a DNSP to amend its final project assessment report if the DNSP has made a manifest error in its calculations. It considered that this would be a technical review, which would be beyond the AER's compliance review of a DNSP's assessment process.[203]	We note Ergon Energy's comments. We do not agree with ENA's comments as we consider it to be within AER's role of reviewing compliance.

199 Submissions on the Draft Report from: ENA, p. 33; Jemena, p. 5; Victorian distribution businesses, p. 11.

200 ETSA, Submission on the Draft Report, pp. 9, 13.

201 Ergon Energy, Submission on the Draft Report, p. 20.

202 Ergon Energy, Submission on the Draft Report, p. 20.

203 Submissions on the Draft Report from: ENA, p. 34; Jemena, p. 5.

	Draft Recommendation	Issue raised in submissions	Commission Response
62.	The proposed process for the consideration of disputes and the grounds on which the AER is able to request DNSPs amend their final project assessment reports are consistent with the dispute process for the RIT-T.	The AER considered that there was a discrepancy in the proposed dispute process where the AER will not be able to recover consultant costs from parties to RIT-D disputes, which is possible under the dispute process for the RIT-T.[204]	We agree with the AER's comments and have clarified the requirements in the draft Rules.
Other Issues			
63.	The Draft Report noted that appropriate transitional arrangements will need to be put in place.	Some DNSPs were concerned that the national framework requirements would duplicate their jurisdictional requirements. In addition, they were concerned that an appropriate transition timeframe should be established.	We have made our recommendations on the basis that the jurisdictions would review their requirements and roll back those that are covered by the national framework. We have clarified these discussions in the Final Report.
64.	The Draft Report discussed observations on the reliability standards across the NEM and the potential for greater consistency in the processes adopted in setting these standards.	Some DNSPs noted that they did not think any significant changes should be made and noted that differences in reliability standards were necessary.	The Draft Report contained our observations on these issues, which were that there should be greater consistency in the way in which the reliability standards were set out and not that the reliability standards should be the same in each jurisdiction. We have recommended that a review

204 AER, Submission on the Draft Report, p. 5.

	Draft Recommendation	Issue raised in submissions	Commission Response
			be conducted to further consider these issues.
65.	Our recommendations relate to the planning and regulatory investment test processes.	Victorian distribution businesses proposed that clause 6.18.7, recovery of charges for transmission use of system services, under the Rules should be amended to provide for the full pass-through by a distribution business of all charges levied on it in relation to transmission services.[205]	We consider that this issue would be most appropriately addressed as a separate Rule change proposal to allow any potential issues to be adequately assessed.

205 Victorian distribution businesses, Joint submission on the Draft Report, p. 9.

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B Draft Terms of Reference for Review into Distribution Reliability and Security Standards

MCE Direction to the AEMC

Section 41 of the National Electricity Law (NEL) enables the Ministerial Council on Energy (MCE) to direct the Australian Energy Market Commission (AEMC) to review any matter relating to the National Electricity Market (NEM) or any other market for electricity.

Pursuant to section 41 of the NEL, the MCE directs the AEMC to conduct a review into the current electricity security and reliability standards (standards) relating to the design and planning of distribution networks.[206]

The Review is to investigate the arrangements for determining the standards, the form in which the standards are expressed and how the standards are applied by the DNSPs. The objectives of the Review are to identify whether consistency at a national level in these arrangements would:

- deliver net benefits to the form of efficient provision of reliability by promoting more efficient and timely network investment, and improving network operation and performance;
- strengthen the accountability of DNSPs for cost-effective achievement of the reliability and security standards; and
- improve the transparency of network reliability and security performance to users of network services, providers of non-network alternatives and final energy consumers, and thereby promote the ability to operate on a NEM wide basis.

The Review is to advise on:

- the benefits of adopting a common framework for determining and expressing jurisdictional standards and the form and design of such a common framework;
- whether the form of the standards should be derived on an economic basis to promote economic efficiency, including facilitating consideration of non-network alternatives, and if so, how;
- the effectiveness of the standards set out in Schedule 5.1 of the National Electricity Rules (Rules) insofar as they relate to distribution;

206 The Review shall encompass both the standards set at a jurisdictional level and those standards contained in Schedule 5.1 of the National Electricity Rules.

- the current interpretation and application of standards in the NEM;
- the accountability and compliance of DNSPs to all standards; and
- the appropriate consistency between transmission and distribution standards.

In making any recommendations to change the current arrangements, the AEMC shall have regard to the need for the change to be proportionate to the materiality of the issue, as well as the value of stability and predictability in the energy market regime. The AEMC review shall provide detailed advice on implementation of any recommendations the AEMC considers appropriate.

The Review shall recognise the existing regulatory treatments in balancing reliability and costs to consumers and that each jurisdiction has its own standards and differ in the method of application and determination of such standards. As the performance of networks, and its applicable standards, is directly attributable to the network characteristics and the resources which are invested it is appropriate for the standards to differ across jurisdictions. The outcomes of this Review must be consistent with providing each jurisdiction the option of adopting differing standards, and with the application of either deterministic or probabilistic criteria.

Issues to be considered

A number of issues arise from the current arrangements that may affect the efficiency and performance of the market and could possibly act as a barrier to the up-take of non-network alternatives. The Review should assess the materiality of the following issues:

- the lack of transparency and clarity of the methodology for determining, and the processes for setting, standards may not allow network users, including embedded generators, to make the most efficient investment decisions;
- the lack of consistency in the form and description of the standards may lead to uncertainty for existing and potential market participants seeking to understand the basis upon which a DNSP will make an investment. This may make it difficult for non-network businesses to operate on a NEM wide basis;
- the form of the standards may not be derived from economic considerations. Requiring all standards to be economically derived, such that they would consider customer value of reliability, may improve the prospects for efficient capital investment and the inclusion of demand side participation;
- the responsibilities for setting the standards, or for interpreting the standards, tends to be delegated to DNSPs. This gives rise to questions of conflict of interest where DNSPs also have responsibility for planning and investment;
- the specification and relevance of Schedule 5.1 of the Rules to distribution;
- how DNSPs comply with the standards and the penalty for non-compliance; and

- the consistency between the standards set at the distribution and transmission levels, especially given that often system limitations can be addressed by either a transmission option or a distribution option.

What the AEMC is to take into consideration

It is noted that, as a part of the developments for the national transmission planning function, the MCE directed the AEMC to conduct a review into the electricity transmission network reliability standards in 2007, where the final report was submitted to the MCE in September 2008. In conducting this review, the AEMC will have regard to the MCE's policy response to, and actions arising from, the transmission reliability standards review.

The AEMC is also to have regard to the following in conducting this review:

- the National Electricity Objective;
- the national framework for distribution network planning;
- any relevant transmission provisions with a view to maintaining consistency between the transmission and distribution frameworks where appropriate;
- the reporting to the Australian Energy Regulator (AER) on target setting of reliability performance under Chapter 6 of the Rules;
- other relevant reviews and Rule change determinations; and
- any other relevant information.

Consultation

The review shall also involve the AEMC:

- consulting on a regular basis with jurisdictional representatives and the MCE Standing Committee of Officials; and
- consulting and engaging with stakeholders.

Timing and process

The MCE requires the AEMC to:

- undertake a formal consultation process including publication of an Issues Paper and Draft Report;
- if considered appropriate by the AEMC, hold a public forum; and
- provide its final report by [12 months after initiation].

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C Related AEMC Reviews and Rule changes

There are a number of current policy reviews and Rule changes that relate to the arrangements for distribution network planning. We have managed the various interactions between this Review and other workstreams as we conducted our assessment of the appropriate national framework. This Review has incorporated, where relevant, the outcomes of our reviews into Demand Side Participation, Climate Change, and Extreme Weather Events.

The following areas of work, some of which were cited explicitly in the MCE's terms of reference, were relevant to this Review.

C.1 Review of Demand Side Participation in the NEM

We are currently undertaking a review into Demand Side Participation (DSP) in the NEM. The objective of this review is to determine whether there are barriers or disincentives within the Rules for the efficient uptake of DSP in the NEM. Part of this DSP Review will assess whether there are any barriers to the uptake of non-network investments within the current arrangements for distribution network planning.

The Draft Report on the DSP Review was published on 29 April 2009.[207] In the DSP Draft Report, it was noted that probabilistic planning standards are likely to be more consistent with the efficient use of DSP as they appear to be more amenable to handling DSP with different degrees of 'firmness'. The DSP Draft Report also highlighted that variability in network planning and consultation processes across DNSPs is likely to increase the costs associated with operating across the NEM for non-network proponents.

C.2 Demand Management Rule Change

On 23 April 2009, we published the final Rule determination on Total Environment Centre's Demand Management Rule change proposal and determined to make the proposed Rule with some modifications.[208] The Rule change proposal sought to increase the requirements and incentives for the use of demand management in the NEM. The Rule as Made:

- requires TNSPs to provide specific information in their Annual Planning Reports about forecast constraints, where an estimated reduction in forecast load would defer a forecast constraint; and

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[207] AEMC 2009, *Review of Demand-Side Participation in the National Electricity Market, Stage 2: Draft Report*, 29 April 2009, Sydney.

[208] AEMC 2009, *National Electricity (Demand Management) Rule 2009, Rule Determination,* 23 April 2009, Sydney and *National Electricity Amendment (Demand Management) Rule 2009, No. 11*, 23 April 2009, Sydney.

- requires the AER to consider the extent to which TNSPs have made provision for appropriate efficient non-network alternatives, when it assesses revenue proposals. To assist the AER in this task, TNSPs must provide information on the appropriate non-network alternatives they have considered in their revenue proposals.

The Rule as Made commenced operation on 1 July 2009.

C.3 Review of Energy Market Frameworks in light of Climate Change Policies

The MCE has directed that we undertake a review to determine whether the existing energy market frameworks should be amended to accommodate the introduction of the Carbon Pollution Reduction Scheme (CPRS) and the expanded 20% Renewable Energy Target (RET). This review is to consider both the electricity and gas markets across all states and territories. The outcomes of this review are to provide advice on what, if any, changes are needed to energy market frameworks, including how these changes should be implemented. The Second Interim Report to this review, which set out our proposed options for changes to energy market frameworks, was published on 30 June 2009.[209] The Review will conclude with advice to the MCE in September 2009.

This Review will be particularly important for the consideration of demand management, as the CPRS and expanded RET will impact on the potential costs and benefits of demand side solutions in the NEM. Also there is a need to ensure that the project assessment process for distribution is consistent with climate change policies and especially whether the process appropriately values carbon costs.

C.4 Review of Effectiveness of NEM Security and Reliability Arrangements in light of Extreme Weather Events

On 28 April 2009, the MCE directed that we conduct a review of the effectiveness of NEM security and reliability arrangements in light of extreme weather events. Under the MCE's terms of reference, we were required to report on measures that are currently under consideration that would improve system reliability and security, and any further cost-effective measures that could be taken in the short term that would impact on system reliability for the summer of 2009-10. This report was provided to the MCE on 1 June 2009.

On 14 August 2009, the MCE revised the terms of reference to this review; requiring that we provide specific advice on the reliability standard and the market mechanisms to achieve that standard in a second interim report by 18 December 2009.

[209] AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: 2nd Interim Report*, 30 June 2009, Sydney.

We are to also consider in a final report to the MCE any cost-effective changes that could be made to energy market frameworks to improve system reliability in the longer term and contribute to the more effective management of system reliability during future extreme weather events. The MCE's revised terms of reference extended the timing for this report to be provided to the MCE from 30 October 2009 to 30 April 2010. The MCE will determine whether our final report will be published.

The MCE has requested that we provide advice in relation to generation and transmission networks. While the MCE notes that the performance standards of distribution networks are the responsibility of the jurisdictions, the MCE's terms of reference also requests that we provide any advice which would ensure network security and reliability.

C.5 Regulatory Test Thresholds and Information Disclosure on Network Replacements Rule change

On 23 October 2008, we published the *Regulatory Test Thresholds and Information Disclosure on Network Replacements, Rule Determination* and Rule as Made on the Rule change proposed by Grid Australia.[210] The Rule as Made:

- raises the new small transmission network asset threshold from $1 million to $5 million and the new large transmission network asset threshold from $10 million to $20 million;
- provides for a three yearly review of threshold values by the AER; and
- requires the following information to be provided on all proposed replacement transmission assets over $5 million in TNSPs' Annual Planning Reports: the purpose of the proposed asset; a list of alternative projects; and the TNSPs' estimated total capitalised expenditure on the proposed asset.[211]

As part of this Rule change, we also considered aligning the revised new transmission network asset thresholds to the thresholds for new distribution network assets. However, while noting the applicability to distribution of many issues in the Rule change proposal, we considered that the appropriate thresholds for distribution should be subject to separate analysis and consultation, particularly as the scope for demand side projects is greater for distribution than for transmission.

The Rule as Made commenced operation on 23 October 2008.

[210] AEMC 2008, *Regulatory Test Thresholds and Information Disclosure on Network Replacements, Rule Determination*, 23 October 2008, Sydney and *National Electricity Amendment (Regulatory Test Thresholds and Information Disclosure on Network Replacements) Rule 2008 No. 9*, 23 October 2008, Sydney.

[211] At the time the Rule change proposal was submitted, only network augmentations were subject to information disclosure requirements.

C.6 Regulatory Investment Test for Transmission Rule change proposal

On 20 February 2009, we received a Rule change proposal from the MCE. The Rule change proposal sought to implement a revised Regulatory Investment Test for Transmission (RIT-T) to improve the identification of transmission investment options which maximise net economic benefits. We recommended this Rule change proposal to the MCE in our Final Report on the National Transmission Planning Arrangements in June 2008.[212]

On 25 June 2009, we published the *Regulatory Investment Test for Transmission, Final Rule Determination* on the RIT-T Rule change proposal and determined to make the corresponding Rule.[213] Under the Rule as Made, the revised RIT-T:

- only applies when the capital cost of investment options exceed $5 million in value, with the exception of urgent or unforeseen investments, investments related to the provision of connection or negotiated services, and transmission projects which only involve replacements;
- amalgamates the reliability and market benefits limbs of the current regulatory test;
- facilitates earlier consultation in the planning process to enable other potential viable non-network options to be identified and assessed appropriately;
- ensures that national market benefits are recognised under the project assessment process; and
- includes an additional market benefit category of option value, to recognise the benefits that the proposed project may have on future investments and costs.[214]

The Rule as Made commenced operation on 1 July 2009. Under the Rule as Made, the AER will be required to publish the RIT-T and RIT-T Application Guidelines by 1 July 2010.

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[212] AEMC 2008, *National Transmission Planning Arrangements, Final Report to MCE,* 30 June 2008, Sydney.

[213] AEMC 2009, *Regulatory Investment Test for Transmission, Final Rule Determination*, 25 June 2009, Sydney and *National Electricity Amendment (Regulatory Investment Test for Transmission) Rule 2009 No. 15*, 25 June 2009, Sydney.

[214] Ibid.

D Comparison of Jurisdictional Reporting Requirements with the National Framework

The current jurisdictional requirements for reporting on the planning process are set out in the table below. A comparison of these obligations with the reporting requirements under the proposed national framework, as contained in the draft Rules, is also outlined.

The proposed national framework captures the existing jurisdictional reporting requirements, with the exception of the following points:[215]

- the jurisdictions require reporting on historical information. Given the planning document is a forward looking document to identify investment and connection opportunities and that historical information is included in other reporting requirements, the draft Rules include the requirement to report on a summary of the performance of the network for the preceding year only; and
- some of the jurisdictional requirements relating to operational processes and procedures have not been included in recommended reporting requirements. It was considered that operational procedures and reporting (such as reporting on the adherence to safety procedures) were outside the scope of planning.

The proposed reporting requirements for the national framework that are in addition to the existing jurisdictional requirements are outlined below:[216]

- DNSPs would be required to establish and implement a Demand Side Engagement Strategy. Comparable obligations currently exist in NSW and SA only. However, it is noted that DNSPs in the other jurisdictions are required to consider potential demand management and embedded generation solutions in carrying out their planning;
- the draft Rules clarify the requirements for: forecasting; identifying and reporting on system limitations (or constraints); and reporting on projects and investments;
- DNSPs would be required to conduct a public forum, if requested by a stakeholder, following the publication of the DAPR. Certification of the DAPR by the CEO and a Director or Company Secretary would also required. Currently, no DNSPs conduct public forums and certification by the CEO is only required in QLD; and
- the draft Rules also clarify the joint planning provisions and changes the requirements such that joint investments would be assessed under the RIT-T.

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215 These issues are also discussed in Chapter 3.

216 These issues are discussed in more detail in Chapter 2 and Chapter 3.

Summary of the Current Distributor Planning Requirements (compared with the draft Rules)[218]

	QLD	NSW	VIC	SA	TAS
Regulatory Instruments[219]	Queensland Electricity Industry Code	Relevant Acts and Regulations	Electricity Distribution Code	ESCOSA Guideline No. 12	Tasmanian Electricity Code
Planning requirements	*Plan covering the next 5 years.* DNSPs to produce a Network Management Plan (NMP) under the code to set out how the DNSP is to manage and develop its supply network. (This requirement is included in the draft Rules) Additional plans – The regulator may request DNSPs to prepare a "summer preparedness plan". (No specific provisions are made for this requirement however, the draft Rules would require DNSPs to take account of peak conditions (summer or winter).)	*Network management plan unspecified period. Demand management plan covering the next 5 years.* Under the regulation, DNSPs are to review the network management plan when any significant changes occur and in any event at least once every 2 years. (This management plan considers operational issues, some of which are outside the planning framework). Additional plans – Under the code of practice, DNSPs are to produce an "Electricity System Development Review" (ESDR), looking out over the "foreseeable future". (This requirement is included in the draft Rules where an annual report on planning would be required.)	*Plan covering the next 5 years.* Under the code, DNSPs are required to produce plans on meeting forecast demand requirements and improving reliabilityover the next five years in a Distribution System Planning Report (DSPR). (This requirement is included in the draft Rules)	*Plan covering the next 3 to 5 years.* ETSA is required to publish an Electricity System Development Plan (ESDP) setting out its planning criteria and five years of historical and forecast load data and expected network constraints over the next three years. (The forecasting requirement is included in the draft Rules, which would extend the forward looking period to five years for system limitations. The draft Rules also require a qualitative assessment of historical performance and compliance. It has been considered that as the planning reports are forward looking and historical information is reported under other requirements, historical information would not be included in the draft Rules to the same extent.)	*Plan covering the next 5 years.* Under the code, the DNSP is required to provide an annual plan on meeting predicted demand and improving reliability covering the next five years. (This requirement is included in the draft Rules)

218 There are no state-based requirements for the ACT.

219 Any applicable industry codes as outlined. Refer to Appendix B of the Scoping and Issues Paper for additional details on applicable Acts and Regulations and licence conditions.

Summary of the Current Distributor Planning Requirements (compared with the draft Rules)[218]

	QLD	NSW	VIC	SA	TAS
Contents of plans	*Requirements are outlined in the code.* The Electricity Industry Code section 2.3.2 specifies that the network management plan is to include: • Background providing an explanation of the purpose of the report; (Included in draft Rules.) • General information on the DNSP's supply network; (Included in draft Rules) • Forecasts and discussion of the current operating environment; (Included in draft Rules.) • Asset management policy and qualitative assessment of its compliance with the policy; (Included in draft Rules where a general summary of the asset management strategy is required and a qualitative assessment of the DSNP's compliance with its regulatory requirements.) • Demand management strategy including description of existing and planned programs and opportunities for demand side participation; (Included in draft Rules.) • Historical reliability	*Requirements are outlined in the regulation for the "management" plan and a specific guideline is issued by the Department of Water and Energy (DWE) for the "performance" plan.* The Electricity Supply (Safety and Network Management) Regulation 2008, Part 3, sets out the required contents for the network management plan. These include discussion of: • Characters of the distribution network; (Included in draft Rules.) • Planning process employed including demand management technologies; system reliability planning standards; (Included in draft Rules) • Asset management strategies including risk management; technical service standards for quality and reliability of supply; (Included in draft Rules where summary information on these areas would be required.) • Safety management strategy including analysis of hazardous events; emergency procedures; adherence to safe working	*Requirements are outlined in the code.* The Electricity Distribution Code section 3.5 specifies that the distribution system planning report is to detail plans for the following 5 years covering areas including: • Forecast and historical demand; (Forecast demand included in draft Rules. Description of performance of preceding year also required.) • Feasible options for meeting forecast demand including opportunities for embedded generation and demand management; (Included in draft Rules.) • Preferred option for meeting forecast demand details including estimated costs; (Included in draft Rules.) • Ability to defer or avoid augmentation by reducing forecast demand through embedded generation or demand management; (Included in draft Rules.) • Impact of loss load assessment; (Not specifically included in the draft Framework however, DNSPs would be required to	*Requirements are outlined in an industry guideline.* The Electricity Industry Guideline No. 12 (made under section 8 of the Essential Services Commission Act 2002) sets out in detail the DNSP's obligations to report and consult on its system constraints and demand management plans. The guideline specifies that the ESDP is to include: • Background providing an explanation of the purpose of the report; (Included in draft Rules.) • General information on the DNSP's supply network; (Included in draft Rules.) • Descriptions of the basis for formulating load forecasts; (Included in draft Rules.) • System planning and reliability guidelines; (Descriptions of the planning methodology and reliability standards are included in draft Rules.) • Description of the state-wide sub-transmission network; (Description of the distribution network included.) • Regional development plans; (Regional	Requirements are outlined in the code. The Tasmanian Electricity Code clause 8.3.2 specifies that an annual distribution system planning report detailing plans over the following five years is to include: • Forecast and historical demand; (Forecast demand included in Draft Framework. Description of performance of preceding year also required.) • Feasible options for meeting forecast demand including opportunities for embedded generation and demand management; (Forecast demand included in draft Rules. Description of performance of preceding year required.) • Preferred option for meeting forecast demand details including estimated costs; (Forecast demand included in draft Rules. Description of performance of preceding year required.) • Ability to defer or avoid augmentation by reducing forecast demand through embedded generation or demand management;

Summary of the Current Distributor Planning Requirements (compared with the draft Rules)[218]

	QLD	NSW	VIC	SA	TAS
Contents of plans cont'	performance for the previous five year period; (The draft Rules require a qualitative description of historical performance. More detailed historical information has not been required given the planning reports are forward looking.) • Statement of reliability targets for the next five years including details of improvement programs including major expenditure initiatives; (Included in draft Rules.) • Risk assessment of major constraints. (Included in draft Rules.)	procedures; (Emergency procedures and adherence to safe working procedures would be an operational consideration and is not included in the draft Rules . Consideration of contingency events should be included by DNSPs in their obligations under the draft Rules to meet their reliability targets.) • Strategies employed to comply with licence conditions relating to the design and operation of the system. (Draft Rules require a summary of the asset management strategy adopted.) The DWE guideline sets out in detail the requirements of the annual network performance plan. The plan sets out the requirement to provide operational and planning statistics including in relation to: • Audits and independent appraisals conducted; (This is considered an operational issue and is not included in the draft Rules.) • Network design planning criteria; (Draft Rules require a description of the planning methodology adopted and	provide a description of the planning methodology employed and assumptions applied.) • Planning standards employed; (Included in draft Rules.) • Reliability improvement programs description including the nature, timing, cost and expected impact on performance; (Included in draft Rules as system limitations arising from the requirement to meet reliability standards are included.) • Reliability programs evaluation. (Not included as considered an operational requirement.)	development plans have been included in the draft Rules.) • Consultation Framework; (Included in Demand Side Engagement Strategy and under the RIT-D process.) • Register of interested parties. (Included in draft Rules.)	(Forecast demand included in draft Rules. Description of performance of preceding year required.) • Assessment of load at risk for the system and supply regions; (Not specifically included in the draft Framework however, DNSPs would be required to provide a description of the planning methodology employed and assumptions applied. Forecasts are also required to be provided at the system level taking into consideration peak conditions.) • Planning standards employed; (Included in draft Rules.) • Reliability improvement programs description including the nature, timing, cost and expected impact on performance; (Included in draft Rules as system limitations arising from the requirement to meet reliability standards are included.) • Reliability programs evaluation. (Not included as considered an operational requirement.)

Summary of the Current Distributor Planning Requirements (compared with the draft Rules)[218]

	QLD	NSW	VIC	SA	TAS
Contents of plans cont'		the assumptions applied to planning and forecasting.) • Technical service standards; (Draft Rules require a summary description of the reliability and quality of supply standards that apply.) • Detailed annual performance results; (Draft Rules require a description of the performance of the preceding year.) • Network safety incidents and incident reports; (This is considered an operational issue and not included in the draft Rules) • Customer installations. (Draft Rules include the requirement for DNSPs to forecast the level of embedded generation.)			

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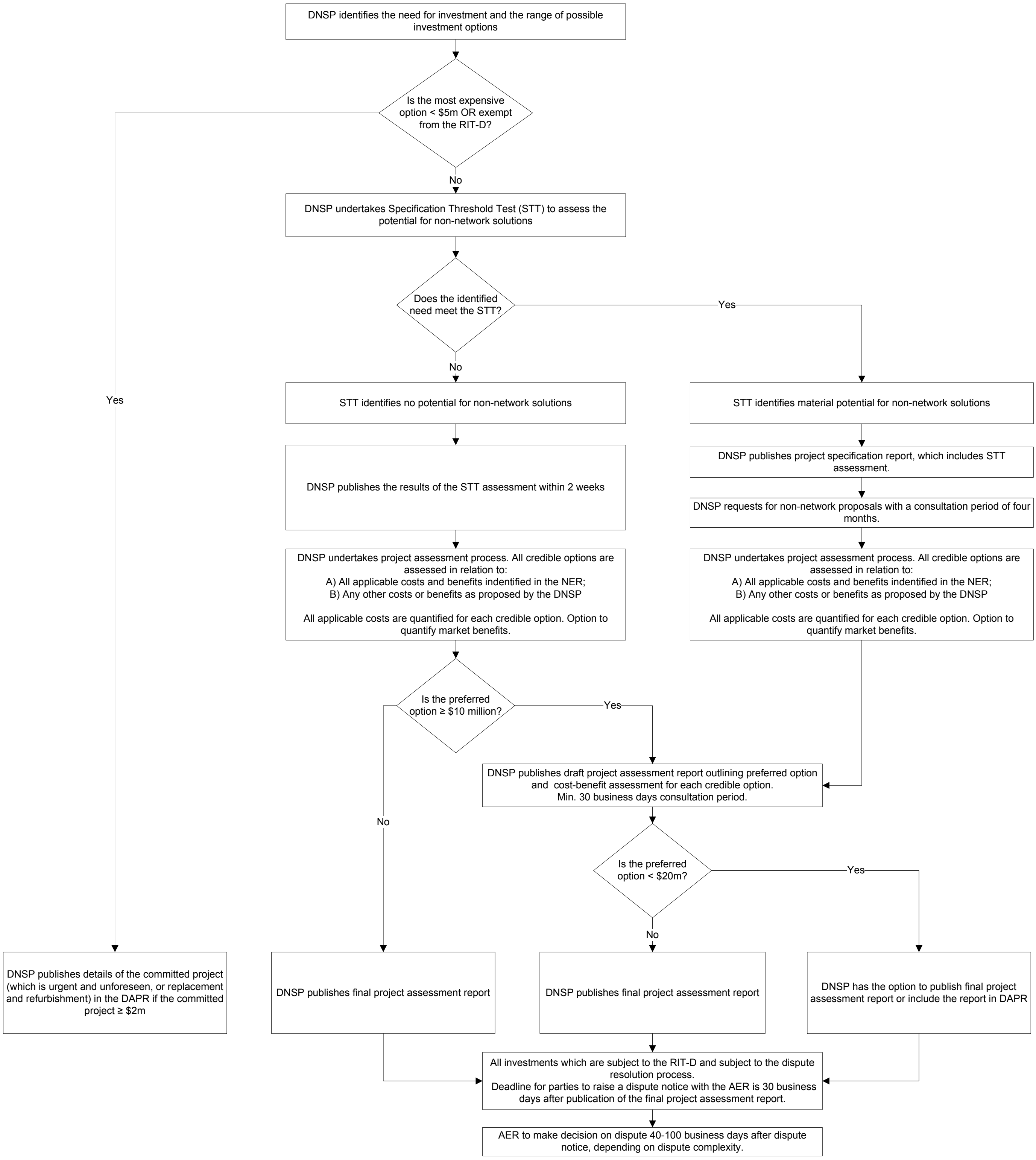
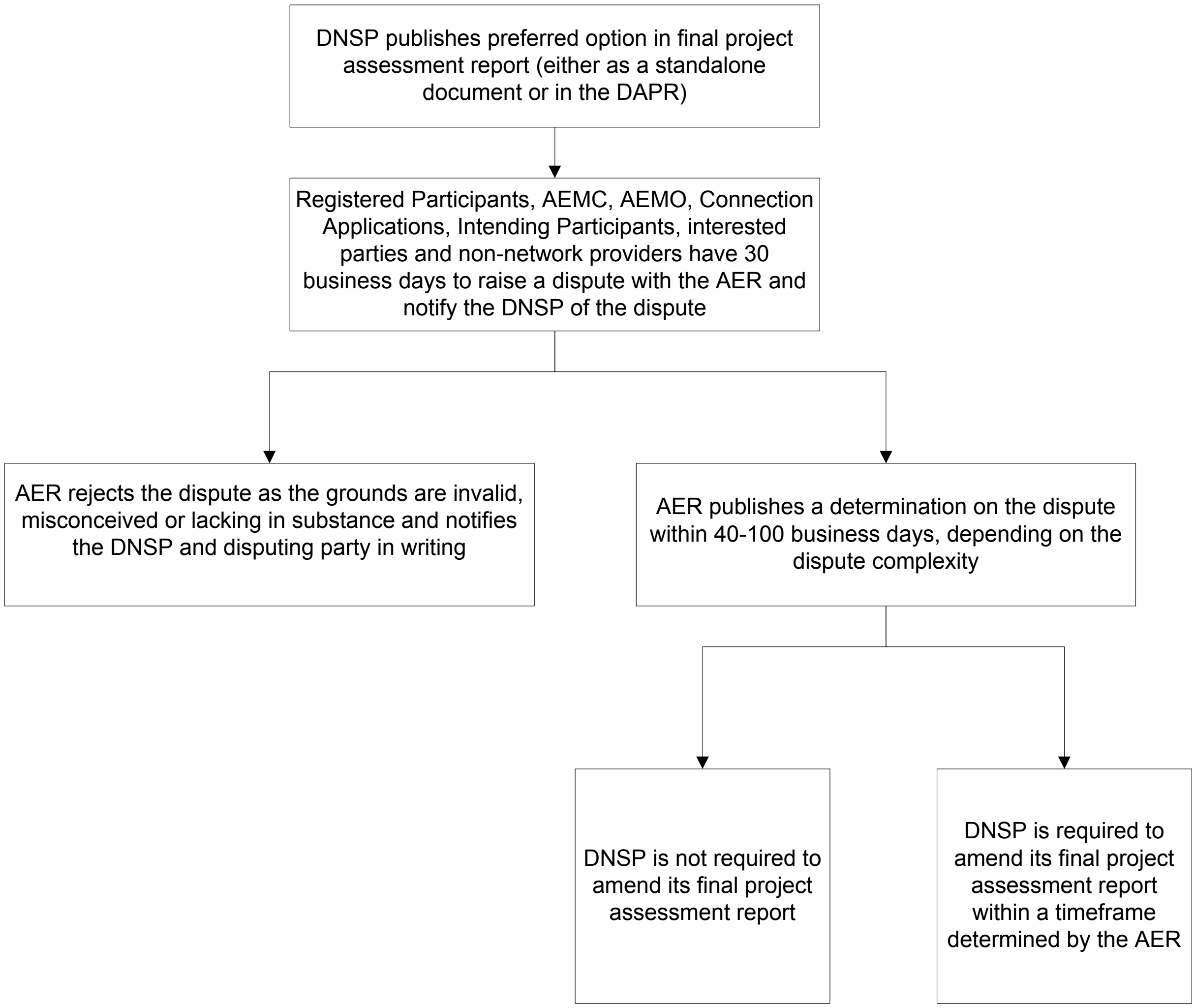
E Summary of the Regulatory Investment Test for Distribution and Dispute Resolution Process

E.1 Design of the Regulatory Investment Test for Distribution



E.2 Design of the Dispute Resolution Process



E.3 Comparison Checklist: RIT-D vs. RIT-T

Aspect	RIT-D	RIT-T
Scope		
Cost threshold (relates to the most expensive option which is technically and economically feasible)	$5m (subject to AER review)	$5m (subject to AER review)
Urgent and unforeseen investments	✗	✗
Replacement/ refurbishment expenditure with no augmentation component	✗ Investment is subject to RIT-D if the replacement/ refurbishment expenditure has an augmentation component ≥$5m	✗ Investment is subject to RIT-T if the replacement/ refurbishment expenditure has an augmentation component ≥$5m
Joint network investments between a TNSP and DNSP (including network to network connections)	✗	✓
Dual function assets	✓	✗
Customer Connection assets	✗	✗
Negotiated services	✗	✗
Assessment and Consultation Process		
Consultation before project assessment	Only if there is potential for non-network options under the Specification Threshold Test (STT)	Yes, TNSPs to publish a project specification consultation report
Project Specification Stage		
Information provided under prior consultation stage	Description, technical characteristics and assumptions behind identified need; Summary of STT Assessment; limited information (e.g. estimated capital and operational costs etc) on the range of options	Description, technical characteristics and assumptions behind identified need; Any relevant reference to NTNDP; Credible options and outline the material market benefits which apply to each credible option
Consultation timeframe	Minimum of 4 months	Minimum of 12 weeks

Aspect	RIT-D	RIT-T
Project Assessment Stage		
Cost benefit assessment	✓	✓
Requirement to quantify market benefits	Optional quantification of market benefits	Material market benefits must be quantified
Preferred option maximises the present value of net economic benefits. A preferred option may have a negative net economic benefit where the identified need is for reliability corrective action.	✓	✓
Requirement to publish and consult on Draft Project Assessment Report	✓	✓
Consultation period for Draft Project Assessment Report	Minimum of 30 business days	Minimum of 6 weeks
Exemptions from Draft Project Assessment Report and Consultation stage	✓ Exemption available if identified need does not meet STT AND the preferred option is < $10m	✓ Exemption available if the preferred option is <$35m AND the preferred option and any other credible options have no material market benefits
Requirement to publish a Final Project Assessment Report	✓	✓
Option to publish Final Project Assessment Report in Annual Planning Report (APR)	✓ Applies if preferred option < $20m	✓ Applies if the APR is published within 4 weeks of when the Final Project Assessment Report must be made available

Aspect	RIT-D	RIT-T
Dispute Resolution Process		
Time period to raise a dispute following the publication of Final Project Assessment Report	30 business days	30 business days
Parties able to raise a dispute	Registered Participants, AEMC, AEMO, Connection Applicants, Intending Participants, non-network providers, interested parties	Registered Participants, AEMC, AEMO, Connection Applicants, Intending Participants, interested parties
Scope of disputes is restricted to a compliance review against the Rules requirements	✓	✓
Potential for the AER to reject disputes immediately if the dispute is invalid, misconceived, or lacking in substance	✓	✓
AER is able to make a determination requiring the network service provider to amend its final project assessment report if it considers it has not complied with the Rules requirements	✓	✓
Time period for the AER to make a determination is 40 -100 business days, depending on dispute complexity	✓	✓

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F Distribution Reliability in the NEM

The reliability of distribution systems generally and in the NEM varies significantly across different geographical areas. Reliability is generally best in CBDs and high density inner urban areas (typically 2 – 20 minutes off supply per annum), and worst in remote rural areas where outages may exceed 1000 minutes in aggregate per annum. The exact reasons for the differences have not been studied, however some of the factors that influence differences in reliability performance are discussed in this appendix.

Distribution reliability in Australia is measured using three parameters, namely SAIDI, SAIFI and CAIDI, which are defined below:

System Annual Interruption Duration Index (SAIDI) is the sum of the duration of each sustained customer interruption, multiplied by the number of customers impacted by each interruption, divided by the total number of customers serviced (expressed in minutes).

In common language, SAIDI is the average aggregate number of minutes per annum that supply is lost (for greater than one minute), to the average customer.

System Annual Interruption Frequency Index (SAIFI) is the total number of sustained customer interruptions, multiplied by the number of customers impacted by each interruption divided by the total number of customers serviced (expressed as a unit number).

In common language, SAIFI is the average number of outages that the typical customer will experience in a year.

Customer Average Interruption Duration Index (CAIDI) $= \frac{SAIDI}{SAIFI}$

In common language, CAIDI represents the average time taken to restore supply, after an interruption occurs.

F.1 The Process for the Determination of Jurisdiction Reliability Standards

The security of supply and reliability standards, set out in jurisdictional instruments, underpin how the annual planning processes are currently undertaken by the DNSPs. The SKM Background Report details the various reliability criteria and standards applicable in each jurisdiction and showed that a mixture of deterministic and probabilistic criteria are applied.[220]

[220] SKM Background Report, op cit.

The SKM Background Report highlights the processes for, form and function of setting reliability standards. It also discusses that how businesses interpret and comply with these standards, which vary significantly across the NEM. The SKM Background Report stated that while it is difficult to make direct comparisons between different reliability criteria, there is no evidence that either deterministic or probabilistic criteria produces a superior outcome.[221]

Under probabilistic criteria, DNSPs may load certain system components above normal ratings based on a risk assessment which balances the annualised cost of augmentation against the probability weighted cost of energy not supplied, at the estimated community cost of loss of supply. This means that a certain proportion of the DNSP's system will be loaded above normal ratings at peak load times.

Under deterministic criteria, commonly known as N-1, other DNSPs plan to have a level of redundancy built into critical parts of their system such that the unplanned loss of one component (usually the one with the highest rating) does not result in a loss of supply. The N-1 criterion is usually applied only to loads above a certain threshold, which may vary from 5MVA to 15MVA, depending on the particular circumstances. Even above this threshold there may be a period of loss of supply while automatic or manual switching is undertaken to restore supply. There are a number of "variants" of N-1, where supply is actually lost for a single contingency event.

We note that, due to factors such as areas of high load growth and capital and resource shortages, some DNSPs operate with parts of their systems in breach of their target N-1 criteria. As a result, this produces similar (but more random) outcomes to the application of probabilistic criteria.

F.2 Factors Affecting the Reliability of Distribution Systems

F.2.1 Legacy Issues and Externalities

DNSPs in Australia are faced with managing and improving the reliability of their distribution systems under circumstances where historical decisions taken many years ago have left them with a legacy of system design and configuration issues, which cannot be easily changed in the short to medium term.

In addition, the performance of any distribution system is affected by local environmental, weather and terrain factors for which the design of the distribution system can mitigate against, but cannot eliminate (e.g. bushfires, earthquakes, cyclones).

221 SKM Background Report, p. 4.

F.2.2 System Security

Most distribution systems worldwide are designed and operated with their distribution and sub-transmission systems being partly radial (no redundancy) and partly meshed (N-1 redundancy or better). There are many variations in the practices of designing redundancy into a distribution/sub-transmission system, including load management, embedded generation, manual switching, and automated switching. However, the fundamental issue that mostly impacts the level of reliability achieved is whether the system is radial, or whether it has in-built redundancy (full or partial) to cater for an N-1 contingency.

The system security standards used by DNSPs in the NEM are summarised in Appendix A of the SKM Background Report.

Distribution/sub-transmission networks are complex systems, with many different components (e.g. transformers, overhead feeders, underground feeders, switches), each with their own individual failure modes, failure rates and mean repair times. To be able to accurately statistically model the impact of the different levels of system security on the level of reliability achieved by distribution companies requires large amounts of data and complex modelling techniques (e.g. Markov modelling).

F.2.3 System Configuration & Design Factors

The reliability of a distribution network is intrinsically dependent on the network configuration/design characteristics, the environment in which it operates in, and the maintenance practices employed. Factors such as customer density, operating environment, and geographical service area, influence the design of the distribution system, as well as economic and safety considerations.

Examples of differences that exist between various parts of the distribution systems used in Australia include:

- customer/load density;
- voltage levels;
- network length and service area;
- mix of overhead and underground;
- backup/duplication for network failures (planning philosophies) and the degree of spare capacity (asset utilisation);
- automatic protection schemes to remove faults and limit the number of customers interrupted; and
- remote control load transfer schemes to improve the speed of restoration for faults.

At one extreme is a fully underground meshed network for a CBD type network, which may deliver around 2 – 10 minutes of SAIDI, and at the other extreme is a fully overhead radial network for short and long rural networks, which may deliver 200 – 600 minutes of SAIDI or more. Most Australian DNSPs operate a mixed underground and overhead network. The majority of urban customers are supplied from a mixed overhead/underground interconnected network, while most rural customers are supplied from an overhead radial network.

F.2.4 Environmental Factors

Australia is a large and diverse country with significant extremes in the terrain, environmental and weather conditions that impact on the operation of the distribution systems. Those environmental factors that mostly impact on the reliability performance of distribution systems include:

- vegetation density;
- bird and wildlife activity;
- human activity;
- storm activity (both electrical and wind);
- heavy rain and flooding;
- temperature extremes; and
- remoteness.

These influential factors vary in their relative impact on different parts of the distribution systems. For example, storm activity tends to have a greater impact on the overhead system, whereas heavy rain and flooding tends to have greater impact on underground systems and ground level equipment.

The differences in performance across apparently similar systems can be quite dramatic. For example, it is well recorded that across a wide range of overhead distribution systems (11kV/22kV), both in Australia and overseas, the average annual fault rate in overhead distribution systems is about 10 sustained outages per 100 km of line, per annum. What is not so well known is that the single wire, earth return (SWER) systems supplying the remote parts of rural Australia actually exhibit lower than average fault rates (possibly as low as 2 – 5 outages/100 km/annum), while overhead feeders in urban areas exhibit higher than average fault rates, some as high as 30 – 40 outages/100 km/annum.[222]

The reasons for these differences are explained by the fact that:

- SWER systems are a simple design, with fewer components subject to failure;
- distribution lines in urban areas are more complex, with more poles, more insulators, more components generally subject to failure;

222 SKM fault rate and reliability database.

- vegetation and wildlife (e.g. possums) generally have closer access to overhead lines in urban areas, with trees growing close to houses, service wires and street mains; and
- human activity in urban areas have a greater impact on overhead distribution (e.g. cars hitting poles, high vehicle transport, other construction activities).

Although fault rates (expressed as faults/100 km/annum) are higher in urban areas than rural areas and the number of customers impacted in urban areas are generally higher, the overall SAIDI minutes of supply are higher in rural areas due to the longer lengths of overhead lines and longer response times.

F.2.5 Other Factors

Other important factors that can have an impact on the overall level of distribution system reliability include:

- the ageing and deterioration of the condition of critical infrastructure assets;
- asset management philosophy and general maintenance policies and practices;
- fault levels and equipment/feeder loadings;
- the extent to which live line work practices are adopted;
- auto-reclose and remote reclose practices; and
- extent of Supervisory Control and Data Acquisition (SCADA) and distribution automation (DA or Smart Networks).

F.3 Differences in the Underlying Performance Potential of Different Distribution Systems

As noted in the previous section, there are a range of factors which can influence the reliability performance of a distribution system. Some of these factors are within the ability of DNSPs to control, or at a minimum, influence, while other factors are of a legacy nature beyond the immediate ability of the DNSP to mitigate against. Some of these legacy and external influences are discussed below.

F.3.1 Selection of Primary Distribution Voltage

Historically, and for a variety of reasons, the primary distribution systems in Australia are built and energised at different voltages, the most common being 11 kV and 22 kV. There are also small amounts of other legacy voltages such as 5 kV and 6.6 kV. In addition, many parts of rural and remote rural areas are supplied by 12.7 kV and 19.1 kV SWER systems.

Approximately 70 – 80% of all customer minutes lost (SAIDI) occur on the primary distribution systems, and consequently the number of customers connected, the exposed length of overhead line, and the outage performance (outages/100 km/annum) is critical in determining the overall reliability of a DNSP's network.

The main difference in the relative performance between 11 kV systems and 22 kV systems comes from the first two of these factors, namely:

- the difference in the average number of customers connected per 11 kV and 22 kV feeder; and
- the difference in the route length of exposed overhead line per 11 kV and 22 kV feeder.

While there may also be differences between the fault rates (per 100 km/annum) on 11 kV lines versus 22 kV lines, there are no known national or international studies to confirm this, and most studies assume a similar outage rate.

As indicated above, it is known that the average number of customers connected to each 22 kV feeder in Australia is significantly higher than the average number of customers connected to each 11 kV feeder. While the exact number will vary from network to network (and will depend predominantly on whether they are CBD, urban, rural or remote rural feeders) typically one would expect to find between 3000 – 5000 customers connected to a 22 kV feeder in an urban area, while typically only 1000 – 2000 customers may be connected to an 11 kV feeder in a similar urban area.

This means that for every substantial fault on the 22 kV feeder, and assuming a similar network configuration and level of automation, more customers lose supply on a 22 kV feeder than an equivalent 11 kV feeder resulting in proportionately higher SAIFI and SAIDI.

Similarly, one of the reasons that 22 kV was historically favoured over 11 kV is that it can convey electrical loading over longer distances than 11 kV, without suffering from excessive voltage drop. Therefore, the 22 kV feeder is often favoured for supplying rural areas, resulting in more customers being connected per feeder and the feeder having a greater level of exposed route length.

In a study of selected Australian and international utilities conducted by SKM, it was found that this difference in the selection of primary distribution voltage (and the subsequent impact on customers connected and exposed route length) was the single largest factor in explaining differences in system reliability (SAIDI).

F.3.2 Mix of Overhead and Underground Systems

Appendix B of SKM's Background Report identified the different levels of undergrounding that exists between DNSPs in Australia. This is summarised in Table F.1 below, together with the primary distribution system voltage level.

Table F.1: Comparison of overhead and underground systems between Australian DNSPs[223]

DNSP	Distribution voltage (kV)	% underground (approx.)	% overhead (approx.)
ETSA Utilities	11	17	83
CitiPower	11 & 22	37	63
Powercor	22	5	95
Jemena	22	Not available	Not available
SP AusNet	22	0.5	99.5
United Energy	22	Not available	Not available
Aurora	11 & 22	8	92
EnergyAustralia	11	28	72
Integral Energy	11	31	69
Country Energy	22	3	97
ActewAGL	11	54	46
ENERGEX	11	28.8	71.3
Ergon Energy	11 & 22	3.5	96.5

Note:
Dominant primary distribution voltage shown first.
SWER and other minor voltages not listed.

As can be seen, the level of undergrounding varies from a minimum of 0.5% (SP AusNet) to a maximum of 54% (ActewAGL).[224]

Since the average fault rate (outages/100 km/annum) on an overhead system is approximately three times more than on an underground system (approximately 10.2 compared with 3.5), this will be a significant factor in overall system reliability (SAIDI).[225]

F.3.3 Weather Influences

Using the 2.5 beta method (or any other method), the exclusion of extreme weather and other events such as cyclones and bushfires generally does not compensate for differences in the ongoing daily, weekly and annual variations in weather patterns from country to country, state to state, or region to region. The differences in the levels of "average thunder days", "heavy rain days" and "high wind days" can impact on distribution systems in different ways, and can be significantly different from region to region, as shown in the following table.

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[223] Ibid.

[224] SKM, 2009, 'Advice on Development of a National Framework for Electricity Distribution Network Planning and Expansion', Appendix B, 13 May 2009.

[225] SKM reliability and fault rate database.

Table F.2: Relativity of weather events[226]

Weather event per annum	Queensland	Victoria	New Zealand
Average thunder days	20 – 40 (11%)	10 – 20 (6%)	10 – 15 (4%)
Heavy rain days (>50 mm)	7.5	1	5
Percentage high wind (>30 km/hr)	3%	21%	0.6%

In the SKM study of selected national and international utilities, the relative impact of prevailing weather conditions was second only to the selection of primary distribution voltage levels in explaining differences in the reliability of distribution factors. Those factors were outside of the immediate control of distribution companies.

F.3.4 Other Influencing Factors

This appendix has described the relative impact that external or unmanageable factors (at least in the short term) have on the overall reliability of distribution systems. In addition, there are a number of other factors that are within the control and decision making processes of a DNSP to influence. The most notable of these and those which have most impact on overall system reliability are:

- geographical area and travel times;
- live line work practices;
- extent of SCADA and distribution automation; and
- auto reclose and remote reclose practices.

F.4 SKM Comparison of NEM reliability performance

SKM has researched the availability and comparability of published electricity distribution reliability statistics for the Australian DNSPs in the NEM, as well as distributors in New Zealand, the United Kingdom and a number of European countries (for which comparable data is available). As we have noted previously, different DNSPs collect, analyse and report reliability data in different ways, even if they use a standardised concept and definitions such as SAIDI and SAIFI.

In addition, the scope and voltage levels of different DNSPs' networks are different, resulting in some DNSPs reporting on LV, MV and HV outages, while other DNSPs' systems only have LV and MV networks with the HV network being the responsibility of the relevant TNSP. Further, some DNSPs do not collect and report

[226] Bureau of meteorological data for the jurisdictions indicated for 2005.

outages on their LV networks, their statistics being for the MV and HV networks only.

The results of SKM's research in this area are presented below, and demonstrates the relative levels of comparable distribution reliability statistics for 11 countries where we are confident that, to the extent possible, any material differences between network boundaries, definitions, scope of data collection, and analysis and reporting differences have been eliminated. While further minor differences in calculation of the reliability statistics still exist, these are known and identified in as many cases as possible.

All of the data and results presented are for either 2007 (presumed to be calendar year), or for the 2007/08 financial year (in some cases commencing in March 2007 and ending in March 2008).

F.4.1 Information Sources

The main sources of information used to prepare this report are:

- SKM's own research on a number of publicly available regulatory and DNSP documents, as listed in tables F.3 and F.4;
- Council of European Regulators 4th benchmarking report on Quality of Electricity Supply, dated 10 December 2008;
- PricewaterhouseCoopers (NZ) report, Electricity Line Business and Gas Pipeline Business, 2008 Information Disclosure Compendium, dated May 2009;
- PB report, Resetting the 2009 Quality Thresholds, dated 19 December 2007, to Commerce Commission (NZ); and
- OFGEM (UK) – 2007/08 Electricity Distribution Quality of Service Report, Dec 2008 & associated spreadsheets.

F.4.2 Overall Results – International SAIDI and SAIFI Comparisons

After researching all available data, and identifying differences in data comparability, we have identified that only 11 countries have provided SAIDI and SAIFI data for 2007 which is reasonably consistent and comparable. In particular, we were looking for SAIDI and SAIFI statistics which included both planned and unplanned interruptions, but which excluded extreme events (even though the definition of "extreme event" may be different). We were also keen to ensure that the distribution network being compared consisted of a sub-transmission system (HV – high voltage), a primary distribution system (MV – medium voltage) and a secondary distribution system (LV – low voltage). Where there are material differences between the scope of networks covered, these are mentioned in notes to graphs, appendices, tables, etc.

Figure 1 (below) shows the reported 2007 SAIDI statistics for the 11 countries, for which comparable data is available. Figure 2 (below) shows the reported 2007 SAIFI statistics for the 11 countries.

Figure 1 SAIDI (system average interruption duration index, or system minutes lost) for which comparable data is available, for both planned and unplanned interruptions (excluding exceptional events). All figures are for 2007 or 2007/08.

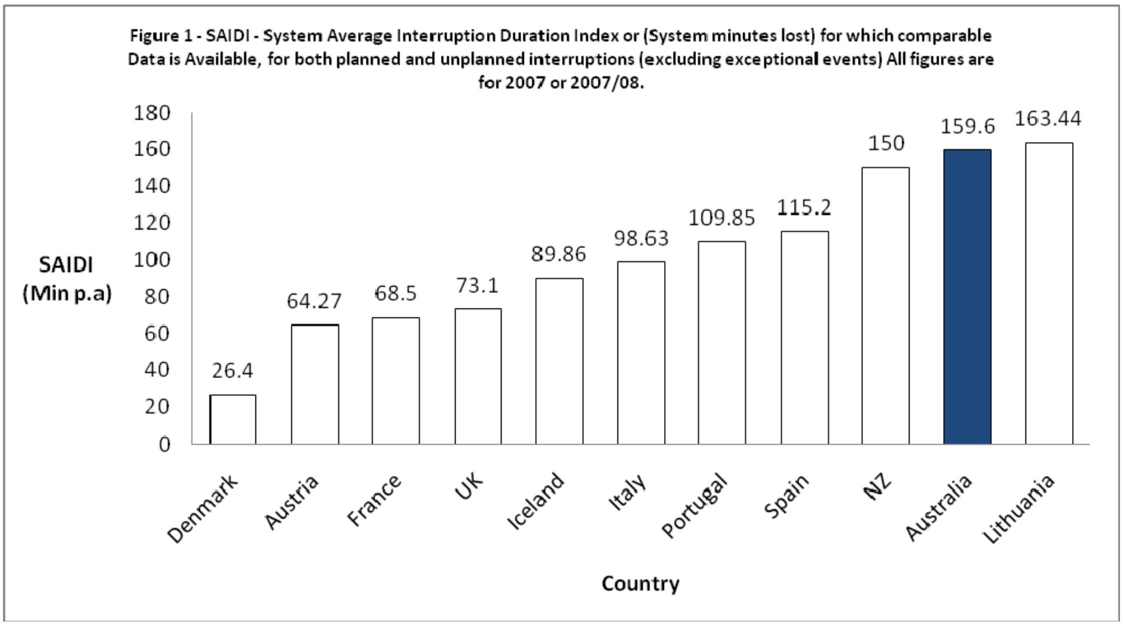
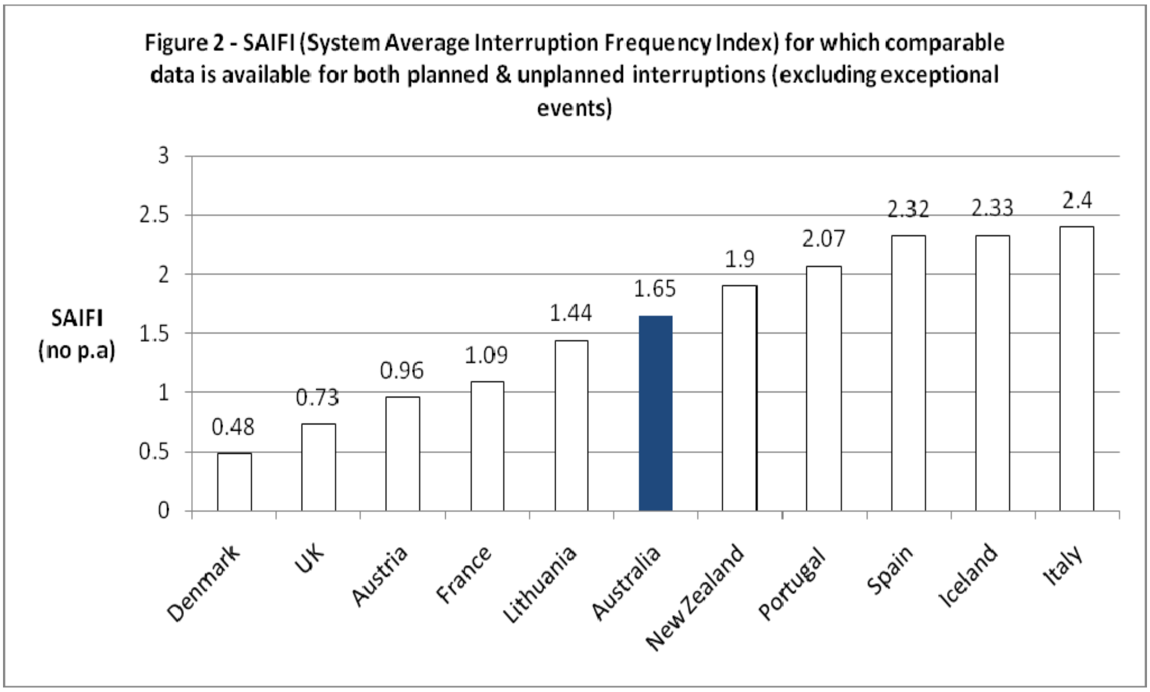


Figure 2 SAIFI (system average interruption frequency index) for which comparable data is available, for both planned and unplanned interruptions (excluding exceptional events). All figures are for 2007 or 2007/08.



The composite Australian result is for the 13 DNSPs that operate within the NEM, the composite UK result is for the 14 UK DNO's that come under OFGEM jurisdiction, and the composite New Zealand result is for the 28 distributors that come under the New Zealand Commerce Commission jurisdiction.

The selected European countries provided data for both planned and unplanned outages, and the calculation of total SAIDI and SAIFI are shown in Appendix 2 of SKM's Background Report, along with any notes on country specific differences in data collection or definition issues.

The composite Australian, NZ, and UK SAIDI and SAIFI statistics shown in figures 1 and 2 are not weighted by customer numbers, while it is unclear whether the European statistics are simple averages or weighted averages.

It is interesting to note the different rankings of some European countries in regard to SAIDI and SAIFI, in particular Iceland (ranked 10th on SAIFI, but 5th on SAIDI), Italy (ranked 11th on SAIFI, but 6th on SAIDI), and Lithuania (ranked 5th on SAIFI, but 11th on SAIDI). In the case of the first two (Iceland and Italy), this suggests a distribution system which suffers a relatively high number of outages, but with a rapid response time to restore supply (possibly an increased level of system control and automation). In the case of Lithuania, the opposite is the case, with a moderate number of outages (ranked 5th), but the highest level of total system SAIDI, which suggests a slower than average response time (CAIDI).

F.4.3 Underlying Differences in the Calculation of Distribution Reliability Statistics

While the overall SAIDI and SAIFI comparisons shown in figures 1 and 2 represent the best available data on a reasonably comparable basis, there remain some small, but not insignificant differences between the data collected and reported in each country. In addition, there are different levels of regulatory scrutiny and audit of the data. These differences are summarised below on a country by country basis.

All countries

- CEER 4th benchmarking report only provides data on systems up to 35 kV
- SAIDI/SAIFI statistics are for "long interruptions", defined as > 3 minutes or ≥ 3 minutes

Australia

- Reported SAIDI/SAIFI statistics are for interruptions greater than one minute
- Aggregated national average is a simple numeric average of all DNSPs, not weighted by customer numbers
- Not all DNSPs count individual faults on LV system
- Majority (not all) of DNSPs use 2.5 beta method to determine exclusion of extreme events

- Majority (not all) of DNSPs calculate SAIDI/SAIFI based on the actual/estimated number of customers affected by an interruption (an alternative method is to estimate the magnitude of load lost)

- Independent audits of reported results conducted in most jurisdictions

New Zealand

- Reported SAIDI/SAIFI statistics are for interruptions equal to or greater than one minute

- Aggregated national average is a simple numeric average of all EDBs, not weighted by customer numbers

- Reported data excludes all LV outages, and all single phase HV (non-SWER) outages

- SAIDI/SAIFI statistics are as provided by the EDBs under the NZ Commerce Commission information disclosure regime, and is not subject to independent auditing

- 2007 SAIDI/SAIFI statistics have extreme events excluded using the 2.5 beta method

- It is not stated as to whether SAIDI/SAIFI statistics are calculated based on "actual/estimated customers affected" method, or "estimated demand lost" method

- A small number of EDB's take supply at the distribution bus-bar of Transpower substations, and therefore do not operate a sub-transmission system

United Kingdom

- Reported SAIDI/SAIFI statistics are for interruptions greater than three minutes

- Aggregated national averages is a simple numeric average of all DNOs, not weighted by customer numbers

- Reported SAIDI/SAIFI data includes all LV outages

- Reported SAIDI/SAIFI statistics are calculated based on actual numbers of customers impacted (full customer connectivity models exist)

- Regulator audits annual reliability results

- Exclusion of major storm events is based on a multiple of the "mean daily HV faults"

- Results for 2007/08 exclude 1.5 min. SAIDI and 0.011 SAIFI of incidents on the transmission system

Austria

- SAIDI/SAIFI statistics exclude interruptions on the LV system
- No independent audits, regulator does plausibility check
- Calculations based on energy not supplied
- Exceptional events defined by local authority declaration of natural disaster

Denmark

- SAIDI/SAIFI statistics exclude interruptions on the LV system
- Calculations based on number of customers affected by interruptions
- No independent audits
- Exceptional events classified by the Regulator under Executive Order 1520 (mainly hurricane and floods)

France

- SAIDI/SAIFI statistics include all voltage levels (HV/MV/LV) up to 35 kV
- Calculations based on number of customers affected by interruptions
- In 2007, special interruptions on MV and LV systems were planned to eliminate PCB transformers (approx three minute increase in level of planned interruptions)
- No independent audits
- Exceptional events classified by TSO and DSO based on interruption to > 100,000 end-users and 1:20 year climate events

Iceland

- SAIDI/SAIFI statistics include all voltage levels (HV/MV/LV), up to 35 kV
- Method of calculation (customer based or load based) not stated
- Audit regime not stated
- Exceptional event definition not stated

Italy

- SAIDI/SAIFI statistics include all voltage levels (HV/MV/LV) up to 35 kV

- Calculation based on number of customers affected by interruptions
- National statistics is a simple numerical average not weighted by customer numbers of individual distributors
- Exceptional events classified by DSO based on a statistical algorithm developed by the national regulator
- Regulator may conduct ex-post audits

Lithuania

- SAIDI/SAIFI statistics include all voltage levels (HV/MV/LV) up to 35 kV
- Calculation based on number of customers affected by interruptions (estimated for LV)
- Exceptional events not defined
- Independent audits conducted by Regulator

Portugal

- SAIDI/SAIFI statistics include all voltage levels (HV/MV/LV) up to 35 kV
- Calculation based on number of customers affected by interruptions (some estimation at LV level)
- Exceptional events classified by the TSO and DSO based on force majeure situation and threshold limits of energy not delivered (50 MWhr for mainland Portugal)
- Independent audit not conducted

Spain

- SAIDI/SAIFI statistics include all voltage levels (HV/MV/LV) up to 35 kV
- Calculation based on number of customers affected by interruptions (connectivity model exits)
- Exceptional events classified by Regional Government/National Government/Civil Protection Service as force majeure under Royal Decree 300/2004
- Independent audits conducted by distribution consultants, and subject to regulatory review

Table F.3: Latest Available SAIDI/SAIFI Statistics for Australian Distributors

DNSP	Total system SAIDI	Total system SAIFI	Year	Comments	Source
VIC					
Alinta AE	76.4	1.3	2007	Planned & Unplanned – excluded events. SAIFI is unplanned only – excluded events.	ESC Comparative Performance Report 2007, dated October 2008.
Citipower	39.8	0.56	2007	As above	As above
PowerCor	161.3	1.7	2007	As above	As above
SP AusNet	316.0	2.69	2007	As above	As above
United Energy	84.2	1.04	2007	As above	As above
QLD					
Ergon Energy	411.0	3.18	2007/ 08	Planned & Unplanned – Excluded events	NMP Part A 2008/9-2012/13
ENERGEX	132.0	1.54	2007/ 08	Planned & Unplanned – Excluded events	NMP Part A 2008/9-2012/13
NSW					
EA	100.8	1.16	2007/ 08	Planned and Unplanned – Excluded events	Network Performance Report, 2008
Integral	119.3	1.28	2007/ 08	Planned & Unplanned – Excluded events	Network Performance Report, 2008
CE	225	2.28	2007/ 08	Planned & Unplanned – Excluded events	Network Performance Report, 2008
TAS					
Aurora	192	1.76	2007/ 08	Planned & Unplanned	OTTER Report Dec 2008 (page 83)
SOUTH AUST					
ETSA	132.6	1.33	FY 2007	Planned & Unplanned – Exclusions (Excludes LV)	ETSA Regulatory Submission to AER (p210)
ACT					
ActewAGL	84	N/A	FY 2007	Planned & Unplanned – Excl	Wilson Cook Report to AER, dated Oct 2008
Simple Numerical Average	159.6	1.65			

Table F.4: Latest Available SAIDI/SAIFI Statistics for European Countries

Country	Total system SAIDI	Total system SAIFI	Year	Comments	Source
Austria (HV & MV)	45.5	0.77	2007	Unplanned – excluding exceptional events	Council of European Regulators – 4th B/M Report on Quality of Electrical Supply 2008, dated 10 Dec 2008
	18.77	0.19		Planned	
	64.27	**0.96**		**TOTAL**	
Denmark (HV & MV)	21.7	0.43	2007	Unplanned - excluding exceptional events	
	4.7	0.05		Planned	
	26.4	**0.48**		**TOTAL**	
France (HV&MV&LV)	57.7	0.98	2007	Unplanned - excluding exceptional events	
	10.8	0.11		Planned	
	68.5	**1.09**		**TOTAL**	
Iceland (HV&MV&LV)	77.93	2.22	2007	Unplanned - excluding exceptional events	
	11.93	0.11		Planned	
	89.86	**2.33**		**TOTAL**	
Italy (HV&MV&LV)	52.47	2.10	2007	Unplanned - excluding exceptional events	
	46.16	0.30		Planned	
	98.63	**2.40**		**TOTAL**	
Lithuania (HV&MV&LV)	92.21	1.19	2007	Unplanned - excluding exceptional events	
	71.23	0.25		Planned	
	163.44	**1.44**		**TOTAL**	
Portugal (HV&MV&LV)	102.54	2.03	2007	Unplanned - excluding exceptional events	
	7.31	0.04		Planned	
	109.85	**2.07**		**TOTAL**	
Spain (HV&MV&LV)	103.80	2.23	2007	Unplanned - excluding exceptional events	
	11.40	0.09		Planned	
	115.20	**2.32**		**TOTAL**	

G Joint Planning in Victoria

During the course of this Review, Victorian stakeholders raised a number of issues about joint planning between Victorian DNSPs and AEMO. To facilitate discussion between the relevant parties, a meeting was organised by the AEMC, which was held in Melbourne on 26 August 2009. The meeting was attended by the Chairman and staff of the AEMC and representatives of the Victorian distribution businesses, the AEMO and the Victorian Department of Primary Industries (DPI).

As discussed in Chapter 2, we consider that our recommendations on joint planning can be applied in Victoria as they clarify the obligation for both parties to come together and work towards identifying the most economic investments. This Appendix provides a detailed outline of the provisions for joint planning in Victoria and the issues raised, giving consideration to stakeholder submissions made during the Review and the discussions from the meeting held in Melbourne.

G.1 Summary of Current Provisions

The Victorian DNSPs and AEMO have a number of obligations under various regulatory instruments relating to their planning functions. These are summarised as follows.

Victorian DNSPs under:

- their licence conditions, are responsible for planning and directing the augmentation of *transmission connection assets* that connect their distribution systems to the shared transmission network;[227] and
- the Victorian Electricity Distribution Code, are to publish an annual "Joint Transmission Connection Planning Report".[228] This report is publicly available.

AEMO, under the National Electricity Law (NEL):

- section 50C(1)(a) – AEMO's declared network functions are as follows: to plan, authorise, contract for, and direct, augmentation of the declared shared network;[229] and
- section 50F(2)(a) and (b) – in deciding whether a proposed augmentation to the declared shared network should proceed, AEMO must undertake a cost benefit analysis and must apply a probabilistic (as distinct from a deterministic) approach to determining the benefit of an augmentation.[230]

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[227] Victorian distribution licence, clause 14.

[228] Victorian Electricity Distribution Code, clause 3.4.

[229] NEL, section 50C(1)(a).

[230] NEL, section 50F(2). Exceptions apply to the application of the probabilistic approach as set out in sections 50F(2)(b)(i)-(ii).

In addition Chapter 5 of the Rules, including Schedule 5.1, outlines some provisions for transmission connections. In particular, S5.1.1 describes the planning, designing and operating criteria that must be applied by NSPs to the transmission networks and distribution networks which they own, operate or control.

G.2 Underlying Scenario

Issues have arisen in cases where the DNSPs have planned transmission connection investments, which have also required investments in the shared transmission network to facilitate the connection services.

The planning process, as reported by stakeholders, is outlined as follows:

1. Joint Planning

DNSPs and AEMO conduct joint planning, including meeting on a quarterly basis to discuss joint projects. AEMO noted that DNSPs and AEMO (and previously VENCorp) have not, to date, conducted joint regulatory test assessments. AEMO noted that it has had limited involvement in the DNSPs' connection asset planning role as all shared transmission network augmentations have, until recently, been funded by DNSPs.

DNSPs also prepare a Joint DNSP Transmission Connection Planning Report, which is a publicly available annual report that provides a 10-year forecast of the DNSPs' transmission connection plans. The DNSPs have indicated that AEMO (and previously VENCorp) would have been involved in the development of this report. It is noted that, at the meeting held on 26 August 2009, AEMO indicated that, historically, it was satisfied with the level of consultation and joint planning between itself and DNSPs on technical matters, but that it has not been involved in the economic analysis of connections including determining the benefits of addressing emerging constraints or whether an option is the most appropriate economic option to address that constraint. AEMO noted that it had not been involved in the economic analysis as the shared transmission network augmentations had been funded by DNSPs and AEMO would recover the cost of the augmentation from the relevant DNSP as a negotiated service under contract.

2. Planning for a specific investment

Once a transmission connection investment progresses through the joint planning process, the Victorian DNSPs:

- develop preferred options, including identifying any investments that may be required to the shared transmission network, consulting with AEMO as required. AEMO indicated at the meeting on 26 August 2009 that it had been satisfied with the level of technical involvement it had through this process in the past given that the projects have traditionally been proposed as funded augmentations and recovered directly from the DNSP as a negotiated service;

- voluntarily conduct the regulatory investment test as specified under the Victorian Electricity Distribution Code, where DNSPs are required to augment transmission connections in a way which minimises costs to customers.[231] As the investments being considered are to meet distribution requirements, DNSPs conduct cost benefit analysis and/or least-cost assessments and, to date, most regulatory investment tests undertaken have been on the basis of a probabilistic assessment of unserved energy. DNSPs indicated at the meeting on 26 August 2009 that AEMO may participate in the economic assessment process where there are benefits to be assessed for the declared shared transmission network, however AEMO noted that assessing the shared network solely without consideration of the entire project would not deliver the most economic outcomes. AEMO noted that limiting the assessment of benefits to the shared transmission network would rarely, if ever, identify sufficient benefits to justify the transmission augmentation as most, if not all, the benefits would be located in the DNSP's network. AEMO considered that to limit the assessment of benefits to the transmission network would not meet the DNSP's objectives because, on its own, the benefits identified on the shared transmission network would be unlikely to justify the project;
- based on their understanding of the definition of prescribed transmission services, proceed on the basis that the connection investment, and any required investment to the shared transmission network to facilitate the connection, would be a prescribed transmission service. However, AEMO noted that, until earlier this year, all shared transmission services had been funded by DNSPs and recovered under contract as negotiated services. The consequence of this was that, since the DNSP was funding the augmentation and receiving a negotiated level of service, AEMO should not be as concerned with the economic efficiency of the project or present alternative options to the DNSP.

3. Finalising a specific investment

Prior to finalising a transmission connection investment, DNSPs lodge a connection application with AEMO. As required under Chapter 5 of the Rules, AEMO then reviews the application to ensure that it satisfies the technical specifications relating to the quality of supply set out in Schedule 5.3 of the Rules. Where augmentations are funded by DNSPs through the funded augmentation or negotiated service provisions, AEMO consults on these augmentations using the funded augmentation consultation process in the Rules.

231 Victorian Electricity Distribution Code, clause 3.1(b).

G.2.1 Issue 1 – Responsibilities for Assessing Costs and Benefits of Project

G.2.1.1 Actions under regulatory provisions

As the DNSPs are responsible for planning and directing the augmentation of transmission connection assets, where a transmission connection investment is required, the DNSP would conduct the relevant regulatory investment test. DNSPs apply probabilistic planning in the vast majority of cases. However, where an investment is required to meet regulatory reliability standards, it is likely that the regulatory investment test conducted could be a least-cost assessment.[232]

A proposed augmentation to the shared transmission network must be authorised or directed by AEMO. In deciding whether to carry out the augmentation, AEMO noted that it must undertake a cost benefit analysis and adopt a probabilistic approach to determine the benefit of the augmentation.[233] At the meeting on 26 August 2009, DPI indicated its understanding that section 50F of the NEL was inserted to explicitly require a probabilistic (as distinct from a deterministic) approach to planning be used.[234]

G.2.1.2 Scenarios where issues arise

DNSPs and AEMO jointly plan projects that arise from an identified need on the distribution network, including transmission connection investments to assess requirements and feasible alternatives. Once a connection investment progresses to the stage where DNSPs make a connection application to AEMO (or apply for an amendment to an existing connection agreement), some of the DNSPs considered that AEMO treats the investment in the shared transmission network as an augmentation that must be subject to clause 50F(2) of the NEL.[235]

In its submission on the Draft Report for the Review and in the context that "joint" regulatory tests have only been recently applied (as opposed to a less extensive "joint planning process"), AEMO noted:[236]

> …AEMO has not to date seen any transmission network augmentations arising from a distribution network requirement that could not be justified

232 It is noted that the recommendations for the Distribution Network Planning Review require joint investments to be assessed under the RIT-T. This would then require market benefits to be assessed.

233 AEMO noted that it must adopt a probabilistic approach unless the results will be immaterially different from applying a deterministic approach or it will not be reasonably practicable or for some other reason inappropriate. AEMO noted that in Victoria there are no jurisdictional deterministic standards applicable to the transmission network and, to the best of its knowledge, there are no mandatory ones that apply to the distribution networks either.

234 NEL, section 50F(2).

235 CitiPower/Powercor, notes provided at the meeting on 26 August 2009, p. 3.

236 AEMO considered that, to date, AEMO and DNSPs have not undertaken a true joint regulatory test where both parties have a commonly understood set of assumptions and approaches in relation to the measurement of the source data and application of such data.

on net economic benefit grounds rather than solely on reliability grounds. Consequently, AEMO's preference in this respect is to adhere to the discipline that the economic planning test applies to the greatest possible extent.[237]

G.2.1.3 What the issues are

i) DNSPs are concerned that there are duplicated but uncoordinated economic assessments (as DNSPs have already conducted their assessments during the joint planning process). AEMO noted that a joint process should provide for all assessments, including regulatory investment tests, to be conducted "jointly".

ii) DNSPs questioned whether section 50F(2) of the NEL should apply at all in these cases. The provision applies to "augmentations", which is defined under the NEL as "work to enlarge the system or to increase its capacity to transmit or distribute electricity". DNSPs believed it is arguable whether an investment in the shared transmission network that is required to facilitate a transmission connection is an "enlargement". AEMO noted that whether a project increases or enlarges a system's capacity to transmit electricity is one of fact to be determined by the circumstances and not related to the purpose of the project.

iii) AEMO considered that, given its obligations under the NEL, it needs to have confidence in the economic analysis of any augmentation to the shared transmission network and that it needs "to be satisfied that the augmentation passes the applicable regulatory test analysis" if it is to recover the costs of the augmentation from all transmission network users.[238]

iv) DNSPs considered that most (if not all) the economic benefits of the connection project are assessed by carrying out the planning functions of the DNSP, and this requires detailed knowledge of the DNSPs' distribution network. DNSPs did not consider that AEMO is in a position to take the responsibility to assess benefits to a DNSP's network.

v) DNSPs noted that even if it is accepted that AEMO must conduct a separate economic assessment, greater transparency is required to the process undertaken by AEMO and appropriate thresholds should apply. DNSPs questioned whether AEMO conducts its assessment on the whole project or just the components in the shared transmission network. If the latter, clarity on whether the total project costs and benefits are being considered would be required. However, as previously noted, AEMO contended that a separate test would be inappropriate and would not achieve the DNSPs' goal of having the costs of the service passed to customers through transmission use of system (TUOS) charges. AEMO considered that goal can only be achieved by a joint assessment carried out by the DNSP and AEMO.

237 AEMO, Submission on the Draft Report, p. 3.

238 AEMO submission, op. cit, p. 3.

G.2.2 Issue 2 – Prescribed or Negotiated Transmission Services Under the Rules

The second issue relates to the definition of prescribed transmission service under the Rules.

G.2.2.1 Current situation

DNSPs considered that shared transmission network investments required to facilitate a network to network connection should be classified as a prescribed transmission service as defined under Chapter 10 of the Rules.

AEMO noted that AEMO and DNSPs need to jointly conduct a regulatory investment test for the proposed investments and it would only consider recovering costs associated with the shared transmission network services from transmission network users if the solution is the most economically efficient solution. AEMO noted that it would always enable any investment proposed by a DNSP to proceed as a negotiated transmission service provided that it satisfies the technical requirements under Chapter 5 of the Rules.

G.2.2.2 What the issues are

i) At the meeting on 26 August 2009, the DPI indicated that it would have expected that investments in the shared transmission network to facilitate a connection service would be classified as prescribed transmission services.

ii) The Rules were specifically developed to refer to connection "services". Should an investment be required in the shared transmission network to facilitate the connection, then it would form part of the connection service and hence should be considered a prescribed transmission service.

iii) AEMO considered that the Rules do not automatically define shared transmission network augmentations which support network-to-network connections as prescribed transmission services. AEMO noted that, in Victoria, due to the absence of jurisdictional service standards, a range of solutions varying in cost and effectiveness would satisfy (and often exceed) the needs requirements. Therefore a regulatory investment test assessment (taking a probabilistic cost benefit approach) would enable the identification of the optimal solution. AEMO agreed that provided the regulatory investment test was used to identify an optimal solution that would meet the DNSPs' need, that solution should be allowed to be classified as a prescribed service and recovered from customers through TUOS charges.