RIT-T Economic Assessment Handbook

For non-ISP RIT-Ts

Version 3.0

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Energy Networks Australia

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Scope

The National Electricity Rules (NER), and the Australian Energy Regulator's (AER) Regulatory Investment Test –Transmission (RIT-T) and RIT-T Application Guidelines are prescriptive in relation to the process to be followed in undertaking the RIT-T, including the documentation that is required to be produced and the consultation required.[1,2] There is less prescription in these documents in relation to how the economic cost benefit assessment required under the RIT-T should be conducted, and the approach to determining some of the input assumptions.

The cost-benefit analysis involves the calculation of the net present value (NPV) of the net market benefit associated with each credible option, across a range of reasonable scenarios.

The AER's Cost Benefit Analysis Guideline provides detailed guidance on the application of the RIT-T for 'actionable ISP' projects included within AEMO's Integrated System Plan (ISP).[3] This guidance is also likely to be relevant for 'future ISP projects'.

This Handbook focuses on non-ISP RIT-Ts only.

The purpose of this Handbook is to:

» provide additional 'practitioner level' guidance on undertaking the economic assessment; and
» facilitate enhanced transparency and consistency in the application of the RIT-T economic assessment across, and within, TNSPs.

This Handbook should be read in conjunction with the NER, and the AER's RIT-T and RIT-T Application Guidelines. The Handbook is not intended to replace any of these documents, and does not repeat the guidance already in those documents.

This version updates the October 2020 ENA RIT-T Handbook (Version 2.0) and reflects, amongst other things, the 2022 NER changes relating to the Material Change in Circumstance provisions and the subsequent October 2023 update to the AER's RIT-T Application Guidelines, as well as the AER's November 2022 determination in the dispute of two NSW RIT-Ts.

Throughout the Handbook, a distinction is drawn between non-ISP RIT-Ts being undertaken for repex purposes and those being undertaken for wider purposes (eg, augmentation) due to their different drivers and market benefits.

This Handbook relates to the practical application of the RIT-T for non-ISP projects as currently required, particularly in the case of repex.

This Handbook will be periodically updated to reflect the practical experiences of TNSPs in applying the RIT-T to non-ISP projects, as well as ongoing regulatory reform. In particular, the anticipated update in the AER's RIT-T Application Guidelines on the approach to calculating the benefits of greenhouse gas emission reductions in the RIT-T assessment (expected by 31 December 2024) may require a future updating of this Handbook.

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[1] See NER clause 5.16.4 and section 4 of: AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023 - referred to throughout this Handbook as 'the AER RIT-T Guidelines'.

[2] At the time of updating this Handbook, the latest versions of these documents were: NER version 203; AER, *Regulatory investment test for transmission*, Version 2, August 2020, and AER, *Regulatory Investment Test for Transmission Application Guidelines*, Version 5, October 2023.

[3] AER, *Cost benefit analysis guidelines*, Version 2, October 2023.

1 What is the RIT-T and when is it applied?

Key points[4]

- The RIT-T identifies the investment option that maximises net economic benefits in the National Electricity Market and, where applicable, meets the relevant service and technical standards set out in the NER, or in other applicable regulatory instruments (including safety-related requirements).
- It involves consultation on an economic cost benefit assessment, which ranks different project options – typically involving both network and non-network technologies – to identify the 'preferred option' (the option with the highest ranking).
- A RIT-T is required whenever the most expensive credible option has an estimated capital cost above **$7 million** – a threshold reviewed every three years.
  - The test should use the central cost estimate in determining whether this threshold is met or not.
  - This test should subtract any financial or capital contributions from any external parties (eg, governments, generators and customers) from the capital cost for comparing to this threshold.[5]
- For some repex projects, the **$7 million** threshold test should be applied to an overall replacement program (the cost of which may therefore be above the threshold) requiring a RIT-T, rather than to each individual replacement project.
  - The threshold applies to the entire program cost, ie, it should not be applied to the annual cost of the program.
  - A RIT-T is only required to be applied to an asset replacement program to address an identified need where that program involves proactive replacement (ie, replacing assets prior to failure), as opposed to reactive replacement (ie, replacing assets when they fail outright, or fail serviceability tests).
- Additional exemptions exist for when an investment does not require the RIT-T to be applied – however these are not used often in practice.
- The RIT-T is not required for general business capital expenditure that does not form part of the network, ie, that is not used to convey and control the conveyance of electricity, such as IT, communication systems, property and vehicle fleet. Connection assets are also not part of the network and thus are exempt from a RIT-T process. (with the exception of connection between transmission and distribution networks)[6]
- If a RIT-T is cancelled before it is finalised, the TNSP should clearly set out, and publish, the reasons that led to the cancellation of the particular RIT–T assessment.
- **Following completion of a RIT-T, the TNSP** should **monitor whether there is a material change in circumstances that could affect the preferred option identified in the PACR.**

1.1 Overview and purpose of the RIT-T

In general, the purpose of the RIT-T is to identify the investment option that maximises net economic benefits in the National Electricity Market (NEM) and, where applicable, meets the relevant jurisdictional or National Electricity Rule (NER) based reliability standards.

[4] The NER requirements relating to when the RIT-T needs to be applied can be found in clause 5.16.3 of the NER. The AER's guidance regarding the identified need and applying the RIT-T can be found in sections 2 and 3.1 of AER's RIT-T Application Guidelines.
[5] This treatment of financial contributions is to determine whether the threshold for applying the RIT-T has been reached. For guidance on how wealth transfers should be treated in the RIT-T assessment itself, see section 4.3.
[6] NER 5.16.3(a)(6) sets out the exemption for connection assets, and states that this only applies where those assets are providing services other than prescribed transmission services or standard control services.

- It is a transparent process for identifying the most efficient solution to meeting an 'identified need' for projects above a certain financial threshold.
- The RIT-T requires a cost benefit assessment of different investment options.
- The key outcome of the RIT-T economic assessment is the relevant ranking of options against each other, rather than the dollar outcome of the assessment.
- The economic assessment identifies the top ranked option (ie, the 'preferred option').

The RIT-T is applied by TNSPs when considering options to address an 'identified need'.

Investment options considered in the assessment can include both capex by the TNSP (or others), and opex by the TNSP (including network support payments to providers of non-network options).

The RIT-T applies to the majority of augmentation and replacement expenditure.[7]

The RIT-T does not apply to general business capital expenditure such as Information Technology (IT), communications systems ,[8] property and vehicle fleets.[9] Investments associated with physical security systems and protective fencing also fall within the scope of 'general business capital expenditure' and so do not need to have the RIT-T applied.

These expenditures are assessed by the AER as part of the separate revenue determination process.[10] The exemption from having to apply a RIT-T to IT and communications equipment is also consistent with the AEMC's earlier decision not to require TNSPs to report on these investments as part of their Transmission Annual Planning Reports (TAPRs).[11]

A RIT-T is not required for strategic land purchases.[12]

1.1.1 AER guidance and distinction between ISP and non-ISP RIT-Ts

In August 2020, the AER published its 'Guidelines to make the integrated system plan actionable' consisting of:

- Updated ***Regulatory investment test for transmission*** (RIT-T Instrument): this instrument sets out the regulatory investment test for transmission in accordance with NER 5.15A.1;
- ***Cost benefit analysis guidelines***: this guideline provides binding and non-binding guidelines for AEMO and the TNSPs in the application of cost benefit analysis in preparing an Integrated System Plan (ISP) and in applying the RIT-T to actionable ISP projects;
- ***Forecasting best practice guidelines*** (FBPG): the FBPG provides procedural guidance to promote transparency and stakeholder confidence in the forecasting practices and processes that AEMO undertakes when developing reliability forecasts, its Input Assumptions and Scenarios report (IASR) and the ISP; and

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7 The application of the RIT-T to repex commenced on 18 September 2017.
8 Energy Management Systems are considered to fall within the scope of 'communications systems'.
9 In particular, the definitions in the NER limit the RIT-T to investments in the 'network', ie, 'the apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity excluding any connection assets. In relation to a Network Service Provider, a network owned, operated or controlled by that Network Service Provider'. See also AEMC, *Rule determination: National electricity amendment (replacement expenditure planning arrangements) rule*, July 2017, p. 65 which expressly states that the RIT process is not designed for general business capital expenditure such as IT and communication systems.
10 AEMC, Rule Determination, National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017, 18 July 2017, p. 65.
11 Op cit.
12 However, the market value of land should be included in a RIT–T that explores building on a previously acquired easement (that is, land should not be treated as a sunk cost, to the extent that it can otherwise be sold). See section 4.1.1.

» ***Regulatory investment test for transmission application guidelines*** (RIT-T Application Guidelines): the application guidelines provide binding guidance for RIT-T proponents when undertaking the RIT-T for investments which are not actionable ISP projects.

In October 2023, the AER updated its cost benefit analysis guidelines and its RIT-T application guidelines.

The AER's cost benefit analysis guidelines, together with AEMO's Inputs Assumptions and Scenarios Report (IASR) and the ISP, largely prescribe the approach TNSPs need to adopt in applying the RIT-T to an actionable ISP project. An 'actionable ISP project' is one where the ISP identifies that the TNSP needs to complete the RIT-T Project Assessment Draft Report (PADR) within the next two years. These guidelines are also relevant for TNSPs that may seek to apply the RIT-T early for future ISP projects that have not yet been identified as actionable, albeit that the process to be followed in this case would differ to that for actionable ISPs.[13]

For projects that are not included in the ISP (termed 'non-ISP projects' in this Handbook), the AER's RIT-T Application Guidelines are directly relevant, but AEMO's IASR and ISP will also be relevant in some cases. The focus of this handbook is to provide practical guidance to TNSPs in undertaking non-ISP RIT-Ts.

Figure 1 illustrates the various AER and AEMO documents of relevance to non-ISP RIT-Ts.

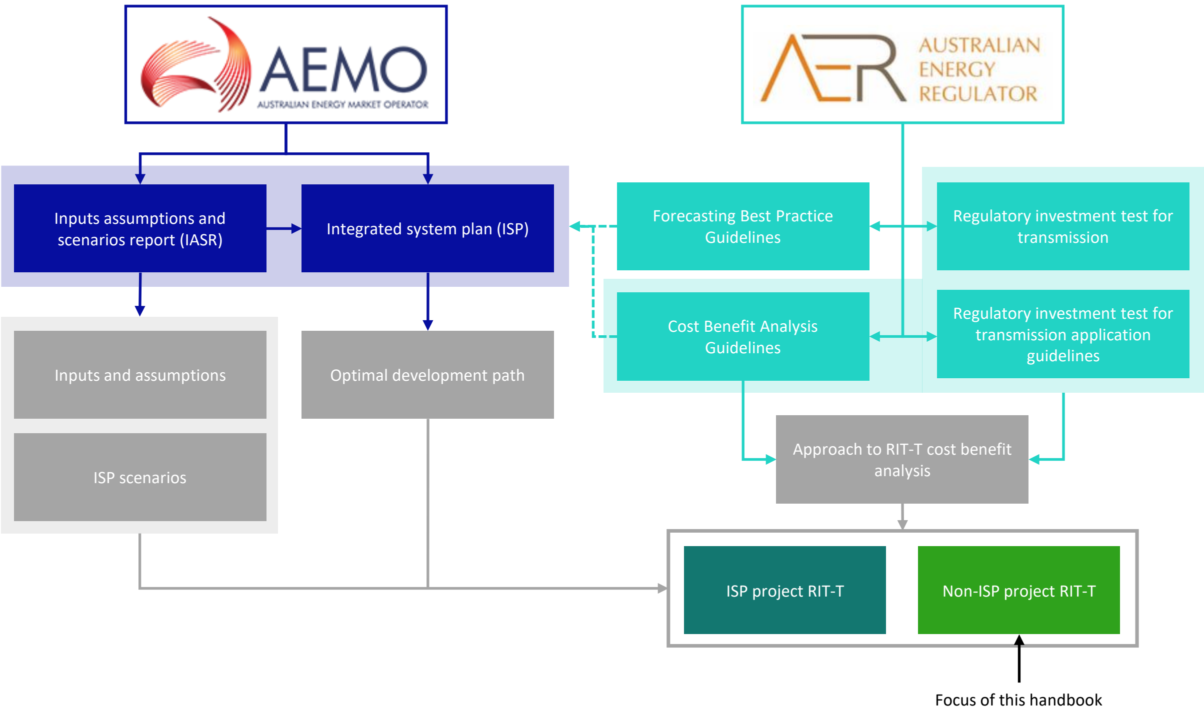

Figure 1 Current context of guidance for the non-ISP RIT-T

13 In particular the TNSP would need to issue a Project Specification Consultation Report (PSCR), which is not required for actionable ISP projects.

1.2 When does the RIT-T need to be applied to non-ISP projects?

Figure 2 summarises when the RIT-T needs to be applied to non-ISP projects (and when it does not).[14]

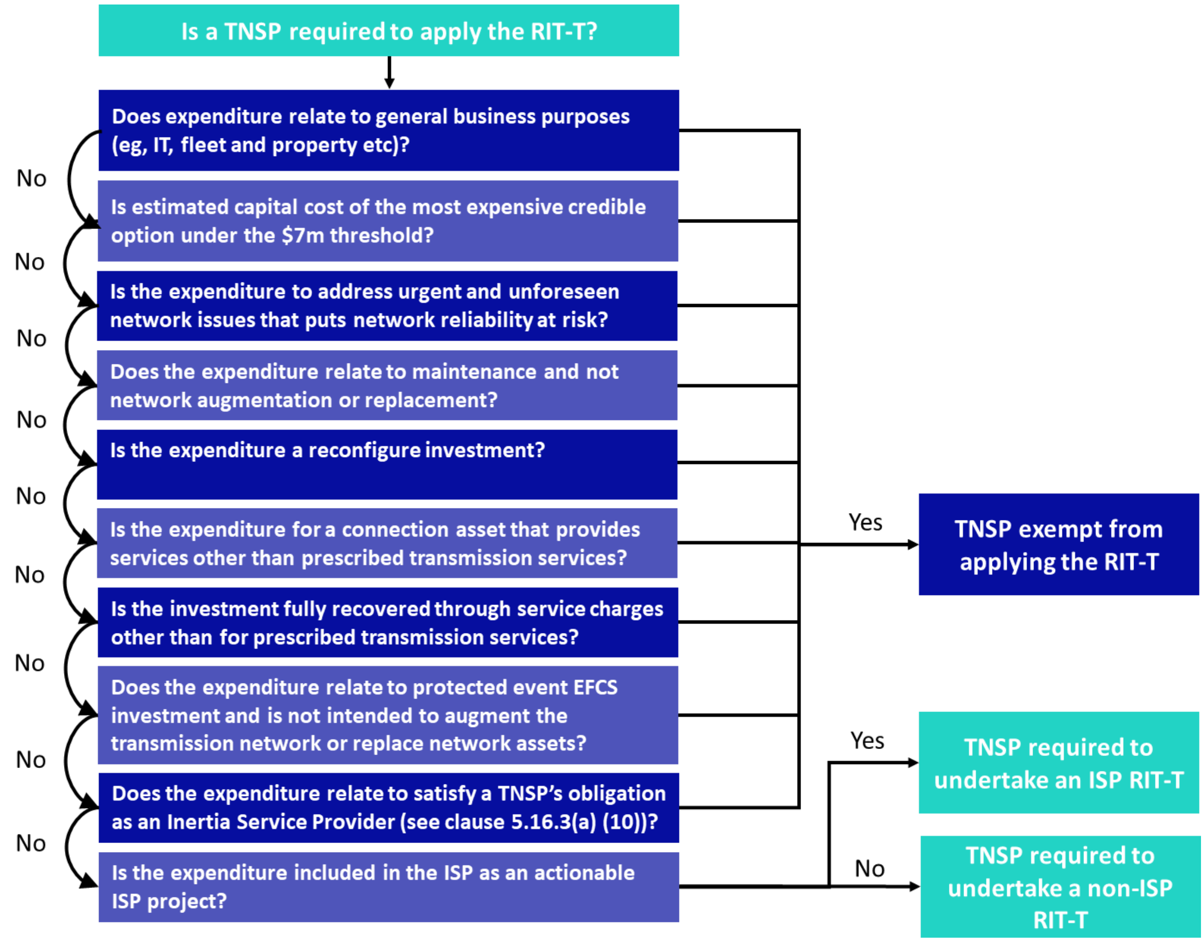

Figure 2: When the RIT-T needs to be applied (and when it does not)[15]

The value of the proposed investment is the key consideration in determining whether the RIT-T is required:

- A RIT-T is only required for investments above a 'trigger' threshold – currently $7 million.[16]

In considering this threshold, a TNSP should:

- note that this threshold applies to the *estimated capital cost* of the most expensive credible option – operating and maintenance costs are therefore excluded from this threshold.[17]

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[14] Refer to NER clause 5.16.3(a) for more information, and specific definitions, relating to this figure.
[15] The RIT-T does not apply to proposed expenditure on "inertia service payments" or to network investment undertaken by the TNSP where an inertia shortfall is declared in a region. This exemption will apply, where the time for making the inertia services available is less than 18 months after AEMO provides its inertia shortfall notice (see clause 5.16.3(a)(9)-(10) of the NER).
[16] The RIT-T threshold level is reviewed by the AER every three years. The last update was in November 2021. The next update is due by November 2024.
[17] Any costs of 'complying with laws, regulations and applicable administrative requirements' that are not reflected in the capital costs (eg, the cost of tending to oil spills that may be expected to continue to occur under an option) should also be excluded when considering the capital cost threshold. These broader costs, as well as operating and maintenance costs generally, are discussed in more detail in section 4 of this Handbook.

- subtract any 'external'[18] financial or capital contributions from the capital cost for comparing to this threshold, including any contributions from other NEM participants.
- note that the threshold only applies to the *most expensive* credible option – while some options could have a much higher cost than others, they may be considered non-credible and excluded from the threshold analysis (see section 3.2).
- use the central capital cost estimate based on the TNSP's typical cost estimation process for planning purposes (as outlined in section 4.1 below).
- remain aware in making any subsequent changes to the scope of a project which falls below the RIT-T threshold (including making changes to an existing repex program such as a change to a procurement or design standard or altering the engineering criteria) whether those changes have the consequence of the RIT-T threshold now being met.[19]

The RIT-T is required to be applied to all projects (including repex projects) that meet the RIT-T threshold (and for which there is no explicit exemption), regardless of whether expenditure for that project (or program) is already included in the TNSP's expenditure forecasts.[20]

The RIT-T or RIT-D is required to be applied to the augmentation of transmission/distribution connection points:

- if the connection service provided by a transmission/distribution connection asset is a 'prescribed transmission service' as defined in the NER,[21] and so the exemption from applying the RIT-T does not apply;
- if the driver for the investment is to address a limitation on the transmission network, the RIT-T applies;
- if the driver is to address a limitation on the distribution network, the RIT-D applies, and
- by agreement of the relevant network service providers, or if at least one potential credible option to address the identified need includes investment in a network or non-network option on a transmission network/distribution network, a joint planning project may be applied as a RIT-T/RIT-D.

When a preferred option that has previously passed a RIT-T has several stages, and where the TNSP has published a clear decision rule for progressing with subsequent stages, the initial RIT-T is considered to cover *all* stages of the investment (in the absence of a material change in circumstance - see section 1.6). In this situation, an additional RIT-T only needs to be applied to subsequent investment stages of the preferred option when:[22]

- the subsequent investment exceeds the RIT-T threshold; <u>and</u>

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[18] In these circumstances, an 'external' contribution means that, to the extent of that contribution, the costs of the project do not need to be recovered from electricity consumers via the regulated charges of the relevant network business (or businesses). It therefore covers contributions from other NEM participants (eg, generators, retailers) as well as parties external to the NEM (eg, governments, ARENA).
[19] AER Compliance Bulletin No. 10, *Determining whether proposed replacement capital expenditure constitutes a RIT-D project*, November 2021 p.9. The AER notes (p. 4) that the principles discussed in this compliance bulletin equally apply to TNSPs applying the RIT-T.
[20] AER Compliance Bulletin No. 10, *Determining whether proposed replacement capital expenditure constitutes a RIT-D project*, November 2021 p.8.
[21] See the NER definition of 'prescribed connection services', which can be found in Chapter 10 and clause 11.6.11 of the NER.
[22] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, pp. 20-21.

- there has been a material change in circumstances beyond the contingences explored in the RIT-T when forming the decision rule,[23] or consistent with re-opening triggers specified for that RIT-T.

Under the RIT-T, 'material' should be interpreted as referring to a reasonable expectation that the change could affect the identified preferred option. An example would be a new emissions policy being announced that the TNSP expects will lead to AEMO updating the IASR and the ISP, and which could affect whether the second stage of the preferred option is optimal.[24] Typically, any such changes will be outside of those considered in the scenario and sensitivity analysis of the initial RIT-T.

Where a preferred option reflects a decision rule, the TNSP should update stakeholders when a subsequent stage of an investment is undertaken (eg, by issuing an addendum to the PACR).

1.3 Application of the RIT-T to replacement programs vs replacement projects

Many existing transmission network assets were installed at the same time (some 50 or 60 years ago) by the predecessors of current TNSPs (eg, state electricity commissions). Consequently, these assets are now approaching the end of their technical lives, and are requiring replacement around the same time. A RIT-T will be required to assess, and consult on, the efficient replacement options available (including decommissioning).

It may ultimately be efficient to replace multiple assets of the same type across more than one location – ie, as a 'program' of replacement, rather than as individual projects.

- In this circumstance, the threshold test should be applied to the cost of the whole replacement program (which may be above the threshold), rather than to the cost of each individual project (which may not be above the threshold).
- The identified need for this RIT-T would likely be centred on growing reliability or safety concerns in relation to these deteriorating assets, all of which were installed at a similar period and face the same issues of degradation and decreasing reliability.[25]
  - The identified need for this RIT-T could also be based on meeting externally imposed regulatory instruments related to safety, eg, for replacing ageing transformers, the identified need may be focussed on meeting requirements contained in a jurisdictional *Electricity Safety Act*.

The AER guidelines state that a RIT-T is only required to be applied to an asset replacement program to address an identified need where that program involves *proactive* replacement (ie, replacing assets prior to failure), as opposed to *reactive* replacement (ie, replacing assets when they fail or when those assets have failed inspection or serviceability tests). The latter is considered by the AER to be captured in the revenue allowance process as 'business-as-usual' expenditure.[26] The AER expects TNSPs to use their

[23] These contingencies can be considered as defining when changes in circumstances are not material to the outcome of the RIT-T, consistent with NER 5.16.4 (z4)(3). See also AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, pp. 20-21.
[24] Clause 5.16.4(z4) of the NER defines a material change in circumstances as including, but not limited to: a change to the key assumptions used in identifying the identified need described in the PACR; for RIT-T projects where the estimated capital cost of the proposed preferred option is greater than $100 million and AEMO is not the sole RIT-T proponent, one or more RIT reopening triggers applying to the project having been triggered; or a change in circumstances which, in the reasonable opinion of the RIT–T proponent, the preferred option identified in the PACR report is no longer the preferred option.
[25] Articulating the identified need for repex RIT-Ts, as well as other RIT-Ts, is discussed in more detail in section 2 below.
[26] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, p. 12.

discretion in determining the rigour to apply to their investment decisions, which should be commensurate with the magnitude and risks associated with the investment at hand.[27]

However, the NER does not categorise replacement expenditures as 'reactive' or 'proactive'. Thus, TNSPs should assess their replacement expenditure plans against the requirements of the NER, which requires TNSPs to undertake a RIT-T if a response to an identified need introduces or materially alters a replacement expenditure project and the aggregate incremental forecast costs under that project exceed the RIT-T cost threshold.[28]

In determining whether the RIT-T should be applied to a program, or mix of programs, or to an individual project, consideration should be given to the drivers behind the replacement and the geographic area of the projects. In short, the decision regarding whether to focus the RIT-T on a bundle of multiple components of programs at a single site or on a single program across multiple sites should be based on the overall single 'need' being addressed. For example:

- It may be appropriate to treat a program of asset replacement across multiple locations as a single credible option for the purposes of undertaking a RIT-T;
  - For example, a credible option could consist of a program to replace specific substation elements across the network (due to the identification of a fault in that specific element, leading to higher expected failure rates and therefore unserved outages or safety risk concerns).
- Alternatively, similar drivers and/or programs in a similar geographic area (and therefore which all affect the same 'node-to-node' supply of electricity) may be more appropriately treated as a single 'RIT-T project', and for the purposes of applying the RIT-T threshold.
  - For example, a program may include replacement of elements in a substation, and of sections of a line, over time between two nodes (due to the age of those assets leading to higher expected failure rates and therefore unserved outages or safety risk concerns).
- In addition, a number of programs may need to be split and then re-combined for the purposes of undertaking a repex RIT-T:
  - For example, a TNSP may have ten programs of different asset replacement exercises planned all of which overlap for one (or more) key assets, such as substations. In this example, the relevant assets expected to be replaced at the overlapping site would be combined into a credible option for the purposes of applying the RIT-T.

The RIT-T cost threshold also applies to the entire program cost, ie, it should not be applied to the annual cost of the program.

The AER states that a RIT-T must be carried out if the incremental, aggregate costs of all asset replacements after the project change exceed the RIT-T cost threshold relative to a counterfactual where the change had not occurred.[29]

In the case of an ongoing project with a cost that is below the RIT-T cost threshold, there is currently no explicit guidance regarding whether a RIT-T will be required if, prior to delivery, costs escalate above the threshold.

However, given that the AER requires TNSPs to apply the RIT-T when there are changes to the scope of their ongoing replacement expenditure projects, it is suggested that a RIT-T be applied where the

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[27] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, section 2.2.
[28] AER Compliance Bulletin No. 10, *Determining whether proposed replacement capital expenditure constitutes a RIT-D project*, November 2021, p 8.
[29] See: AER Compliance Bulletin No. 10, *Determining whether proposed replacement capital expenditure constitutes a RIT-D project*, November 2021, section 3.2.

estimated cost of the project increases above the threshold (even where there has been no change in project scope), provided that there remains scope for the delivery of the project to be amended in light of the RIT-T outcome.

While non-network options may not form part of credible options for many repex RIT-Ts, there will be instances where non-network technologies may be relevant.

- For example, where a TNSP has multiple replacement programs that span several substations, for the majority of cases non-network alternatives to each partial investment may not be feasible. However, at a particular substation, the sum of works across multiple replacement programs may be substantial and create an opportunity for a non-network proponent to provide an alternative solution.
- In this example, a RIT-T should be applied to *all* replacement assets/programs affecting that substation at once and the documentation should assess, and call for submissions on, the feasibility of non-network solutions for that particular substation, noting that they are unlikely to be feasible at other locations.

In deciding how to group works, explicit care should be taken to not inadvertently preclude any potential non-network options.

1.4 Exemption from preparing a PADR

The NER include provisions for a TNSP to be exempt from preparing a Project Assessment Draft Report (PADR) under certain conditions – namely:[30]

- if the estimated capital cost of the preferred option is less than $46 million;[31]
- if the TNSP identifies in its PSCR its proposed preferred option, together with its reasons for the preferred option and notes that the proposed investment has the benefit of exemption; and
- if the TNSP considers that the proposed preferred option and any other credible options in respect of the identified need will not have a material market benefit for the classes of market benefit specified in the NER, with the exception of market benefits arising from changes in voluntary and involuntary load shedding.

In practice, this requires that the NPV assessment used to identify the preferred option (ie, that which is usually included in the PADR) is presented in the PSCR.

In terms of the third requirement, 'material' is to be interpreted as having an impact on the preferred option. Put another way, market benefit categories other than changes in voluntary and involuntary load shedding may be expected and estimated as part of the economic assessment but they cannot be considered material in terms of identifying the preferred option, if this exemption is to apply.

The exemption from producing a PADR will no longer apply if additional credible options, or market benefits, are identified during the PSCR consultation period. This includes where credible non-network options are proposed in consultation.[32] In this instance, the TNSP needs to produce a PADR which includes an NPV assessment of the net market benefit of each additional credible option.

[30] NER clause 5.16.4(z1) specifies these circumstances.
[31] This threshold level is reviewed by the AER every three years. The last update was in November 2021. The next update is due by November 2024.
[32] NER clause 5.16.4(z1)(4).

1.5 Cancellation of a RIT-T

There may be instances where a material change in circumstances leads to the identified need no longer existing, part-way through the RIT–T process. This may lead the TNSP to cancel its RIT–T assessment before completing the RIT-T process.

In these circumstances, the TNSP should clearly set out, and publish, the reasons that led to the cancellation of the particular RIT–T assessment.[33] The TNSP should also inform stakeholders as soon as they are aware of the material change in circumstances.[34,]

1.6 Material change in circumstances

Following completion of a RIT-T (publication of the PACR), the TNSP needs to monitor whether there is a material change in circumstances (MCC) that could affect the preferred option identified in the PACR.[35] This could occur by the change in circumstance:

- changing the identified need for the RIT-T;
- changing the credible options that were considered in the RIT-T. For example, this could occur through resulting in the preferred option no longer being credible (such as where a non-network proponent is no longer able or willing to enter into a network service agreement);
- materially changing the costs and/or benefits of the options considered in the RIT-T such that an alternative option may now have a greater net market benefit; or
- where the identified need for the RIT-T is to provide market benefits (rather than being a reliability corrective action), resulting in the net market benefits of the preferred option no longer being positive.

Where the estimated capital cost of the preferred option exceeds $100 million, [36] RIT-T proponents must propose one or more relevant RIT reopening triggers. RIT reopening triggers must be tailored to the specific circumstances of the project and should be informed by analysis conducted as part of the RIT-T assessment.

The principles identified by the AER to guide the development of a RIT reopening trigger are:[37]

- identifying the key inputs and assumptions used in RIT-T modelling, and the events, factors and changes in circumstances that may alter those key inputs and assumptions;
- identifying an event, factor or circumstance that would have a real, rather than a potential or a possible, likelihood on affecting the key inputs and assumptions and may eliminate net benefits of the preferred option and/or alters the ranking of credible options;
- being objective and capable of being verified; and
- where possible, quantify boundary values of key inputs and assumptions, for example the cost limit of a project before the net benefits of the project becomes negative.

The TNSP must include the proposed reopening triggers in the PADR for consultation.

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[33] For examples of RIT-T cancellations, see: Transgrid, *Managing expected demand in the Panorama area*, Notice of RIT-T cancellation, 1 August 2023. Available at: https://www.transgrid.com.au/media/ywkp4x3w/notice-of-rit-t-cancellation_managing-expected-demand-in-the-panorama-area.pdf. ElectraNet, https://web.archive.org/web/20190228085924/https://www.electranet.com.au/projects/northern-south-australia-region-voltage-control/, accessed 29 November 2023. ElectraNet, https://web.archive.org/web/20190228090849/https://www.electranet.com.au/projects/managing-voltages-in-the-mid-north/, accessed 29 November 2023.
[34] AER, *Regulatory Investment Test for Transmission Application Guidelines,* October 2023, section 4.5.2.
[35] NER clause 5.16.4(z3).
[36] This threshold is to be reviewed an updated by the AER every three years as part of the RIT-T cost threshold review. The next review is due by November 2024. See: NER clause 5.16.4(k)(10). AER, *Regulatory Investment Test for Transmission Application Guidelines,* October 2023, section 4.5.1.
[37] AER, *Regulatory Investment Test for Transmission Application Guidelines,* October 2023, section 4.5.1.

For projects which do not meet the above threshold, it may still be helpful to set out in the PACR (or in the PADR, if appropriate) the conditions that could lead to a material change in circumstance (eg, the change in costs that would be required), drawing on the threshold analysis included in the RIT-T analysis.

If a material change in circumstances does occur (which may, but need not only, be linked to the occurrence of a reopening trigger), then the RIT-T proponent must notify the AER and provide supporting information regarding the actions that it proposes to take as a result.

The RIT-T proponent must, at a minimum publish a statement identifying whether the preferred option is still the preferred option, and if not, the new preferred option. The RIT-T proponent must also provide any supporting information necessary to demonstrate the reasons behind these conclusions.[38]

Other actions that the RIT-T proponent may undertake after a reopening trigger event occurs include:[39]

» conducting desktop analysis only, which may be appropriate if the reopening trigger affects the costs or market benefits of credible options in a reasonably similar manner;
» conducting stakeholder consultation and submitting a report to the AER that summarises stakeholders' views and the conclusions from the consultation, which may be appropriate depending on:
  – the likely impact of the RIT reopening trigger being triggered; and
  – whether the activation of a reopening trigger indicates that stakeholder consultation is worthwhile to test whether the costs and market benefits of other options have changed significantly since the RIT was undertaken; and
» reapplying the RIT-T, which may be appropriate if the change in circumstances is complex to the point that a desktop adjustment or stakeholder consultation will not generate a sufficiently robust assessment of the potential change in the preferred option, particularly where more than one key input or assumption is affected.

Box 1 sets out three additional examples of actions that the RIT-T proponent may consider after a reopening trigger event occurs.[40]

Example 1: The proponent continues with the original preferred option, despite the MCC leading to another option becoming more highly ranked

A reopening trigger event occurs, leading to the following sequence of actions:

1. the proponent updates the RIT NPV analysis and finds that the second-ranked credible option would now be the preferred option, although only by a slim margin;
2. substantial costs have already been sunk on the originally preferred option, and the proponent concludes that the original option should continue to be pursued after taking these sunk costs into account;
3. the proponent presents the results of the updated NPV assessment and its decision to proceed with the original option to its customer reference group; and
4. the proponent informs the AER (in line with the NER):
   – that an MCC has occurred;
   – the feedback received from its customer reference group; and
   – that it intends to continue with investment in the previously preferred option.

[38] AER, *Regulatory Investment Test for Transmission Application Guidelines,* October 2023, appendix B.7.
[39] AER, *Regulatory Investment Test for Transmission Application Guidelines,* October 2023, appendix B.7.
[40] ENA, *AER consultation paper – review of the cost benefit analysis guidelines and RIT application guidelines*, Submission, 3 September 2023, pp 6-8.

Example 2: Updated NPV analysis shows the second ranked option is now preferred by a substantial margin, and the proponent decides to proceed with this option instead

A reopening trigger event occurs, leading to the following sequence of actions:

1. the proponent updates the RIT NPV analysis and finds that the previously second-ranked credible option is now the preferred option, by a substantial margin;
2. the proponent publishes the updated NPV analysis and its decision to now proceed with an alternative option, and seeks feedback from consumers – since the second option has already been consulted on as part of the RIT process, and is now preferred by a substantial margin, a second detailed consultation process is not considered required;
3. the proponent informs the AER (in line with the guidelines) that:
   - an MCC has occurred;
   - it has updated the NPV analysis and sought feedback from consumers, who support pursuing the alternative option; and
   - it intends to re-issue the PACR and pursue the previously second-ranked option.

Example 3: a new credible option is introduced as a result of the MCC – the proponent decides to re-issue the PADR to allow for further stakeholder input

A reopening trigger event occurs, leading to the following sequence of actions:

1. the proponent identifies a new credible option as a consequence of the MCC event, eg, use of a new technology;
2. the proponent updates the RIT NPV analysis and finds the new credible option to be top-ranked;
3. the proponent briefs its customer reference group and concludes it would be appropriate to re-issue the PADR to allow for further consumer consultation, given the change in the nature of the preferred option;
4. the proponent informs the AER (in line with the guidelines) that:
   - an MCC has occurred;
   - it has updated the NPV analysis and sought feedback from consumers, who support pursuing the alternative option; and
   - it intends to re-issue the PACR and pursue the previously second-ranked option; and
5. following AER approval of this course of action, the proponent reissues the PADR with updated analysis and undertakes consultation in line with the usual PADR process.

Box 1 Examples of potential actions following an MCC

2 The 'identified need' for a RIT-T

Key points[41]

» The 'identified need' for a RIT-T is a prescribed term and is the reason why a TNSP proposes that a particular investment or action be undertaken.
» The identified need can only take one of four forms:
  (1) to meet externally imposed service standard requirements on the TNSP in the NER or in other applicable regulatory instruments (including obligations relating to safety) – generally referred to as a 'reliability corrective action RIT-T';
  (2) to provide inertia network services as required by AEMO under **NER 5.20B.4** – referred to as 'inertia network services RIT-T';
  (3) to provide system strength services required by AEMO under **NER 5.20C.3** – referred to as 'system strength services RIT-T'; or
  (4) to increase net market benefits in the NEM – referred to as a 'market benefits RIT-T'.
» For clarity, market benefits are also calculated under 'reliability corrective action', 'inertia' and 'system strength' RIT-Ts, but may result in a positive or negative net benefit overall.
» The identified need for repex RIT-Ts is most likely to be 'reliability corrective action', although evaluation of avoided risk costs and avoided unserved energy may result in a positive net market benefit.
  – Some repex RIT-Ts will be market benefits RIT-Ts (ie, where there is no relevant external obligation) and are required to have positive net market benefits (which can be driven by avoided unserved energy and risk costs).
» The identified need should be expressed as the achievement of a desired outcome, and not by relation to specific assets or actions.
  – The identified need is essentially the proposal to consumers about the benefits to them of proceeding with the investment.

2.1 Identified need should be expressed in relation to outcomes not actions

Proposed RIT-T projects must have objectives that can be classified into one of four types of 'identified need' – namely:[42]

» a **'reliability corrective action'** RIT-T – which relates to meeting any of the service standards linked to the technical requirements, or other requirements, under either:
  – the NER (eg, maintain acceptable voltage fluctuations on the network in accordance with the technical standards in NER Schedule 5.1, provide inertia network services in accordance with clause 5.20B.4 or provide system strength services in accordance with clause 5.20C.3); or
  – in other applicable regulatory instruments (eg, transmission or distribution licences, jurisdictional reliability standards and relevant safety standards);[43]
» an '**inertia network services**' RIT-T – TNSPs, as Inertia Service Providers, are required to make inertia network services available where AEMO gives notice of an inertia shortfall or likely inertia shortfall under NER clause 5.20B.4;

41 The NER requirements relating to when the RIT-T needs to be applied can be found in clause 5.16.3 of the NER. The AER's guidance regarding the identified need and applying the RIT-T can be found in sections 2 and 3.1 of the AER's RIT-T Application Guidelines.
42 The TNSP must identify one of these four drivers as the 'identified need' for a particular RIT-T.
43 NER clause 5.10.2. See definition for 'reliability corrective action'.

- a ‘**system strength services**’ RIT-T – TNSPs, as System Strength Service Providers, are required to make system strength services available:
  - to meet a fault level shortfall or likely fault level shortfall identified by AEMO, in line with NER clause 11.143.15 (applicable until 1 December 2025); and/or
  - from 2 December 2025, to deliver system strength services to meet the minimum and efficient levels of system strength forecast by AEMO, in line with NER schedule 5.1.14.
- a **‘market benefits’** RIT-T – where the project results in an overall increase in benefits to participants in the NEM (described formally in the NER as ‘an increase in the sum of consumer and producer surplus’).

For each type of RIT-T, the objective is to identify the option with the *greatest* expected net market benefit.

- since ‘reliability corrective action’, ‘inertia network services’ and ‘system strength services’ projects are undertaken to meet externally imposed obligations, the preferred option can have *negative* net market benefits;
  - however this does not preclude ‘reliability corrective action’, ‘inertia network services’ and ‘system strength services’ projects resulting in positive net market benefits, once evaluation of avoided risk costs and avoided unserved energy is taken into account;
- the preferred option for a market benefit RIT-T must have a *positive* net market benefit.
  - typically, these market benefits arise as a consequence of the projected impact of the options on the wholesale market; and
  - repex RIT-Ts that do not have an external driver/obligation, and do not affect the wholesale market, may also have positive net market benefits (eg, on account of avoiding risk costs).

	Reliability corrective action	Inertia network services	System strength services	Market benefits
Summary of the ‘identified need’	To meet externally imposed reliability and service standards	To meet requirement to provide inertia network services	To meet requirement to provide system strength services	Increase the sum of consumer and producer surplus
Objectives of the RIT-T	To identify the option with the greatest net present value of market benefits	To identify the option with the greatest net present value of market benefits	To identify the option with the greatest net present value of market benefits	To identify the option with the greatest net present value of market benefits
Requirement for positive net benefits?	No	No	No	Yes

‘Repex RIT-Ts’ will typically be reliability corrective actions (may still have a positive net market benefit, which could be driven by avoided ‘risk costs’).

‘Repex RIT-Ts’ where there is no external obligation are ‘market benefits’ RIT-Ts (need to have positive net market benefits, which may be driven by avoided ‘risk costs’)

Figure 3: There are four types of identified needs for RIT-Ts

The identified need for a RIT-T should be expressed as the achievement of a desired outcome and/or the provision of a service. It should not refer to a particular approach or investment to achieving that outcome.

For example:

- where a line is coming to the end of its useful life, the identified need should be couched in terms such as "ensuring that the jurisdictional reliability standard is met for affected customers", rather than "replacing a transmission line due to its age";
- where secondary systems require replacing, the identified need should be described as "ensuring on-going compliance with Schedule 5.1 of the Rules" rather than "replacing faulty relays, meters and other systems" or "responding to technical obsolescence";
- where there is a requirement for a TNSP to provide inertia network services, the identified need should be described as "to provide inertia network services as required by AEMO's inertia network shortfall notice under NER clause 5.20B.4", rather than "to install a synchronous condenser";
- where a TNSP is considering a network augmentation project to connect renewable generation, the identified need should be termed as "realising market benefits from lower wholesale market dispatch costs from relieving transmission constraints affecting the connection of new renewable generation thus improving reliability to consumers", rather than "to build new transmission lines to connect renewable generators"; and
- where the proposed investment is addressing the levels of reactive power near a terminal station, the identified need should be expressed as "ensuring adequate voltage support is provided in the vicinity of the terminal station, consistent with the requirements in the NER, which will contribute to system security in the NEM to the benefit of consumers", rather than "installing additional capacitor banks at the terminal station".

Whilst the trigger to take action may arise out of a condition, reliability or safety driver for a specific asset (or group of assets), the identified need in terms of the RIT-T must be phrased to address the ongoing reason for the functionality/service that the affected assets deliver to the users of the transmission network in terms of ensuring reliable supply of electricity or compliance with external obligations, including those that reference good industry practice.

In describing an identified need, a TNSP should also articulate what will or may happen if the TNSP fails to take any action, with a particular focus on the impact on consumers. It is here where the reasons why the TNSP considers investment is required are explained, eg, deteriorating asset condition, network constraints etc. Essentially the identified need is the proposal to consumers about the benefits to them of proceeding with the investment.

For example:

- for a transmission line coming to end of life, the consequence of not undertaking a line replacement project may be a significantly increased risk of outages that increases expected unserved energy;
- where a TNSP is proposing to replace secondary systems, the potential effect of not replacing these systems may be increased corrective maintenance costs associated with responding to failures, as well as a higher risk of outages (unserved energy) and safety impacts;
- where there is a need to provide inertia services, not undertaking the project would result in risks to the stability and security of the system, which AEMO has deemed unacceptable;
- for a network augmentation project to connect renewable generation, not undertaking the project will prevent realising market benefits from the reduction in wholesale market fuel costs;
- for investments to address reactive power levels, not addressing the issue may lead to voltage stability issues and potential voltage collapse that increases system security and reliability risks – in describing such a counterfactual, the breach of the relevant reliability standards, system standards and/or sources of market benefit should be articulated.

In the case of repex RIT-Ts, the identified need will typically be cast in terms of the avoided operating and maintenance costs (eg, associated with keeping ageing assets in-service), as well as potentially increases in involuntary load shedding (from outages caused by failing ageing assets) and environmental and safety risk costs faced by the TNSP.

Section 3 outlines how the 'base case' should be considered and articulated. It provides examples of how to consider the identified need for different types of RIT-Ts, including those being undertaken for repex purposes.

2.2 Reliability corrective action, inertia network services and system strength services RIT-Ts vs market benefits RIT-T

Reliability corrective action projects are undertaken to meet externally imposed NER service standard or system security requirements, or other applicable regulatory instruments. Specifically:

- **Schedule 5.1 of the NER** describes the planning, design and operating criteria that must be applied by TNSPs to transmission networks which they own, operate and control;[44] and
- **Applicable regulatory instruments**[45] refers to all laws, regulations, orders, licence conditions, codes, determinations and other regulatory instruments that regulate or contain terms and conditions relating to transmission services.
  - Most relevantly, they include jurisdictional licence conditions relating to the performance and reliability standards with respect to transmission networks.

Inertia network services and **system strength services** projects are undertaken in response to a requirement notice issued by AEMO:

- **Clause 5.20B.4** sets out the obligations of an inertia service provider to make available inertia services, following notice by AEMO; and
- **Schedule 5.1.14** sets out the obligations of a system strength service provider to make available system strength services to meet the minimum and efficient levels of system strength forecast by AEMO .

Reliability corrective action, inertia network services and system strength services RITs can have positive or negative net market benefits relative to the base case, although the full range of market benefits may be difficult to quantify accurately. NER service standards and regulatory instruments are mandatory requirements which have been determined externally to the TNSP (and, in many instances, may have been assessed on non-economic grounds), and which must be met. Similarly, a notice from AEMO to provide inertia services or system strength services, and AEMO's forecast of the minimum and efficient levels of system strength, is an external requirement that the TNSP is required to meet, based on AEMO's assessments of system needs. However, whether or not reliability corrective action, inertia network services and system strength services RIT-Ts have a negative market benefit will depend on the source of benefits – see section 3.1.1.

When demonstrating the requirement for reliability corrective action, it may be helpful to consider obligations in the following order:

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44 These standards cover: network reliability, frequency variations, magnitude of power frequency voltage, voltage fluctuations, voltage harmonic or voltage notching distortion, voltage unbalance, stability, protection system and fault clearance times, and load, generation and network control facilities.

45 'Applicable regulatory instruments' is a defined term under the NER, which also lists the relevant jurisdictional instruments.

- that the project meets the obligations set out in applicable regulatory instruments as defined above, or in a notice issued by AEMO;
- that not carrying out the project would be inconsistent with good electricity industry practice, as required under an obligation in the NER or a jurisdictional licence or other requirement.

In addition, it may be worth considering whether a reliability corrective action will also reduce the risk of a high-impact-low-probability (HILP) event (eg, a redundancy may be needed to prevent a widespread outage), consistent with good industry practice. Whilst the value of avoiding a HILP event may be difficult to quantify, some indication could be provided by using different probabilities for the event occurring and/or this benefit could be referred to qualitatively.

Table 1 below lists some examples of reliability corrective actions in previous RIT-Ts, along with the specific obligations cited by the RIT-T proponent.

Table 1: Examples of legislation cited in reliability corrective actions in previous RIT-Ts

Identified need	Example RIT-T	Cited legislation	Legislative requirement
Secondary systems maintenance	Transgrid – Maintaining compliance with performance standards applicable to Ingleburn substation secondary systems, June 2022 (PACR)[46]	NER, clause S5.1.9(c)	To provide sufficient protection systems to ensure faults on transmission and distribution systems are automatically disconnected.
		NER, clause 4.11.1	Prescribed standards for remote control and monitoring devices.
		NER, clause 4.6.1	Requirements for determination of power system fault levels by AEMO.
	Powerlink Queensland – Addressing the secondary systems condition risks at Cairns, August 2020 (PACR)[47]	NER, clause S5.1.9(c)	To provide sufficient protection systems to ensure faults on transmission and distribution systems are automatically disconnected.
		Electricity Act 1994 (Qld), clause 34(1)(a)	To operate and maintain the transmission grid for adequate, economic, reliable and safe transmission.
Voltage control	ElectraNet – SA Transmission Network Voltage Control, December 2022 (PSCR)[48]	NER, clause S5.1a.4	For voltage variances relative to the normal voltage level to be within prescribed ranges under normal circumstances and contingency events respectively.
	AusNet Services – Voltage Control in North West	Electricity System Code 2000 (Vic),	To maintain voltage at or above 100kV, within the range of plus or minus 10% of the

[46] Source: https://www.transgrid.com.au/media/cjwnm2gk/transgrid-pacr_ingleburn-secondary-systems.pdf
[47] Source: https://www.powerlink.com.au/sites/default/files/2020-08/Project%20Assessment%20Conclusions%20Report%20-%20Addressing%20the%20secondary%20systems%20condition%20risks%20at%20Cairns.pdf
[48] Source: https://www.electranet.com.au/wp-content/uploads/ritt/PSCR-EC.11645-Transmission-Network-Voltage-Control.pdf

Identified need	Example RIT-T	Cited legislation	Legislative requirement
	Victoria, October 2022 (PACR)[49]	clause 110.2.2(a)	nominated voltage level by VENCorp.
Capacitor bank maintenance	Transgrid – Managing the risk of capacitor bank failure, August 2023 (PSCR)[50]	NER, clause S5.1a.4	For voltage variances relative to the normal voltage level to be within prescribed ranges under normal circumstances and contingency events respectively.
Replacement of transformers and circuit breakers	AusNet – Maintaining supply reliability in the Shepparton and Goulburn-Murray area, October 2021 (PACR)[51]	Electricity Safety Act 1998 (Vic), section 98	To design, construct, operate, maintain and decommission networks to minimise hazards and risks.
Replacement of suspension structures and remediation of line components on tension structures	Transgrid – Managing risk on Line 23, August 2023[52]	Electricity Supply (Safety and Network Management) Regulation 2014 (NSW), clause 5	To ensure that the design, construction, commissioning, operation and decommissioning of networks are safe.

Unlike reliability corrective action RIT-Ts, market benefit RIT-Ts are not driven by any external standard and must always have positive net market benefits.

Reliability corrective action, inertia network services and system strength services RIT-Ts are likely to have a smaller number of relevant market benefit categories, compared to a market benefit RIT-T where they are driven by external compliance obligations or requirements. Further, market benefit RIT-Ts are typically (but not always) driven by benefits associated with outcomes in the wholesale electricity market. This is discussed in section 6.

2.3 Application of RIT-T to replacement expenditure (repex) vs. augmentation expenditure

TNSPs are required to apply the RIT-T to replacement expenditure as well as augmentation expenditure. This Handbook uses the terms 'repex RIT-T' and 'augmentation RIT-T' where it is helpful for the purpose of the guidance provided to distinguish these two cases. However, these terms are not prescribed terms used in the NER.

The interaction between the identified need and whether the expenditure relates to augmentation or replacement is set out in figure 4. Typically, repex RIT-Ts will be driven by an external standard or obligation and so will be considered reliability corrective actions (they may also have positive net market

[49] Source: https://www.ausnetservices.com.au/-/media/project/ausnet/corporate-website/files/about/regulatory-investment-test/horsham-svc-pacr_final.pdf?rev=f04013a896db4114923a12a5ac7a3542&hash=E917A7BF964147DE6BA5A6E20E8C89E6
[50] Source: https://www.transgrid.com.au/media/qzwjethp/transgrid-pscr_managing-the-risk-of-capacitor-bank-failure.pdf
[51] Source: https://www.ausnetservices.com.au/-/media/project/ausnet/corporate-website/files/about/regulatory-investment-test/regulatory-investment-test-for-transmission-pdfs/shepparton-pacr_final.pdf?rev=96c9c4feccd24ed9b154674741921e52&hash=C8E4FCF6ED29646E1DC35499EFC268F2
[52] Source: https://www.transgrid.com.au/media/c5wn1f30/transgrid-pacr_line-23.pdf

benefits once avoided risk costs and unserved energy are considered).[53] Some repex RIT-Ts will be market benefits RIT-Ts (ie, where there is no relevant external standard or obligation) and these are required to have positive estimated net market benefits (typically avoided risk costs and unserved energy).[54]

The identified need for augmentation RIT-Ts may be for reliability corrective action, or for market benefits.

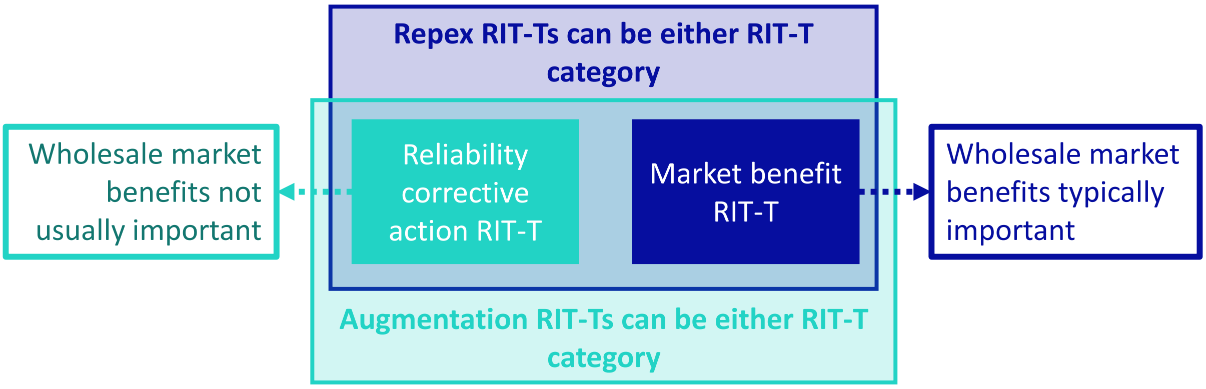

Figure 4: Relationship between 'identified need' and whether the RIT-T is applied to repex or augmentation

Projects under inertia network services or system strength services identified needs can typically be considered as a subset of augmentation RIT-Ts, as these services increase the capacity or resilience of the transmission network. Projects under both of these identified needs will typically have some effect on the wholesale market as inertia and system strength concern network constraints and energy flow (or lack of) across the transmission network. However these wholesale market benefits may not be material in determining the RIT-T outcome (as the investment is being driven by an AEMO requirement, and so has similarities with reliability corrective action). The exception is where there are non-network options proposed to meet an inertia or system strength requirement, which could also impact the wholesale market and so which could also have material associated market benefits.

[53]. Some TNSPs may prefer to frame all of their repex RIT-Ts as market benefit RIT-Ts. .
[54] Noting that other market benefits arising from the impact of the investment on the wholesale market are unlikely to be relevant for the majority of repex RIT-Ts

3 Options to address the identified need

Key points[55]

- The RIT-T economic assessment is conducted against a 'base case':[56]
  - For a **market benefit** RIT-T the base case should typically reflect no investment by the TNSP.
  - For **inertia network services** and **system strength services** RIT-Ts the base case should also typically reflect no investment by the TNSP.
  - For **a reliability corrective action** RIT-T (particularly for repex) the base case should typically reflect 'business-as-usual' activity by the TNSP (including potentially escalating risk costs).
  - The base case for all RIT-Ts is permitted to include minor capital expenditure (ie, less than the RIT-T threshold) but cannot include capital costs over this amount and, importantly, is not permitted to include a credible option.
- Typically, more than one 'credible' option should be included in the RIT-T analysis.
- Options should include both network and non-network options, and may include a combination of both network and non-network elements.
- The more costly the options being considered, the more options should be included.
- A credible option must be 'technically feasible' and 'commercially feasible'
  - An option that is substantially more expensive, but is not also expected to have substantially higher benefits, is not considered 'commercially feasible.'
  - As a rule of thumb, an option is not credible if it has an estimated capital cost 150 per cent above that of the next most expensive credible option.
- A credible option is one which is able to be in place in time to meet the identified need:
  - Social licence c**ons**iderations may inform views on whether an option may be delayed (or of the costs of ensuring timely delivery), and therefore whether it is a credible option.
- The absence of a proponent does not exclude an option from being considered in the economic assessment.

3.1 The concept of the 'base case'

The RIT-T requires a 'base case' to be defined for all assessments. A base case is a situation in which no credible option is implemented by, or on behalf, of the TNSP. The base case includes a description of relevant NEM outcomes in that case (including future wholesale market outcomes, where those are relevant to estimating the costs and benefits for a particular project), as well as a description of the action by the TNSP (typically 'do nothing').

The RIT-T economic assessment of each credible option needs to be undertaken *relative* to the base case, ie, expected costs and market benefits for each option should be estimated, and reported, relative to those expected under the base case.

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55 The NER requirements relating to identifying credible options can be found in clause 5.15.2 of the NER. The AER's guidance regarding credible options can be found in section 3.2 of the AER's RIT-T Application Guidelines. There is some ambiguity in the drafting of clause 5.15.2 of the NER, whereby clause 5.15.2(b) requires the RIT-T proponent to consider all options that could reasonably be classified as credible options, but is subject to clause 5.15.2(b1) that states clause 5.15.2(b) only applies to actionable ISP projects. Section 3.2.4 of the AER guidelines suggests that clause 5.15.2(b1) refers to the circumstances in which clause 5.15.2(b) applies to ISP projects, rather than when it applies to any transmission project.

56 The AER's guidance regarding characterising the base case (for both reliability corrective actions and market benefit RIT-Ts) can be found in section 3.3 of the AER's RIT-T Application Guidelines.

What this means in practice is that if a credible option is found to have overall:

» *positive* net market benefits then it is considered preferable to the base case; or
» *negative* net market benefits then it is considered worse than the base case.

For a market benefit RIT-T, the base case must always be based on no action by the TNSP. For an option to pass a market benefit RIT-T, it needs to have positive net market benefits (and hence be found to be better than 'doing nothing'). In the case of a market benefit RIT-T, this base case typically reflects a viable alternative.[57]

For reliability corrective action (and in particular repex RIT-Ts), the 'base case' should reflect a situation in which the TNSP continues 'business as usual' activities (such as responding reactively to equipment failures, or undertaking minor replacement works) in order to comply with applicable regulatory requirements as far as possible, rather than strictly 'doing nothing'. However, these activities may still result in the TNSP not meeting required standards, ie, the base case for reliability corrective action is still likely to reflect a situation in which required service standards are violated, and may therefore not reflect a realistic alternative (see below).

The base case is permitted to include minor capital expenditure (ie, less than the RIT-T threshold) but cannot include capital costs over this amount and, importantly, is not permitted to include a credible option.[58]` However, the AER has recently indicated that BAU practices can include an on-going repex program (eg, involving proactive replacement), but that any changes to the scope of that program would be subject to the RIT-T (where the resulting cost changes meet the RIT-T threshold).[59]

3.1.1 The base case for 'reliability corrective action' RIT-Ts

The base case should be considered on a case-by-case basis for each RIT-T.

For repex RIT-Ts, the base case will typically have escalating operating and maintenance costs (eg, associated with keeping ageing assets in-service), as well as potentially increases in involuntary load shedding (from outages caused by failing ageing assets) and environmental and safety risk costs faced by the TNSP.

Risk costs can also include the cost of reactively replacing or repairing assets when they fail. 'Non-standard interventions'[60] can be included, where the cost is similar to what is considered BAU practices.[61] For particular RIT-Ts, it may also be relevant to include other costs in the base case, such as the expected (ie, probability-weighted) collateral damage risk cost for assets that pose an explosive failure risk. However, in considering any such costs, it is important that they are treated in a consistent manner with any approach taken to including compliance costs (as discussed in section 4.1.3 below).

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[57] 'Viable' is used in this Handbook to mean 'meets the relevant external standard'.
[58] This is different to the AER's guidance for the RIT-D, which allows a credible option to be selected to serve as a business as usual base case, which reflects differences in the NER regarding the RIT-T and the RIT-D – in particular, the NER requires that the RIT-T *must* be based on a cost-benefit analysis that assesses each credible option relative to the situation where no option is implemented (NER clause 5.15A.2(b)(1), which is not prescribed for the RIT-D.
[59] AER, Compliance Bulleting No. 10, *Determining whether proposed replacement capital expenditure constitutes a RIT-D project*, November 2021, section 3.2. The AER notes that the principles in this compliance bulletin apply equally to RIT-Ts.
[60] The AER define the phrase 'non-standard intervention' to contrast actions that could be taken under the base case but are not generally the standard operating and maintenance practices that the business would apply under its usual asset management practices. That is, such practices may be 'materially different' from the BAU practices. See: AER, *Industry practice application Note - Asset replacement planning,* 25 January 2019, p. 27.
[61] This is consistent with the AER industry practice Application Note to support network businesses in adopting best practice asset replacement planning, see: AER, *Industry practice application Note - Asset replacement planning,* 25 January 2019, pp. 27 & 42.

Credible options would then typically avoid these base case costs (see section 6.2). As a result, the option that passes the RIT-T may have a positive net market benefit (although, this is not necessary for the option to satisfy the RIT-T for a reliability corrective action).

Where the base case for reliability corrective actions is not considered a viable option (eg, where it includes high levels of unserved energy or risk costs that are not consistent with external standards or obligations), the RIT-T consultation documentation should acknowledge that the base case is not considered a credible option in itself, and would never be pursued by the TNSP, but has been formulated consistent with the NER and AER Guidelines as a means of comparing credible options. The AER RIT-T Guidelines explicitly acknowledge that this may be the case and can be referenced in these documents.[62]

3.1.2 The base case for 'market benefit' RIT-Ts

While the identified need for repex RIT-Ts is most likely to be 'reliability corrective action', some repex RIT-Ts will be market benefits RIT-Ts, ie, where there is no relevant external obligation to be met. These RIT-Ts are required to have positive net market benefits and this will typically be derived from avoided unserved energy and risk costs under the base case (in the same way as described in section 3.1.1 above).

For more complex market benefit RIT-Ts (typically those relating to augmentations), there will likely be a different base case under each reasonable scenario investigated, reflecting different ways the world may unfold going forward. Although the TNSP's action is the same in each base case (ie, 'do nothing'), other assumptions may differ, leading to different NEM outcomes.

To characterise base cases for a RIT-T, inputs, assumptions and scenarios should be sourced from the latest AEMO IASR and the latest ISP, to the extent they are relevant.[63] Further, the base case for each scenario should include all of the transmission investments in the ISP optimal development path (actionable ISP projects, and future ISP projects), as relevant for that scenario.

For example:

- there are two ISP scenarios that have different implications for the timing of future interconnector investment in the NEM (unrelated to the project being assessed under the RIT-T) – under the central scenario in the IASR a new interconnector investment is made by 2028/29, while under the high DER scenario the additional interconnection is not needed until 2034/35
- the base case in the non-ISP RIT-T would include this interconnector investment, but the timing would differ under each scenario, reflecting the different timing of the transmission investment in the ISP scenarios.
- generation investment, generation dispatch costs and emissions would also vary in the base case, under each scenario.

Where the optimal development path incorporates a decision rule for future ISP network development, any guidance provided by AEMO in the ISP on the appropriate assumptions to adopt in relation to the future timing and extent of these investments should be reflected in the RIT-T base case assumptions.

3.1.3 The base case for inertia and system strength RIT-Ts

The base case for inertia and system strength RIT-Ts should reflect a situation where no action is taken by the TNSP (as for market benefit RIT-Ts). However, the outcome of these RIT-Ts may be a negative net

[62] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, p. 24.
[63] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, p. 25. Specific circumstances that may allow for new, omitted or varied input assumptions or scenarios include parameters that may not have been reflected by AEMO in the IASR, ISP or an ISP update but would otherwise be updated, or where the parameter is not covered in the IASR or ISP.

benefit, and so the base case acts as a point of reference rather than determining whether an investment satisfies the RIT-T. This implies that the base case for these RIT-Ts can be fit-for-purpose and may not always require market modelling.

Characterisation of the base case should be proportionate to the project and the options being considered in the RIT-T:

- Some projects will require market modelling to determine the base case, especially where options considered may provide more capacity for inertia or system strength than required by AEMO, or which involve non-network options which are also expected to provide services to the wholesale market, in order to correctly capture the additional benefits associated with those investment options.
- However, where all options considered are only sufficient to meet AEMO's inertia or system strength requirements, and are not also expected to have an impact on the wholesale market, a simplified representation of the base case may be suitable, with a focus on unserved energy estimates rather than wholesale market impacts more broadly.

TNSPs should note that the arrangements for procuring both system strength services and inertia services are changing, and as a consequence practice in applying the RIT-T to these investments is expected to evolve.

3.2 Determining whether options are 'credible'

There are three requirements for an option to be considered credible.

Figure 5: Credible options have three requirements

In relation to the second requirement, an option is **technically feasible** if the TNSP reasonably considers that there is a high likelihood that it will provide the services that it has claimed it could provide, while also complying with all mandatory requirements in relevant laws, regulations and administrative requirements.[64]

Whether the TNSP considers that there is a high likelihood an option is able to provide the required services can be informed by the option demonstrating its feasibility in similar operating contexts:

- Demonstration of technical feasibility can be informed by an option operating successfully in other countries or within Australia, where the option has been applied within similar operating contexts.
- Conversely, where the option has not been demonstrated to work in similar operating contexts, including international experience, this may provide grounds for concluding that the option is not technically feasible.

Technical feasibility for options for an inertia network services RIT-T need to also be considered in relation to the specific solutions that are currently permitted under the NER:

[64] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, section 3.2.2.

» solutions for the provision of inertia network services are currently limited to synchronous condensers[65] or an inertia services agreement where a registered participant uses a synchronous generating unit or a synchronous condenser. However this restriction is expected to shortly be relaxed.

Options that are unlikely to obtain environmental and/or planning approval would be assessed as not technically feasible – for example:

» line route options that would traverse a national park; and
» substation options that include air insulated switchgear rather than gas insulated switchgear where there are space or environmental constraints.

Assessment of whether an option is technically feasible will always depend on the relevant facts and circumstances but will ultimately require a degree of judgement. This judgement should however be supported by evidence, where possible – for example:

– references to information contained in the TNSP's planning documentation (such as the Transmission Annual Planning Report or the Asset Management Strategy);
– evidence that similar routes and/or equipment have been refused planning permission;
– an independent assessment of the likelihood that a particular investment would receive relevant permissions.

An option is **commercially feasible** if an objective and reasonable operator, acting rationally, would be prepared to develop the option.[66]

An option is unlikely to be commercially feasible if it has an estimated cost that is substantially larger than that of other options, and is not expected to have significantly higher market benefits.

In practice, TNSPs will need to make judgement calls in order to assess whether options are commercially feasible or not. However, in some cases this assessment will be more obvious.

» For example, if there are five high-level network options, and four have an estimated cost of around $10 million, and one has an estimated cost of $30 million, then the high cost option should be eliminated as not being commercially feasible (assuming it is not expected to deliver commensurate additional market benefits).
» A reasonable rule of thumb is that projects with a cost more than 150 per cent *greater* than the cost of the next most expensive option are not commercially feasible, unless there is a reason to think that the option may also have proportionally greater benefits. For example, if the most expensive credible option is $10 million, then the capital cost rule of thumb would exclude any options with a capital cost greater than $25 million.

For a non-network option, where the network support costs proposed by the proponent are substantively above the costs that would be passed through to consumers through an alternative network or non-network option, the non-network option may be considered to be not commercially feasible:

» This is because the AER may not consider the costs of the non-network solution to be prudent and efficient in assessing the TNSP's application for a pass-through of the network support costs;
» Again, this is likely to be a matter of judgement for the TNSP, but there may be clear cases where the network support costs are orders of magnitude above the cost of an alternative network or non-network option without an expectation of commensurately higher market benefits.

[65] NER clause 5.20B.4(d).
[66] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, section 3.2.2.

A TNSP is not entitled to reject an option that would otherwise satisfy the RIT-T purely on the basis that the option lacks a proponent or that the TNSP is not willing to be the proponent for the option (eg, for a non-network option that does not have an advocate).

All options identified in the PSCR as being technically and commercially feasible should be included in the economic assessment.

The third requirement for a credible option is that **the option can be implemented in time to meet the identified need**. This means that there needs to be sufficient time for an option to be planned, procured and commissioned. As an example, where an option requires a new easement, this may be 'technically' feasible in that there are no environmental reasons why the easement could not be secured, but the timeframes in acquiring the easements and securing environmental approval for the works preclude construction of the option meeting the identified need and so, overall, it is not considered a credible option for addressing the identified need. Similarly, if there is expected to be substantial difficulties in obtaining social licence for the project, due to the need to work through particular environmental, community and/or First Nations impacts, this should be taken into account in considering whether the option could be developed in time.

If there are additional options that have been raised in submissions to the PSCR or to the later PADR then these should also be included as credible options, unless the TNSP does not consider them to be commercially or technically feasible (in which case the reasons why should be documented in the PADR and/or the PACR).

While a credible option does not need a proponent at the PSCR and PADR stage, the preferred option ultimately needs to have a proponent at the PACR stage (the exception is in Victoria, where AEMO's role as a planner-procurer means that a proponent is not required at the PACR stage, as the project will then be put out to tender). RIT-T proponents may need to assess the costs of a generic non-network option if there is no such proponent at the PADR stage, drawing on cost information from credible published sources such as AEMO's latest IASR.[67] In this circumstance, the TNSP would not be able to estimate the required network support payment, but as this is treated as a wealth transfer in the RIT-T it will not affect the option rankings in the PADR.

Overall, the number of credible options that are included in a RIT-T should be proportionate to the magnitude of the estimated cost of the options being considered, as far as feasible.[68]

Even if options are not considered 'credible', they should be presented in the RIT-T documentation to illustrate that they have been considered. This is typically presented in a section in the PSCR and/or PADR titled 'Options Considered But Not Progressed'.

3.3 Typical types of network options to consider

This section provides high-level guidance of the typical types of network options that should be considered for each RIT-T. It is divided into typical network options for 'repex RIT-Ts', as well as typical network options for broader RIT-T applications.

3.3.1 Typical network options for repex RIT-Ts

There are six broad types of options that could be considered for repex RIT-Ts:

- 'like-for-like' replacement;
- smaller capacity replacement eg, replacing a current double-circuit line with a single circuit line;

[67] See: AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, section 3.2.3.
[68] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, section 3.2.4.

» larger capacity replacement;[69]
» re-configuring and/or optimisation of the network;
» phased options, ie, undertaking part of a replacement option now and deferring part of the option to a later period, if possible; and
» decommissioning the asset(s) in question, which may also include a network rearrangement or alternate investment in the same area.

Not all of these options will be feasible in a particular circumstance. In considering the feasibility of these options, the TNSP should ensure its analysis is fit for purpose.

Credible options may also differ in terms of their assumed timing. The optimal timing of an option should be assessed as part of developing the option. It should be determined by comparing the costs expected from not commissioning an option (eg, increases in unserved energy, additional operating costs associated with safety and environmental requirement breaches etc.) with the annualised cost of the option, as outlined in section 7 below.[70]

Credible network options may be integrated solutions, ie, several investments, with different stages. Options may also involve both network and non-network components. In particular, any of the above broad categories of options could be coupled with non-network components to form a credible option, eg, an option for replacing an ageing double-circuit line to an area where N-1 level of reliability is required could be a single-circuit line combined with embedded generation.

3.3.2 Typical network options for broader RIT-T applications

There is a range of typical types of network options that should be considered for broader RIT-T applications (ie, 'reliability corrective actions', outside of those for repex purposes, as well as for 'market benefits' RIT-Ts) – namely:

» smaller capacity options;
» larger capacity options;
» options involving different network routes and/or network configurations;
» options involving both network and non-network components;
» phased options, which may provide flexibility to alter later stages of the option based on an updated assessment of conditions at that time and/or include interim measures that can defer the date of a major investment (eg, demand side management);
» distribution network load or switching; and
» potential options that may involve investment in other NSP's networks.

For RIT-Ts for reliability corrective action, it is important to consider whether non-network options could be put in place more quickly to meet the identified need, ahead of later network investment.

Where the identified need relates to external drivers (eg, load growth, new generation connections etc.), and different scenarios are considered under the RIT-T in relation to those drivers, the timing of the option (and in particular of any later phases within the option) may differ between these scenarios. This is discussed further in section 7.

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[69] While this option would, strictly speaking, be an 'augmentation' under the NER, it may be relevant to include such an option as a credible option in a RIT-T, which is focussed on replacement.
[70] In addition, the TNSP's Transmission Annual Planning Report will typically flag when an asset is going to be retired and why, which will help inform the timing of replacement investments.

3.3.3 Typical options for inertia RIT-Ts

Options for an inertia network services RIT-T are currently limited by the NER which requires inertia network services to be provided by:[71]

- synchronous condensers; or
- an inertia services agreement where a provider uses a synchronous generating unit or a synchronous condenser.

While other solutions may technically be able to provide inertia network services (eg, grid scale batteries), the current NER effectively preclude them from being considered as investment options under the RIT-T. This also precludes NNO options unless they use a synchronous generating unit or synchronous condenser solution.

It follows that typical options for inertia RIT-Ts will be synchronous condensers with different technical specifications or inertia services agreements that use synchronous condensers or synchronous generating unit with different technical specifications.

The AEMC is currently considering options to improve current market arrangements for the provision of security services to ensure the power system remains secure, in response to rule change requests from Hydro Tasmania and Delta Electricity.

The second directions paper includes a rule drafting proposal that expands the range of allowed inertia network services to:

- include other equipment set out in an inertia network service specification to be published by AEMO; and
- allow inertia service providers to seek AEMO approval for equipment that will contribute to operating the relevant inertia sub-network in a satisfactory operating state.[72]

The AEMC is scheduled to publish its final determination and final rule change in March 2024.[73]

3.4 Consideration of non-network options

A key focus of the RIT-T is to elicit solutions from non-network proponents and to assess these against 'traditional' network solutions. To assist with this, the PSCR is required to set out the characteristics that a non-network solution would need to exhibit to contribute to meeting the identified need.

In short, potential non-network solutions may:

- address the identified need on a stand-alone basis (and hence form a credible option); or
- be able to be out in place more quickly, and/or reduce the required scope of a network option and/or enable the efficient deferral of the preferred network option (and hence, form part of a credible option, ie, coupled with a network element(s)).

'Efficient' deferral relates to where the annual costs of the non-network option is less than the NPV of the capex deferral benefit associated with the preferred network option. If this is found to be the case, a

[71] NER clause 5.20B.4(d).

[72] AEMC, *Indicative rule drafting for the Improving security frameworks for the energy transition Directions Paper published on 24 August 2023*, 24 August 2023, clauses 5.20B.4(d) and 5.20B.4A.
[73] See: https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

credible option should be formed comprising a program of activities, ie, a non-network option(s) followed by a network option.

Non-network options that do not have a proponent can still be included in the RIT-T economic assessment (assuming that these options are considered both technically and commercially feasible).

In addition, options that are included in a RIT-T may:

- feature a combination of both network components and non-network components; and/or
- pair short-term non-network solutions with longer-term network solutions;
  - this may be appropriate if the long-term network solutions are subject to constraints on when they can be put in place (eg, as a result of supply-chain constraints and/or required build time), such that short-term non-network solutions are needed to fulfil regulatory obligations in the near-term and/or to otherwise increase the net benefits associated with the option.

3.5 Material inter-network impact

A TNSP is required to comment in the PSCR on whether the credible options are expected to have a material inter-network impact.[74]

A 'material inter-network impact' is defined in the NER as:

> *"A material impact on another Transmission Network Service Provider's network, which may include (without limitation): (a) the imposition of power transfer constraints within another Transmission Network Service Provider's network; or (b) an adverse impact on the quality of supply in another Transmission Network Service Provider's network."*

AEMO has outlined a suggested screening test to apply in determining whether a transmission investment has a material inter-regional impact.[75] The AEMO test states that an option has no material inter-network impact if it satisfies the following:

- a decrease in power transfer capability between the transmission networks or in another TNSP's network of no more than the minimum of 3 per cent of the maximum transfer capability and 50 MW;
- an increase in power transfer capability between transmission networks of no more than the minimum of 3 per cent of the maximum transfer capability and 50 MW;
- an increase in fault level by less than 10 MVA at any substation in another TNSP's network; and
- the investment does not involve either a series capacitor or modification in the vicinity of an existing series capacitor.

AEMO's screening criteria should be used to determine whether there are expected to be any material inter-network impacts associated with the credible options included in the PSCR, and the outcome should be included as a standalone section in the PSCR.

[74] NER clause 5.16.4(b)(6)(ii).
[75] The screening test is set out in Appendix 3 of the Inter-Regional Planning Committee's *Final Determination: Criteria for Assessing Material Internetwork Impact of Transmission Augmentations*, Version 1.3, October 2004.

4 Costs of credible options

Key points[76]

- **The capital costs of options should be estimated to a level of accuracy fit for purpose for that stage of the RIT-T and consistent with each TNSP's planning-level estimates (typically ± 30 per cent).**
- **Where the capital cost of the preferred option in a RIT-T is above $100 million, the TNSP should adopt the AACE cost classification system or provide the reasons why it has not (for any or all options in that RIT-T).**
- **To the extent practicable, the key inputs, assumptions and reasoning relating to the basis for option cost estimates should be clearly set out, including the level and basis for any contingency allowances.**
- **The amount of opex should be determined on a case-by-case basis, particularly for large investments – in some instances, a '2 per cent of capex' or '1 per cent of capex' rule of thumb may be appropriate.**
- **Quantifiable direct costs associated with environmental and safety impacts should be included (most relevant for repex RIT-Ts).**
- **Non-network option costs should be based on prices included in submissions from potential proponents**):
  - **however an offsetting amount should also be incorporated in the estimation of market benefits (as it is a transfer between the TNSP and the NNO proponent), together with the incremental resource cost (capex and opex) associated with the NNO.**
  - **prior to the PACR, if there are no submissions from potential proponents then the TNSP may adopt reasonable estimates of non-network option costs, where feasible.**
  - **the operating costs incurred by the TNSP associated with establishing and managing the non-network option should be included in the non-network option costs.**
  - **TNSPs should consider whether NNOs should be reflected in the base case by reference to the criteria for committed and anticipated projects in the RIT-T. Committed projects and any anticipated projects included in the ISP should be incorporated in the base case, with the TNSP exercising reasonable judgement in deciding whether to include any other anticipated project in the base case.**
- **Any financial or capital contributions from a party external to the NEM (eg, government) should be netted off the costs of the option in undertaking the NPV assessment.**
  - **Where this applies, the NPV assessment in RIT-T consultation documents should be reported both with and without the payment from an external party.**
  - **Payments from other NEM participants should not be netted off the option costs.**

4.1 Costs of network options

The NER requires three key classes of costs to be included in a RIT-T assessment. Each of these is discussed below.

[76] The NER requirements relating to the costs of credible options can be found in clause 5.15A.2(8) of the NER. The AER's guidance regarding the costs of credible options can be found in section 3.5 of the AER's RIT-T Application Guidelines.

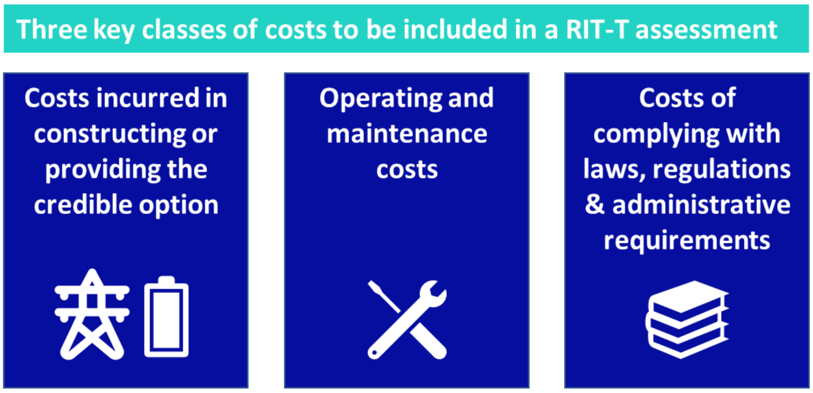

Figure 6: Key classes of costs to be included in the RIT-T

For repex RIT-Ts, the difference between these expected costs under the base case, and under the option case will often represent one of the key 'benefits' associated with a credible option.

The following types of costs should not be included in a RIT-T assessment:

- sunk costs, that have previously been justified as economically efficient, and where there is no resale value if not used (this may include costs associated with prior expenditure to secure strategic easements);[77] and
- externalities, such as costs of visual amenity impacts.

The reduction in the volume of greenhouse gas emissions, although previously treated as an externality, may now be taken into account as part of the RIT-T assessment, following the inclusion of emissions reduction into the NEO (see sections 6.4.2 and 6.4.3 below).

4.1.1 Costs of constructing or providing the credible option

This class of cost includes all capital and operating costs, such as: design reviews, project management, specifications and procurement costs, biodiversity offset costs, decommissioning of existing assets (including any site rehabilitation costs, to the extent they are material), easements and/or land costs (including disposals) relevant to the specific asset, and any replacement costs required during the RIT-T assessment period.

All land costs associated with a credible option should be included in the RIT-T analysis, at the current market value (including any land that has already been acquired, where it is material to the assessment).

Any costs associated with outages of existing network infrastructure during construction should also be included in the assessment, where material. This includes both any direct costs associated with constructing or providing the credible option, as well as any indirect costs (such as the impact on unserved energy).

The level of estimation accuracy for the capital costs of options should be at a level of accuracy fit for purpose for that stage of the RIT-T and consistent with each TNSP's planning-level estimates (typically around ± 30 per cent). Planning level cost estimates typically reflect the inherent input cost uncertainty due to factors such as exchange rates and raw material prices, and so separate 'cost scenarios' to reflect these factors are not typically required.

[77] Costs associated with previous strategic land acquisition should be included in the RIT-T assessment, as such land is likely to have resale value if not used as part of an option.

Where the capital cost of the preferred option in a RIT-T is above $100 million,[78] a TNSP should either adopt the AACE cost classification system or, if it decides not to, to provide the reasons why not. The AER also encourages consideration of use of the AACE classification system for all RIT-Ts.

In considering the appropriateness of applying the AACE cost classification system:[79]

» the $100m threshold applies to an individual project, rather than a program of works;
» the appropriateness of applying AACE classification can be considered separately for each option in that RIT-T (ie, if the AACE classification is applied to one (or more) options in the RIT-T it does not need to also be applied to all other options);
» similarly, the same AACE classification class does not need to be applied to all options included in the RIT-T, where there is a justification for adopting different AACE classification classes for different options;
» it may be more appropriate to adopt AACE class 5 estimates at the PSCR stage, which can be refined to AACE class 4 at the PADR stage;
» further, where some options in the RIT-T are unlikely to be top-ranked, that may justify applying a lower level of accuracy in estimating costs for those options (eg, an AACE class 5 rather than an AACE class 3 or 4), where the costs and/or time to derive more accurate estimates would be material;
» it may be difficult to apply the AACE classification to the capital cost estimate for some cost items for network options (such as land and biodiversity costs). This difficulty provides a justification to depart from the AACE classification in these cases;[80]
» where a TNSP does not currently adopt the AACE classification system in deriving its project cost estimates, and where it would incur substantial additional costs in doing so, this can justify why an alternative cost estimation approach is more appropriate.

The key inputs, assumptions and reasoning relating to the basis for option cost estimates need to be clearly set out in the RIT-T (for all RIT-T projects):[81]

» this transparency should be to the extent practicable and fit for purpose for that stage of the RIT-T;
» commercially sensitive information does not need to be disclosed in providing a cost breakdown, but it is important to explain in the RIT-T documentation why that information is commercially sensitive (eg, disclosing unit rates for repex projects may have an impact on the procurement outcomes for contractor tenders); and
» cost estimates do not need to include an explicit contingency allowance, but where they do the RIT-T documentation should clearly set out the level of that allowance and the basis on which it has been derived.

Sensitivity testing should be undertaken consistent with the level of accuracy in the cost central estimates, ie, consistent with the estimating accuracy range of the TNSP.

In undertaking sensitivity testing, consideration should be given to whether the costs for all credible options are likely to be affected by:

» the same factors – so sensitivity testing applies to all network options simultaneously; or
» different factors – so sensitivity testing affects the costs of some network options more relative to others.

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[78] AER, *Regulatory Investment Test for Transmission Application Guidelines,* October 2023, section 4.5.1. This threshold is reviewed by the AER as part of its cost threshold determination every three years. The next review is due by November 2024.
[79] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, pp. 29-30.
[80] AER, *Cost benefit analysis guidelines and RIT application guidelines, Explanatory Statement*, October 2023, p. 26.
[81] AER, *Cost benefit analysis guidelines and RIT application guidelines, Explanatory Statement*, October 2023, section 3.2.1.

Costs incurred in constructing or providing the credible option costs should be included in the RIT-T economic assessment either (i) in the year of construction, or (ii) on commissioning (in which case the cost should incorporate interest-during-construction, where appropriate).

Terminal values

Network assets will likely have an economic life longer than that of the RIT-T analysis period. In order to account for the residual value of the network assets at the end of the period, Energy Networks Australia recommends that a terminal value approach be applied.[82] [83] The use of terminal values ensures that options with differing asset lives (and different mixes of capital and operating expenditure) are assessed on the same basis.

The calculation of terminal values should reflect the asset's expected economic life, which may be shorter than its technical life (eg, if the asset is expected to become obsolete before the end of its technical life). This is consistent with the requirement under the National Electricity Rules to depreciate assets over their expected economic life.

An explanation of how terminal values are calculated, being the undepreciated value of capital costs at the end of the analysis period, should be included in the PADR and PACR, including the observation that a terminal value for capital costs can be interpreted as a conservative estimate for benefits (net of operating costs) arising after the analysis period.

4.1.2 Operating and maintenance costs

Operating and maintenance costs must be included in the RIT-T analysis for each credible option and the base case where these costs are relevant.

There may be cases where it is possible to adopt a 'per cent of new capex' rule of thumb in estimating operating costs – with 2 per cent likely to be a reasonable guide, although some TNSPs suggest this may be shifting towards a 1 per cent of capex rule of thumb.

However, in many cases the exact percentage (or the dollar amount of opex) will need to be determined on a case by case basis, as some credible options may be associated with a higher or lower proportion of operating costs than others. For example:

- older assets will likely have higher opex than newer ones; and
- a 2 per cent rule of thumb is unrealistic for significant assets like interconnectors, which have a high capital cost.

Any substantive periodic maintenance requirements over the assessment period should also be included. This includes periodic refurbishment costs that maintain the capacity or performance of a network asset.

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[82] A terminal value approach is consistent with standard cost benefit analysis (see for example, Commonwealth Department of Finance, *Introduction to cost-benefit analysis and alternative evaluation methodologies*, Financial management reference material no. 5, January 2006, p 22

[83] Alternatives to using a terminal value are (i) to calculate the annualised capital cost for each year of the analysis period. Energy Networks Australia notes that this approach will result in the same option rankings, provided that the discount rate used to derive annualised costs is the same as that used for the NPV assessment (rather than the regulated WACC); or (ii) projecting net benefits (eg, benefits net of operating costs) for the remainder of the asset's life, based on the net benefits estimated for the final years of the analysis. However this approach relies on an assumption that the benefits in the last years of the assessment period reflect a 'steady state' which will be maintained in future years, or can be projected forward in a credible way. It also relies on all options in the RIT-T having the same asset life. The use of terminal values represents a more conservative approach, where the market benefit being generated by the asset is above its annual depreciation cost at the end of the assessment period.

For repex projects, there may also be differences in terms of expected corrective and/or reactive maintenance costs between options, which means that direct estimates of opex will be required for each option.

- A key 'benefit' of options considered under repex RIT-Ts is likely to be the reduction in future maintenance costs, compared to the outcomes that would be expected in the base case where an ageing asset is assumed to be kept in service. This is captured in the RIT-T analysis in the comparison of the *expected operating costs* between the base case (in which these costs are incurred) and the option cases, rather than being captured in one of the market benefit categories set out in the RIT-T.

Some business' risk cost estimation practices may include these avoided reactive maintenance costs and so, where they do, they should not be separately estimated as avoided operating and maintenance costs since doing so would result in double-counting.

4.1.3 Compliance costs

Costs incurred in complying with laws, regulations and applicable administrative requirements in relation to the construction and operation of the credible option should be included in a RIT-T assessment. These costs can include:

- cost of complying with environmental standards – eg, managing oil spills, removing asbestos etc;
- costs relating to managing bushfire risks, where relevant;
- costs associated with safety incidents; and
- costs in complying with environmental obligations.

Such compliance costs should typically be based on externally verifiable penalties and/or estimates (eg, penalties associated with breaching environmental legislation, or penalties associated with personal injuries).

These costs may sometimes be appropriately treated as a hard constraint (ie, options are only technically feasible if they meet these constraints), in which case they do not need to be costed separately as they are the same for each credible option and will be reflected in the capital and operating costs for the option.

However, if, instead the TNSP manages compliance obligations to an acceptable degree of risk, this can be captured under this cost category – based either on:

- the expected cost, ie, probability of occurrence multiplied by the financial consequences; or
- a 'risk cost' framework, which assigns a value to these risks based on standard estimates (such as the Value of Statistical Life in the case of safety incidents, which may include a 'disproportionality factor' (see below) to estimate the appropriate cost of preventing a fatality). A 'risk cost' approach involves estimating the probability of asset failure ('PoF'), the likelihood of a consequence occurring ('LoC'), and the cost of that consequence ('CoC'). These variables are estimated for each relevant asset in question and multiplied together to arrive at an estimate of the 'risk cost' for that asset.[84]

Where an applicable jurisdictional *Electricity Safety Act* requires that safety risks be managed in accordance with the 'As Low As Reasonably Practicable' (ALARP) principle, this requirement might justify valuing safety risks using a 'gross disproportionality factor'. Any 'gross disproportionality factor' must be

[84] The 'risk cost' approach is consistent with that considered by the AER in developing its industry practice Application Note to support network businesses in adopting best practice asset replacement planning (AER, *Industry practice application note - Asset replacement planning,* 25 January 2019), as well as with the way that reductions in involuntary load curtailment are valued under the RIT-T (see section 6.3.1 below).

justified and RIT-T consultation documentation needs to reference the compliance requirement driving the use of that factor.

A key 'benefit' of options considered under repex RIT-Ts is likely to be the reduction in future costs associated with environmental and safety regulation/requirement breaches, compared to the outcomes that would be expected in the base case.

- This is captured in the RIT-T analysis in the comparison of the *expected* compliance *costs* between the base case (in which these costs are incurred) and the option cases, rather than being captured in one of the market benefit categories set out in the RIT-T.

Similarly, a key benefit may be the avoided expected risk cost of reactively replacing or repairing assets when they fail (or any equivalent 'non-standard intervention' cost, as outlined in section 3.1.1).[85]

Any harm to any party that is not expressly prohibited or penalised under the relevant laws, regulations or administrative requirements should not form part of the costs of a credible option.

4.2 Costs of non-network options

Recent commentary from the AER[86] has changed the presumptive approach to incorporating the cost of non-network options in the RIT-T analysis, which to date has been to adopt the costs for network support services proposed by a non-network proponent. The revised approach is set out below.

The RIT-T assessment needs to take into account the resource cost impacts of any non-network options. These resource costs may not correspond with the amounts that an NNO proponent proposes to charge a TNSP for network support.

While costs of non-network solution are ultimately based on resource costs, presentation of NNO network support costs should still be included in the RIT-T so as to communicate those costs in the analysis.

The suggested approach to include NNO costs in a RIT-T is shown in figure 7 and is as follows:

- Include the NNO proponent's proposed network support contract costs as part of the option cost in the RIT-T (together with any associated TNSP costs):
  - An equal and offsetting amount to the network support payment should also be reflected in the market benefit side of the RIT-T calculation, as the NNO proponent will receive this payment from the TNSP (ie, it is a wealth transfer which will ultimately not affect the RIT-T net benefit outcome);
  - Any TNSP costs associated with management of the NNO option should also be included as part of the option costs in the RIT-T (see discussion below).
- Include the incremental capital and operating costs of the NNO option as part of the assessment of market benefits (ie, as a 'negative benefit'), as this reflects a resource cost that would not have been incurred in the absence of the NNO. This may be:[87]
  - the full cost of the assets used to provide the NNO (and associated operating costs), if the non-network solution involves completely new assets;
  - the cost of upgrades or additions to an existing asset;
  - zero where an existing asset does not need upgrades or additions in order to provide the network support service.

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[85] This is consistent with the AER industry practice Application Note to support network businesses in adopting best practice asset replacement planning, see: AER, *Industry practice application note - Asset replacement planning,* 25 January 2019, pp. 27 & 42.
[86] AER, *Guidelines to make the Integrated System Plan actionable - Final Decision*, August 2020, p. 26.
[87] Section 4.2.1 of this Handbook discusses the approach to determining whether a non-network option should be considered committed, anticipated or a new project.

» Include an estimate of the market benefits arising as a consequence of the operation of the NNO, eg, as a result of the impact of the NNO on the operation of the wholesale and/or ancillary services markets.
» This will again likely differ depending on whether the NNO is provided by an existing asset or a new asset.
» Ancillary service market impacts may not be material to the outcome of the RIT-T, and so may not need to be modelled. However as new markets are introduced for a wider range of ancillary services, and NNO offerings evolve, consideration of ancillary market benefits is likely to increase in importance.

Other transactions that may occur between the NNO and third parties (eg, to allow third parties to use non-network solution assets to participate in the wholesale market and/or ancillary services markets) do not need to be explicitly included in the RIT-T to the extent that they are wealth transfers between NEM market participants and so will net off to zero (and will not affect the outcome of the RIT-T). However where these transactions have an impact on market outcomes (eg, in the wholesale or ancillary service markets) and where this impact may be material to the RIT-T outcome, then this impact should be reflected in the assessment of market benefits.

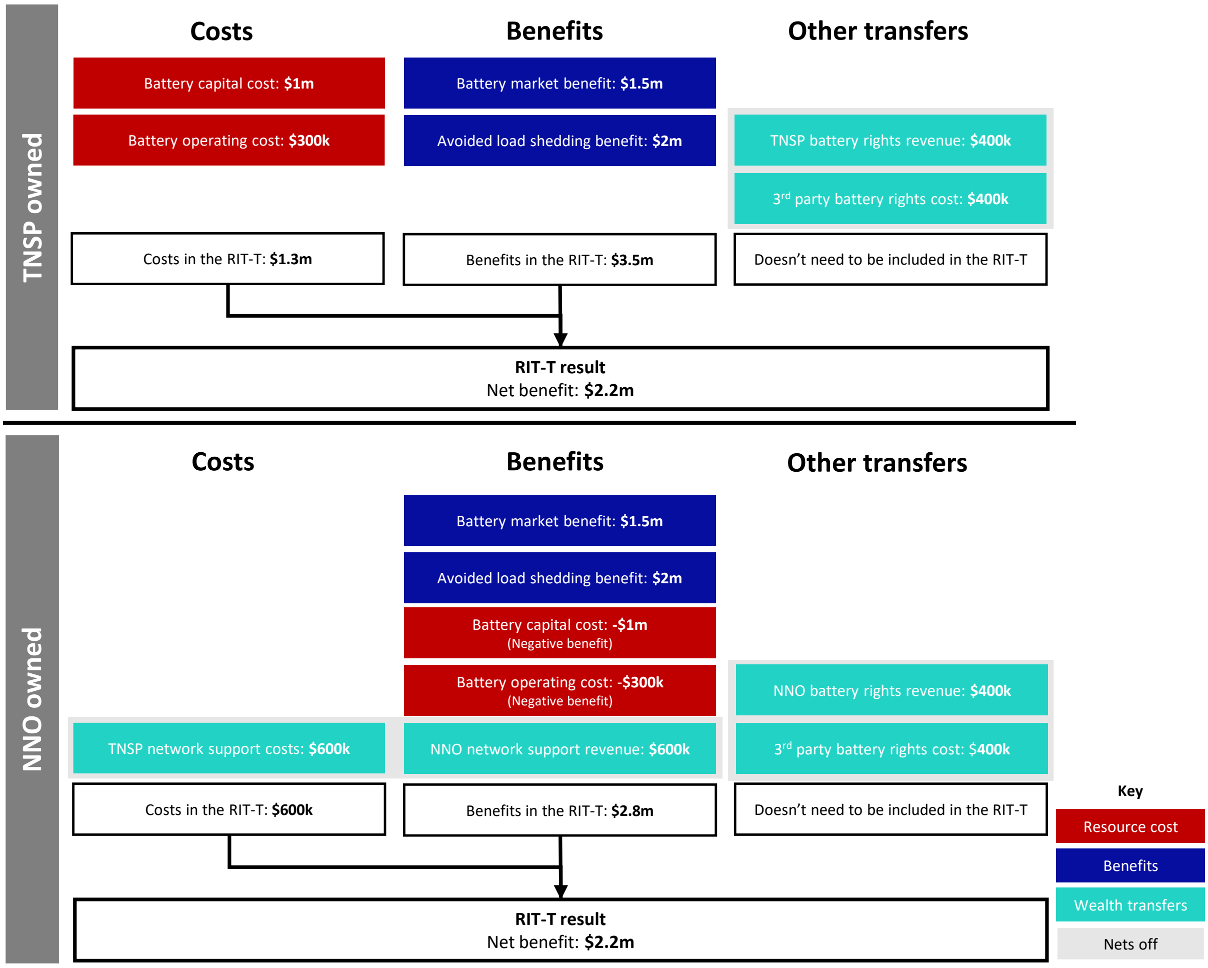

Figure 7: Treatment of NNO costs under TNSP owned and NNO owned in the RIT-T

Figure 7 also demonstrates that the proposed treatment of NNO means that the RIT-T assessment will result in the same outcome where an asset (such as grid-scaled storage) is owned directly by the TNSP and where it is provided under a network support contract by a NNO proponent. This is consistent with the AER's guidance on the treatment of NNOs in the RIT-T.[88]

Examples of how NNO costs should be treated in the RIT-T are presented in the box below.

Examples of treatment of NNO costs in the RIT-T

Costs that need to be included will depend on the circumstances of the non-network option:

- **New grid-scale battery used to provide a non-network solution**: assume a NNO proponent offers a network support service for $52,000 per year to a TNSP ($600,000 PV). Avoided load shedding benefits are equal to $2 million in PV terms. The NNO proponent uses a grid scale battery that costs $1 million plus $300,000 (PV) operating costs to provide the proposed network support service, but the battery will also be leased to a third party to provide services in the wholesale market. The third party will pay the NNO proponent $400,000. The battery is expected to provide market benefits of $1.5 million from its impact on the wholesale market outside of the times it is needed for network support (eg, by displacing the dispatch of higher cost generation). In this case, the net benefits from the non-network option in the RIT-T is $2,200,000 consisting of:
  - costs included in the RIT-T:
    - network support costs of $600,000 in present value terms
  - benefits included in the RIT-T:
    - a corresponding benefit of $600,000 (PV) for revenue from the network support contract received by the NNO (which exactly offsets the network support costs);
    - avoided load shedding benefits of $2 million in PV terms (calculated based on MWh avoided load shedding × VCR).
    - a battery cost (negative benefit) of $1 million;
    - NNO operating costs (negative benefit) of $300,000 (PV) to maintain the battery;
    - Wholesale market benefits of $1.5 million (PV).

  The $400,000 fee paid by the third party to the NNO proponent for the right to use the battery is a wealth transfer. This transaction can be included in the RIT-T as a benefit to the NNO proponent, provided that an offsetting cost of $400,000 incurred by the third party is also included. However, given that the benefit to the NNO proponent and the cost of fees for the third-party offset each other in the RIT-T, the transaction does not need to be explicitly included in the RIT-T.
  - The impact of the third party transaction in terms of wholesale market outcomes is already captured as a benefit in the RIT-T (ie, wholesale market benefits of $1.5 million (PV).

- **Existing non-network solution owned by NNO proponent without incremental upgrade**: assume a non-network proponent has an existing gas turbine that can provide network support services without needing an upgrade modification. The NNO proponent offers this service for $52,000 per year ($600,000 PV). Operating costs for the NNO proponent are $26,000 per year ($300,000 PV). Avoided load shedding benefits are equal to $2 million in PV terms. In this case, net benefits from the non-network option will be $1.7 million consisting of:
  - costs included in the RIT-T:
    - network support costs of $600,000 (PV); and
  - benefits included in the RIT-T:

[88] AER, *Guidelines to make the Integrated System Plan actionable - Final Decision*, August 2020, p. 26.

- a corresponding benefit of $600,000 (PV) for revenue from the network support contract received by the NNO (which exactly offsets the network support costs);
- NNO operating costs (negative benefit) of $300,000 (PV) associated with incremental operation of the gas turbine for network support; and
- avoided load shedding benefits of $2 million.

In this example, it is assumed that the existing gas turbine does not need modification so there are no incremental capital costs. Further, this example assumes that there are no material changes to the operation of the gas turbine in the wholesale market arising from its use for network support. Where the operation of the gas turbine is materially altered through its offering of network support, the impact of its changed operation in the wholesale and ancillary service market benefits should be quantified as part of the market benefits and included in the RIT-T.

- **Existing non-network solution with incremental upgrade**: assume a non-network proponent has an existing gas turbine that can provide network support services but requires upgrade modifications costing $100,000 in order to do so. The NNO offers this service for $52,000 per year to a TNSP ($600,000 PV). Operating costs for the NNO proponent are $26,000 per year ($300,000 PV). Avoided load shedding benefits equal to $2 million in PV terms. Net benefits from the non-network option in the RIT-T will be $1.6 million consisting of:
  - costs included in the RIT-T:
    - network support costs of $600,000 (PV);
  - benefits included in the RIT-T:
    - a corresponding benefit of $600,000 (PV) for revenue from the network support contract received by the NNO (which exactly offsets the network support costs);
    - incremental capital costs (ie negative benefit) of $100,000 (PV) for modifications to the gas turbine; and
    - NNO operating costs (negative benefit) of $300,000 (PV) associated with operation of the gas turbine for network support; and
    - avoided load shedding benefits of $2 million.

  This example again assumes that that changes to the wholesale and ancillary service markets arising from the using the gas turbine for network support are not material.

- **Demand management solution:** assume an iron smelter proposes to provide a demand management solution to a TNSP for $500,000 per year availability fee, a one off $1 million contract fee and $100,000/MWh fee. In return, the iron smelter will incur one off costs of $700,000 to install the required meters and communications equipment, and opportunity costs of $65,000/MWh from foregone electricity demand. Avoided load shedding benefits achieved from the demand management solution equal $2 million in PV terms. In this case:
  - Costs included in the RIT-T are:
    - Availability fee of $500,000 per year, one off contract fee of $1 million, and demand management service fee of $100,000 per MWh are included in the RIT-T
  - Benefits included in the RIT-T are:
    - the corresponding network support revenues received by the NNO (exactly offset NNO costs);
    - $700,000 cost (ie negative benefit) to install the required meters and communications equipment;

» $65,000/MWh opportunity cost × MWh interrupted under contract (negative benefit); and
» avoided load shedding benefits of $2 million.

The opportunity costs for the iron smelter are likely to be difficult to quantify. TNSPs may consider using the proposed NNO cost as a proxy, or alternatively may use an appropriate VCR value best reflecting the NNO proponent type.

Box 2 Examples of including NNO costs in the RIT-T

4.2.1 Estimating resource costs for NNO

TNSPs will need to request information from potential proponents of NNO on the resource costs associated with the provision of NNO services (in addition to their proposed network support price).

In considering the resource costs of NNO:

» The key inputs, assumptions and reasoning relating to capital cost estimates for non-network options need to be clearly set out in the RIT-T, to the extent practicable and appropriate for that stage of the RIT-T and subject to any confidentiality concerns flagged by proponents in providing the cost estimates.[89] Where the estimates provided by the proponent are confidential, they can be redacted from the public RIT-T documentation, noting that the AER considers it best practice for the RIT-T proponent to explore whether it can aggregate, anonymise or redact the information.
» The TNSP should also consider providing analysis that utilises that information as part of the assessment of that option on a confidential basis to the AER;
» It is likely to be difficult to apply the AACE classification to the capital cost estimate for non-network options (as this information is provided by the non-network proponent). This difficulty provides a justification to depart from the AACE classification in these cases;[90]
» If there are no prices and/or cost information provided by proponents at the PADR stage, or if the costs provided appear out of line with other cost estimates for similar projects, then then TNSP may choose to adopt reasonable estimates of the cost of the non-network option, where there is a clear non-network option and the TNSP has a credible basis for estimating the likely costs. For example, AEMO's IASR database has capital cost estimates for BESS of different durations.
» The price proposed by non-network proponents will factor in their required return on capital, to reflect the risks the proponent sees in relation to its project. The TNSP does not have to factor the project risk incurred by non-network projects into the return on capital used in the NPV assessment.

The costs the TNSP expects to incur in contracting with a non-network provider should also be included – for example:

» any connection costs should also be included in the cost of non-network options; and
» it should also include any decommissioning costs for existing network assets that may no longer be needed if a non-network solution is adopted including any site rehabilitation costs, to the extent they are material.

In costing any non-network options, TNSPs can also include the expected costs associated with any residual risk that the non-network option may not be able to meet the identified need, or will not meet the identified need in full. This may include the following:

[89] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, section 3.5A.
[90] AER, *Cost benefit analysis guidelines and RIT application guidelines, Explanatory Statement*, October 2023, p. 26. See section 4.1 of this Handbook for a discussion of consideration of the AACE cost classification system.

» the TNSP's contract with the non-network provider will contain clauses setting out the liability and obligations the non-network provider takes on in providing the non-network option; or
» the costs associated with any failure in performance (such as the increase in USE, or safety risk) can be included in the assessment, provided that there is a robust case for assuming that the non-network solution may not meet the identified need in full.[91]

However, unquantifiable reputational damage to the TNSP from the non-network solution not meeting its obligations cannot be included in the assessment.

4.2.2 Assessing whether a non-network option is committed or anticipated and whether it should be included in the base case

As discussed above, where an NNO reflects a project that already exists or that is expected to be developed regardless of the outcome of the RIT-T, then the resource costs of this option (ie, the capital and operating costs) are considered to already be sunk (ie, they are assumed in the base case). The resource costs of this option in the option case will only reflect any incremental costs incurred to enable the NNO to provide network support services. Similarly, the market benefits associated with such NNOs will only reflect any change in behaviour of the non-network project as a consequence of the provision of network support services.

NNOs which should be assumed to be in the base case are: [92]

» all committed non-network projects;
» any anticipated non-network project which is included in the most recent draft or final ISP; and
» any anticipated non-network project which is absent from the ISP but where the RIT-T proponent, using its reasonable judgement, considers the project sufficiently far advanced to be likely to proceed regardless of the outcome of the RIT-T.

Where an NNO is anticipated but not considered to be sufficiently certain to be included in the base case, the TNSP should consider including a sensitivity in the RIT-T assessment in which the NNO project is included in the base case, to identify whether this may change the outcome of the RIT-T.

The box below sets out the definitions of **committed** and **anticipated** projects, as set out in the RIT-T. These definitions should be used to classify NNO as either committed, anticipated or new projects. AEMO maintains a database of NEM Generation information (including battery projects) which adopts the same criteria and which is a helpful resource.[93] However it is likely to also be necessary to obtain additional, more recent information from the non-network proponent in relation to the relevant criteria.

Box 3 Definition of committed and anticipated projects[94]

A project is ***committed*** if it meets the following criteria:

» the proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement;
» construction has either commenced or a firm commencement date has been set;
» the proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for the purposes of construction;

[91] As set out in section 4.1.1, these types of costs may also need to be included for a network option which may increase USE in the short term (e.g. if a line drops out or has to be taken out during construction).
[92] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, pp. 34-35.
[93] Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information
[94] AER, *Regulatory investment test for transmission*, August 2020, p. 13.

- contracts for supply and construction of the major components of the necessary plant and equipment (such as generators, turbines, boilers, transmission towers, conductors, terminal station equipment) have been finalised and executed, including any provisions for cancellation payments; and
- the necessary financing arrangements, including any debt plans, have been finalised and contracts executed.

A project is ***anticipated*** if it does not meet all of the criteria of a committed project as defined above, but is in the process of meeting at least three of the criteria.

4.3 The treatment of 'external' funding contributions

Any 'external' financial or capital contributions from parties outside of the NEM should be netted off the costs of the option in undertaking the NPV assessment. This includes any funding from governments, or other external parties (eg, ARENA).

Where this applies, the TNSP should report on the outcome of the NPV assessment in RIT-T consultation documents both with and without the payment from an external party.

In this context, 'external funds' do not include funds from registered participants under the NER or any other party in their capacity as a consumer, producer or transporter of electricity in the NEM.[95] Any funding from generators or retailers is therefore not deducted from the cost of the options under the RIT-T analysis.

[95] This differs from the treatment of funding from other NEM participants in determining whether the RIT-T threshold is met – see section 1.2.

5 RIT-T economic assessment framework

Key points[96]

- The RIT-T is a 'with and without' test, ie, costs and benefits of an option ('with') are estimated relative to a base case ('without').
- The analysis should be proportionate to the size, scale and potential benefits for each credible option and be focused on assumptions that affect option rankings
- The default analysis period should be between 15 and 30 years.
- The central (real, pre-tax) discount rate used in the assessment should be a 'commercial' discount rate (which is a different rate to the regulated WACC), sourced from the most recent IASR.
  - The central, high and low discount rates in the IASR at the time of updating this Handbook are **7.0%, 10.5% and 3.0%** respectively.
  - The regulated WACC should be used as the lower bound discount rate for sensitivity testing, also sourced from the latest IASR.
  - The regulated WACC from the most recent AER regulatory determination for a TNSP can be used where AEMO has not specified a lower bound discount rate in the IASR.
  - A symmetrical uplift to the discount rate (based on the difference between the lower bound and central discount rates) can be used to derive a high discount rate, where AEMO has not specified a higher bound discount rate in the IASR.

5.1 Overview of the RIT-T economic assessment framework

Fundamentally, the RIT-T economic assessment framework is a 'with and without' test that compares the costs and benefits associated with each credible option ('with'), relative to a base case ('without'). The base case describes a world where credible options are not implemented.

The comparison of credible options enables an understanding of the economic impact they are likely to have relative to each other, as well as relative to the base case. It allows the ranking of options to be derived, which is the primary objective of the RIT-T economic analysis.

[96] The NER requirements relating to the RIT-T economic assessment framework can be found in clause 5.15A.2(b) of the NER. The AER's guidance regarding the framework can be found in section 3 and Appendix A of the AER's RIT-T Application Guidelines.

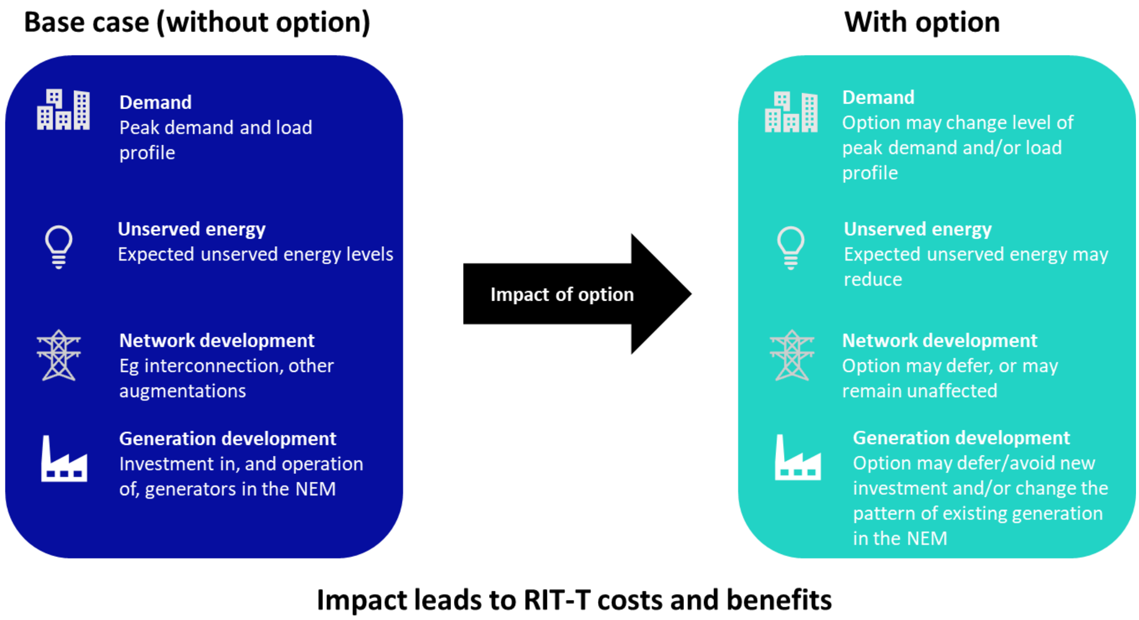

Figure 8: The RIT-T is a 'with and without' test

The RIT-T assessment considers costs and benefits that arise from a credible option for all participants in the NEM, including all those who produce, consume or transport electricity across all NEM jurisdictions. In particular, this means that:

- it does not just focus on the TNSP applying it – it includes costs and benefits for all market participants; and
- it does not just focus on the TNSP's jurisdiction – it considers all NEM jurisdictions.

Benefits considered in the RIT-T assessment framework are those that are derived from real resource savings (ie costs that would have been incurred under the base case but are avoided, or deferred, under a credible option). They also have to relate to the NEM.[97]

- Unmonetised 'externalities' are excluded from the analysis.
  - The only exception is changes in Australia's greenhouse gas emissions (including carbon emissions), which are now explicitly included as a benefit category under the RIT-T.[98]
- Price changes that give rise to economic transfers between one NEM participant and another are also excluded from the RIT-T analysis. This is because such price changes do not provide any real resource savings.[99]
- Costs and benefits that are incidental to electricity consumption are excluded from the RIT-T analysis. This includes costs and benefits associated with the impact of changes in electricity prices on broader economic activity. While all individuals and businesses in the NEM are electricity

[97] In particular, and as stated above, the RIT-T framework considers costs and benefits that arise from a credible option for all participants in the NEM, including all those who produce, consume or transport electricity across all NEM jurisdictions.
[98] The change in greenhouse gas emissions is expected to be explicitly added as a category of benefits for quantification under the RIT-T, following finalisation of the AEMC Rule change on *Harmonising the national energy rules with the updated national energy objectives* (due by 1 February 2024). [To update prior to publication]
[99] Where price changes also lead to changes in behaviour that does have resource impacts (such as the timing of a decision to investment in new generation), then this is captured in the RIT-T analysis.

consumers, the meaning of 'parties consuming electricity' is interpreted more narrowly as each party's capacity as a consumer, producer or transporter of electricity.[100]

A key guiding principle for any RIT-T analysis is that it should be proportionate to the size, scale and potential benefits for each credible option and be focused on assumptions that affect option rankings.

- This means that it is not necessary to undertake complex and resource-intensive analysis for all credible options unless, doing so, is considered the only way to robustly rank credible options.
- However, assumptions that are found to be material to option rankings should be refined to improve the accuracy of the estimates used.

5.2 Relevant assessment period and the use of 'real' dollars

The default analysis period should typically be between 15 and 30 years from the time when costs or benefits deviate between the base case and option cases. However, this should be assessed on a case-by-case basis. If the period selected is not between 15 or 30 years, an explanation of the chosen analysis period should be included the PSCR, PADR and/or PACR.

In general, the duration of the analysis period should reflect the size, complexity and expected life of the credible options being assessed – for example:

- it is unlikely that a period of less than five years would adequately capture the market benefits associated with any credible option;
- if a credible option is of significant size or very long-lived, then this might enable a deferral of future network augmentation or future generation investment beyond a 15 year period, and so adopting a longer analysis period may be more appropriate.

The guiding principle for determining the relevant assessment period is that the network should be in a 'similar state' at the end of the analysis period across the different options in relation to the next major investment decision required.

The assessment period should be sufficiently long so that it captures the key differences in the costs and market benefits across the credible options assessed. That is, the assessment period should be the point at which identification of the preferred option stabilises, and assuming a longer period would not change the identified preferred option, as beyond this point the relativity of the costs and benefits between options is not expected to change materially.

In practice, a longer assessment period (eg, 30 years) will be more relevant in instances where:

- an option, or options, exhibit different stages; and
- there are changes in the drivers of market benefits over time.

The same analysis period should be used for the assessment of all the credible options, and under each reasonable scenario.

The assessment should start from the current financial year, which allows for the assessment of different options commencing in different years (and associated staging), as well as an assessment of advancing or deferring the timing of options.

All costs and benefits should be denominated in 'dollars of the day', eg, if the assessment is being undertaken in the financial year 2022/23, then all costs and benefits should be in real 2022/23 dollars (as opposed to nominal dollars).

[100] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, section 3.11.

Including all costs and benefits in the RIT-T analysis in real terms aligns with the use of a real discount rate to discount these values back to the year in which the analysis first begins (ie the start year).

5.3 The RIT-T uses a 'commercial' discount rate

The RIT-T requires the discount rate used in the NPV analysis to be the commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. This is different to the regulated cost of capital (or 'WACC') of a network business.

This section outlines the role of the discount rate in the assessment and the requirement to use discount rates set out in AEMO's latest IASR.

5.3.1 Role of the discount rate

The discount rate used should be a real, pre-tax rate. This avoids the need to calculate a separate tax component and is consistent with the analysis being conducted on a 'real' basis.

Importantly, the discount rate is *not* applied in order to equate the 'riskiness' of different options, and, in particular, non-network options funded by commercial entities. Specifically:

- the costs being discounted for a non-network option reflect the price that the TNSP is paying for that service; and
- the proponent's risks associated with the delivery of non-network options (eg, as a result of those options utilising new technology or new business models) would be reflected in the price proposed by proponents of those options.

Consequently, the risks associated with non-network technologies do not need to be considered in the selection of an appropriate discount rate.

5.3.2 Selection of an appropriate discount rate

The drivers of a commercial discount rate are not fixed and will vary over time with wider financial market conditions.

TNSPs are required to adopt the discount rate assumptions from the most recent IASR published by AEMO, unless there is a demonstrable reason why a variation of the discount rate assumption is necessary for a particular RIT-T.

- At the time of updating this handbook, the central discount rate estimate adopted in the IASR is 7.0%.[101]

Sensitivity testing (as outlined in section 7 below) should be undertaken on the discount rates used by AEMO in its ISP and included in its IASR. In addition to the central discount rate of 7.0% noted above, the most recent IASR at the time of preparing this handbook provides an upper bound discount rate of 10.5% and a lower bound discount rate of 3.0%.[102] The IASR lower bound is a regulatory WACC based on the most recent AER Final Decision for a regulatory determination for a TNSP.

Where AEMO has not specified a lower bound discount rate in the IASR, or where there has been a more recent AER Final Decision for a regulatory determination for a TNSP since the publication of the IASR,

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[101] AEMO, *2023 Inputs, Assumptions and Scenarios Report*, July 2023, p. 123.
[102] AEMO, *2023 Inputs, Assumptions and Scenarios Report*, July 2023, pp. 23, 123.

then the regulated WACC determined by the AER in the most recent Final Decision for a TNSP at the time of the RIT-T assessment should be used.[103]

A symmetrical uplift to the discount rate (based on the difference between the lower bound and central discount rates) can be used to derive a high discount rate, if AEMO has not specified a higher bound discount rate in the IASR.

To further test the robustness of RIT-T results to discount rates, boundary values that triggers a change in outcomes (ie a change in the preferred option) should be identified. This would inform how extreme discount rates would have to be to in order to change the preferred option or how sensitive RIT-T results are to discount rates.

» Where the capital costs of the preferred option in the RIT-T is above $100 million, this in turn could inform the identification of appropriate reopening triggers for that RIT-T.[104]

[103] Note that this may not be the TNSP applying the RIT-T. Energy Networks Australia notes that the AER uses a trailing average cost of debt to estimate the regulatory WACC, which does not equate to a *prevailing* rate. A prevailing regulated real pre-tax WACC would be constructed using only prevailing parameters (eg, using the prevailing yield on 10 year BBB+ Australian corporate debt). However, Energy Networks Australia acknowledges that simply using the AER reported real, pre-tax WACC as a lower bound sensitivity represents a pragmatic approach for the purposes of conducting a RIT-T.

[104] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, section 3.8.2.

6 'Market benefits' of credible options

Key points[105]

- » The RIT-T includes nine classes of market benefits **(shortly to be expanded to ten with the inclusion of greenhouse gas emissions)** – however, classes do not need to be calculated if they can be shown to be not material to the RIT-T outcome.
- » Where options do not impact wholesale market outcomes, many benefit classes will not be relevant.
  - – However, in some cases (including repex RIT-Ts) non-network options may affect wholesale market outcomes, even if network options do not.
- » Only two categories of market benefit are expected to be relevant for most repex RIT-Ts: (1) changes in unserved energy; and (2) the impact on unrelated transmission investment.
  - – The key 'benefits' for many repex projects are avoided opex and costs associated with environmental and safety regulation/requirement breaches.
- » While wholesale market modelling is the default estimating approach for wholesale market benefits, alternative simplified market modelling approaches may be used, depending on the materiality of the market benefits and/or to ensure that the level of analysis is not disproportionate to the cost of investment.

6.1 Overview of market benefits

Figure 9 shows the ten classes of market benefit to be considered for credible options under a RIT-T. It highlights how the majority of market benefit categories are only relevant when an option affects the wholesale electricity market.

[105] The NER requirements relating to the relevant 'market benefits' that need considered can be found in clause 5.15A.2(b)(4) of the NER. The AER's guidance regarding each category of market benefit can be found in section 3.6 and Appendix A of the AER's RIT-T Application Guidelines (with the exception as at the date of this Handbook of the change in greenhouse gas emissions, where the updated AER guidance is expected by 31 December 2024).

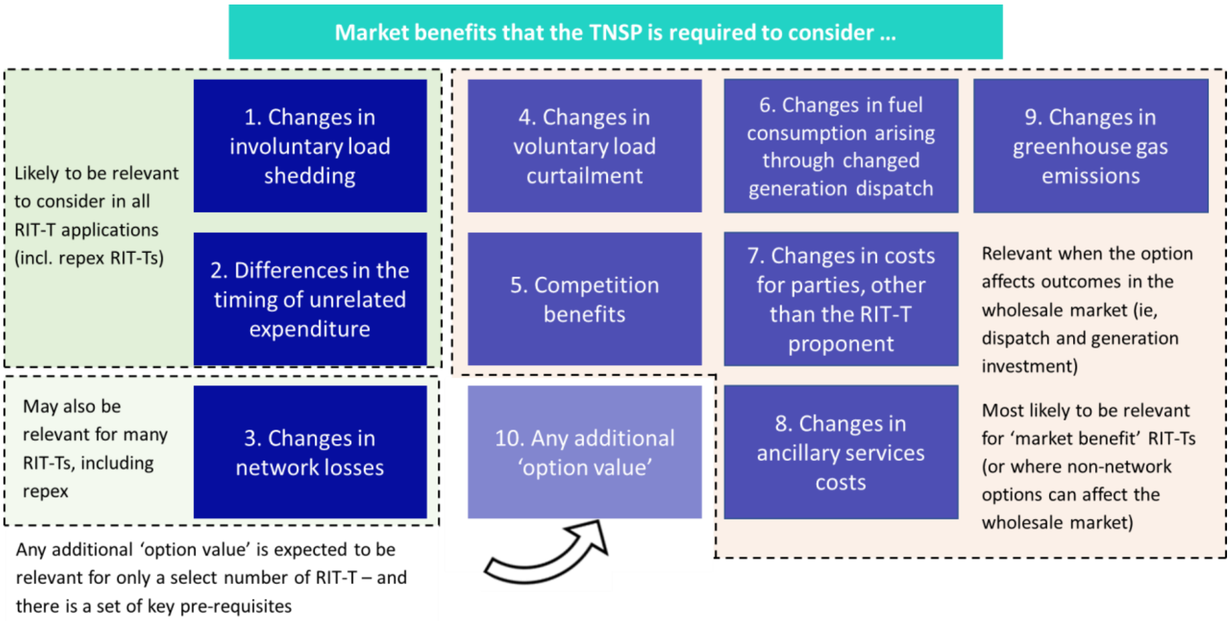

Figure 9: The ten classes of market benefit required to be considered

The sections below outline how each category of market benefit should be considered, as well as which categories are likely to be relevant for different types of RIT-Ts.

6.2 Need to consider whether benefit categories are material

All categories of market benefit should be included in the RIT-T assessment, unless the TNSP can demonstrate that a specific category (or categories) is unlikely to be material.

In order to demonstrate that any individual class of market benefit is not material, and so is exempt from being quantified under the RIT-T, the TNSP can:

- demonstrate through qualitative analysis that there will be no material changes to the project rankings under the RIT-T (and therefore to the RIT-T outcome):
  - this is particularly relevant where the options will have no impact on the wholesale market; or
- undertake indicative order of magnitude quantifications to demonstrate that there will be no impacts on the option rankings
  - this can be relevant in relation to changes in network losses and USE; or
- demonstrate that the level of analysis needed to quantify the benefits is disproportionate compared to the cost of investment
  - this is relevant to ancillary services costs, option value and competition benefits.

In terms of the first two points, a particular category of market benefit is unlikely to be material if:

- it is not expected to be materially different between options – for reliability corrective action RIT-Ts, inertia RIT-Ts and system strength RIT-Ts; and
- it is not expected to be materially different between options and/or it is not expected to change the sign of expected net market benefits (ie, result in negative expected net market benefits) – for 'market benefits' RIT-Ts.

Importantly, the following market benefits are only likely to be material if the proposed investment will have an impact on the wholesale market:

» changes in fuel consumption arising through different patterns of generation dispatch;
» changes in greenhouse gas emissions;[106]
» changes in voluntary load curtailment (since there is no impact on pool price);
» changes in costs for parties, other than the TNSP;
» changes in ancillary services costs;
» competition benefits; and
» LRET penalties.

For other RIT-Ts, these market benefit categories will not need to be estimated. This is likely to be the case for the majority of repex RIT-Ts,[107] as well as for many reliability corrective action RIT-Ts more broadly.

RIT-Ts concerned with inertia network services and system strength services may need to include market benefits from the changes in wholesale market, but this depends on the specification of the options included in the RIT-T (and in particular the inclusion of non-network options) and should be considered on a case by case basis.

However, for RIT-T assessments where there are credible non-network options, these options may impact the wholesale market (for example, by displacing generation output) and therefore have material market benefits, even if the credible network options do not impact the wholesale market. In these cases, the market benefits for the non-network options may need to be assessed.

The figure below summarises the general process for considering the categories of market benefit under the RIT-T, as well as when a simplified modelling approach can be applied.

[106] Changes in greenhouse gas emissions are likely to arise from the impact of an option on the pattern of generation dispatch.
[107] For some repex RIT-Ts there may also be changes in greenhouse gas emissions associated with reducing emissions from failing network components.

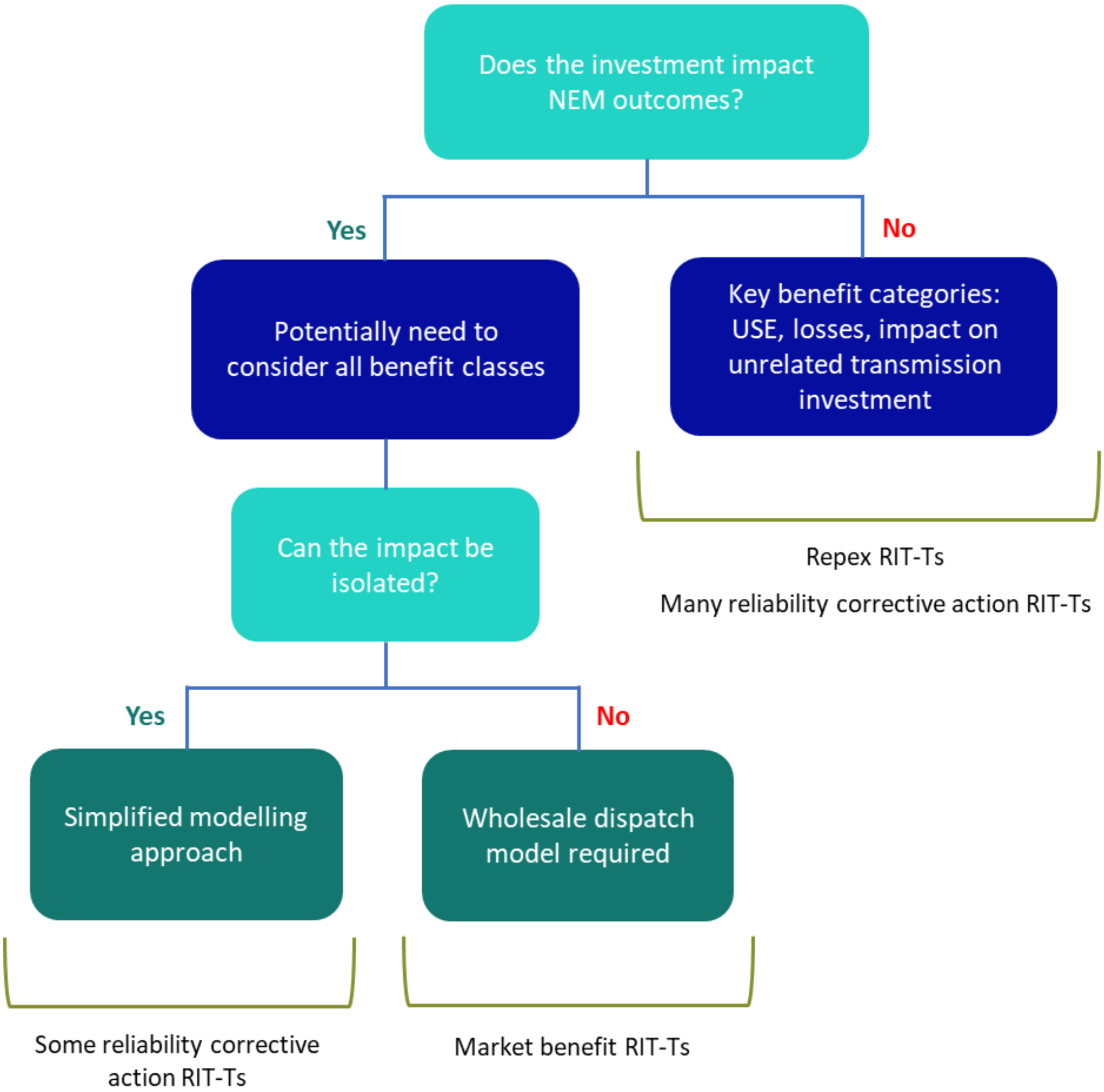

Figure 10: Process for determining whether to include market benefits

Guidance is provided below on how to calculate individual market benefit categories. The two market benefit categories most likely to be relevant to repex RIT-Ts are discussed first, followed by those market benefits that result from impact of an option on the wholesale market.

Appendix A provides detailed guidance on how to calculate individual market benefit categories using a simplified modelling approach (ie, a non-market modelling approach).[108] This Handbook does not provide detailed guidance on dispatch modelling, as this will be specific to the particular model used.

[108] The RIT-T requires that in estimating market benefits, a market dispatch modelling methodology must be used, unless the TNSP can demonstrate that this is not relevant. The AER RIT-T Application Guidelines recognise that in some circumstances it may be appropriate to use methods other than market dispatch modelling to estimate some classes of market benefits. See: AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, section 3.7.3.

6.3 Benefits most relevant for repex RIT-Ts – changes in USE and impact on unrelated transmission investment

While repex RIT-Ts will have different drivers, the two most common categories of material market benefit for these RIT-Ts are likely to be:

» changes in involuntary load shedding (ie, unserved energy) above the relevant reliability standard; and
» differences in the timing of unrelated transmission expenditure.

These benefits can be calculated without market dispatch modelling, as described below.

A further key 'benefit' of options under repex RIT-Ts is likely to be the reduction in future maintenance costs and the reduction in costs associated with environmental and safety breaches, compared to the outcomes that would be expected in the base case.

» safety and environmental outcomes may be key drivers of repex RIT-Ts;
» however, this is captured in the RIT-T analysis in the comparison of the *expected costs* between the base case (in which these costs are incurred) and the option cases, rather than being captured in one of the market benefit categories set out in the RIT-T (see section 4.1).

Changes in losses may also be relevant for some repex assessments. However, in many instances, the magnitude of the change in losses between the options compared to the differences in the capital and operating costs is not expected to be material enough to affect the outcome of the RIT-T assessment. In this case, a simplified calculation of the change in losses may be appropriate to demonstrate this (see Appendix A).

6.3.1 Calculation of unserved energy benefit

The extent that each option allows unserved energy (USE) to be reduced (or 'avoided'), relative to the base case, is captured as a market benefit under the RIT-T.

For each option, this benefit is calculated as:

» the quantity (in MWh) of USE expected to be avoided each year (ie, on a probability weighted basis, across a range of non-credible events); multiplied by
» the estimated 'Value of Customer Reliability' (VCR).

The quantity of avoided USE can be estimated either using market modelling or via a separate network modelling approach. For repex RIT-Ts, applying a separate network modelling approach is likely to be sufficient.

The RIT-T requires that the USE benefit be estimated *over and above* the reliability standard for all jurisdictions (besides Victoria). Victoria has probabilistic reliability standards, which require all changes in USE to be estimated and valued.

For jurisdictions outside of Victoria, it can be difficult to separate out the change in USE over and above the requirements of the planning standard, particularly as more planning standards are now being set using probabilistic techniques. This requirement also makes the presentation of the RIT-T assessment less intuitive.

» In these cases it may be a reasonable and proportionate approach to value all of the change in USE between the base case and other options. In doing so, it is important to highlight in the RIT-T documentation that this approach does not affect the outcome of the ranking between options, since the difference in USE between the base case outcome and the reliability standard will be the same for all options. This is illustrated in figure 11.

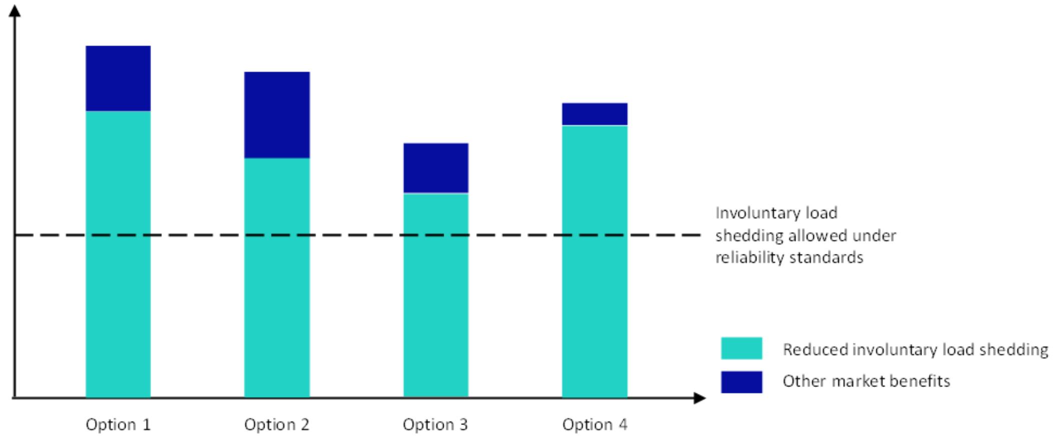

Figure 11 Why valuing all avoided USE does not change the identified preferred option

Where the 'do nothing' base case results in the reliability standard being breached (and where it is therefore unrealistic), it may be appropriate to 'cap' the level of USE at the level reached after a certain period (e.g, 10-15 years), where this is considered uncertain. This avoids a situation where an exponential increase in USE in later years[109] dwarfs other market benefits and skews the RIT-T results by over-shadowing differences in market benefits between options.

Estimated changes in USE for each option should be valued using the most recent VCR estimate published by the AER. The AER adjusts VCR values on an annual basis using a CPI-X approach, where X is set to zero.

At the time of updating this Handbook, the latest AER VCR values are those contained in 'AER – Annual update – VCR final decision – Appendices A to E – December 2023'[110] (presented in the three tables below).

	NEM	NSW	VIC	QLD	SA	TAS
Residential	28.23	30.31	25.13	27.86	35.53	19.89

Table 2: Residential VCR values ($/kWh, real 2023)

Sector	Agriculture	Commercial	Industrial
Sector average	44.40	52.20	74.79
Small and medium	67.58	80.07	93.06
Large size	39.51	46.81	73.70

Table 3: Business VCR values ($/kWh, real 2023)

[109] An exponential increase in USE results from assumptions that failure rates increase exponentially with asset age. 'Capping' the USE level recognises that in reality action would be taken before this occurred. The RIT-T is considering 'action' in the near term, compared to this implied 'future action'.
[110] AER, *AER - Annual update - VCR review final decision - Appendices A to E – annual update December 2023(161005581).xlsx*, sheets 'App A – VCR values – Res' and 'App A – VCR values – Bus'.

Sector	VCR values
Services	12.36
Industrial	138.34
Metals	23.28
Mines	41.22

Table 4: Very large business customer VCR values by sector ($/kWh, real 2023)

The standard AER VCR estimates should be weighted according to the make-up of the specific gross load (which excludes customer behind the meter generation) affected under the options being considered in a particular RIT-T:

- for example, the affected gross load may be comprised of 80 per cent residential customers, 15 per cent commercial customers and 5 per cent industrial customers.

This calculation should be included in the PADR/PACR so that stakeholders can understand how the VCR value used has been derived.[111]However, in some cases the state-wide VCR will be the relevant value to use, eg, for repex RIT-Ts relating to a program of works across the state. In this case the TNSP should explain why the state-wide VCR value has been used.

The level of VCR adopted should be held constant across the different scenarios used in the RIT-T, unless a different VCR has been adopted by AEMO across its different ISP scenarios.[112] However, the sensitivity of the RIT-T outcome to VCR values should be tested. The AER recommends applying a sensitivity analysis that considers a range of ± 30% to relevant VCRs[113] (as outlined in section 7.4 below), as well as threshold analysis to identify the value of VCR that would change the RIT-T outcome.

Load-weighted VCR estimates based on the AER's latest published VCR estimates are also expected to be used even for situations where there is a risk of widespread (eg, entire areas, as opposed to only one street), severe or prolonged supply disruptions (eg, lasting several days and/or rolling outages).[114] However, this case may warrant greater weight being placed on the outcome of the sensitivity testing assuming +30% VCR.

6.3.2 Differences in timing of unrelated transmission expenditure

Undertaking a credible option can affect the timing of other, unrelated transmission investments. This can provide a market benefit where the unrelated investment can be deferred or reduced in scope, relative to the base case.

The only investments whose changes in timing/scope should be taken into account in applying the RIT-T are those directed towards addressing *different* purposes to the identified need for that specific RIT-T. For example:

- a credible option involving replacing an existing but aging and constrained transmission line to maintain reliability of supply to a bulk supply point may allow deferral of a separate and unrelated planned transmission line that is intended to provide transmission system access to renewable generation resources.

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[111] AER, *Decision: North West Slopes and Bathurst, Orange and Parkes: Determination on dispute - Application of the regulatory investment test for transmission*, November 2022, p. 28.
[112] AER, *Decision: North West Slopes and Bathurst, Orange and Parkes: Determination on dispute - Application of the regulatory investment test for transmission*, November 2022, p. 28.
[113] AER, *Widespread and Long Duration Outages – Values of Customer Reliability Final Conclusions*, September 2020, p. 8.
[114] AER, *Widespread and Long Duration Outages – Values of Customer Reliability Final Conclusions*, September 2020, p. 9.

- a 275kV network option to meet a localised distribution network need may provide additional voltage support to the broader transmission network and defer the need for additional capacitor banks.

The market benefit from differences in timing of unrelated transmission expenditure is calculated as the difference in the present value of the costs associated with this investment.

Changes in the timing and/or magnitude of unrelated expenditure can result in a negative market benefit (ie, a market cost). For example, an option may result in costs where unrelated TNSP expenditure increases and/or is brought forward.

6.4 Market benefit categories resulting from the impact of an option on wholesale market outcomes

For some RIT-Ts, particularly market benefit RIT-Ts, credible options can affect outcomes in the wholesale electricity market. This occurs where options change transmission network constraints, and/or impact wholesale price outcomes such that generation and/or storage dispatch and investment decisions are affected. This gives rise to the following potential market benefit categories:

- changes in fuel consumption (ie, dispatch costs);
- changes in Australia's greenhouse gas emissions;[115]
- changes in costs for other parties (ie, changes in generation and/or storage investment);
- changes in voluntary load curtailment;
- changes in ancillary service costs; and
- competition benefits.

For many RIT-Ts the wholesale market benefits of investment may be couched in non-RIT-T parlance, when discussed outside of the RIT-T process. While this narrative may be reflected in the RIT-T consultation documentation, it is important to also note how these benefits map to those accommodated for under the RIT-T. A few examples include:

- managing diversity in renewable resources (captured via changes in load curtailment under the RIT-T);
- accessing efficient new sources of electricity supply (captured via changes in fuel costs associated with generation dispatch under the RIT-T);
- managing an increased prevalence of extreme weather events (captured via changes in load shedding, ancillary services, and costs for other parties under the RIT-T); and
- reducing wholesale market outcomes (captured via changes in fuel costs associated with generator dispatch and competition benefits under the RIT-T).

There are two approaches for estimating these market benefits:

1. A wholesale market model that models the wholesale electricity market outcomes and the transmission network to derive dispatch[116] and ancillary service costs, forecast generation and storage investments and unserved energy.
   - This approach is likely to be suitable for larger and more complex RIT-Ts, such as transmission augmentations that connect new generation sources.

[115] Expected to be added to the NER as a new RIT-T benefit category by 1 February 2024. This benefit category is discussed further in section 6.4.2.
[116] Including voluntary load curtailment.

- Inputs, assumptions and scenarios for wholesale market modelling are required to be sourced from AEMO's most recent IASR where relevant (unless it can be demonstrated that there are circumstances where it is necessary to depart from those parameters).[117]
  - It may also be possible to draw on market modelling that has been done by AEMO.
  - However, this approach requires a high level of modelling expertise and resources that are likely to be disproportionate for simpler RIT-Ts.
2. A simplified modelling approach that may be more appropriate when a partial analysis of potential market benefits is sufficient, given the size and scale of the credible option proposed.

The simplified approach will be particularly relevant where non-network options, such as local generation or support from storage devices, may also be operated in a manner that affects the wholesale market, but where the network options considered are not expected to have an impact on the wholesale market.

» This may be the case for RIT-T's which are being applied to repex, and for reliability corrective action. In this case, a simplified approach is likely to be a proportionate means of including these market benefits for the non-network options.

Calculations for each class of market benefit under a simplified modelling approach will depend on the nature of the market benefit under consideration. Appendix A details a number of the simplified modelling approaches that can be applied.

6.4.1 Competition benefits

'Competition benefits' are identified as a class of market benefit in the RIT-T, and refer to the impact of an option on the degree of market power of generators such that it leads to a change in wholesale market outcomes.

If the credible options do not address network constraints between competing generation centres, then there is unlikely to be any material competition benefits.

The process of estimating competition benefits requires the comparison between the present values of:

» the overall economic surplus arising with the credible option, with bidding behaviour reflecting any market power prevailing with that option in place; and
» the overall economic surplus in the base case, with bidding behaviour reflecting any market power in the base case.

The estimation of competition benefits necessarily requires modelling of generator bidding behaviour, based on wholesale market modelling based on realistic bidding. Competition benefits will only be relevant when the credible options being considered affect power flows between two competing generation centres, which are most likely to be relevant for options that affect interconnector flows.

In order for there to be material competition benefits there are two necessary conditions that must always be met and a further three conditions of which at least one must hold.

The two necessary conditions are that:

» there must exist non-competitive bidding strategies in at least one of the relevant spot markets (or, to the extent that intra-regional transmission constraints exist, in some subsets of that spot market) which result in prices being above marginal cost for a sustained period; and

[117] See: AER, Regulatory *Investment Test* for *Transmission* Application *Guidelines*, October 2023, section 3.4.

» there must be some change in either the modelled outcome of the non-competitive bidding strategy or in the bidding strategy itself as a result of the option being considered, such that spot market prices fall closer to marginal costs.

The likely existence and extent of strategic bidding behaviour amongst generators is therefore the first factor that should be established, in assessing competition benefit. Equally important is establishing that this behaviour is likely to be affected by the credible option being assessed under the RIT-T. Where there is strategic bidding behaviour, but this is left unaffected by the credible option being assessed, there will be no competition benefit associated with the option.

If the above two conditions are satisfied, then in order for there to be material competition benefits, it is also necessary that one of the following three further conditions are met:

» there must be some responsiveness of end-users' consumption to spot market prices (i.e., demand is not completely inelastic); and/or
» the pattern of generation dispatch must be made more efficient as a result of the impact of the option on bidding strategies; and/or
» there must be some investment that is delayed as a result of the reduction in the spot market price.

6.4.2 Treatment of greenhouse gas emission policies in RIT-T wholesale market modelling

At the time of updating this Handbook, there is continuing development around the regulatory framework for considering greenhouse gas emissions policy, and, in particular policies affecting low carbon emissions renewable energy.

The Large-scale Renewable Energy Target (LRET) policy remains in place until 2030. The LRET aimed to deliver 33,000 GWh of Australia's electricity from renewable sources by 2020, with this objective being met in September 2019. High-energy users are required to continue meeting their obligations under the scheme until 2030, although AEMO no longer captures the LRET in its modelling assumptions.[118] As a consequence, there is also no longer a need to incorporate the LRET into RIT-T market modelling.

There are a number of both Federal and jurisdictional schemes targeted at reducing emissions.

TNSPs should reflect the assumptions included in the latest IASR in incorporating these various carbon emission policies in the market modelling for a specific RIT-T assessment. The exception is any new policies which are yet to be reflected in the IASR or an ISP, but which are expected to be reflected in a future ISP, in which case the TNSP may choose to reflect this policy in the RIT-T assessment.

The NER contains the following 'public policy criteria' to guide AEMO's consideration of environmental and energy policies:[119]

» a commitment has been made in an international agreement to implement that policy;
» that policy has been enacted in legislation;
» there is a regulatory obligation in relation to that policy;
» there is material funding allocated to that policy in a budget of the relevant participating jurisdiction; or
» the MCE has advised AEMO to incorporate the policy.

[118] AEMO, *2023 Inputs, Assumptions and Scenarios Report*, July 2023, p. 32.
[119] NER 5.22.3(b)

Changes to the National Electricity Law now also require the AEMC to prepare and maintain a 'targets statement' stating the greenhouse gas targets set by the participating jurisdictions.[120] The first targets statement was published in September 2023.[121]

The IASR assumptions take into account the policies included in the targets statement, as well as those that meet the public policy criteria.

Table 5 sets out policy settings regarding carbon emissions policy in the 2023 IASR (which is the most recent IASR at the time of updating this handbook).[122]

In conducting a RIT-T, and considering whether to vary any carbon policy assumptions from the latest IASR, TNSPs should consider both the public policy criteria in the NER and the targets stated in the latest targets statement.

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[120] NEL, section 32A.

[121] See: https://www.aemc.gov.au/sites/default/files/2023-09/AEMC%20Emissions%20targets%20statement%20-%20final%20guide%20September%202023.pdf

[122] AEMO noted that it will remove a policy from its modelling inputs and assumptions if it does not meet the criteria set out in the 'public policy clause' (ie, NER 5.22.3(b)) or is excluded in the AEMC's targets statement prior to the delivery of the 2024 ISP. AEMO, *2023 Inputs, Assumptions and Scenarios Report*, July 2023, pp. 26-27.

	Federal	ACT	NSW	QLD	SA	TAS	VIC
Emission reduction	43% below 2005 levels by 2030 and net zero by 2050 under the *Climate Change Act (2022)* (C'th)		Economy-wide emission reduction targets of 50% by 2030 and net zero by 2050		Emission reduction target of 60% by 2050		Emission reduction target of 28-33% by 2025, 50% by 2030, 75-80% by 2035 and net zero by 2050; Unlegislated but announced net zero emission target by 2045
Renewable energy targets	82% renewable energy target by 2030		Construct new renewable generation by end of 2029 that can produce the same electricity as 8 GW in New England REZ, 3 GW in Central-West Orana REZ, and 1 GW elsewhere (NSW EII Act)	Expansion of QRET to 50% by 2030, 70% by 2032, and 80% by 2035		150% TRET target by 2030 and 200% by 2040	VRET of 40% by 2025, 50% by 2030 and the intentions for further VRET of 65% by 2030 and 95% by 2035; Victorian Renewable Energy Target (VRET) auctions 1 and 2
Storage targets			Target of 2 GW of deep storage by 2030 under the NSW EII Act	Support to Borumba pumped hydro energy storage (PHES) (based on normal commitment criteria);		Battery of the Nation (as development candidate)	Intentions to legislate storage targets of 2.6 GW by 2030 and 6.3 GW by 2035
Offshore wind targets							Intentions to legislate offshore wind targets of 2 GW by 2032, 4

	Federal	ACT	NSW	QLD	SA	TAS	VIC
							GW by 2035, and 9 GW by 2040
Hydrogen policies			Renewable Fuels Scheme of the NSW Hydrogen Strategy	Support to Kogan Renewable Hydrogen Project[123]	Hydrogen Jobs Plan including 250 MW electrolyser project, 200 MW hydrogen turbine		
Transmission support policies			REZ network infrastructure projects and priority transmission infrastructure projects under the NSW EII Act, including Waratah Super Battery System Integrity Protection Scheme as Committed and CentralWest Orana Transmission Project as Anticipated.	SuperGrid Infrastructure Blueprint and Queensland Renewable Energy Zone (QREZ) infrastructure will be treated as options. CopperString 2032 development is considered to be Anticipated with the Townsville to Hughenden connection being modelled quantitively as a REZ network expansion.			NEVA-supported transmission projects and VicGrid planning of REZs, including some projects treated as development options and others as Anticipated projects (for example, Western Renewables Link and the Mortlake Turn-in as Anticipated).

[123] See https://www.treasury.qld.gov.au/programs-and-policies/queensland-renewable-energy-and-hydrogen-jobs-fund/.

	Federal	ACT	NSW	QLD	SA	TAS	VIC
Transmission land payment programs			Strategic Benefit Payments Scheme	SuperGrid Landholder Payment Framework			Landholder Payments For A Fairer Renewables Transition
CER-related policies	SRES	PV subsidies for pensioners/ veterans, and Sustainable Households Scheme (batteries and PV)	Energy efficiency and peak demand reduction target under the NSW Energy Security Safeguard, and the Renewable Fuels Scheme		Voluntary retailer contributions feed in tariff		Victorian solar panel rebate, solar battery rebate
Electric vehicles	EV fringe benefits tax (FBT) exemption, infrastructure funding and fleet purchases	ACT EV stamp duty, registration and financing savings			EV subsidy and free registration	Stamp duty waiver	Zero emissions vehicle subsidy
Energy efficiency	National Construction Code 2022; National Australian Built Environment Rating System; Greenhouse and Energy Minimum Standards; National Energy Performance Strategy;		New South Wales Energy Savings Scheme		South Australian Retailer Energy Efficiency Scheme		Victorian Energy Upgrades program

	Federal	ACT	NSW	QLD	SA	TAS	VIC
Other government policies	Safeguard Mechanism Capacity Investment Scheme	ACT's ban on new gas connections		Conversion of publicly owned coal-fired generation in Queensland into clean energy hubs.			Gas Substitution Roadmap

Table 5 2024 ISP scenario policy settings

6.4.3 Valuing reduction in greenhouse gas emissions

A new category of RIT-T market benefits is expected to be formally added to the NER in [February 2024], following the incorporation of the reduction in Australia's greenhouse gas emissions as part of the National Electricity Objective (NEO). This category is the change in Australia's greenhouse gas emissions.[124]

The AER is required to update its RIT-T guidelines to provide guidance on how to estimate this new benefit category before December 2024. The AER is expected to provide interim guidance ahead of this date.

Prior to this interim guidance being provided by the AER, this benefit category can be estimated, for each relevant category of greenhouse gas emissions, by:

- Estimating the change (in tonnes) in that category of emissions between the base case and the option case (identified from the wholesale market modelling undertaken for that RIT-T); and
- Applying a value ($/tonne) to that change in emissions, sourced from an external party (such as the value used by relevant jurisdictional government or (once available) the Value of Emissions Reduction published by the Federal Government.

Sensitivity analysis should also be considered based on alternative values for the relevant emissions.

6.5 Option value

'Option value' is essentially the difference in the net benefit of a fixed and a flexible investment strategy. It recognises the value of adapting an investment strategy over time, in response to learning about future uncertainties.

- In particular, it refers to the benefit that results from retaining investment flexibility in a context in which certain actions are irreversible (ie, 'sunk'), and new information may arise in the future as to the payoff from taking a certain action.

Option value can be estimated using 'real options analysis', which is a recognised modelling technique applied to a range of business investment decisions. However, it is a complex and resource-intensive exercise and therefore should only be pursued for options that exhibit certain pre-requisites and when the amount of any option value in question is expected to be material to identifying the preferred option.

The following four pre-requisites are required for a credible option to have option value:

1. there is significant uncertainty about future conditions (eg, demand, spot load etc);
2. there is expected to be 'learning' about that uncertainty in the future (eg, demand continues to increase, or decreases);
3. investment in the options needs to exhibit flexibility (in particular, there are different stages for the investment); and
4. there needs to be a possibility of regret (ie, there is no 'obvious' best alternative under all future outcomes).

The AER guidance notes that option value can be captured in the RIT-T analysis by adequately specifying options and scenarios.[125] In particular, the impact of uncertainty, and option value itself, can be accounted for in the RIT-T to some extent through scenario analysis. For example, if any options involve staging (or

[124] AEMC, *Harmonising the national energy rules with the updated national energy objectives (electricity)*, draft Rule, Clause 5.15A.2(b)(4)(vii).
[125] AER, Regulatory *Investment Test* for *Transmission Application Guidelines*, October 2023, section 3.9.3.

‘phasing’), then for these options in scenarios in which demand turns out to be low, the assumed timing of the second stage can be been deferred in the economic assessment. These options will therefore capture the ‘option value’ of being able to delay future elements of capex, if it turns out that future demand is lower than that currently expected in the most likely scenario.[126]

Conducting a real options analysis extends the range of scenarios that can be considered from 3 or 4 to, possibly, thousands and enables a more sophisticated treatment of uncertainty.

[126] This approach to capturing ‘option value’ is consistent with AER guidance. See: AER, Regulatory *Investment Test* for *Transmission Application Guidelines*, October 2023, sections 3.9.3 and A.9.

7 Scenario and sensitivity analysis

Key points[127]

- The 'preferred option' is the option identified as being the top ranked in terms of expected net market benefits across a range of reasonable scenarios.
- The number of reasonable scenarios will vary between RIT-Ts, and should be appropriate to the magnitude of the investment costs.
- Where relevant, the most recent IASR scenarios are required to be adopted.
  - **Assumptions must be drawn from AEMO's ISP and IASR, with any departures being necessary and well-justified.**
- Where AEMO IASR scenarios are not relevant, reasonable scenarios must be internally consistent.
- Two tranches of sensitivity tests should be undertaken:
  - one to derive the optimal timing of each option (ie, the 'trigger year'); and
  - once an optimal trigger year has been determined, testing the sensitivity of the total estimated net market benefits and identifying boundary values for different key underlying assumptions.
- Appendix B provides suggestions as to how the economic assessment results could be presented in the various RIT-T consultation documents.

7.1 The preferred credible option is determined by investigating a range of 'reasonable scenarios'

The RIT-T is focused on identifying the top ranked credible option in terms of expected net market benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future 'states of the world').

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net market benefit – it is this 'expected' net market benefit that is used to rank credible options and identify the preferred option.

Each 'reasonable scenario' reflects a different 'state of the world'.

[127] The AER's guidance regarding scenario and sensitivity analysis can be found in section 3.8 of the AER's RIT-T Application Guidelines.

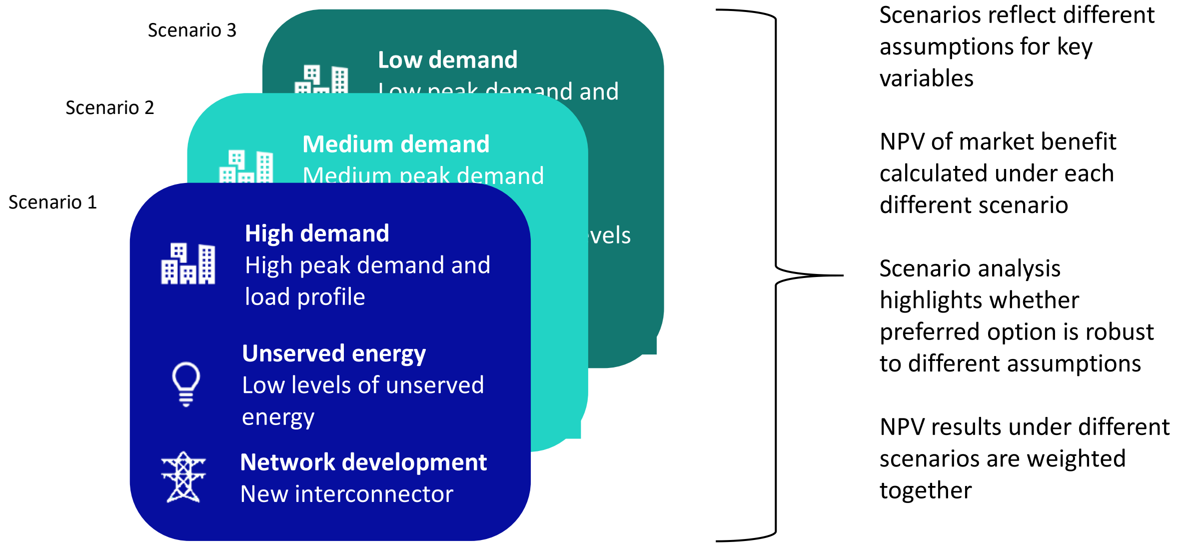

Figure 12: Uncertainty means there can be more than one future 'state of the world', as captured in a 'scenario'

7.2 Reasonable scenarios should reflect ISP scenarios where relevant

In general, TNSPs are required to include any ISP scenarios from the most recent IASR that is relevant to the specific RIT-T. This general requirement applies except where:[128]

- the RIT-T proponent demonstrates why it is necessary to vary, omit or add a reasonable scenario to what was in the most recent IASR; and
- the new or varied reasonable scenarios are consistent with the requirements for reasonable scenarios set out in the RIT-T instrument.

Where ISP scenarios are relevant, it is not necessarily the case that all ISP scenarios included in the IASR will be relevant, as different scenarios may explore assumptions and risks which are not relevant for the specific investments being considered under the RIT-T. In this case the TNSP is only required to adopt those ISP scenarios that are relevant.

Whether a scenario is relevant should be considered in light of whether any variables or parameters are likely to affect:[129]

- the ranking of credible options, where the identified need is for reliability corrective action, inertia network services or system strength services; and
- the ranking or sign of net economic benefits of any credible option for a market benefits RIT-T.

Where ISP scenarios are not considered relevant or where modification is made to the ISP scenario to make it relevant (such as a blending of different ISP scenario parameters), TNSPs should provide an explanation as to why they are omitted or modified in order to provide transparency in deciding what scenarios are adopted in a RIT-T.

In practical terms, it is expected that ISP scenarios will be the most relevant where wholesale market benefits are material to the RIT-T analysis. For other RIT-Ts, including the majority of repex RIT-Ts, the only relevant ISP scenario may be the one that has been identified by AEMO as the most likely (currently the 'step change' scenario in the 2023 IASR), and this scenario may only be relevant to the extent of the

[128] AER, *Regulatory investment test for transmission Application Guidelines*, October 2023, p. 43.
[129] AER, *Regulatory investment test for transmission Application guidelines*, October 2023, pp. 45-46.

discount rate and (potentially) the VCR value assumed in that scenario (see further discussion in section 7.2.1 below).

TNSPs should adopt relevant ISP scenarios fully or provide adequate explanations for deviating from these scenarios. For example, TNSPs should use VCR or discount rates that are consistent with those used in the relevant ISP scenarios, with variations in these parameters being considered as part of a sensitivity analysis.[130]

If TNSPs need to identify reasonable scenarios different to ISP scenarios, then there should be a focus on reasonable scenarios that reflect changes in key parameters. This means reasonable scenarios should reflect any variables or parameters that:

- are likely to affect *the ranking of the credible options*, where the identified need is for reliability corrective action, inertia network services or system strength services; and/or
- are likely to affect *the sign of the net market benefits* of any of the credible options, for market benefits RIT-Ts.

The development of reasonable scenarios and the selection of parameters and assumptions involves a degree of judgement and needs to be determined on a case-by-case basis.

In general, reasonable scenarios are identified by undertaking sensitivity testing of individual parameters (as outlined in section 0 below).[131] If varying the value of an individual parameter (eg load growth) leads to changes in the ranking of credible options, then that parameter should be included in constructing a reasonable scenario.

Once parameters that affect option rankings have been identified, scenarios can be determined based on those parameters.

It is important to apply the following recommendations from the AER in developing reasonable scenarios, namely:[132]

- use the information provided in the ISP in the first instance;
- use sensitivity analysis to assist in determining an appropriate set of reasonable scenarios;
- as a principle, be conscious of current NEM reforms and relevant policy developments, and consider whether they are relevant for the specific RIT-T; and
- construct scenarios that are genuinely reasonable, in that they comprise of internally consistent parameters so that they can define a reasonable range of plausible states of the world.

The following two subsections outline key considerations for reliability corrective action RIT-Ts (including repex RIT-Ts) and market benefit RIT-Ts, respectively.

7.2.1 Scenarios for reliability corrective action RIT-Ts (including many repex RIT-Ts)

For reliability corrective action RIT-Ts (including many repex RIT-Ts) ISP scenarios may have limited relevance, as these investments tend to (but not always) have a limited effect on the wholesale market.

In this case, the only relevant ISP scenario may be the one that has been identified by AEMO as the most likely (currently the 'step change' scenario in the 2023 IASR). Further, this scenario may be relevant only to the extent of the discount rate and (potentially) the VCR value assumed in that scenario.

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[130] See: AER, *Decision: North West Slopes and Bathurst, Orange and Parkes – determination on dispute – application of the regulatory investment test for transmission*, November 2022, pp. 18-19.
[131] The RIT-T contains a (non-exhaustive) list of parameters that may be varied in deriving scenarios.
[132] AER, *Application guidelines for the regulatory investment tests*, Final Decision, October 2023, p. 44.

Where ISP scenarios are of more limited relevance, a TNSP should provide an explanation as to why that is the case and expand on the parameters incorporated in the ISP scenario to develop its own reasonable scenarios,[133] by considering variables that are likely to be relevant, such as:

- differences in forecast electricity demand; and
- assumed failure rates.

In the first instance, the most recent IASR inputs and assumptions should be considered in forming a view of which variables are relevant. This includes assumed generation commitment assumptions which may also be relevant for some reliability corrective action RIT-Ts. For example, different assumed quantities, and/or types, of renewable generation locating in an area may impact the scope of the preferred option.

Overall, scenarios should be constructed using variables and assumptions that are expected to affect identification of the preferred option.

7.2.2 Market benefit RIT-Ts

For market benefit RIT-Ts, the investments are more likely to have an effect in the wholesale market, which makes AEMO's ISP scenarios more likely to be relevant. Where the most recent ISP scenarios are relevant then they must be adopted in the RIT-T.

In some cases refinements to these scenarios may be appropriate – for example:

- the identified need may reflect more specific load estimates than are provided for by AEMO (eg, Inner Melbourne), in which case the TNSP may use its own, or DNSP-sourced, load-specific forecasts; and
- the TNSP may have more detailed information relevant to the particular identified need being considered, or more information may have been provided in submissions (eg, in relation to non-network technology costs).

It is important that any departures from the most recent ISP scenarios are well-justified in the RIT-T documentation.

7.3 Scenario weights

Individual scenario NPV results are weighted to derive an overall weighted result that is used to identify the preferred option.

Scenario weightings should be based on the ISP weightings, where multiple ISP scenarios are used.

Where only one ISP scenario is used, scenario weights should be consistent with the basis for developing the additional parameter estimates. The weighting adopted will ideally be supported by evidence, but may require some subjective assessment by the TNSP in estimating how likely each individual scenario is to occur.

In the absence of evidence or basis for assigning a higher probability for one reasonable scenario over another, then each scenario should be weighted equally.[134]

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[133] The RIT-T instrument defines a reasonable scenario as 'a set of variables or parameters that are not expected to change across each of the credible options or the base case'. This includes variables or parameters appropriate to the credible option under consideration, such as the costs associated with actionable ISP projects, committed projects, anticipated projects and modelled projects (including demand-side and generation projects). Anticipated projects may be included or excluded based on their degree of likelihood of being commissioned within the modelling period. See: AER, *Regulatory investment test for transmission*, August 2020, clause 22.
[134] AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, p. 53.

If future variable or parameter values (eg, demand) were based on quartile values, then the probability assigned to each reasonable scenario should be the same for example, 25 per cent in the case of a quartile.

In contrast, if future variable or parameter values reflect a range of equally spaced values, then reasonable scenarios with more extreme values of future demand should receive a lower probability than those with demand values closer to the mean.

The box below provides a worked example of how to apply scenario weights to identify the preferred option.

Box 4 – Example of deriving weighted scenario NPV results

A repex RIT-T for a reliability corrective action has three scenarios, reflecting differences in future forecast load growth:

Variable	Scenario 1 (low demand estimate)	Scenario 2 (central demand estimate)	Scenario 3 (high demand estimate)
Load growth	Low load growth, eg, POE90	Central estimate for load growth	High load growth, eg, POE10
Weighting	0.25	0.5	0.25

In this example, weightings are 50 per cent for the central demand scenario and 25 per cent for the low and high demand scenarios. These weightings reflect the TNSP's evaluation that the central demand scenario is more likely than other scenarios, and is a reasonable starting point for the assessment. However, where the outcome of the RIT-T is found to be sensitive to the scenario weights assumed, the TNSP would need to refine the weightings further based on evidence such as the likelihood of each scenario eventuating.

The example adopts scenarios that varies by probability of exceedance to reflect different demand expectations. Alternative approaches that vary demand forecasts or demand growth directly across scenarios could also be used.

In identifying the preferred option, it is also important to take into account the magnitude of the difference in weighted net benefits between options, in light of the degree of uncertainty of the key cost and benefit categories in the analysis. .Where the weighted NPVs of credible options are not materially different and other factors (eg, technical, WHS, delivery) have significant influence on the selection of the preferred option, it may be reasonable to conclude that the NPVs are effectively evenly ranked in identifying the preferred option.

7.4 Sensitivity testing

Sensitivity analysis across all credible options is to be conducted where the capital cost of the preferred option in a RIT is above $100 million. However, the AER also encourages all RIT-T proponents to consider undertaking sensitivity analysis where the estimated capital cost of the preferred option is less than $100 million.[135]

Any spot loads that are key drivers of the RIT-T outcome should be subject to specific sensitivity analysis.

Two tranches of sensitivity tests should be undertaken as part of a RIT-T – namely:

135 AER, *Regulatory Investment Test for Transmission Application Guidelines*, October 2023, p. 44.

1. testing the sensitivity of the optimal timing of each option (ie, the 'trigger year') to different assumptions in relation to key variables; and
2. once an optimal trigger year has been determined, testing the sensitivity of the total estimated net market benefits associated with the investment proceeding in that year, in the event that actual circumstances turn out to be different.

That is, sensitivity analysis should first be undertaken to determine the optimal timing of the project, to conclude that a particular year represents the 'most likely' date at which each option will be needed.

For example, if demand turns out to be lower than expected, what would be the impact on the net market benefit associated with the option continuing to go ahead in the identified trigger year. For options, which have two stages, this sensitivity test would include a deferral of the second stage of the project, if relevant.

Having assumed to have committed to the option by the identified trigger year, the second set of testing looks at the consequences of 'getting it wrong'. This requires:

» varying inputs and assumptions (eg discount rates, capital costs, VCR) to test the sensitivity of RIT-T results; and
» identifying boundary values for inputs and assumptions that changes the preferred option.

An expected sensitivity test is to identify boundary values for key parameters (typically including capital costs, the discount rate and VCR values). Sometimes known 'tipping points' or 'thresholds', identifying boundary values involves finding parameter values where the preferred option changes, in order to inform how sensitive RIT-T outcomes are to key parameters.

» Where the capital costs of the preferred option in the RIT-T is above $100m, this in turn could inform the identification of appropriate re-opening triggers for that RIT-T.

Appendix B provides examples on how these two stages of sensitivity testing should be undertaken, as well as suggestions for how these tests could be communicated as part of the RIT-T consultation documents.

Appendix A – Additional guidance on simplified market modelling approaches

TNSPs will need to undertake some degree of market modelling where market benefits are expected to be derived from changes in the wholesale market. As noted in the body of this Handbook, in general, in order to calculate market benefits a market dispatch model may need to be used.

However, simplified modelling approaches are outlined below that may be appropriate to adopt in some circumstances for non-ISP RIT-Ts, depending on the extent and nature of expected market benefits from the wholesale market changes.

This appendix provides a description of a simplified market modelling approach that is suitable under circumstances where extent and nature of expected market benefits from the wholesale market changes are not expected to be central to a credible options being assessed and/or the level of analysis associated with full market dispatch modelling may be disproportionate to the cost of the investment.

Changes in fuel consumption arising through different patterns of generation dispatch

Whether or not market benefits from changes in fuel consumption are relevant for non-network options will depend on the form of the non-network option. If demand management/embedded generation operates only at times of peak demand, then there is unlikely to be any material market benefit from changes in fuel consumption. However energy efficiency measures or an embedded generator operating as base load may result in an associated benefit in terms of reduction in fuel consumption across the NEM.

Under a simplified approach, the market benefits arising from the changes in fuel consumption should be calculated for each *state of the world* as:

- the amount of output expected from the non-network option (MWh); multiplied by
- an estimate of the fuel cost for the marginal generators in the relevant NEM jurisdiction in question ($/MWh).

An estimate of the fuel cost for the marginal generators in the relevant NEM jurisdiction in question should be sourced from the ISP assumptions. In particular, a TNSP should make an assumption about the marginal generator (which will typically be a gas plant) and derive the $/MWh fuel cost using the heat rate and fuel cost assumptions in the ISP.

Variants on this approach can be adopted where the non-network option does not operate for the whole year.

Changes in voluntary load curtailment

Where the credible option does not have an impact on the wholesale market and therefore will not change NEM price outcomes, then benefits associated with changes in voluntary load curtailment will not be material.

- It is unlikely that there will be changes in voluntary load curtailment unless an interconnector is constructed that changes the flows of energy between jurisdictions (as market prices are determined at the Regional Reference Node).

Changes in costs for parties, other than the TNSP

Changes in costs for parties other than the TNSP come predominantly from changes in the pattern of generation investment; i.e.

- Differences in the timing of investment in new generation plants leading to:
  - differences in capital costs;
  - differences in operating and maintenance costs; and
  - differences in carbon emission costs (for calculating these costs refer to section 6.4.3).
- Any costs associated with DNSP investment are likely to form part of the credible option. For instance, any DNSP costs that are part of meeting the identified need, such as new switching bays for additional transformer capacity, are part of the costs of the credible option.
- Generation costs should be sourced from AEMO's latest IASR.[136]

A simplified approach could be adopted as follows:

- Identify what generation investments in the base case state of the world may be impacted by the non-network option
  - For example, a non-network option involving an 80MW OCGT may impact the timing of investment for a separate OCGT plant in the base case
- Identify the likely deferral of generation investment, based on the assumed operating profile for the non-network option
  - The extent of deferral is likely to be greater where the non-network option is assumed to also operate outside of times of peak demand
- Estimate the cost of the deferral of generation investment on the basis of generic capital, operating and fuel cost information from AEMO's IASR.

Changes in network losses

The simplified approach involves calculating the differences in losses of the different options (including any non-network options) through load flow analysis, and then applying a load factor to these loss differences and an assumed cost of losses to calculate the overall market benefit from changes in losses.

Specifically, the simplified approach is:

- Load flow studies are used to calculate changes in network losses at peak load (expressed in MW);
- A loss load factor (load-squared factor) is then applied to these loss differences:
  - This depends on the ratio of peak losses to average losses, but standardised values could be used (for example, 0.450 is the load squared factor for NSW).
  - The loss load factor approximates the load factor squared for transmission; however, the loss load factor does not approximate the load factor squared for distribution.
- This amount should then be multiplied by 8,760 (i.e. the number of hours in the year) to obtain a MWh figure for the year.

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[136] At the time of updating this Handbook, the latest generation cost assumptions were published in July 2023, which can be found, and downloaded, at: https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf?la=en

- Multiplying by the number of hours in the year is appropriate where the credible option is a network option, and for some non-network options (for example, base load generation and energy efficiency demand management in office buildings).
- However, for other non-network options it may be more appropriate to multiply by a proportion of hours in the year (for example, the amount of hours that the non-network option will be operating if it is a peak generator).

» An assumed cost of losses can be used to calculate the overall market benefit from changes in losses.
  - The cost of losses should be based on an estimate of the fuel cost for the marginal generators in the relevant NEM jurisdiction in question ($/MWh).

Changes in ancillary services costs

If any of the credible options would lead to an increase in the dispatch of intermittent generation, then it is likely that there will be changes in ancillary service costs as there will need to be more ancillary services to manage the increased uncertainty.

Changes in the costs of Frequency Control Ancillary Services (FCAS) are likely to be rare, as it is only when an option materially changes the quantity of FCAS procured by AEMO that there will be material market benefits.

» Importantly, the cost of FCAS provision is inherently quite small, measured in cents/MW/Trading Interval. As with energy prices, prices in excess of the cost of provision represent a wealth transfer and so a reduction in these prices is not necessarily a market benefit.

» There may be FCAS savings if there is construction of a third interconnection circuit in addition to an existing double circuit line, so that additional FCAS requirements during single circuit outages or reclassifications can be avoided.

In some circumstances, it is appropriate to use simplified approaches to estimate the value of ancillary services costs.

For example, one method as set out in the AER RIT-T Application Guidelines, to calculate reactive power ancillary services, savings (i.e. the reduction in reactive power ancillary service requirements following the implementation of the credible option) may be represented by the annual cost of a capacitor bank.

» For example, if a 50 MVAr 132kV capacitor bank costs $1.5 million, then the equivalent annual cost is approximately $150,000/annum.

» The potential market benefit from changes in reactive power ancillary services requirements is then: 150,000($) / 50(MVAr) / 8760 (hours pa) / 2 (intervals per hour) = $0.17/MVAr/TI

» If the reactive power ancillary services requirement is reduced by 100 MVAr for the top 100 hours of demand each year then the market benefit is: 100 MVAr x 100 Hrs x 2 TI's/hr x $0.17/MVAr/TI = $3,400/annum.

Appendix B – Examples of how the economic assessment results can be presented

While each RIT-T will differ in terms of what is relevant to communicate in the various consultation documents, this appendix provides some illustrative examples of how costs, benefits and sensitivities could be presented. The examples below are to be treated as examples only and each RIT-T should be assessed on a case-by-case basis.

This appendix also considers the AER's discretionary guidance on:

- presenting data in a way that reflects stakeholder preferences; and
- presenting distributional effects.

Overall, the guiding principle should be that the RIT-T consultation documents need to highlight RIT-T outcomes and the robustness of those outcome in an accessible fashion for stakeholders.

Example of how gross market benefits for each option could be presented

The estimated gross market benefits should be presented in present value terms (and relative to the base case) for each option, separately for each reasonable scenario investigated.

This could be done in both:

- a table – setting out the actual estimate of gross market benefits; and
- figures – to clearly illustrate the relativities between the options.

An illustrative example of the structure and presentation of such tables and figures is provided below.

Option	Description	Scenario 1	Scenario 2	Scenario 3
1	'Like-for-like' replacement	$29	$79	$115
2	A phased option	$32	$58	$103
3	A smaller capacity option with demand management	$33	$63	$82
4	A larger capacity option	$25	$56	$79

Table 6: ***Illustrative example of how the gross market*** benefit of each option under each scenario could be presented, (NPV $m, $2017/18)

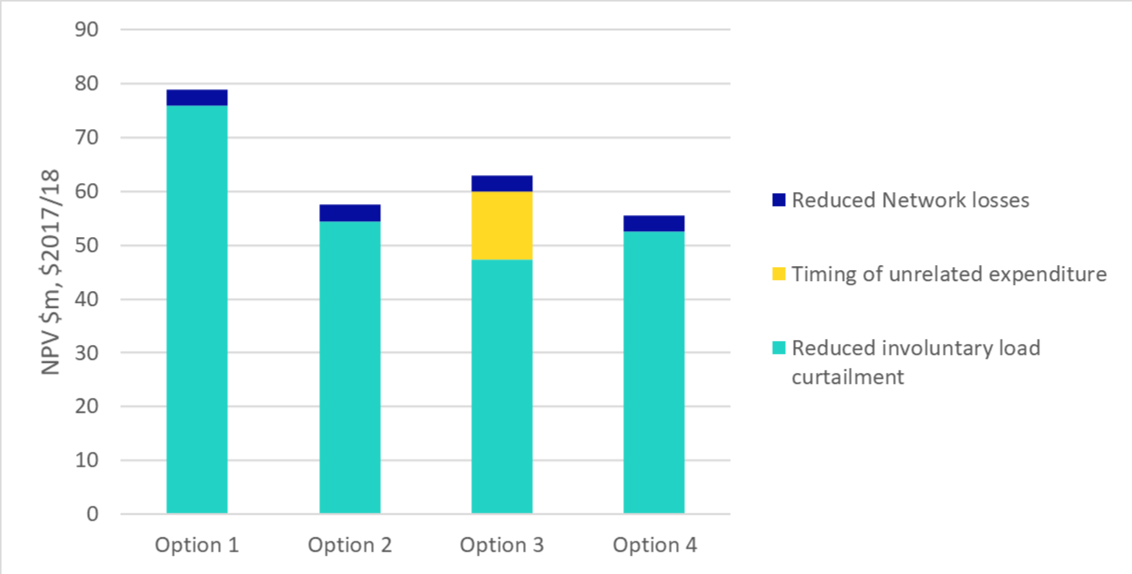

Figure 13: Illustrative example of how to present the gross market benefit of each option under Scenario 2, (NPV $m, $2017/18)

The figures summarising the break-down of estimated market benefits for each scenario should include accompanying statements explaining the key drivers of overall estimated benefits.

For example, in the figure above, such a statement might include something like:

> *"…the major contribution to the gross benefit across all options is the benefit of reduced expected unserved energy following a network development. Outside of avoided unserved energy, all categories of market benefit estimated are similar across the options, except for 'differences in unrelated expenditure' under Option 3 since the demand management defers the need for wider voltage support investment otherwise required'.*

Example of how the costs for each option could be presented

As with market benefits, the estimated costs should be presented in present value terms (and relative to the base case) for each option, separately for each reasonable scenario investigated.

This could be done using both:

- a table – setting out the actual estimate of costs; and
- figures – to illustrate the relativities between the options.

An illustrative example of the structure and presentation of such tables and figures is provided below. Please note that the table and figure below communicating the results of the present value calculations and not the breakdown of costs for each option – these will instead be presented in a standalone section in the consultation documents on the credible options.

Option	Description	Scenario 1	Scenario 2	Scenario 3
1	'Like-for-like' replacement	8	9	9.5
2	A phased option	7	7.5	8
3	A smaller capacity option with demand management	7.5	8	8.5
4	A larger capacity option	10	10.5	11

Table 7: Illustrative example of how the estimated cost of each option under each scenario could be presented, (NPV $m, $2017/18)

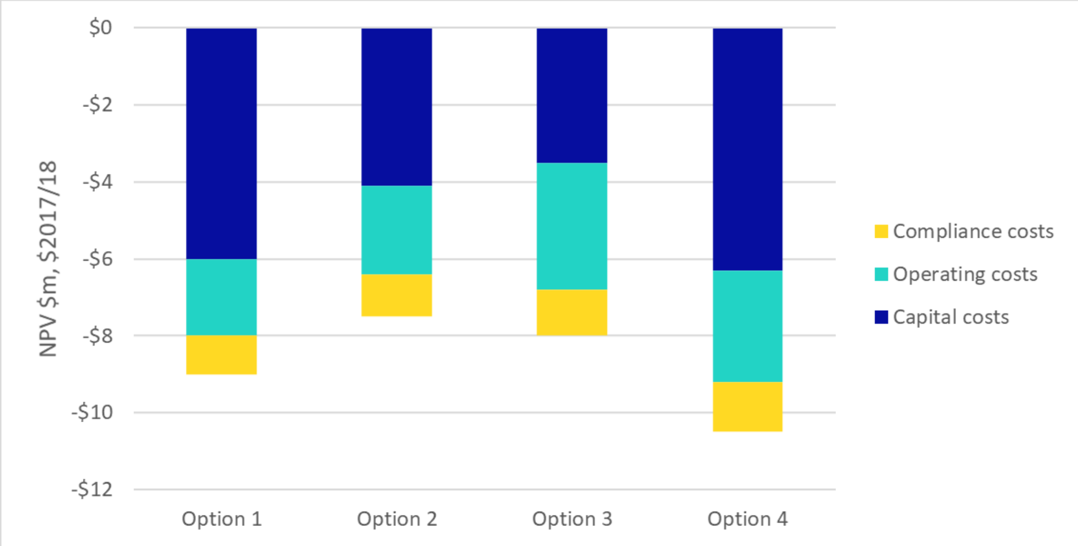

Figure 14: ***Illustrative example of how the costs of each option under one scenario could be presented, (NPV $m, $2017/18)***

As with presenting gross market benefits, the table and figures summarising the break-down of estimated costs for each scenario should include accompanying statements explaining the key drivers of overall estimated benefits.

For the illustrative example above, this might include statements like:

- *'Option 4 has the highest estimated cost of all options due to it building additional capacity';*
- *'While the capital costs of Option 3 are lower than the other options, on account of it building to a lower capacity, it has higher assumed operating costs, associated with procuring the requisite demand management services.'*
- *'Option 2 has the ability to phase stages in light of observed demand and so has lower costs, in present value terms, under the 'low scenario' on account of being able to defer the timing of later stages of the investment, and the consequently higher terminal value.'*

Example of how the net market benefits for each option could be presented

The net market benefit is the gross market benefit minus the costs of each option, all in present value terms.

The net market benefits could be summarised in a table for each option, under each scenario as well as on a weighted-basis.

The table could also show the corresponding ranking of each option, for each scenario, with the options ranked in order of descending net market benefit. Options that are effectively ranked equally (eg, within 10-15 per cent of each other, due to the estimation uncertainties) can be labelled as such.

The table below provides an example of how the net market benefits could be presented, drawing on the illustrative examples presented in the sections above.

Option	Description	Scenario 1		Scenario 2		Scenario 3		Weighted Average	
		Net benefit	Rank	Net benefit	Rank	Net benefit	Rank	Net benefit	Rank
1	'Like-for-like' replacement	$21	2	$70	1	$105	1	$65	1
2	A phased option	$25	=1	$50	3	$95	2	$57	2
3	A smaller capacity option with demand management	$25	=1	$55	2	$73	3	$51	3
4	A larger capacity option	$15	4	$45	4	$68	4	$43	4

Table 8: ***Illustrative example of how the net market benefit of each option could be presented, (NPV $m, $2017/18)***

As with presenting gross market benefits and estimated costs, this table summarising the break-down of estimated costs for each scenario should include accompanying statements explaining the key drivers of overall estimated net market benefits.

Example of how the results of the sensitivity analysis could be presented

As outlined in section 7 above, two tranches of the sensitivity testing should be undertaken and communicated as part of the RIT-T consultation documents. The recommended approach to presenting the results of each of these sensitivities is provided in the following two sections.

Presenting the sensitivity of the assumed optimal timing

The following figure illustrates how the effect of different assumptions on the optimal trigger year for a particular option can be clearly communicated in the RIT-T consultation documentation.

In particular, it shows the distribution of optimal commissioning years to a range of underlying assumptions and, in this illustrative example, can be used to justify an assumed commissioning of Option 1 in 2022/23. Sensitivities yielding the same optimal commissioning year are shown in the same colour to help with interpreting the figure.

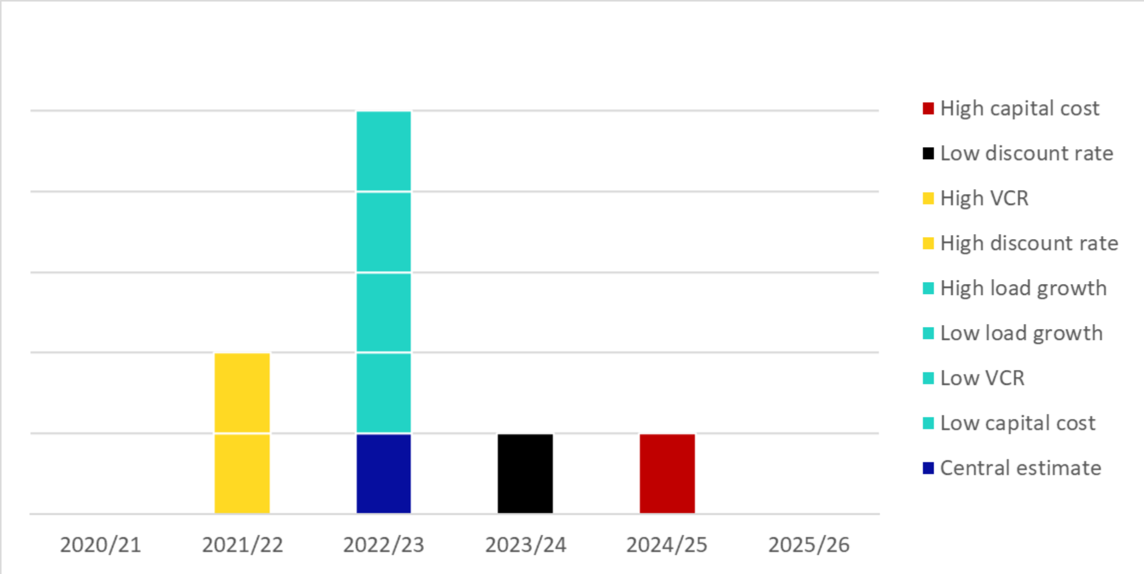

Figure 15: ***Illustrative example of how the sensitivity of the optimal commissioning year to underlying assumptions could be presented***

Presenting the sensitivity of the overall net market benefit

An important set of information to communicate as part of the RIT-T is the sensitivity of the results (and, in particular, identification of the preferred option) to the underlying assumptions.

This is done by assuming that the optimal commissioning year is committed for each option, and investigating the consequences of 'getting it wrong' through sensitivity testing.

While the results of such sensitivity tests should be presented in tables, it is also recommended that they are also presented graphically as it helps convey the robustness of the findings. The two figures below present illustrative examples of how to present the results of such sensitivity tests – specifically:

» the first figure illustrates the results of assuming a range of underlying VCR values – in particular, it shows that the finding that Option 1 is the preferred option is insensitive to VCR values above $32/kWh;
» while the second figure illustrates the results of assuming a range of underlying discount rates – this figure shows that Option 1 is preferred for all assumed discount rates below 7.7 per cent.

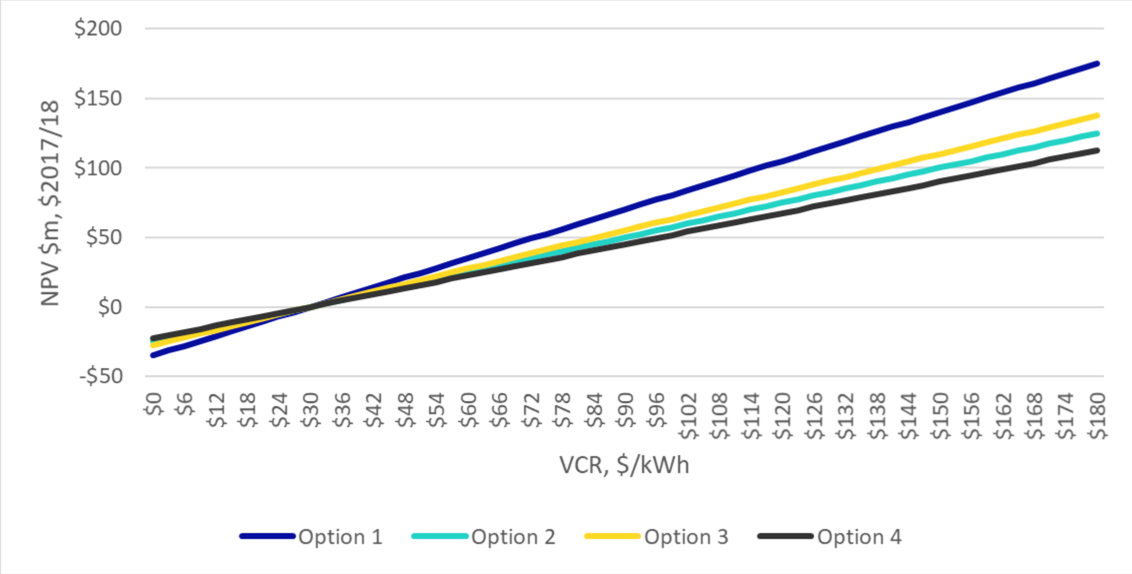

Figure 16: Illustrative example #1 of how sensitivity testing could be presented

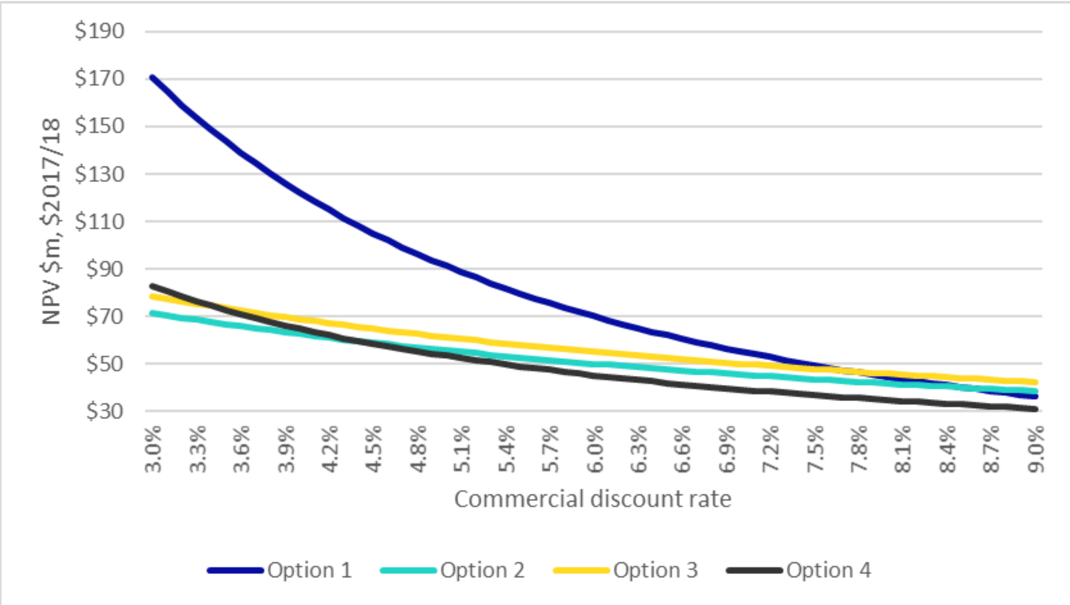

Figure 17: Illustrative example #2 of how sensitivity testing could be presented

In addition, it is often useful to generate 'thresholds' or 'tipping points' to assist in communicating the robustness of the results. These can include:

- the value that a certain parameter (or set of assumptions) needs to vary by to result in an option having a zero net market benefit – for example, and following on from the first figure above, it is found that there is in fact no assumed positive VCR that would result in Option 1 not having a positive expected net market benefit; and
- the value that a certain parameter (or set of assumptions) needs to vary by to result in one option being preferred over another – for example, and following on from the second figure above, it is found that the discount rate would need to be at least 7.77 per cent for Option 3 to be preferred to Option 1.

Such thresholds should be discussed in the RIT-T consultation documentation along with the results of the sensitivity testing and to inform the reopening triggers included in the PADR/PACR (for RIT-Ts where the capital cost of the preferred option is more than $100 million).

Consideration of AER guidance on presenting information and distributional effects

RIT-T proponents should consider stakeholder preferences in the way information is presented when providing data. This reflects that there may be circumstances where stakeholders value receiving information in particular ways.[137] This potentially includes information on the bill impact associated with the RIT-T investments.

However, the AER recognises that there may be valid reasons why it may not be possible to present information in a way that is consistent with stakeholder preferences or provide key distributional effects. This includes where the cost of doing do would be disproportionate.

[137] AER, *Guidelines to make the Integrated System Plan actionable Final decision*, August 2020, p. 29.

Appendix C – Key references for assumptions underpinning a RIT-T assessment

This appendix provides a range of key assumptions and documents from which assumptions can be sourced for undertaking the RIT-T economic evaluation. Please note that those presented below are relevant as at the date of this Handbook but may be updated from time-to-time. It is therefore important that the most recent version of each source document is relied on at the time of conducting any RIT-T assessment.

Key document	Purpose	URL/source
AEMO Integrated System Plan	Outlines key transmission investment recommendations, scenarios, descriptions of key assumptions etc.	https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp
AEMO Inputs, Assumptions and Scenarios Report	Contains descriptions of scenarios, inputs and assumptions used in the Integrated System Plan and Electricity Statement of Opportunities for the NEM. The 2023 AEMO Inputs, Assumptions and Scenarios Report includes the following values for pre-tax real discount rates:[138] • Central discount rate: 7.0% • Lower bound discount rate: 3.0% • Upper bound discount rate: 10.5%	https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios
Latest AER Final Decision for a TNSP	Provides the lower bound discount rate (when not specified by AEMO in its Inputs, Assumptions and Scenarios Report) At the time of preparing this handbook, the lower bound discount rate is 3.15%.[139]	https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements?f%5B0%5D=field_accc_aer_sector%3A4&f%5B1%5D=field_accc_aer_segment%3A9
AER Values of Customer Reliability Final Report on VCR values	For sourcing a central estimate of the VCR, as part of valuing any reductions in USE estimated.	https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/update-0

Table 9: Key references for assumptions underpinning a RIT-T assessment

[138] AEMO, *2023 Inputs, Assumptions and Scenarios Report*, July 2023, p. 123.
[139] The AER published final decisions for ElectraNet and Murraylink on 28 April 2023. The pre-tax real discount rate for ElectraNet is 3.15%, while the pre-tax real discount rate for Murraylink is 3.31%. The table above states the lower rate from the two decisions. See: AER, *ElectraNet 2023-28 – Final Decision – Post-tax revenue model*, April 2023, sheet 'WACC' cell R23. AER, *Murraylink 2023-28 – Final Decision – Post-tax revenue model*, April 2023, sheet 'WACC' cell R23.

Appendix D – Elements of the AER RIT-T Guidelines that are binding

This appendix identifies the elements of the AER RIT-T Guidelines that are binding.

RIT-T Application Guideline section	Description
Section 3.5A.2	For all projects (no materiality threshold) TNSPs must specify, to the extent practicable and in a manner which is fit for purpose for that stage of the RIT-T): all key inputs, assumptions and reasoning relating to the basis for option cost estimates in their RITs, including the level and basis for any contingency allowances.
Section 3.5A.1	Where the capital cost of the preferred option in a RIT-T is above $100m (as varied in accordance with the process for updating the re-opening trigger threshold), a TNSP ***must*** adopt the AACE cost classification system or, if it decides not to, to provide the reasons why not
Section 3.8.1	Where the capital cost of the preferred option in a RIT is above $100m, the RIT-T proponent ***must*** undertake sensitivity analysis on all credible options, by varying one or more inputs and/or assumptions.

Table 10: Binding elements of AER RIT-T Application Guidelines

Energy
Networks
Australia