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Dear Chris,

Submission on the Regulatory Investment Test for Distribution issues paper

EnerNOC appreciates the opportunity to comment on the RIT-D.

EnerNOC is an independent aggregator of demand response (DR), currently managing 8,500 MW of dispatchable demand response sourced from over 13,500 commercial and industrial sites across markets in North America, the UK, Australia, and New Zealand.

Our comments relate particularly to the processes for consulting on and assessing DR options.

To date, none of the applications of the RIT-T have produced a preferred option based on DR. It has also been extremely rare for DR options to be favoured under the current regulatory investment test arrangements for distribution networks.

Since DR can be dramatically less costly than conventional network augmentations, and is much more flexible, providing considerable option value, this suggests that some aspect of the consultation and assessment process is not working.

We recommend below some improvements over existing regulatory test designs, including the RIT-T, that may lead to more efficient DR options being correctly chosen.

1 The limits of prescription

The design of regulatory investment tests tends to be quite prescriptive. The intention seems to be to ensure that the party administering the test is unable to bias the outcomes to favour their commercial interests.

It is neither possible nor desirable to make the RIT-D completely prescriptive, such that the RIT-D proponent has no way to influence the outcome. Fortunately, it should not be necessary.

It is not possible because there are too many elements which require technical or commercial judgement, such as the selection of credible options and realistic scenarios.

It is not desirable because any attempt along these lines would necessarily lead to a design which was overly simplistic, not reflecting real-world complexity and uncertainty. It would hence give the wrong answers, leading to inefficient spending.

It should not be necessary to be so prescriptive, so long as the distribution network service provider (DNSP) has an incentive to pursue the most efficient outcomes.

To date, for the many reasons discussed during the AEMC's Power of Choice review,[1] there has been often been tension between the economically optimal choices that regulatory tests are meant to favour, and the profit incentives faced by DNSPs. This appears to have led to DNSPs using whatever leeway they have to favour more profitable options, even when they are not the most efficient. This may have taken the form of an "avoidance culture", in which the consultation process and assessment process is viewed as a compliance issue – carried out as prescribed, but without enthusiasm or creativity – rather than as an integral part of the planning process.

This tension can be resolved through reforms to the regulatory framework and the application of explicit incentive schemes, so that it will be clearly in DNSPs' own best interests to pursue the most efficient options.

We note that the AER intends to consult on such reforms and schemes as part of its Better Regulation programme. They may therefore be considered out-of-scope for this consultation. **It is important to understand, however, that, since the RIT-D cannot possibly be completely objective, unless those reforms are correctly implemented, the RIT-D will inevitably fail to produce efficient outcomes.**

2 Collaborative approach

The application of the RIT-D should not be an adversarial process. Rather, the Network Service Provider (NSP) should work closely with proponents of both network and non-network solutions in an effort to discover the option that produces the greatest net benefit.

[1] See, for example, AEMC, Power of Choice Review Supplementary Paper, *Demand Side Participation and Profit Incentives for Distribution Network Businesses*, 23 March 2012, available from http://www.aemc.gov.au/Media/docs/EPR-0022-Power-of-choice-review-directions-paper---Supplementary-on-network-incentives-FINAL-for-publication-pdf-fc525c51-840b-470e-873b-f6422d2dce3b-1.PDF

All options require a number of design decisions to be made before their costs and benefits can be assessed. For example, in developing a network option, the key parameters may be:

1. The capacities of the major plant items
2. The commissioning dates of the major plant items

Similarly, for a generation option, the parameters may be:

1. Unit size
2. Number of units
3. Commissioning and decommissioning dates

Demand response options tend to have many more parameters, including:

1. Programme commencement date and duration
2. Initial capacity
3. Capacity to be added in each subsequent year (which may vary)
4. Geographical area from which resources can be recruited
5. Response time
6. Available hours
7. Expected and maximum dispatch hours
8. Reliability requirements

This additional flexibility is a good thing, as a DR programme can be tailored to suit actual needs, achieving a better fit, and hence a more efficient outcome, than is possible with a network or generation option.

However, getting these parameters right is difficult – the ideal settings for a specific project are unlikely to be found on the first attempt.

Crucially, the cost of a DR programme depends on all of these parameter values, and can be quite sensitive to them. This means that over-specifying a programme, which is easily done, can lead to it being much more expensive than necessary. This can cause a DR option to appear to be uneconomic, whereas if it were correctly specified it would cost less and/or provide greater benefits.

The current RIT-T approach of developing a short list of credible options, typically only one of which will include DR,[2] is unlikely to hit upon the optimal design of DR

[2] For example, the RIT-T for the *South Australia – Victoria (Heywood) Interconnector Upgrade* considered only single DR option of a fixed quantity of 200 MW for 5 years, combined with the implementation of a particular network option, deferred by 2 years.

programme that maximises the expected net economic benefit for that particular situation.

There are two ways around this problem:

1. A much longer list of credible options could be included, covering all reasonable parts of the parameter space for the DR options.
2. A more iterative, collaborative approach could be taken, in which the cost benefit analysis is applied repeatedly in an attempt to find optimal programme designs.

The first approach would be extremely cumbersome, and put a considerable burden on DR proponents to estimate costs for a very large number of potential programme designs.

The second approach seems more sensible: **proponents of all credible options should have the opportunity to explore the cost benefit model and tweak the parameters of their options.**

3 Option value

When estimating the expected benefits of the various options, the RIT-D proponent has to rely on forecasts. Forecasts are often wrong; the further ahead into the future they look, the less accurate they tend to be.

This can lead to regrettable investment decisions being made, even though they appeared to be the right decisions at the time they were made.

To take a simple example, in year N, forecasts may indicate that peak demand on part of a network is likely to exceed the network's secure capacity by year N+3. On this basis, the DNSP could decide to carry out augmentation works to increase the network's secure capacity, and that it is necessary to start these works in year N+1 for them to be commissioned in time for the peak season in year N+3.

It may be that demand does not grow as forecast: year N+3 arrives, and revised forecasts now show that secure capacity is unlikely be exceeded until year N+5. The DNSPs decision to start building in year N+1 is irreversible: the money was spent before this better information was available.

If instead the DNSP had chosen in year N to defer the network augmentation using a DR programme, they would have benefited from option value: as revised forecasts became available, they could have changed the commissioning date of the augmentation to maximise the net benefits.

A DR programme itself can adapt over time to suit changing circumstances. For example, while it may be thought in year N that a DR programme will need to grow year-on-year at a particular rate, this need not be an irrevocable commitment: it could be revised up or down as needed.

It is not only the required commissioning date for an eventual network augmentation that might change in the light of newer forecasts. It may be that a different network augmentation option becomes optimal, or, *in extremis*, that no augmentation is required at all. This is not far-fetched: in recent years, system-level demand forecasts have been revised sharply downwards, to levels that would not have been considered credible just a few years earlier.

Deferring the making of irrevocable investment decisions increases the likelihood that the optimal decision will be made. This can have significant value, which should be quantified, and counted as a benefit.

The current RIT-T application guidelines contain a reasonable discussion of the problems of making irreversible decisions on the basis of uncertain information,[3] but then states:

> *"The AER believes that appropriate identification of credible options and reasonable scenarios captures any option value"*[4]

We believe that this guidance is wrong: to model option value correctly using this approach, dozens of scenarios and sub-options would be needed, e.g.:

1. Build Option A.
2. Build Option B.
3. Start a DR programme, then either:
    a) Demand forecasts do not change significantly, so build Option A deferred by 1 year.
    b) Demand forecasts change, so build Option A deferred by 2 years.
    c) Demand forecasts change further, so build Option A deferred by 3 years.
    d) Demand patterns change such that Option B is now preferable, so build that instead, deferred by 2 years.
    e) Demand forecasts change such that no augmentation works are actually needed, as the constraint can be alleviated indefinitely by a modified DR programme.
    f) etc…

[3] AER, *Regulatory investment test or transmission application guidelines*, June 2010, pp.36-37.

[4] *Ibid.*, p.39.

This is a cumbersome approach, which has not been used in RIT-Ts to date. Instead, RIT-T proponents have simply quoted the AER's statement, but then not considered option values at all.

Option value is likely to be more significant in the more localised projects that will be considered under the RIT-D than under the RIT-T: local forecasts are even less accurate than wider area ones.

It is therefore important that option value is properly estimated, using a robust methodology, and counted as a benefit.

4 Other sources of uncertainty

The RIT-T application guidelines discuss a number of sources of uncertainty in evaluating costs and benefits.[5] However, they overlook a potentially significant one: the commissioning date of network augmentations.

It is not uncommon for construction projects to run behind schedule. This can cause a planned network augmentation to miss the peak demand season in which it was first expected to be needed. This can lead to the network operating beyond its secure capacity, putting customer load at risk.

Where the network augmentation is following on from (possibly having been deferred by) a DR programme, it is quite straightforward to stretch the DR programme out for a further year, avoiding putting load at risk. In contrast, if no DR programme is in place, the NSP is unlikely to be able to organise one unless they realise a long way ahead of time that their construction project is going to be late.

In this way, **options which include DR programmes provide further option value: insurance against construction delays. This should also be counted as a benefit.**

5 Partial solutions

The issues paper mentions the AEMC's *Review of distribution reliability outcomes and standards*, indicating that the national workstream is likely to recommend a framework based on "outputs based", probabilistic measures.

This would be unequivocally a good thing. However, it is not yet certain to be implemented, so it is worthwhile considering a particular issue that arises for DNSPs that are required to meet deterministic reliability requirements.

If unforeseen load growth occurs, a DNSP can find itself unable to construct an appropriate reliability-driven network augmentation soon enough to meet the

[5] *Ibid.*, pp.32-35.

standards. It may also be unable to implement a DR programme sufficiently large to meet the standards.

In this case, a smaller DR programme can provide a “partial solution”, reducing the customer load at risk while the network augmentation is being built.

This need was identified by Energy Australia, who proposed a methodology for evaluating the benefit of such schemes by reference to the cost of the augmentation that they are obliged, but unable, to build. This methodology was evaluated and endorsed by IPART,[6] and then by the AER.[7]

To the extent that DNSPs continue to be subject to deterministic reliability standards, **the design of the RIT-D should allow the benefits of such “partial solutions” to reliability-driven needs to be evaluated in a similar manner.**

6 Treatment of demand response payments

We note that AER is contemplating including a broader class of market benefit to capture the savings from improved demand management, and encourage them to do so.

The Rules requirement for the RIT-D is “to identify the credible option that maximises the present value of the net economic value to all those who produce, consume and transport electricity” in the NEM.[8]

To comply with this requirement, when considering the net benefits of DR options, if the availability and dispatch payments made by the DNSP are to be counted as an economic cost, then **the availability and dispatch payments received by participating customers should be counted as an economic benefit.**

I would be very happy to provide further information or clarification, should you require it.

Yours sincerely,

Paul Tr

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[6] The proposal and IPART’s evaluation are reproduced as Appendix F of AER, *Guideline – Replacement DMIA for ACT-NSW,* 28 November 2008.

[7] AER, *Final Decision – ACT and NSW demand management incentive scheme,* 29 February 2008, pp.28-29.

[8] National Electricity Rules clause 5.17.1(a).