5 June 2009

The Australian Energy Market Commission
AEMC Submissions
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SUBMISSION BY ENERGY RESPONSE PTY LTD

STAGE 2: REVIEW OF DEMAND SIDE PARTICPATION

DRAFT REPORT – REFERENCE EPR0002

Thank you for the opportunity to make this submission. Energy Response has and will continue to contribute to this Review both through the Reference Group and via submissions like this.

However, we are disappointed that some of the information provided to the Review by us and others through these processes has not been understood or fully reflected in the draft Report. We therefore have some significant concerns that, near the end of Stage 2 of this Review, the findings in several areas in this Report are not supported by real commercial evidence about what will make DSP work in the NEM.

We have attempted to explain our concerns below within the limit of the resources that a small company can apply. We have focussed our comments on the key opportunities where, based on real commercial experience in a range of electricity markets, electricity consumers of all sizes should be able to participate on equal and fair terms with the supply side. Identifying these fair terms will make the NEM a more dynamic and efficient market for the benefit of all Australians.

This Review process must end up recommending a framework and a set of Rules which ensure that 8+ million electricity consumers will have the opportunity to engage with the NEM in a number of different ways to continue to improve its performance and receive the full benefits that the NEM is meant to provide.

If we collectively fail to achieve this we will be imposing on the Australian economy significantly higher than necessary prices and lower than achievable reliability and security of supply in the future. Such an undesirable outcome in an environment of Climate Change and strong international competition for Australia's products and services will inhibit the growth of the country and our ability to realise our full potential as a nation and individually.

The Review process and its leadership must make sure that we address a bigger vision in the changes that are ultimately recommended by this Review which will enable a fully responsive and effective DSP. Such changes are now rapidly emerging in many other electricity markets around the world.

To achieve this, the outcomes of the Review will have to end up being much more clearly defined, supported by evidence of DSP working effectively and much more focussed on changes that will result in consumers being engaged in the NEM within the next few years. Without such a focus this Review will be considered a waste of valuable time and money and a lost opportunity to provide Australians with the ability to participate in the NEM. On the other hand, the engagement of consumers from a very good outcome from the Review will provide a positive motivation for consumers to actively consider their energy demands and consumption and also be motivated to alter their behaviour to reduce Carbon Pollution.

We should note that the NEM design works well for most of the time except when under stress for any of a range of reasons when it shows that it cannot cope, for example:

- Sustained extreme wholesale prices but no realistic ability for those creating the demand at this time to see or respond to these prices - even if they reduce their demand they do not receive the full value of the benefit they create for others; and
- As seen in recent cases, shutting off the supply to hundreds of thousands of people without notice or compensation for many hours at a time due to a short term inability of meet the demand.

These major concerns can be addressed with well organised DSP. From our commercial experience, in perspective, the NEM compares poorly in the areas related to successfully managing extreme events, and to encouraging DSP and Energy Efficiency, both critical to Australia's future. The opportunity to address this imbalance must not be squandered or delayed.

Where possible we have endeavoured to provide evidence based on our experience as a commercial aggregator of DSR in 4 different electricity markets.

Comments on specific points in the draft Report

Executive Summary

What is Demand Side Participation?

The Report seems to indicate that consumers as individuals will be motivated to reduce consumption with what will be modest changes in price. The evidence to date with industrial and commercial consumers is that it will take a significant overt payment to consumers and sound facilitation to attract a reliable and strong response.

Economic Regulation of Networks.

This does not appear to consider the real issue, viz, that the last 10% of the capital expenditure to build the network capacity will only supply short peaks of only a few hours per day for perhaps 3 to 10 days per year. If the network business receives the same revenue for providing the same peak capacity but does this by sourcing a reliable supply of DSP to meet these peaks then there is a strong business case and this is acknowledged by DNSPs.

With a strong business case we do not believe that there is any need to pay the networks for R&D in any manner. There have already been some "R&D" contributions through the current regulatory process and they have basically not resulted in any advancement that we can see. Network companies can apply for R&D concessions or grants if they need them like any other business.

Wholesale Market Participation.

We support the views expressed under this policy area. We strongly support the recognition that, with minor Rule modifications, aggregated DSP will be able to participate in the FCAS markets and believe that the Rule changes associated with this need to be followed through promptly.

Reliability.

We are encouraged by the recognition that NEMMCO/AEMO should have an expanded role to procure "reserve capacity" from the demand side on an enduring basis for emergency circumstances. However, no evidence that can be relied on has been provided to show that DSP for "reserve capacity" from the demand side on an enduring basis will not improve efficiency. On the contrary, a Report developed by CRA International for the Australian IEA Task XIII Team (copy provided to AEMC usc) indicates that the opposite is correct. Our appreciation is expressed to these two organisations.

With regard to distortion of the market, it seems illogical to us that a formally approved "reserve capacity" from the demand side, organised in advance and to be dispatched in defined extreme circumstances, is part of the market and hence not a distortion. It certainly cannot be any more of a distortion than involuntary load shedding. Both the "reserve capacity" and involuntary load shedding are alternative emergency responses to extreme events when the market has "failed" to provide the required supply.

The wording used in the draft Report sounds like a reason not to do anything in this area rather than what we are proposing, viz, that consumers have the opportunity to participate in the solution. Surely it is far better to ensure that consumers can make a significant contribution to a more reliable supply, even better than 0.002% if they want to, rather than electricity supply to hundreds of thousands of people being turned off with no warning and no compensation just to ensure purity of a market.

Given the right commercial mechanism participating consumers will be able to pre-agree to turn off some of their demand (energy consumption) in the emergency. This reserve will be reliable and economic and will dramatically reduce the need to ever shed load involuntarily.

Please also refer to Energy Response's submission (copy included as Attachment 1) to the "Review of Operationalisation of the Reliability Standards" which provides our views on how to make this work.

Section 2 – Economic Regulation of Networks

Please also see our overall comments above.

Energy Response agrees that providing incentives other than the real commercial driver mentioned in our comments on the Executive Summary have done little to promote DSP for use by the Network businesses. Empirical evidence shows that, despite having a natural profit motive and the D factor incentive scheme (where available), successful DSP projects among NSW DNSPs are minimal. We can provide real examples to support this. In contrast, DSP for networks is the big issue in other markets.

The NSPs are naturally driven to maximising their asset base, as it directly affects their revenue, and perception of risk. They perceive that DSP increases their operating expense, reduces their capital base, and increases their risk (substituting DSP for physical assets which are culturally preferred by NSPs). This can be overcome if the process described in our comments on the Executive Summary were adopted.

Please also refer to Energy Response's submission (copy included as Attachment 2) on the Scoping and Issues Paper, Review of National Framework for Electricity Distribution Network Planning and Expansion.

It is unfortunate that the Illustrative Example shown in Box 2.2 is unrealistic numbers, eg, DSP for networks is generally sourced to support a substation of or line or feeder rather than the whole network and the 100MW additional capacity is completely out of the normal scale. It would however be valuable to the general understanding with more realistic figures, scope and understanding of how the DSP would respond to such a situation.

Section 3 – Service Incentives and Reliability Standards

Our experience has been that DSP is not seriously being considered to meet either mandatory or discretionary service standards. NSPs mostly consider DSP for *shadow* deferral's, ie, meeting mandatory requirements where regulatory funding has been obtained, but new network will be commissioned later than the planned date.

For example, a NSP obtains regulatory approval for network augmentation to be completed and in service in two year's time. But actual completion will only occur in three year's time due to project constraints. Furthermore, mandatory standards (eg N-1) require network augmentation to be in place now. So, while the DSP should be considered for a period of three years, ie from now to the actual network delivery, the NSP will only consider DSP for one year period (between 2 to 3 years in the future), as it will receive regulatory funding in two year's time.

We believe this occurs because the NSPs are not 'funded' until the infrastructure has been built (see description in our comments on the Executive Summary). They should be 'funded' for supplying the capacity to service the peak demand even when the last 5 or 10% of the capacity is supplied (in a virtual sense) by clipping the peaks to ensure the majority of the consumers in that area can stay on supply because others (DSP providers) have foregone / deferred some of their demand at the time of the peak. The result of this is that the NSP earns the same revenue overall initially but makes a slightly larger profit on this part of the infrastructure, the DSP providers get paid by the NSP (or via the aggregator) and overall the lower costs of network infrastructure result in lower network costs for all consumers over time.

Section 4 – Distribution Network Planning

Please refer to Attachment 2

Section 5 – Network Access and Connection Arrangements

5.2.1 The process for connection

While the detailed connection process specified in the Rules may in principle provide safeguards for embedded generator proponents, in reality the complexity and expense of completing following the process makes those safeguards inaccessible to proponents of small embedded generators.

5.2.2. Minimum technical standards

We would strongly recommend standardised connection arrangements for small embedded generators. In particular, standardisation of protection arrangements is the key. DNSPs tend to take an extremely cautious approach when specifying the protection equipment needed on embedded generator connections.

While it is important for safety, security and reliability purposes to have adequate protection against all plausible failure modes, there are often several different ways in which to provide the necessary protection. Unfortunately some DNSPs require a disproportionately expensive approach to be taken, when a simpler one would suffice, and does in the rest of the world.

In the UK, the Electricity Networks Association's Engineering Recommendation G59/1 describes protection arrangements for the connection of generators with capacities up to 5MW. The straightforward arrangements described in this document have been widely adopted, leading to the manufacture of protection relays designed to meet this standard. By removing uncertainties, this approach greatly reduces the barriers to the connection of small generators, and we strongly support its adoption here.

Please also refer to Attachment 2.

Section 6 – Wholesale Markets and Financial Contracting

Refer also to comments in on the Executive Summary.

6.2.1. Costs and obligations of participating directly in the wholesale market

The discrepancies between the five minute dispatch price and the thirty minute settlement price have a disproportionate impact on DSP providers. This is because their marginal cost is typically much higher than that of a generator, even a peaking generator, and so the cost to them of a "false positive" dispatch (i.e. a dispatch in which the settlement price turns out to be below their marginal cost, despite the initial dispatch price being higher) is greater. This problem applies not only to scheduled providers, dispatched by NEMMCO, but also to providers who dispatch themselves in response to the actual and forecast spot price.

Removing the five minute/thirty minute discrepancy would reduce the unhedgeable risk faced by many market participants (not only DSP proponents) and hence increase efficiency. Moving to 15 minute dispatch and settlement would be one way to do this.

6.3.1. Remuneration in the wholesale market

The supporting analysis on page 65 argues that the net economic effect of DSP is zero, as reducing wholesale spot prices merely results in a wealth transfer from generators to consumers. We disagree. As we see it, reducing the cost of electricity to consumers promotes the National Electricity Objective.

6.4. Forecasts of demand

For DSP providers who are exposed to the spot price, it is not the demand forecasts themselves which are relevant, but the resulting spot price forecasts. The most significant inaccuracies in these seem to result not from inaccurate demand forecasting but from generator rebidding.

Section 7 - Reliability

We are particularly pleased to see the emerging thinking aimed at resolving the serious matter of short term lack of supply capacity to meet demand. This is a very important policy area as it deals with finding ways for consumers to contribute to protecting themselves against a total, involuntary loss of electricity supply for which there is no compensation, which occurs when the market has failed to deliver the capacity.

Our thinking about this is based on the fact that, given the right mechanism, consumers can and are willing to create a reliable supply of “reserve capacity” from pre-contracted commitments to reduce part of their demand in such an event/s. This will then avoid, or at least dramatically minimise, the times when any consumers involuntarily lose their total electricity due to a direction to undertake load shedding.

Our view is that it is unnecessary to build more supply than is required to meet the 0.002% and that the current level of VoLL at $10,000 / MWh is sufficient to bring about a level of supply side capacity to meet the needs of the market in all but the most extreme circumstances. Well organised DSP with an appropriate mechanism can efficiently meet the needs in these extreme circumstances in response to a market failure.

It is inferred in the draft Report that RERT will increase costs to consumers and we challenge that view. There is no analysis or other evidence provided in the draft Report to support this assertion. The draft Report infers that the cost of RERT will be high. However, based on the Reserve Trader contracts formed by NEMMCO in 2006, the published cost was some $4.3 million which provided 375MW of Reserve for 8 weeks over nominated high risk hours. This contracted ‘readiness to act’ by the parties engaged cost $40/MWh for availability and if it had been necessary to dispatch it for 8 hours this would have increased the overall cost to some $8.5 million or an overall $74/MWh. Not bad to cover an emergency over a peak period that would have any need for involuntary load shedding.

This compares with consumer losses of say $100 million dollars for an event with load shedding similar to January 2009. The costs inferred in the draft Report on a comparative basis as this example can be calculated as 8 hours of dispatch for 375 MW at $10,000/MWh which is a total of $30 million. We think that the logic and price estimates for RERT are not correct when compared with the only real commercial evidence which is from the Reserve Trader contracts.

The overall cost of establishing and using DSP as emergency reserve from consumers is not likely to exceed an average estimated $10 million pa out of a total retail turnover of some $22 billion pa. This is less than 0.05% of the average cost to consumers (or approximately 0.006 c/kWh) compared with asserted costs of RERT or the huge losses by those consumers who involuntarily load shed.

We do not see RERT or a Standing Reserve as a market distortion because when this Reserve is required the market will already be distorted.

We have also covered this matter in our comments on the Executive Summary and in Attachment 1.

The overall thinking on this matter has developed to some extent via the CRR and this Review but it has not yet resolved a number of issues. On this basis we strongly suggest that the AEMC conduct a workshop on this specific area with a range of parties who could offer working solutions with costs and benefits to enable an appropriate ultimate outcome.

Yours faithfully

Ross S. Fraser
Executive Chairman

linking demand with supply in the Australian energy market

Attachment 1

29 May 2009

The Reliability Panel
Australian Energy Market Commission
PO Box A2449
Sydney NSW 1235

Dear Sir,

Reference Code REL0035
Submission by Energy Response Pty Ltd

Thank you for the opportunity to make this submission. Energy Response strongly supports RERT and believes improving its flexibility and using it for system security will improve the efficient operation of the electricity market. However, we suggest changes to both the concept and mooted rules of RERT that would make it a much more effective program.

RERT is a scheme to provide extra capacity to insure against market failure

Page x of the executive summary of the draft report of the AEMC Demand-Side Participation in the National Electricity Market Review (28 April 2009) states:

> "The final policy area considered in the Review relates to the short-term management of reliability by NEMMCO. In circumstances where the market does not deliver sufficient **capacity** to meet the desired reliability standard of 0.002 per cent average unserved energy, then NEMMCO can intervene to buy additional **capacity** or issue directions to existing market participants. These are additional potential markets for DSP".

Clearly the AEMC report sees the issue as one of capacity which logically should be addressed with a capacity product. But conceptually the RERT program is based on the premise that NEMMCO is buying energy only.

If the energy-only market worked perfectly, there would be no need for RERT. However, the possibility of the price reaching $10,000/MWh has not and does not give sufficient incentive to build enough capacity to cope with extreme situations. It is this market failure that necessitates the RERT scheme. In effect, RERT provides insurance against market failure.

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Rationale for short-term RERT

The purpose of the proposed short-term RERT panel is to allow NEMMCO to delay a decision about exercising RERT. Insurance is a useful analogy to understand this idea. Consider private health insurance.

Under the current RERT scheme, a person considers how healthy they are feeling each year. If they're feeling fit, they don't buy health insurance for that year. They gamble they won't need it.

Under the proposed short-term RERT scheme, they avoid this gamble by getting firm quotes from various insurers at the start of the year for a policy under which they don't pay any premium unless they start feeling ill.

No insurer would offer such a policy. They would have to build hospital capacity to treat the customer without any certainty that they will receive a premium payment. This would only be a sensible business decision if the premium was set as high as the treatment cost for an uninsured patient – i.e. if it was not insurance at all.

Market failure

When RERT is exercised, it is because the market has failed: more capacity is needed than the market has made available. It follows that the potential of earning $10,000/MWh has not proved to be a sufficient incentive to provide the capacity needed. To elicit extra capacity, the RERT scheme must offer some further incentive:

Option 1: The "uninsured private patient" scenario. An uninsured patient can seek private treatment if they pay the full cost. The cost of this is set sufficiently high to recover the costs of having the hospital capacity available. For RERT, this could mean paying much more than $10,000/MWh for the extra energy needed. From the point of view of consumers, however, this is still preferable to involuntary load shedding.

Option 2: The "proper health insurance" scenario. In reality, people are encouraged to have continuous cover. The regular premium income allows health providers to build hospital capacity to meet demand. In the context of RERT, this would mean assembling sufficient capacity in a RERT panel, and paying a relatively lower premium for it to be available.

Option 2 provides a framework which allows potential reserve providers to make the up-front investments necessary to ensure that the reserve they provide is reliable and fast-acting. Under Option 1, any such investment would be purely speculative, and difficult for a rational business to justify. As a result, Option 1 is unlikely to result in much reliable, fast-acting reserve.

If the desired outcome is for a certain level of reliable, fast-acting reserve capacity to be available, it will be necessary to pay for that capacity to be available.

The need for up-front investment

RERT seems designed to be the least attractive possible use for reserves, as the overriding priority is to minimise market distortion. If this works as intended, it will attract only the reserves that nobody else wanted: the slowest and least reliable. This doesn't seem the right approach for a program that exists to maintain reliability and security and avoids involuntary load shedding.

Energy Response believes that the priority should instead be to ensure that a sufficient quantity of reliable, fast-acting reserve capacity is procured.

Done properly, demand-side response can provide highly reliable reserve capacity. However, doing it properly requires both up-front investment of both time and money:

- Manpower to identify and contract DSR with the right characteristics
- Capital expenditure to install remote control and monitoring equipment – essential for speed and reliability
- Operational expenditure to test that sites perform as expected, before they are needed

Not all uses of DSR require such an approach. Where DSR is used purely for financial hedging purposes, e.g. by a retailer, much lower reliability can be tolerated. Where DSR is used to deal with local network peaks, long lead times are acceptable. For RERT to be effective, however, the provided capacity must be fast-acting and reliable.

Under the proposed short-term RERT, there is no business case to carry out these activities, as no payment is proposed. These steps only make sense if there is a commitment to buy the capacity. Since most of the costs are up-front, the longer the term for which the capacity is contracted, the more cheaply it can be made available.

Detailed comments

Notwithstanding these issues we would also like to make the following observations on the draft rule change proposal:

2.1.2 Dispatching contracted reserves using existing RERT
There is a danger that the existence of a short-term RERT panel will make NEMMCO less likely to choose to exercise normal RERT. Since the short-term RERT seems likely to provide less capacity, less reliably, at much greater cost than normal RERT, this temptation must be avoided. What processes or triggers would be in place to ensure that the existence of short-term RERT does not bias NEMMCO's decision on normal RERT? This is a question of transparency.

2.1.3 Potential amendments to the existing RERT arrangements
Reducing the negotiating time may work for the few large industrial sites who would be able to participate directly. These account, however, for only a small proportion of the potential reserves. Much more is available from aggregating the response of the many providers who are too small to deal with NEMMCO directly. To do this, however, requires contracts in place with a large pool of providers. The details of these contracts depend on the details of the contract between the aggregator and NEMMCO. It is unrealistic to expect all these contracts to be negotiated, or even amended, in four weeks.

2.2.1 Increasing the flexibility of RERT
This clause talks of pre-qualifying by resolving with NEMMCO some of the legal and technical issues. We would argue they should all be resolved. Our preference is that a full contract is in place.

2.2.3 No payments for RERT panel participation
In paragraph 1 the panel suggests to reimburse "one-off auditable out of pocket expenses associated with resolving any associated technical and legal issues with NEMMCO". In paragraph 2 it advises against allowing even that because it might be seen as a form of capacity payment: "Such a payment would be a form of capacity payment, and in the absence of a demonstrated market failure, would be a significant change to the arrangements for the NEM's energy-only market." (top of p.9). As we

have argued, the need for RERT demonstrates market failure and that is why capacity payments are appropriate.

Given that the Panel wants to exclude DSR used for any other purpose (see 2.3.5), it follows that DSR is held in reserve exclusively for RERT, for use with as little as 24 hours notice, in return for no payment. While this may seem attractive to the buyer of reserve capacity, it's not a sensible proposition for anyone providing the DSR.

Payment of auditable expenses associated with RERT panel participation
At the very least we would like to see sourcing costs recovered. There are costs to sourcing and holding ready MW to be available for RERT.

Advising NEMMCO of availability on an ongoing basis
"Entities to advise when their capacity is unavailable". This wording implies that the DSR from a RERT panellist is derived from a single source. This paragraph should be reworded to "advise of *any changes* in the capacity they have available".

2.2.4 NEMMCO can negotiate reserve contracts at any time (but not necessarily enter into)
We agree that NEMMCO should be able to negotiate reserve contracts at any time but the negotiations should be made in good faith and if successful be entered into.

2.3.5 "Double dipping"
We understand that the Reliability Panel wishes to ensure that DSR is not double counted. We agree that DSR must not be in a retail pricing arrangement. However, we would caution that it is dangerous to assume that all other DSR, which has been procured by other parties for other purposes, will be activated or dispatched during a RERT event.

DSR used to address local network constraints will only be dispatched if the local network peak coincides with the RERT event. Since many of these programmes have long notice periods, such facilities may well not be used if a RERT event occurs on a day when extreme demand had not been forecast on the relevant part of the network.

DSR used as an energy product for financial purposes is fast acting, but the decision to dispatch depends on details of the hedge position of the buyer. Also, if a $300 administered price cap is in place, no market-based DSR would be dispatched, as there is no price signal to encourage it.

If we want to ensure that all possible reserve capacity is activated when needed, some provision must be made to allow DSR which is contracted for other purposes to participate in RERT. Otherwise, we risk seeing a repeat of the ridiculous situation which occurred in South Australia in January 2009, where there was involuntary load shedding, inconveniencing thousands of end users, at the same time as reserve capacity from volunteer DSR providers went unused.

2.4 Using the RERT for system security events
Energy Response believes it is a positive change to use reserves contracted under RERT to manage system security events subject to our other comments.

2.8 Market distortion caused by RERT
It needs to be recognised that the distortion is necessary because of market failure. It follows that RERT is a program to provide capacity to restore the supply/demand balance. Therefore,

contrary to clause 2.2.3, for RERT to be truly effective it needs to be treated as a capacity product and contracted with terms and conditions and cost recoveries that reflect this fact.

We trust these comments are useful in the design of the RERT and we would be very happy to discuss any of these matters further.

Yours faithfully

Ross S. Fraser
Executive Chairman

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Attachment 2

17 April 2009

Australian Energy Market Commission
PO Box A2449
Sydney South
NSW 1235

Via email: submissions@aemc.gov.au

Dear Sir,

EPR0015 – Submission on the Scoping and Issues Paper, Review of National Framework for Electricity Distribution Network Planning and Expansion

Energy Response provides demand side response services to electricity supply companies in Australia and New Zealand. Our submission is made with the view of improving and encouraging the implementation of demand side initiatives by the distribution network service providers in the National Electricity Market.

Our comments are as follows:

General perspective

The consideration of non-network solutions should be treated by DNSPs as an integrated part of their planning process, rather than as an extra-cost, non-core activity carried out to appease regulators.

This requires changes not only to the processes within DNSPs, but also to their culture. Such changes cannot be forced upon DNSPs, but they must be encouraged.

Hence the analysis, reporting and consultation requirements which are under discussion should not be seen as an additional burden on DNSPs, but simply as a clarification of what should already be part of their usual business processes.

4. In addition to emerging constraints, what other types of potential problems of the distribution network should be included in annual planning reports?

From our perspective, the purpose of the planning reports is to reduce the information asymmetry between a DNSP and proponents of non-network solutions. As such, the Page 2 of 5 planning report should disclose as much as possible about the problems the DNSP expects to have to address in the next 3-5 years, in a structured, standardised manner.

There are no competitive issues here – the DNSP is a regulated monopoly. Hence it should be able to disclose a great deal of information.

As well as emerging constraints, the planning reports should also include problems which will limit the network's extensibility. For example, if fault levels in parts of the network are close to the maximum allowed level, this will prevent distributed generators from being connected.

6. Should the annual planning report including reporting on work carried out by DNSPs including reporting of actual network performance information and historical data?

Yes.

In particular, it should follow up on the constraints and other problems raised in previous planning reports, showing what actions have been taken, and how reality compares to the previous predictions.

Since planning decisions are made on the basis of forecasts and assumptions about load growth, load profiles, reliability, project cost, and implementation timeframes, there must be some discipline to encourage accurate forecasting – otherwise incorrect decisions will be made. A requirement to publish the forecasting errors is one way to encourage the development of a feedback loop.

The report should also highlight any problems which have arisen which were not anticipated in earlier planning reports, and any constraints or other problems which have arisen but not been addressed, e.g. due to project delays.

9. Should a distinction be made between general information that is publicly available and more detailed information for embedded generators and demand side response proponents?

As a practicing demand side response proponent, we find the existing planning reports to be of little practical use. We support the inclusion and separation of detailed information which would be relevant to providers of non-network solutions. Specifically, information is required on:

- Geographical location such as maps, towns and postcodes. Current reports primarily provide details on the electrical assets only.

- Season, time and durations of support needed

- Trigger conditions, i.e. under what conditions is the support required

- Value placed on non-network solutions, and the method for determining this value. Our experience has been that different DSNPs place significantly different economic value to non-network solutions for very similar capital works. It is essential that standards are developed to value non-network solutions to discourage bias.

We note that the AEMC have proposed such additional reporting for the TNSPs.

10. Would the Australian Energy Market Operator's website be the appropriate central location for the planning reports to be stored and published?

We support a central web facility to access the planning reports. It is important that such a facility makes available all reports (current and past), and that it has a comprehensive search facility.

12. What types of investments should be subject to the project assessment process?

Performing a project assessment – whether a cost benefit assessment or a full RFP – should not be an onerous or costly task – if it is, the DNSP is doing it wrong. Hence we would advocate including all projects apart from routine maintenance and like-for-like replacement.

13. What are the appropriate thresholds to trigger the project assessment process?

Some relatively small projects are particularly suited for non-network solutions. For example, some distribution augmentations in rural areas, where peak growth rates may be relatively low, can be deferred by many years through the use of DSR or embedded generation. Hence it is important to keep the thresholds low.

Rather than having a high threshold to limit the work involved, the processes should be simplified. In particular, at the moment it often seems that DNSPs are reinventing the wheel with each public consultation or RFP. A standard model for cost benefit analysis could help considerably here.

The $500,000 threshold recommended by NERA/ACG for a cost benefit assessment seems sensible. For public consultation and RFPs, we would advocate a threshold of $1 million.

15. What factors should be considered in a RFP process and how should this be specified in the Rules compared to AER guidelines? Including:

– what defines a credible option?

We have found that a significant number of projects are already late – i.e. the constraint is already in place, but the network augmentation is far in the future. Clearly, non-network solutions which partially satisfy the requirements should still be considered credible options.

Currently, many NSPs (both TNSPs and DNSPs) demand that the need be completely satisfied before embarking on a non-network project, even though the alternative is not to have any solution in place – neither network nor non-network.

Since many NSPs have successfully opted to do nothing while waiting for the network augmentation to be completed, one must question the credibility of the requirements as originally defined.

– how long should the consultation take place?

Currently, the NSPs release RFPs, or consultations on non-network options after a network solution has been fully developed. This generally leaves very little time to respond to, and develop any alternative solutions, as the project schedule is now driven by the build imperatives.

Our preference would be for the NSPs to develop both the network and non-network solutions in parallel so that a true comparison of the different methods for tackling the underlying problem can be performed in a timely manner.

16. What is the appropriate list of costs and benefits associated with distribution projects, and should that list be mandated in the NER?

We believe that a wide range of costs and benefits should be considered, to make the cost benefit assessment as holistic as possible.

We will not attempt to provide a complete list, but we believe that the following should be included as benefits:

- Improved reliability, above the mandated minimum level

- Improved extensibility – e.g. alleviation of fault level problems

We do not think it appropriate for the list to be ossified in the NER.

18. How can the project assessment process ensure that environmental benefits are appropriately treated and quantified?

Demand side solutions generally use existing customer infrastructure as an alternative to building new network elements. Hence, such solutions are environmentally superior. These environmental benefits are currently not measured nor allocated. We recommend that the AEMC explore strategies to incorporate such environmental benefits in project evaluation process.

19. How should a net benefit test be designed for distribution investments assessments? What are appropriate circumstances where a least cost assessment should be applied, and if so, should the two limbs of the regulatory test be maintained?

We favour the use of a unified cost benefit assessment for all projects. Having two limbs introduces the possibility of misclassification, so it should be avoided.

We would suggest that there should be regulatory oversight of the design and application of the net benefits test – i.e. there should be the provision for some level of review by the regulator even when a dispute has not been raised.

21. Should the dispute resolution process only apply to project assessments undertaken by DNSPs under the regulatory test or should the dispute resolution process also apply to matters arising from DNSPs' annual planning processes?

It should apply to both.

23. Who should be able to initiate the dispute resolution process?

Demand Management Incentive Schemes benefit the DNSPs in the NEM. Proponents for non-network solutions, and customers, are key stakeholders in demand management initiatives, but currently have no voice as these parties are generally not market participants. A place needs to be made for such stakeholders in any dispute resolution process. The nature of disputes will evolve as the demand management industry matures.

24. What process should be followed to resolve disputes and what should be the timing for this process?

We find it hard to believe that the dispute resolution process will be of use to proponents of non-network solutions. Unlike DNSPs, proponents do not have dedicated regulatory departments, so such a process would be an expensive distraction. Furthermore, DNSPs are their potential customers, so disputing their decisions is unlikely to be a sensible strategy. Nevertheless, any dispute resolution process should:

- Recognise the information and manpower asymmetry between DNSPs and disputing parties.

- Be quick, as there's no benefit in reversing a decision if the change is made too late for a successful non-network solution to be implemented.

27. Should the dispute resolution process be restricted to reviewing the DNSP's compliance with the NER and requiring the DNSP to amend its analysis in its project assessments or annual planning report if it is found that it has not fully complied (i.e. compliance review)? Or, should the dispute resolution process provide for a review of the outcomes of the DNSP's project assessments or annual planning report and if it is found that the DNSP has not reached the best outcomes, direct the DNSP to implement the most suitable outcomes (i.e. merits review)?

What matters is the *outcome*.

29. Should "urgent" investments be exempt from aspects of the national framework? If so, how should "urgent" be defined?

Non-network solutions are particularly relevant in urgent situations (see response to question 15 above). It is important that the design of any exemptions should ensure that non-network solutions are incorporated.

Yours faithfully,

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