24 February 2017

Mr Warwick Anderson
General Manager, Network Regulation
Australian Energy Regulator AER
GPO Box 3131
Canberra ACT 2601

Dear Mr Anderson

RE: AER Consultation Paper – *Demand management incentive scheme and innovation allowance mechanism* January 2017

Endeavour Energy welcomes the opportunity to provide feedback on the AER's consultation paper – *Demand management incentive scheme and innovation allowance mechanism* January 2017. The consultation paper follows from the Australian Energy Market Commission (AEMC) rule change which requires the AER to develop a demand management incentive scheme (DMIS) and demand management innovation allowance (DMIA) in accordance with newly established objectives and criteria.

Endeavour Energy supports the continued development of the market for non-network services through incentive mechanisms. We consider an efficient demand management market will support the National Electricity Objective (NEO) through reducing Distribution Network Service Provider (DNSP) costs and/or enhancing the variety and quality of service provided to end customers.

The AER considers the lack of information on network constraints and demand management solutions capabilities, an underdeveloped demand management market and DNSP investment preferences currently act as a barrier to demand management. The AER intend to address these barriers by implementing mechanisms which enhance competition and information disclosure, balance DNSPs incentives and support cost minimisation and efficient service delivery. In support of these objectives the AER has specified three assessment criteria in addition to the factors contained in the National Electricity Rules (NER). These are; enhance competition, transparent to apply, simple and administratively straightforward. Based on these factors and objectives the AER identify four potential DMIS and DMIA options respectively.

Table 1: DMIS Mechanism Options

DMIS mechanism category	Options
Targeted mechanisms to address disincentives	• Service Target Performance Incentive Scheme (STPIS) and Efficiency Benefit Sharing Scheme (EBSS) exclusions for non-network investments. • Forgone 'return on' or revenue uplift applied to demand management opex. • Innovation return bonus for operationalised DMIA projects.
Net-market benefit sharing mechanism	• Ex-ante allowance for valuation of positive externalities of demand management projects.
Promote the involvement of third party providers	• Incentivise DNSPs to provide information. • DNSP managed bidding mechanism for third parties only.
Target Based mechanism	• Broad-based demand reduction targets.

Endeavour Energy supports a menu-style approach with a number of options available to the AER to better incentivise non-network solutions depending on a DNSPs circumstances. However, it will be important that the guideline sets baseline measures and provides clarity for how complementary options will be applied. Overall, we consider the targeted mechanisms to address disincentives and the net-market benefit sharing mechanism would best contribute to the achievement of the DMIS objective and therefore warrant further investigation as baseline measures.

These mechanisms will ensure that DNSPs are not dis-incentivised to conduct demand management by the STPIS or EBSS. The AER should also review its benchmarking techniques and models to ensure that demand management, which is typically substituting capex with opex, is not dis-incentivised. Additionally, a financial reward would best incentivise demand management. Net-market benefit sharing, as envisaged by the AEMC, is a potential option that should be investigated. We recommend the AER engage an expert consultant to provide a $/kWh estimate for further consultation. Alternatively, we would support a forgone 'return on' payment or opex 'uplift' to neutralise any capex bias theorised to exist under rate-of-return style of regulation. An innovation return bonus would be complementary to either of these mechanisms.

Table 2: DMIA Mechanism Options

DMIA Options	Details
Existing DMIA	• Index allowance by CPI. • Revise assessment criteria (more innovative). • Increase reporting requirements.
Ex-ante high cap allowance	• Based on a proportion of MAR (example of 1per cent). • Based on a proportion of capex (example of 10 per cent). • Capex adjusted for expected benefits/deferrals.
AER Bidding mechanism	• AER to award project funding via competitive tender. • Funded by DNSPs (example of 0.1 per cent of MAR). • DNSPs must comply with ring-fencing guideline and partner with a third party to participate.
DNSP Bidding mechanism	• Incentivising DNSPs to award funding to third parties for R&D projects in their network area via a bidding process.

Endeavour Energy support the existing DMIA and consider an R&D allowance is the best method for facilitating and incentivising innovation. We consider that the high cap allowance should be available to DNSPs that can provide justification for additional funding. A well-functioning DMIS that incentivises operationalising R&D will ensure DNSPs utilise the DMIA. We also note the importance of assessment criteria that allows DNSPs to trial the capabilities and impacts of new technologies in their own circumstances given the heterogeneous nature of Australian DNSPs.

For both the DMIS and the DMIA we caution against satisfying objectives beyond that contemplated and added to the Rules by the AEMC. In particular, focussing on addressing third party supplier concerns regarding competition and information disclosure. The AEMC identified the absence of a genuine DMIS and the inability for DNSPs to monetise the non-DNSP benefits as the most significant barriers to DNSP uptake of demand management. The proposed bidding mechanisms appear to exclude DNSPs from implementing solutions and instead require them to fund, inform and operate a scheme largely for the benefit of third parties. We consider the AER's Ring-Fencing guideline will promote competition and the planning framework in the NER addresses information asymmetry issues (or should be amended directly if it is deficient).

In order to achieve the DMIS and DMIA objectives it is critical that the mechanisms selected by the AER directly and strongly incentivise DNSPs to implement least cost non-network solutions. Any mechanisms which embed a subsidy or delivery bias in the NER for third parties or impose administratively burdensome obligations or reporting requirements on DNSPs are likely to decrease the cost competitiveness of non-network solutions.

Our responses to the consultation paper questions are attached to this letter. If you have any queries or wish to discuss this matter further please contact Jon Hocking, Manager of Network Regulation on (02) 9583 4386 or via email at jon.hocking@endeavourenergy.com.au.

Yours sincerely

Rod Howard
Acting Chief Executive Officer

Attachment A: Response to the consultation paper questions

1. Do stakeholders support our interpretation and proposed implementation of the new rules? If you have alternative views, please share these and provide supporting evidence.

We are generally supportive of the AER's interpretation of the objectives and principles contained in the NER. However, we do not support the additional assessment criteria contained in tables 2 and 3 of the consultation paper.

The factors the AER must take into account in developing and applying any DMIS are outlined in clause 6.6.3(c) of the NER. This is an exhaustive list developed following extensive consultation as part of an AEMC rule change process. This clause does not include an "any other factor the AER considers necessary" style provision that provides the AER broader discretion in its assessment. In noting this, we do not consider it prohibits the AER from implementing a scheme and allowance that are "transparent to apply" and "simple and administratively straightforward". These are generally best practice regulatory principles that we are supportive of.

Rather, our concern is with the "enhances competition" additional assessment factor. The AER note[1]:

> *The contestable market **may** provide non-network options relating to demand management at lower costs than what it would cost distributors to provide non-network options. Facilitating effective competition **should be** possible in this instance because distributors can **generally** procure demand management services from third party demand management providers.*
>
> ***If so,** incentives to enhance competition are likely to promote the Scheme's objective by incentivising distributors to provide demand management options at lower costs than previously. Competition **may** also result in distributors providing a greater diversity of efficient demand management options. Reductions in the cost of providing efficient demand management options would make these options more affordable and **could** result in demand management options being supplied to a larger number of customers.* **[emphasis added]**

Conversely, the contestable market may not be able to provide lower cost solutions or be capable of servicing DNSPs demand. The contestable market may not be able to meet the service standard or other requirements of DNSPs and could result in a lower number of demand management options being supplied to customers.

Endeavour Energy considers that either scenario is possible and this guideline should not proceed on the assumption that outsourced demand management initiatives are superior to insourced options and can therefore be promoted and relied upon in isolation. The guideline should not seek to prescribe a preferred delivery method.

In our view, a contestability objective is separate to the DMIS and DMIA objectives and potentially not complementary if it is employed to limit DNSP discretion and embed a third party bias. The DMIS and DMIA objectives are squarely directed to incentivising DNSPs to <u>undertake and implement</u> demand management projects, not incentivise third parties to, or incentivise DNSPs to only manage, fund and outsource demand management projects[2]:

> *The objective of the demand management incentive scheme is to provide Distribution Network Service Providers with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management (the demand management incentive scheme objective).*
>
> *The objective of the demand management innovation allowance mechanism is to provide Distribution Network Service Providers with funding for research and development in demand management projects that have the potential to reduce long term network costs (the demand management innovation allowance objective).*

For this reason, we are concerned with some options considered in the consultation paper which appear to support a competition objective rather than the DMIS and DMIA objectives. Specifically, the bidding mechanisms which have instead been proposed to operate in a way that excludes DNSPs and requires them to operate the mechanism and pass through a majority of the benefits to third parties. In the absence of a third party supplier with an efficient option DNSPs would be unable to implement their own demand management project under such mechanisms (or significantly delayed in doing so). A third party is not required in every instance, for example a project can be managed by the DNSP and the customer can directly purchase the asset or the solution could involve the partial

[1] AER, Consultation paper: *Demand management incentive scheme and innovation allowance mechanism*, January 2017, p. 18

[2] NER clauses 6.6.3(b) and 6.6.3A(b) respectively.

use of network owned assets and non-network expenditure. Conferring exclusivity to third parties creates a lack of competitive tension that would be to the detriment of the market design and customers in the long term.

We support the development of contestable markets, however we consider the AER's ring-fencing guideline, service classification framework and capex and opex building block decisions are best designed to address this objective. The DMIS and DMIA guideline should simply and strictly focus on incentivising DNSPs to undertake demand management expenditure and R&D. It should be neutral to the delivery method that is employed as a contestable market should naturally develop as DNSPs invest and procure more demand management technologies and solutions. As noted by the AEMC[3],

> …*distribution businesses will always need to be the decision makers with regard to whether a network or non-network option provides the most efficient solution to address a constraint on their networks. The question of who is best placed to provide possible non-network solutions is a separate question. The frameworks in the rules encourage distribution businesses to identify and pursue the most efficient (or least cost) solution, irrespective of whether that solution is a network or non-network option or, in the case of the latter, whether it is provided by the distribution business in house, or by a third party through a competitive tender.*
>
> *The incentive scheme, where it applies to a distribution business, will apply regardless of whether demand management services are provided by the distribution business or by a third party. For this reason, the Commission does not consider that this rule will provide distribution businesses with a competitive advantage. Rather, it will provide a tool to encourage the businesses to make a balanced decision as to whether to implement a network or non-network option and may create opportunities for third party providers by incentivising distribution business to consider and pursue efficient demand management options where they otherwise may not have done so.*

We therefore wish to clarify the AER's understanding of the scope of the incentive scheme in the NER. The scope detailed in Table 4 suggests power factor correction projects are excluded. We wish to understand if this exclusion applies only to power factor correction that involves network assets or if it also applies to power factor correction assets within (and owned by) the customer's premises installed by a third party provider.

We are also concerned that a strict interpretation of the definitions will prohibit DNSPs delivering network based demand management initiatives. The vast majority of our initiatives involve a third party. However, in some instances where no third party may be able to deliver the service it would be unfortunate if a DNSP could not still proceed with the project. For instance, Endeavour Energy's PoolSaver program which involve placing pool pumps on off-peak control and using new technology to ensure appropriate control. This technology had to be purchased by Endeavour Energy and the customer contracted their own electrician to install the equipment. This has been an effective program that we are concerned would be excluded from the new DMIS.

The incentive based regulatory framework, specific incentive schemes (the EBSS and CESS) and the Chapter 6 determination process should ensure that DNSPs select the least cost solution. The DMIS guideline should simply incentivise DNSPs to implement demand management solutions as simply and effectively as possible. It is ill-suited to correcting any fundamental imbalance between capex and opex. Any service delivery bias embedded in the DMIS guideline would detract from the achievement of the DMIS objective.

2. Do you agree with our view on the main demand management incentives (or disincentives) provided under the regulatory framework and the potential issues associated with these incentives? Please provide reasons to support any alternative views you may have.

The consultation paper provides detailed analysis of the existing regulatory framework, which we are generally supportive of. Endeavour Energy considers the incentive based regulatory framework and specific incentive schemes provide strong incentives for DNSPs to pursue least cost options. The long term focus of the framework and incentive schemes requires that DNSPs are dynamically efficient (i.e. innovative).

Stakeholders have raised concerns that an imbalance exists between capex and opex. A capex bias is typically attributed to either a DNSP cultural issue or a deficiency in the regulatory framework. As a counter to this we suggest that a "bias" for network solutions may actually be a reflection on the efficiency of non-network solutions. The market for non-network solutions is relatively immature and

[3] AEMC, *Rule Determination: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015*, 20 August 2015, p. 21

generation and storage technologies are typically high cost. It may simply be difficult for these high-cost, decentralised alternatives to compete with well established, centralised network solutions. If this is the case it is a question of whether the regulatory framework favours productive efficiency over dynamic efficiency or a question of whether non-network solutions are dynamically efficient. We appreciate the policy position in Australia that growing markets that can act as a substitute or complementary option to traditional network investments is likely to improve efficiency in the electricity market in the longer term.

As noted by the AER, a building blocks approach and incentive schemes that individually address capex and opex (rather than totex) may result in an imbalance between the two. The Averch-Johnson effect postulates that entities subject to a rate-of-return style regulatory framework are incentivised to favour capex over opex in order to grow their regulated asset base. We do note that this effect is more strictly applicable to entities with regulated profit margins which is not the case in Australia. As noted by the AER, this kind of imbalance is dependent on each DNSPs actual cost of capital compared to regulated cost of capital based on the benchmark efficient entity.

Mechanisms in the NER which seek to neutralise any imbalance, like the CESS and EBSS, may do so in NPV terms but not over the short term. The timing of cash flows from regulated revenues may create, or fail to resolve, an imbalance between capex and opex in the short term. For instance, a DNSP may benefit in NPV terms from deferring capex by spending additional opex above its allowance in order to obtain a CESS benefit. A DNSP operating in a cash constrained environment may not be able to select this option in a scenario where the CESS benefit is only recoverable in several years. For this reason, a ‘forgone return on’ payment applied to non-network expenditure is likely to be the most effective way of addressing any perceived or real imbalance in incentives.

Our specific comments on the AER’s analysis are detailed below.

<u>EBSS</u>

We consider it is necessary that demand management expenditure and R&D (i.e. DMIS and DMIA opex) is an excluded category for EBSS purposes. This is to ensure that a DNSP is not penalised and therefore dis-incentivised from conducting demand management opex. Alternatively, DMIA should continue to be excluded and unfunded demand management opex should also be excluded. This is because some demand management opex may be contained in the AER’s opex allowance for ongoing and long-term demand management projects. They key is ensuring that DNSPs can be flexible and responsive to opportunities over the course of a regulatory control period to implement further, additional demand management projects without incurring EBSS penalties. If EBSS penalties can apply to demand management they will be factored in to the cost of a non-network project thereby reducing the cost-effectiveness of non-network solutions.

This is particularly important in light of the significant reductions made to the opex allowances of DNSPs in the most recent AER determinations. As noted by the AER, DNSPs are free to allocate their opex allowance as they see fit in order to meet their obligations. Where large opex reductions are made demand management opex is likely to be reallocated to more critical, non-discretionary areas of expenditure such as maintenance, emergency response and vegetation management. This is more likely where equivalent reductions have not been made to capex.

<u>Revenue Cap</u>

A revenue cap removes the risk that DNSPs recover a lower amount of revenue as a result of successful demand management projects. This risk existed with the price cap form of regulation which necessitated the d-factor mechanism. We support the continued application of a revenue cap form of regulation for this and other reasons.

<u>Option value</u>

Stakeholders have suggested that the regulatory framework fails to allow DNSPs to internalise the longer-term economic benefits of investing in flexible, demand-side options. If recognised, this option value may make non-network solutions competitive with network options which allow DNSPs to realise scale efficiencies. While theoretically sound, we appreciate the AERs concerns that valuing the longer term benefits of non-network options is complex and difficult. It may result in an inefficient allocation of resources and assets if incorrectly valued.

We consider it would be harder than developing a net-market benefit value as it involves an assessment of the future state of the electricity market rather than the current state (or marginal cost). Given this, we are more supportive of transparent and simple financial payments based on a non-network opex multiplier, innovation bonus, forgone return on or net market benefit sharing.

STPIS

Demand management projects typically rely on the actions of a customer to address an expected capacity constraint. For example, customer load-shedding, load shifting and back up generation initiatives. Non-performance by the customer or forecasting error can detrimentally impact service quality. The lack of firmness or unreliability of non-network options can be a key deterrent for DNSPs in adopting these solutions over more reliable network solutions.

DNSPs would be dis-incentivised from implementing non-network solutions if they are required to bear the costs of supply outages either via a STPIS penalty or having to insure this risk. It would also be inappropriate if third party providers or customers are responsible for the outage through non-conformance.

To address this issue we consider demand management projects should be exempt from the STPIS, particularly if they are being managed by a third party. Endeavour Energy considers outages from these demand management initiatives and customer non-performance can be demonstrated (by either the DNSP or third-party aggregator). It would therefore be possible to discount the loss of supply as part of the STPIS. However, it will be important to ensure that the exclusion is targeted with set criteria in place to ensure DNSPs do no imprudently adopt inefficient or unreliable non-network solutions.

An additional suggestion is introducing a framework by which DNSP's can offer locational ride-through incentives for customers with such capability to self-supply during an outage. In return the DNSP is allowed to discount the customer outage from performance metrics upon demonstration of the customer achieving outage ride-through and providing subsequent payment. This is a price signal mechanism to a competitive market, allowing potential for additional value to be attributed to such technologies by customers, retailers or aggregators whilst providing DNSPs with additional non-network reliability enhancement options to consider.

Net-market benefits

It has been noted that the inability of DNSPs to internalise the net market benefits of demand management projects reduces their competitiveness with network solutions. This was a critical factor according to the AEMC and a driver for the amendments made to the DMIS and DMIA provisions in the NER. It is envisaged that providing DNSPs a financial payment based on a sharing of these benefits will increase the uptake of demand management.

We support a net market benefit sharing mechanism and consider it will contribute to the achievement of the DMIS objective. However, we appreciate the AER's concerns that valuing up-stream benefits can be complex and inaccurate. We also note that the demand reductions targeted by DNSPs (at least individually) may not be material to transmission companies or generators.

We recommend that the AER engage a consultant to provide an estimate of the net market benefits per unit of demand reduction. This should serve as a starting point for further consultation as to whether this is a viable, appropriate mechanism that can be implemented. The AER would be remiss to not investigate this option further given its potential. Should it prove impractical, alternate, more simple financial payments could be implemented like the forgone return on, innovation bonus of non-network opex multiplier.

Information asymmetry

The AER notes that a lack of information may be restricting the development of a market for demand management solutions. We consider the existing provisions (e.g. DAPR, RIT-D) are sufficient and a significant amount of information is already disclosed. The underlying issue may be the ability of stakeholders to review, understand and utilise this information. We are sceptical that a DMIS and DMIA guideline can incentivise additional reporting. We consider the existing requirements could be simplified and DNSPs are voluntarily taking steps to provide more easily consumable information (e.g. the ISF/ENA led work on Network Opportunity Mapping).

Cost-reflective pricing

We agree with the AER's assessment that better pricing signals will promote demand management however this will take time to achieve. Alternate measures should be implemented to incentivise demand management while tariff reform occurs. Once more cost-reflective tariffs are in place we would expect the need for specific demand management incentives will be reduced.

Broad based Targets

The AER suggests setting targets may be one way of addressing cultural bias within DNSPs for network solutions over non-network solutions. A target would help ensure that DNSPs consider non-network solutions as part of their planning processes. However, as noted by the AER a broad based target may not result in an efficient allocation of resources. Instead, DNSPs may be incentivised to implement demand management where it is not required or beyond what is efficient. This would not result in least cost options being implemented.

Benchmarking

While not considered by the AER in the consultation paper, the impact of the AER's preferred benchmarking models should be assessed. In particular, the AER's preferred multilateral total factor productivity (MTFP) model specification may unintentionally skew a DNSPs' expenditure incentives. The AER's MTFP model considers the following inputs and outputs (with weightings):

Table 3: MTFP model input and output specifications

Inputs	Weighting	Outputs	Weighting
Opex	39%	Customer Numbers	52%
O/H Subtransmission Lines	3%	Circuit Line Length	27%
U/G Subtransmission Lines	1%	Ratcheted Max. Demand	20%
O/H Distribution Lines	9%	Energy Delivered	14%
U/G Distribution Lines	16%	Customer mins off supply	(13)%
Transformer Capacity	31%		

As evident in the table above, capex is not directly included in the MTFP model but instead represented by capacity measures. This may create a disincentive for DNSPs to implement a significant amount of non-network solutions as opposed to capex investments. This is because non-network solutions will increase the heavily weighted opex input value while outputs like circuit line length, ratcheted maximum demand and energy delivered would remain constant rather than increasing under a network based solution. This would result in a DNSPs annual benchmarking performance deteriorating compared to capital intensive DNSPs all else being equal.

We recommend that the AER review the benchmarking techniques and models they employ to ensure that demand management is not dis-incentivised and that incentives between opex and capex more broadly are balanced. It is likely that a "totex" approach is required for benchmarking input costs. Alternatively, utilising opex adjusted for EBSS purposes (i.e. excluding demand management opex) for benchmarking purposes may address this issue.

3. Do you see value in exploring the net-market benefit sharing mechanism further, despite the difficulties associated with measuring net-market benefits? If yes, what detail of guidance should we provide on calculating market-wide costs and benefits? Should we (and if so, how should we) establish a method for valuing smaller demand management projects in a way that reduces the administrative burden of applying the Scheme to these projects?

Yes, as aforementioned the AEMC identified the sharing of net market benefits as a way of incentivising demand management. We acknowledge that doing so may be difficult or more costly than alternate measures like a forgone return on payment. The most straightforward and administratively simple measure should be selected if it will just as effectively promote demand management.

We consider a net market benefit sharing mechanism could be straightforward if an agreed $/kWh could be determined. The LRMC values of DNSPs and transmission companies and wholesale bidding prices may be a potential starting point for this analysis.

4. Since the RIT–D already requires distributors to select the option with the highest total market benefit, should we (and if so, how should we) treat RIT–D projects differently under this type of Scheme (that is, under a net market benefit sharing mechanism)?

The RIT-D focusses on identifying the most cost effective option and involves a consideration of certain market benefits. The most common market benefit is the changes in involuntary load shedding as this represents lost energy due to unreliability.

The RIT-D process ensures the market benefits that can be valued are included which will generally benefit the competitiveness of the non-network option. A net market benefit sharing mechanism should still apply to RIT-D projects (and non RIT-D projects). The DMIS is required to incentivise DNSPs to conduct demand management. The RIT-D should therefore not be relied upon in isolation to force DNSPs to implement demand management solutions with market benefits they cannot monetise.

A net market benefit sharing mechanism would ensure that DNSPs can reliably estimate the total market benefit and then receive a financial payment based on this benefit as per the DMIS. If DNSPs cannot share in the market benefit they are likely to undervalue it resulting in a lower uptake of non-network solutions. When considering non-network options for both RIT-D and non RIT-D projects it is important that an effective DMIS applies to both and a DSNP can be confident of its application.

5. How might we best combine the mechanisms discussed in section 6 into an option that achieves the Scheme's objective? If you prefer a mechanism that we did not discuss in in section 6, please provide details on this mechanism.

Endeavour Energy is supportive of the AER relying on a suite of options to incentivise demand management based on the circumstances of each DNSP. We consider some mechanisms should be core to the scheme whilst others complementary or applied on a case by case basis.

Our views on each mechanism are provided below.

<u>Type 1: Mechanisms to target potential disincentives</u>

We consider this mechanism is critical to achieving the DMIS objective. DNSPs are unlikely to invest in demand management where penalties or disincentives exist. An evaluation of each mechanism is provided below.

A) Exclude demand management projects under the STPIS

Endeavour Energy is supportive of this measure and consider it will be straightforward to implement. The majority of initiatives are inherently unreliable as they involve customer action to reduce load or initiate their back-up. DNSPs will be more willing to implement customer load shedding, shifting and reduction initiatives than they otherwise would be if a STPIS exclusion were provided.

B) Exclude demand management R&D from the opex building block and the EBSS

As aforementioned, Endeavour Energy considers DMIA should continue to be excluded from the EBSS. This exclusion should be expanded to DMIS expenditure as well to ensure that DNSPs are not discouraged from pursuing demand management options as they arise over the course of a regulatory control period. This is particularly relevant in light of the significant reductions in opex allowances many DNSPs have received in recent determinations which restrict a DNSPs ability and incentive to spend opex on discretionary areas like demand management, particularly unforeseen demand management during a regulatory control period.

C) Incentives to place capex and opex on more equal footing.

Endeavour Energy considers this is the most central topic to the issue of disincentives. A financial payment for non-network opex will provide the best incentive to overcome any potential DNSP bias or imbalance in the regulatory framework between capex and opex. The options considered by the AER are:

i) Uplift on the amount spent on a demand management project

This is a transparent and simple mechanism that will incentivise non-network opex (or eliminate any bias). The issue will be the magnitude of any uplift. If it is too small, it will be inconsequential and if it is too large it will result in inefficient investment and higher network charges. The effectiveness of the Network Capability Improvement Incentive Scheme and any available international examples should inform the AER of the level any potential uplift required.

ii) Forgone return on payment for demand management opex

As above, this is a transparent and simple mechanism. We consider this option is preferable as it addresses the concern that DNSPs prefer capex over opex more directly. This mechanism can be expressed as a percentage figure to be applied for a set period of time (two regulatory control periods preferably) to equalise any perceived or real imbalance between capex and opex.

iii) Uplift on demand management opex based on the option value

We consider this option is theoretically sound but practically difficult to implement. It is more complicated than the measures above. While this measure would internalise the option value of a non-network option it would fail to cost the risks of a non-network option.

iv) Innovation return bonus to translate R&D to a DMIS project.

This mechanism would incentivise DNSPs to commercialise R&D projects and encourage DNSPs to implement proven initiatives. We consider this mechanism is complementary to the other mechanisms discussed above. Ideally, a mechanism would be selected to provide a financial reward (forgone return on, net market sharing or uplift) and combined with the mechanism. For instance, if a forgone return on payment is adopted the innovation return bonus could be the use of a higher WACC and/or for a longer period of time if the DMIS project is a commercialised R&D project.

<u>Type 2: Net market benefit sharing</u>

As discussed above, we consider this option is worth consideration as it would address a key issue identified by the AEMC with the previous framework. This mechanism is likely to improve the competitiveness of non-network solutions and increase the uptake of them by DNSPs. The key question will be whether it can be implemented in a simple and transparent way. We consider a valuation by an expert as the starting point for determining its appropriateness.

Should this mechanism not be practical or least cost we would be supportive of the forgone return on and demand management opex uplift mechanisms which also provide financial rewards. Although, the advantage of the net market benefit sharing mechanism is that it is more closely tied to the value a demand management option generates for the end consumer. It is therefore more likely to support efficient levels of demand management expenditure.

<u>Type 3: Mechanisms to promote competition</u>

A) Incentivise DNSPs to provide information

Endeavour Energy is supportive of providing an efficient level of information to the market to address any asymmetry issues between DNSPs and third party providers. Endeavour Energy currently provides a high level of information in the market place and willingly provides additional information to interested parties upon request. Endeavour Energy allocates an individual Project Manager to every large embedded generation application to ensure appropriate and timely advice is provided.

Endeavour Energy is therefore supportive of any mechanism that genuinely incentivises DNSPs to provide timely and accessible information. However, we are sceptical that this can be achieved without penalising some DNSPs or imposing additional reporting requirements on DNSPs. Our position will depend on the nature of the mechanism proposed by the AER. If an appropriate mechanism is developed, we consider it would best be applied on a case by case basis to incentivise worse performing DNSPs to improve the level or quality of their disclosures.

B) <u>Bidding mechanisms to encourage market delivery</u>

Endeavour Energy does not consider this mechanism provides a direct incentive to DNSPs to undertake demand management projects. The options discussed above that provide financial payments to DNSPs are more likely to achieve the DMIS objective. DNSPs would have to receive more than cost reimbursement for running a bidder process. Otherwise DNSPs would have no incentive to conduct a bidding process and it would risks becoming a compliance exercise that amounts to a wealth transfer to third parties for potentially higher cost solutions.

From a practical perspective this mechanism would require a distributor to identify emerging constraints well in advance of them occurring in order to release information to service providers and to then run a bidding process. It is unclear how this mechanism would work with the RIT-D process and whether it would replace or support the Non-network options report phase of the RIT-D. It is also unclear if this mechanism would be intended to replace the respective tender processes of each DNSP and whether it would result in least cost solutions that are not necessarily efficient or prudent.

This mechanism could result in delays in undertaking demand management and prohibit DNSPs from implementing projects where the market is not capable, willing or least cost. If it were to be adopted in the guideline we consider it would be complementary to other measures and DNSPs would require a baseline allowance for existing demand management projects or where the bidding process fails to identify a third party led solution.

Type 4: Targets for demand management deployment

Whilst a target will incentivise DNSPs to implement demand management projects we are concerned it will create a gaming incentive or result in the inefficient deployment of demand management for the sake of meeting a target.

The option of setting a target based on connection points may be onerous and difficult as it could involve managing dozens of demand management projects at a time. This may be beyond the capabilities of the demand management market and coordination capabilities of DNSPs.

Overall, Endeavour Energy considers other measures would be preferable to a broad based target.

Summary

Endeavour Energy considers that a number of mechanisms working in combination to address multiple issues is preferable. Our preferred combination of measures is as follows:

Table 4: Preferred DMIS Mechanism Combination

Type	Issue to be resolved	Mechanism
1	Impacts associated with the unreliability of demand management initiatives	• Excluding demand management projects (or customer reliant projects) from the STPIS.
1	Constrained opex environment	• Exclude demand management R&D and DMIS opex from the EBSS.
1 and 2	Potential imbalance between capex and opex	• Provide DNSPs a financial payment based on one of the following ○ Sharing of net market benefits ○ Forgone return on ○ Demand management opex uplift • Review benchmarking techniques and models to ensure demand management is not penalised and incentives are balanced between capex and opex.
1	Promote commercialisation of R&D	• Innovation return bonus for commercialised R&D (as a stand-alone payment or multiplier of the measure selected above)
3	Promote competition	• Incentivise (with no penalties) DNSPs to provide a higher amount and/or quality of information
1 and 3	Constrained opex environment and promote competition	• A bidding mechanism may be worthwhile for DNSPs that wish to access additional demand management opex (above the baseline amount provided in a determination) for unforseen opportunities.

6. If you have views against applying any of the particular mechanisms discussed in section 6, please provide reasons to support this view.

As explained above.

7. How we might best give effect to or enhance the information and reporting requirements discussed in section 6.5?

Generally, the reporting requirements in section 6.5 appear similar to the d-factor report previously prepared by Endeavour Energy. However, some areas will require additional AER guidance if adopted. Specifically:

- Data and calculation requirements for option value determination and verification.
- Data and calculation requirements for the determination of net market benefits.
- Clarification of the requirement to calculate energy costs with and without a demand management project.
- The disclosure of bidding process details while complying with any confidentiality requirements.

Endeavour Energy is supportive of providing efficient levels of information and generally does so as requested by third parties and as part of our request for tender documents. However, there are two pieces of information that may be problematic to report, being:

- The dollar value to the distributor for each year of deferral; and
- The load profile for an average customer in each customer type/tariff.

The value of deferrals is sometimes difficult to accurately specify as there are many variables. For example, inherently unreliable initiatives will be valued lower due to the need to over subscribe demand reduction to cover the risk of non-performance. There are also differences in payment structures for permanent and temporary demand reduction. While specific customer load profile types may be difficult to obtain due to the metering currently installed in our network area. It may also come at a cost as data would be obtained from Metering Coordinators in the future.

8. Which of the options discussed above in section 7 would best achieve the Allowance Mechanism's objective? Please provide reasons supporting your view. If you prefer an Allowance Mechanism design that we did not discuss as an option in section 7, please provide details on this option.

Endeavour Energy is supportive of the existing DMIA and considers a DMIS which incentivises the commercialisation of R&D will lead to greater uptake of DMIA. We therefore support a DMIA mechanism which allows DNSPs to seek a higher allowance in addition to the existing DMIA level. The higher allowance may be tied to rewarding DNSPs for engaging third party providers.

9. If you have views against applying any of the particular mechanisms discussed in section 7, please provide reasons to support this view.

As aforementioned, we are concerned by the bidding mechanisms and whether their proposed design would actually provide DNSPs an incentive to conduct demand management R&D. Particularly when there are more simple and direct mechanisms available that provide greater flexibility. The table below summarises our views.

Table 5: Proposed DMIA Mechanism commentary

Option	Mechanism	Issues
2	High cap allowance with ex-ante approval	Setting the higher allowance as a percentage of MAR or capex is simple but potentially inappropriate. It would create a significant variation in the funds available to each DNSP when the costs do not vary as greatly. R&D projects are typically small-scale trials. Whilst larger DNSPs will have a larger scope we do not consider the variation would be in the tens of millions. Alternate options for determining the high cap allowance should be considered. Ultimately it may need to be determined on a case by case basis.
3	Bidding to encourage 'ground breaking' R&D. AER led	• 'ground breaking' may set an unnecessarily high threshold for eligible trials. The heterogeneous nature of Australian DNSPs means it is important DNSPs can individually trial new technologies and solutions in their respective network area to understand the potential benefits and impacts.

Option	Mechanism	Issues
		• The bidding process excludes DNSPs, despite being funded by DNSPs. Where a third party cannot be identified to participate in the trial (i.e. beyond supplying and/or installing assets) then it appears it would not be able to be implemented by the DNSP. • Administrative burden for the AER • Competition for funds may disadvantage smaller organisations • May not result in non-network solutions being implemented in all network areas creating a cross subsidy between customer groups.
4	Bidding to encourage market facilitated R&D. DNSP led	• Largely as above, this imposes a burden on DNSPs and the main beneficiary would be a third party.

10. How we might best give effect to or enhance the information and reporting requirements discussed in section 7.5?

Endeavour Energy will be able to comply with the new reporting requirements discussed in section 7.5. It is important that demand management service providers are provided sufficient information so they can develop detailed proposals to DNSPs. However, we are concerned that while revised assessment criteria will provide greater clarity it may be overly prescriptive and inflexible. In particular, we are concerned that an unnecessarily high threshold may be set for what is considered “innovative”. It is important that DNSPs are able to test new technologies and solutions in their own network circumstances to ensure a benefit can be derived with no adverse impacts to the safety and reliability of the network.