# Advice on the DMIS Incentive

prepared for:
Australian Energy Regulator

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# DISCLAIMER

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# DOCUMENT INFORMATION

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# 1. Introduction

## 1.1. Background

This paper is part of the Australian Energy Regulator's (AER) response to the *Demand Management Incentive Scheme* (ERC0177) rule change that was approved by the Australian Energy Market Commission (AEMC) in August 2015.

The final rule:

- provided a set of principles for the incentive scheme, and a separate set of principles for the innovation allowance, to guide the AER in developing the scheme and the allowance in ways that would best achieve their respective objectives, and
- required the AER to develop and publish the incentive scheme and innovation allowance in accordance with the distribution consultation procedures.

A precursor to the DMIS and DMIA was the provision of a $600k allowance provided by the Essential Services Commission Victoria to each of the Victorian distribution businesses to undertake demand management activities.

Subsequently, one of the recommendations of the AEMC's 2012 Power of Choice review was that a Demand Management Incentive Scheme (DMIS) be established.

The COAG Energy Council endorsed this recommendation through a formal rule change request in 2013, and the AEMC undertook a thorough review that concluded in a rule change in 2015 that required the AER to "develop a demand management incentive scheme" (NER, s. 6.6.3).

The AER commenced its consideration of the DMIS / DMIA in 2016. This has entailed:

- Conducting a Stakeholders' Workshop (20 September 2016)
- Publishing its *Consultation Paper: Demand management incentive scheme and innovation allowance mechanism* (4 January 2017)
- Calling for submissions on the issues raised in the Consultation Paper
- Conducting an Options Day Workshop (6 April 2017)
- Accepting supplementary submissions based on items discussed in the Options Day Workshop.

Oakley Greenwood (OGW) was engaged to provide expert advice to the AER's project team in developing a new Demand Management Incentive Scheme (DMIS and Demand Management Allowance mechanism (DMIA)) in accordance with the rule change. The work undertaken in providing this advice was organised in discreet pieces of work undertaken in response to specific issues and Terms of Reference from the AER project team.

The next steps in the AER's process include:

- Videoconference on the AER's direction for the draft scheme and allowance mechanism (June/July 2017)
- Publication of the draft scheme and allowance mechanism (July/August 2017)
- Stakeholder engagement event (September 2017)
- Publication of the final scheme and allowance mechanism (October/November 2017).

## 1.2. Scope

This paper has been provided in response to a request from the AER for an independent report, suitable for publication, that provides advice that the AER can use in setting the direction for the draft scheme in regard to:

- the specific benefits that could be included as being eligible for the DMIS, as well as the corresponding metrics that would then be used to define, measure and reward those benefits;
- the basis and appropriate magnitude of the incentive to be used in the DMIS; and
- how the incentives provided under the DMIS can be linked to tangible performance outcomes.

These scope items are addressed as follows in the remainder of this report:

- Section 2 provides a review of the objective of the Scheme and its implications for the nature and design of the incentive to be used,
- Section 3 explores what economic benefits should be reflected in the DMIS incentive,
- Section 4 discusses two bases on which the level of incentive could be calculated,
- Section 5 provides worked examples of the calculation of the economic benefits to be reflected in the DMIS, and
- Section 6 discusses selected implementation considerations.

# 2. What is the objective of the Scheme?

## 2.1. The Scheme's objective

As stated in the Consultation Paper, the objective of the Scheme is to:

> *contribute to providing distributors with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. In designing a Scheme that achieves this, it is valuable to take into account possible interactions between the Scheme and other incentives available to the distributor to invest in and implement relevant non-network options, particular control mechanisms, and meeting regulatory obligations or requirements. This is because, to achieve its objective, the Scheme should supplement the existing framework in a way that enhances its ability to promote efficient outcomes.*[1]

## 2.2. What this means for the design of the DM Incentive under the Scheme

From an economic perspective, the aforementioned objective means that the DM incentive under the Scheme should be set at a level that results in the price signals that businesses respond to when making investments in DM **reflecting the long-term economic benefits that accrue from making those investments**. This will ensure that market participants make investments in DM up to the point where the marginal benefit to society of that investment equals the marginal cost to society of making that investment.

In this context, the magnitude of any proposed DM incentive arrangement should reflect the value that demand management will deliver to end customers, which in turn will reflect the opportunity cost to the customer of the business not undertaking a DM investment. As was alluded to in the extract from the *Consultation Paper* above, it is important that the economic benefits reflected in the DM incentive *cannot otherwise be captured* by either the distribution business or the DM provider given the:

- current regulatory framework, or
- current electricity market arrangements.

Put another way, it is important that the DM incentive under the Scheme does not duplicate any value of DM that is already able to be captured by a market participant. We have given this explicit consideration when assessing what economic benefits that should be reflected in the DMIS incentive.

The potential benefits accruing to the distribution component of the electricity value chain, as well as other parts of the value chain, are discussed in the following section.

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1 AER, *Consultation paper: Demand management incentive scheme and innovation allowance mechanism*, January 2017, p 5-23.

# 3. What economic benefits should underpin the Scheme?

## 3.1. Objective

The objective of this section is to discuss:

- the benefits that accrue to the distribution part of the electricity value chain, and the extent to which they may or may not be able to be captured by distribution businesses under the current regulatory arrangements, and
- the benefits that accrue to the non-distribution parts of the electricity value chain, and the extent to which they should be factored into the derivation of the DM value that underpins the DM incentive under the Scheme.

## 3.2. Benefits accruing to the distribution part of the value chain

There are a number of generic benefits accruing to the distribution component of the electricity value chain from the use of demand response, including, but not limited to:

- short-term deferral of augmentation assets, which may come about as a result of a reduction in co-incident peak demand or energy at risk,
- long-term deferral of augmentation assets, which may come about as a result of a reduction in co-incident peak demand or energy at risk,
- network augmentation option value,
- long-term reductions in asset replacement expenditure, or
- voltage control.

The financial benefits that may be able to be captured by a distribution business from an investment in DM will be affected by the mechanisms that operate within the existing regulatory framework to incentivise distributors to choose the least-cost mix of capital and operating inputs to deliver services to consumers. At present, these are[2]:

- the Efficiency Benefit Sharing Scheme (EBSS),
- the Capital Efficiency Sharing Scheme (CESS),
- where applied, the revenue cap form of control, and
- the regulatory investment test for distribution (RIT-D) requirements under the Planning Framework.

Of relevance to this report is whether the current regulatory arrangements lead to alignment (or misalignment) of the financial returns accruing to the distribution business from an investment in DM with the economic benefits that accrue to its customers in the long-term from it making such an investment. This is a position that has been put to the AER by a number of stakeholders, including the Institute of Sustainable Futures (ISF), who have, as part of the broader consultation process, submitted modelling that supports a position that there is a significant misalignment.

2 It should be noted that the Service Target Performance Incentive Scheme (STPIS) also provides incentives that can influence network investments. Under the STPIS, businesses are provided with a financial incentive to improve the levels of service they provide customers (or to mitigate a deterioration of service levels), such that overall economic welfare is enhanced.

Whilst it is not the objective of our report to dissect each of the regulatory mechanisms affecting a network business' financial returns (or to assess them collectively), in our view, there appear to be three key issues that need to be considered when assessing whether the financial returns that accrue to a network business from an investment in DM align with the economic returns that can be expected to accrue to its customer base:

- the extent to which the benchmark weighted average cost of capital (WACC) parameters are accurate or not,
- whether or not improved levels of service generated by DM are captured under the current STPIS arrangements, and whether or not the incentive rates applied to marginal improvements in levels of service are accurate, and
- whether or not the *timing* of when the economic benefits stemming from an investment in DM aligns with the period covered by the regulatory incentive mechanisms (i.e., 5 years).

For the purposes of this report, we:

- Are not in a position to make any comment on the first issue, the accuracy of the WACC. Hence, we make no further mention of this issue in the remainder of this report. That said, we would note that if this is an issue, then it would appear to us to have broader ramifications for the regulatory framework, over and above the changes that are being considered in relation to the incentives to undertake efficient investments in DM;
- Believe that *if* there are certain service attributes (e.g., voltage-related issues) that are valued by customers, but which are not currently being efficiently incentivised under the STPIS, *and* there are various types of investments (e.g., capex, DM, non-DM opex) that may be able to be adopted to deliver improvements in those service attributes[3], then it should be the STPIS arrangements that are reviewed and adjusted, as opposed to this being provided for via inclusion in a specific DM incentive, and
- Believe that the last factor (the timing of when economic benefits accrue), is of particular relevance to the assessment of whether additional incentives for DM are required, as it is unclear to us whether the EBSS and CESS incentivise a distribution business to capture the long-term economic benefits of either:
    - Making an investment in a more flexible DM investment now, with a consequent increase in costs, but which from a probabilistic perspective, may reduce the overall cost of supply to customers in the future under certain future supply / demand situations ('option value').

      An example of this would be where an investment in DM in one period can be structured in a way that allows it to cease in the future if certain supply/demand situations occur. The economic benefit in this case is that the flexible DM solution may mitigate locking in a network solution that is subsequently rendered uneconomic as a result of a future supply / demand outcome.

3 Note that if a service standard improvement can be provided by an investment other than in DM, yet only DM is rewarded for that service standard improvement (due to it being included in the DM incentive), incentives for investments will be inefficiently skewed in favour of DM, and away from capex solutions or non-DM opex solutions, potentially even where those solutions might be more cost effective.

- Structuring a DM investment in a way that may require the business to spend more in this regulatory period (or reduce the benefits it receives under the EBSS or CESS), in order to allow a reduction in the investment requirements[4] expected to be needed in a *future* regulatory period ('long-term investment reductions').

  An example of this would be a situation in which a retailer was investing in beyond-the-meter battery storage, with this being driven by high wholesale electricity prices. Everything else being equal, the most efficient use of those batteries from a network perspective may be to incentivise (i.e., pay) the retailer to locate them in a part of a distribution network that is forecast to be constrained in the *following* regulatory control period. However, it is unclear whether the current regulatory arrangements would incentivise a distribution business to pay now (or give up benefits that it otherwise might have achieved under the CESS if those batteries were located in a region that has capacity constraints in the current regulatory period) for the achievement of that future benefit, even if that was the more economically efficient outcome.

## 3.3. Benefits accruing to non-distribution parts of the electricity value chain

As stated earlier, DM may provide benefits to other (non-distribution) parts of the electricity value chain.

Analogous to the discussion above, the magnitude of the incentive should reflect the value that the demand management capability will deliver, and that cannot otherwise be captured by either the distribution business or the DM provider or some other market participant, given current electricity industry market arrangements and policy settings.

The regulatory framework does not provide a direct means for distributors to monetise the economic benefits of demand management service that accrue to other parts of the electricity value chain[5]. However, despite this, if there is no regulatory or legal barrier to a third-party demand management provider selling multiple demand management services to multiple parties across the electricity value chain, then subject to one proviso, there is no reason to reflect this value in the DM incentive value. The proviso is that if the administrative costs associated with relying on the market are so onerous that they are likely to preclude otherwise efficient outcomes from taking place, then it may actually be beneficial to alleviate these prohibitive transaction costs via the inclusion of these benefits in the DM incentive.

As discussed earlier, the economic benefits that might accrue to the non-distribution parts of the electricity industry value chain include, but are not limited to:

- reduction in transmission capacity requirements,
- frequency control,
- reduction in generation system requirements, and
- reductions in greenhouse gas emissions.

Conceptually, it would seem that where a service is currently priced, there is unlikely to be any material limitation to either:

4 It should be noted that this may result from a deferral or downsizing of a future investment.

5 Although the RIT-D allows the distribution business to include upstream or market benefits in its assessment of the overall value of a DM activity, the network business itself does not gain any financial benefit by doing so, or by delivering those market benefits.

- an individual customer accessing that price signal to monetise the benefits that it is providing (e.g., reduction in generation system requirements), or
- a market potentially developing for the aggregation of customers where the administrative costs associated with transactions with individual customers are prohibitive.

Applying these considerations regarding the economic benefits of DM that can accrue to the non-distribution parts of the electricity value chain yields the following conclusions:

- There is already a price signal and a way for market participants to monetise DM's ability to reduce generation system requirements or control frequency. As a result, there does not seem to be any rationale for including these values in the incentive to be provided under the DMIS.
- There is at present no current price signal for greenhouse gas emissions abatement. While this could suggest that including a price signal for this benefit could be justified, in this case, the lack of a price signal is a direct result of a decision by policymakers. It is unlikely to be appropriate for the AER to determine and implement a price signal for a service that policymakers have explicitly elected not to monetise.
- In regard to benefits to the transmission system, it may be the structure of the distribution business' NUoS tariff may compromise the provision of an appropriate price signal that would otherwise allow the DM provider to monetise the benefits their actions can provide to the transmission system. In such cases, there would appear to us to be merit in first providing the opportunity for an individual customer to be able to 'see through' to the transmission price signal, on the assumption that that price signal is cost-reflective.

Based on these considerations, we do not think there is a case for reflecting non-distribution related benefits into the DMIS incentive.

# 4. The preferred basis for the DMIS incentive

The AER's Terms of Reference (ToR) sought a recommendation regarding the preferred basis for the DMIS incentive. It noted that the incentive could be formatted as either:

- the per-unit economic value of the demand response capability provided, or
- an uplift (on the cost) of the demand management component of a non-network option.

This section of the paper describes both of these approaches and discusses the advantages and disadvantages of each.

Ultimately, the choice between the different approaches will entail consideration of the best balance between the accuracy of each approach and its associated administrative cost[6] it imposes on various stakeholders (primarily the distribution business and the AER, but potentially the DM provider as well).

## 4.1. Economic value of the demand management capability provided

The objectives of this section are to:

- describe the economic value approach,
- provide a high-level discussion of its advantages and disadvantages,
- define the additional economic value created by DM that should be the focus of the DMIS incentive (i.e., the economic value that is over and above what can already be monetised by the network business),
- provide a discussion of the principles that should guide how that value can be calculated; and
- outline the additional administrative tasks that would likely have to be undertaken to support this approach.

### 4.1.1. Overview

Using the economic value of the demand management capability provided by the DM initiative would require assessing the likely impact of the specific project or program the distribution business is proposing to implement.

The primary advantage of this approach would be its linking of the incentive to the specific benefit provided, with this benefit being one that cannot otherwise be captured by the distribution business under the current regulatory framework, or by the DM provider (via the broader market). The primary disadvantage would be the perceived difficulty in conducting this assessment and having to do it for each individual DM project or program.

It should be noted that this approach does not require information regarding the cost of the DM program to set the incentive. Rather, it sets the incentive value based on the benefit provided by the DM.

6 The administrative cost can also be thought of as regulatory burden.

### 4.1.2. Identifying the sources of additional economic value created by DM that should be the focus of the DMIS incentive

As noted earlier, we believe that two factors – 'option value' and 'long-term investment reductions' - should form the basis of the DM value to be reflected in the DMIS incentive. This is based on the assumption that the EBSS and the CESS provide a means for the distribution business to monetise the near-term benefits of DM that result in deferral of augmentation, and that if DM were able to provide a changed level of service such as improved voltage control, then this would be better addressed by including voltage control as a service target under the STPIS so that it could incentivise the most efficient mix of projects/programs to achieve that level of service.

However, the option value and long-term deferral value of DM activities will be bespoke, in that their value will depend on a number of project-specific factors, and different projects are quite likely to exhibit very different option and long-term deferral value outcomes. The larger the range of feasible outcomes, the less likely that economic efficiency will be improved by "setting" an ex ante value based on some form of average or prototypical project, and applying this average value across all projects. The decision to do so would only be justified where the administrative cost of calculating the value outcome of DM activities on an individual project basis is high enough to outweigh the inaccuracy entailed in an ex ante value. Where this difficulty exists, the use of sub-groups of projects (e.g., DM projects that address different voltage levels within the network) may be able to reduce the variance of value outcomes and thereby reduce the inaccuracy of the use of ex ante values. However, the identification of the range of value outcomes and the ability of subgroups and/or prototypical projects to reduce that range (and thereby increase accuracy) will require data development and analysis. Use of such an approach will depend on whether the improvement in accuracy justifies the administrative cost of the required data development and analysis.

### 4.1.3. Principles for calculating the option value benefits

If the economic value created by DM were to be calculated on a project/program specific basis, the following principles could be used to calculate the option value benefit of a project:

- The option value should be definitively linked to the following two factors:
  - the range of feasible outcomes affecting demand for the network asset being assessed, in acknowledgement that the greater the range of feasible demand outcomes, the greater the potential value of flexibility, and
  - the range of capital cost outcomes associated with those demand forecasts, in acknowledgement that the greater the cost difference between any feasible demand outcome, the greater the potential value flexibility has.
- To operationalise these principles, the calculation of the option value of a project should in theory:
  - reflect the probability that the flexible option value will be called upon *outside of the period covered by the existing CESS scheme*[7], thus it should be linked to a demand forecast outcome one POE level higher (e.g., POE 90) than what is normally used for planning purposes (e.g., POE 50), and

7 If the flexible option would be called upon within the period covered by the CESS, then in theory, that mechanism should motivate the distribution business to reflect this in its analysis of whether or not to make the network investment, or to procure the alternate DM solution.

- be linked to the costs to the network business of the capital assets that would be needed to support that different POE level (e.g., POE 90), as compared to its typical planning investment levels, so as to capture the impact of scale efficiency[8].

### 4.1.4. Principles for calculating the long-term deferral benefit

If the economic value created by the demand management were to be calculated on a project/program specific basis, then the long-term investment reduction benefit of a project should overcome the potential incentive to pay for DM to be installed in areas that have a higher value the near term (which presumably can be monetised via the CESS and the EBSS), at the expense of areas that have an even higher value in the long term (i.e., over the potential life of the DM).

The relevant principles for calculating the long-term deferral benefit of a DM initiative would then involve:

- calculating the annualised value (e.g., $/kVA/yr) of a DM program's ability to defer future capital expenditure over the longer term (e.g., 10 years) in different parts of its network, based on the NPV of the business' future capex program over that period divided by the NPV of the growth in the future demand over that period that is driving that forecast capex expenditure to be spent,
- comparing those regional annualised values to the regional annualised values that will accrue to the business over the regulatory period given the operation of the current regulatory framework; and
- providing an uplift (in $/kVA) to the DM such that the distribution business is incentivised to pay for DM to be located in regions where it provides the largest long-term benefit over the life of the DM to be undertaken.
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### 4.1.5. Potential sources of administrative cost of the economic value approach

Despite its advantages, the economic value approach would impose administrative costs on the distribution business, the AER, and possibly DM providers.

For the distribution business, these administrative costs might include:

- development of a 90 POE forecast for each area for which an augmentation project was contemplated within the regulatory period (to support the calculation of the option value);
- development and exercise of a methodology and/or model for calculating the option value and potential longer-term deferral benefits of DM activities[9]; and/or

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8 NOTE: Implicitly, the whole approach to option value is an attempt to incentivise the distribution business to identify the level at which they should trade off the scale efficiency of a capex solution versus the flexibility of a DM solution, so the greater the scale efficiency, the less value should be placed on flexibility.

9 An alternative would be for the AER to provide the methodology or a model for doing so. We note that ISF developed such a model and used it to provide comment in the consultation process on the extent to which the financial returns that accrue to a network business from four different types of DM investment align with the economic returns that can be expected to accrue to its customer base. That model could provide a base for further development, should the AER want to provide a model for distribution businesses to use.

- additional reporting to the AER, including provision of all information used in the calculation of the option value and/or the long-term deferral benefit, noting that these data would need to be related to the specifics of each project.

The AER would incur administrative costs in the following areas:

- potentially needing to provide a data template and/or a model;
- data checking, including the need to overcome information asymmetry regarding the data provided by the distribution businesses; and
- the need to review and provide a determination on additional augmentation projects

DM providers might also, at least in some cases, incur administrative costs under the economic value calculation approach. This would most likely entail the need to provide detailed information regarding the impacts of proposed DM initiatives.

It should be noted that while we have conceptualised these potential sources of administrative cost, no attempt has been made to assess their extent or their materiality.

### 4.1.6. Selecting the appropriate metric for denominating the DMIS incentive

A variety of metrics have been put forward by the AER for consideration:

- reduction of kVA at peak
- reduction of kVA
- a metric for improved voltage control, and/or
- any other output that could be used to measure performance.

The first consideration in selecting a metric is to ensure that it expresses the benefit being provided by the DM[10]. In the majority of cases, DM will be used as a means for balancing supply and demand for the capacity of the distribution network, hence the appropriate metric should be directly linked back to a business' underlying augmentation cost driver. In most cases this will be either co-incident peak demand or energy at risk. As such, $/kVA of demand management is likely to be the most appropriate metric.

## 4.2. Cost uplift

The objectives of this section are to:

- describe the cost uplift approach, and
- provide a high-level discussion of its advantages and disadvantages.

### 4.2.1. Overview

Under a cost uplift, the distribution business would be allowed to recover revenue equal to some percentage of the costs of designing, implementing and administering the DM initiative.

10 In this regard, we note our earlier recommendation that voltage control be considered for addition to the STPIS. Assuming that recommendation is taken, the DMIS incentive would not need to reflect the voltage control benefit.

### 4.2.2. Advantages and disadvantages

The primary advantage of this approach is that its administrative costs could be very low, as they could potentially be limited to (a) the cost of an initial study to set the level, and possibly (b) the cost of assessing the impact of the level chosen and the cost-effectiveness of the DM projects undertaken based on it, with the possibility of then revising the level of uplift (either up or down).

Another, secondary benefit would be that the approach could be implemented relatively quickly, which could:

- avoid lost opportunities for capitalising on specific DM initiatives that can reduce network costs and provide benefits to consumers;
- more quickly have an impact to change entrenched behaviour within the distribution business;
- provide additional and earlier opportunities for distribution businesses to build capabilities in DM initiative assessment, design and implementation; and
- hasten the development of the market for the provision of DM products and services.)

However, this approach also has the following disadvantages:

- If the uplift percentage isn't underpinned by a detailed assessment of the value created from a statistically significant sample of projects[11], there will inevitably be a disconnect between the uplift payment and the value created by that project, thus leading to inefficient investment (or potentially non-investment) in DM; and
- Even if the uplift percentage was underpinned by a detailed assessment of the value created from a statistically significant sample of representative projects, the total cost incurred by the distribution business in implementing any particular DM project has no definitive relationship to the benefit that consumers may realise from the implementation of that DM. This is because the benefit that is created by DM is a function of several factors including the cost of the supply-side alternative, the underlying growth rates in demand, the probability and consequence of being able to delay (or defray) the costs of the supply side alternative under alternative demand scenarios, and the unit cost (cost per kVA) of the demand side alternative, and not simply the total cost of obtaining the amount of DM contracted.

11 And even then, there are risks that the value will not be closely representative of the specific project it is being applied to.

# 5. Worked examples[12]

## 5.1. Objective

The objective of this section is to provide worked examples of how the value of the two benefits of DM identified as providing economic value that is not recognised in the current regulatory framework -- 'option value' and 'long-term investment reductions' – could be calculated.

For illustrative purposes, we have also converted the results of this limited number of examples to a cost uplift format.

It should be noted that this modelling was undertaken in a simplified form given the time and resources available for this work, hence it is for illustrative purposes only.

## 5.2. Calculating option value

### 5.2.1. Basis of the analysis

The underlying basis for the analysis is as follows:

- We have used actual RIT-D projects provided by the AER as the basis for the worked examples (see section 5.2.2 below for the specific RIT-Ds used). Wherever possible, we have relied on the data in the relevant RIT-D. In particular, all capex and DM-related costs have been derived from published data. That said, our intention was not to replicate exactly the RIT-D analysis, but rather, to ensure that our simplified modelling reflected reasonably robust 'real-world estimates' of capital and operating costs (of supply-side projects) and the cost of DM alternatives.
- We have modelled a BAU scenario (in terms of NPV of costs), reflecting the RIT-D capex, opex and DM assumptions. This is assumed to reflect the least-cost means of balancing supply and demand, under a POE 50 scenario.
- We have then "estimated" a POE 90 scenario, based on the impact that a large-scale take-up of battery storage could have on the underlying POE 50 demand forecast. More specifically, this POE 90 scenario assumes that there is around a 15% penetration of batteries within 10 years (i.e., there is a 10% chance that this outcome could occur), and that each battery will contribute 2.5kW of peak demand reduction (5kW of continuous cycle, over 2 hours).
- We have estimated the impact that this revised POE 90 demand forecast could have on the timing of the original capex/opex program as described in the RIT-D, based broadly on when the new POE 90 demand forecast would reach the original threshold level that triggered the expenditure under the POE 50 scenario.
- We assumed that to obtain this benefit (being the difference in the NPV of the capex and opex required under the POE 50 and the POE 90 scenario, which can also be described as the 'Raw Option Value'), the distribution business would have to utilise DM for 3 years from the time the original capex was forecast to be spent, in order to see whether the POE 90 forecast comes to fruition.

12 The spreadsheet model developed and used to calculate the benefits in the worked examples was provided to the AER as part of this project.

- We have estimated the uplift percentage applicable to DM based on the NPV of the probability weighted raw option value (being 10% * the raw option value) / NPV of the option cost (being the DM for 3 years).
- The range of the uplift is between 7% and 26% (the details of each of the worked examples are provided in section 5.2.3 below).

### 5.2.2. Data sources used

The examples were based on data taken from the following three RIT-D reports:

- "Sunbury - Diggers Rest Electricity Supply": Jemena Electricity Networks (Vic) Ltd Sunbury - *Diggers Rest Electricity Supply RIT-D Stage 2: Draft Project Assessment Report*
- "Lower Mornington Peninsula Supply Area": *Project Assessment Report Lower Mornington Peninsula Supply Area Project № UE-DOA-S-17-001*
- "Emerald 66kV Project": *Regulatory Investment Test for Distribution, Final Project Assessment Report, Emerald 66kV Network*. [Note that in this project, the alternative is not a DM solution, but rather an embedded diesel generation solution, however the process described above is still the same.]

### 5.2.3. Results

The assumptions used in each of the examples and the results of the calculation of the option value based on the RIT-D data and the specific assumptions made are presented in the sections below.

Each of the examples also used the general assumptions shown in the following table:

Table 1: Key General Assumptions

| General Assumptions | Value |
|---|---|
| Annual inflation | 2.5% |
| Starting Year | 2016 |
| Discount rate | 6.37% (based on Jemena, Diggers Rest RTI-D modelling) |
| Assumed impact of each battery | 2.5kW (based on Tesla Powerwall, continuous discharge of 5KW over 2 hours) |

## Sunbury – Diggers Rest

Table 2: Assumptions for Jemena – Diggers Rest Project

| DM parameters | | Capital and Operating Cost Parameters | | Demand Parameters | |
|---|---|---|---|---|---|
| DM Total Cost in RIT-D ($2016) | $2,013,797 | Total Capital Cost in RIT-D ($2016) | $13,418,915 | Current POE50 Peak Demand (MVA) | 40.21 |
| DM required in RIT-D (MVA per annum required to defer capex) | 5.725 | Original Capex Construction Year in RIT-D | 2018 | Estimated Number of customers served* | 24000 |
| Raw Cost per MVA in RIT-D | $351,755 | New Construction Year (assuming POE90 Deferral) - Capex* | 2025 | No. of customers with a battery in 10 years under POE90 scenario* | 15% |
| Original - Start Year DM in RIT-D | NA | Annual OPEX Costs ($2016) | $201,284 | Impact of battery (MVA)* | 9 |
| Original - End Year DM in RIT-D* | NA | Original Year - Opex Commences | 2019 | | |
| Final year when DM is required to generate OPTION VALUE* | 2020 | New Start Year of Opex (assuming POE90 Deferral)* | 2026 | | |
| Start Year when DM is required to generate OPTION VALUE* | 2018 | | | | |

Source: Jemena Electricity Networks (Vic) Ltd, *Sunbury - Diggers Rest Electricity Supply RIT-D Stage 2: Draft Project Assessment Report*, OGW Assumptions*

The results are outlined in the following table.

Table 3: Results for Jemena – Diggers Rest Project

| Parameter | Results |
|---|---|
| NPV of Original servicing approach | $14,719,202.21 |
| NPV of alternative approach assuming POE 90 forecast (*excluding* Option Cost) | $10,979,048.01 |
| NPV (Option Cost) | $5,084,295.06 |
| Option Value (Raw) | $3,740,154.21 |
| Option Value (Probability weighted) | $374,015.42 |
| **Uplift Percentage on DM expenditure** | **7.36%** |

### Lower Mornington Peninsula

Table 4: Assumptions for United Energy – Lower Mornington Peninsula Project

| DM parameters | | Capital and Operating Cost Parameters | | Demand Parameters | |
|---|---|---|---|---|---|
| DM Total Cost in RIT-D ($2016) | $917,500 | Total Capital Cost in RIT-D ($2016) | $29,500,000 | Current POE50 Peak Demand (MVA) | 110.00 |
| DM required in RIT-D (MVA per annum required to defer capex) | 12 | Original Capex Construction Year in RIT-D | 2022 | Estimated Number of customers served* | 60000 |
| Raw Cost per MVA in RIT-D | $76,458 | New Construction Year (assuming POE90 Deferral) - Capex* | 2028 | No. of customers with a battery in 10 years under POE90 scenario* | 15% |
| Original - Start Year DM in RIT-D | 2018 | Annual OPEX Costs ($2016) | $147,500 | Impact of battery (MVA)* | 22.5 |
| Original - End Year DM in RIT-D* | 2021 | Original Year - Opex Commences | 2023 | | |
| Final year when DM is required to generate OPTION VALUE* | NA | New Start Year of Opex (assuming POE90 Deferral)* | 2029 | | |
| Start Year when DM is required to generate OPTION VALUE* | NA | | | | |

Source: United Energy, *Project Assessment Report Lower Mornington Peninsula Supply Area Project № UE-DOA-S-17-001*; OGW Assumptions*

The results are outlined in the following table.

Table 5: Results for United Energy- Lower Mornington Peninsula Project

| Parameter | Results |
|---|---|
| NPV of Original servicing approach | $26,969,373 |
| NPV of alternative approach assuming POE 90 forecast (*excluding* Option Cost) | $18,923,062 |
| NPV (Option Cost)* | $0.00 |
| Option Value (Raw) | $8,046,312 |
| Option Value (Probability weighted) | $804,631 |
| **Uplift Percentage on DM expenditure**** | **26.53%** |

*There is no incremental option cost in this scenario, as it is assumed that the DM project that underpinned the preferred option in the RIT-D, creates the option value. **Probability weighted option value divided by cost of DM option in RIT-D.

## Emerald

Table 6: Assumptions for Ergon Energy – Emerald 66kV Network Project

| DM parameters | | Capital and Operating Cost Parameters | | Demand Parameters | |
|---|---|---|---|---|---|
| DM Total Cost in RIT-D ($2016) | $602,000 | Total Capital Cost in RIT-D ($2016) | $6,500,000 | Current POE50 Peak Demand (MVA) | 43.00 |
| DM required in RIT-D (MVA per annum required to defer capex) | 5 | Original Capex Construction Year in RIT-D | 2020 | Estimated Number of customers served* | 8700 |
| Raw Cost per MVA in RIT-D | $120,400 | New Construction Year (assuming POE90 Deferral) - Capex* | 2026 | No. of customers with a battery in 10 years under POE90 scenario* | 15% |
| Original - Start Year DM in RIT-D | NA | Annual OPEX Costs ($2016) | $32,500 | Impact of battery (MVA)* | 3.2625 |
| Original - End Year DM in RIT-D* | NA | Original Year - Opex Commences | 2021 | | |
| Final year when DM is required to generate OPTION VALUE* | 2022 | New Start Year of Opex (assuming POE90 Deferral)* | 2027 | | |
| Start Year when DM is required to generate OPTION VALUE* | 2020 | | | | |

Source: Ergon Energy, *Regulatory Investment Test for Distribution, Final Project Assessment Report, Emerald 66kV Network*; OGW Assumptions*; ^The source of the DM in this project was an embedded generator.

The results are outlined in the following table.

Table 7: Results for Ergon Energy – Emerald 66kV Network Project

| Parameter | Results |
|---|---|
| NPV of Original servicing approach | $5,700,353 |
| NPV of alternative approach assuming POE 90 forecast (*excluding* Option Cost) | $4,510,760 |
| NPV (Option Cost) | $1,411,305 |
| Option Value (Raw) | $1,189,593 |
| Option Value (Probability weighted) | $118,959 |
| **Uplift Percentage on DM expenditure** | **8.43%** |

### 5.2.4. Caveats

It is important to note the following caveats regarding the worked examples above:

- None of the analysis has sought to determine whether DM, even after inclusion of an estimate of the option value, was the most economic means of balancing supply and demand in any of the individual projects. The objective of developing the examples was to illustrate a way of calculating the option value, and as a by-product, to ascertain a reasonable estimate of the percentage uplift that could be applied to DM to compensate for this economic value.
- The analysis relies on a number of assumptions, not the least being that there is a 10% probability of a 15% (or thereabouts) penetration of battery storage occurring within 10 years, and that the operation of this battery storage will occur in a manner that leads to a 2.5kW reduction in peak demand (per battery).

  In practice, the option value will be dependent on numerous factors specific to an individual project. A proxy such as that assumed in the worked example could be used to reduce the administrative costs associated with developing a POE 90 forecast and associated capex program. Alternatively, and more accurately (though requiring additional effort on the distribution business' part, and requiring assessment by the AER), the cost uplift could be based on the difference between the POE 50 and a bespoke POE 90 forecast.
- The analysis assumes that everything else is equal between the two projects.

## 5.3. Calculating the value of potential long-term investment reductions

### 5.3.1. Basis of the analysis

The underlying basis for the analysis is as follows:

- We have assumed that the Average Incremental Cost (AIC) approach to determining a business' LRMC (which produces an annualised $/kVA) is a reasonable reflection of the economic benefits that could accrue from an investment in DM;
- We have assumed that the AIC can vary across different parts of a distribution business' service territory, hence the value of DM can vary depending on the part of a business' service territory it is adopted in. Furthermore, we have assumed that <u>the value of DM may differ over time</u>. For example, the economic benefits provided by a battery installation may be high in a particular area (Area A) early in the forecast period (because its capital program is front-ended), whereas the economic benefits provided by a battery in another area (Area B) may be higher than area (A), however these economic benefits may accrue latter in the forecast period than in Area A.
- We have assumed that in some cases the decision to install DM is driven by factors that are outside of the distribution business's control (e.g., such as high wholesale prices, which may drive a retailer to install batteries beyond-the-meter). However, we have assumed that the distribution business can negotiate with the proponent of the DM (e.g., retailer) at the time of installation, to have that DM installed *anywhere* within its region, hence the opportunity cost of a distribution business' decision to negotiate to have DM installed in one part of its service area is that it is depriving another part of its service territory from being able to access that DM.

- We have assumed that a distribution business would negotiate to have the DM installed in the area within its service territory that generates the largest financial benefit under the Capital Efficiency Sharing Scheme (CESS), which in turn may not align with the area within the business' service territory where the DM would generate the largest economic benefit over the life of the DM (e.g., 10 years for a battery). This assumption has been made on the basis that once the battery has been installed, the future benefits flowing from the utilisation of the battery are likely to flow directly through to end customers in the form of:
  - lower demand forecasts, and hence
  - lower capex forecasts in future regulatory period/s.
- We have assumed for modelling purposes that the economic loss that is created in this situation is the difference between the LRMC of the area with the highest annualised cost ($/kVA/yr) in regulatory period 1 (Area A) and the LRMC of the area with the highest annualised cost ($/kVA/yr) over the life of the battery, being 10 years (Area 2).
- For simplicity, the uplift (in $/kVA/yr) assumes the DMIS is simply trying to overcome the incentive under the CESS to install the battery in Area A (where the business can capture the financial benefit because it is within the period covered by the CESS) instead of Area B (where the economic benefits fall outside of the period covered by the CESS, but are higher than in Area A). In effect, the distribution business is incentivised by being given the long-term economic benefits of having the batteries installed in the "correct" area (Area B), less whatever financial benefit they will receive through the CESS (which is approximated by reference to the $/kVA figure measured over five-years).

We adopted this process for one example only. This example utilises actual information from a distribution business. Because this is only one example and because of the caveats presented in section 5.3.3 below, we do not consider the results of one calculation should be relied upon as representing a possible value of this benefit.

### 5.3.2. Results

Table 8: Results – Long-term capital expenditure example

| Parameter | Results – 10-year period ($/kVA)^ | Results - First 5 year ($/kVA)* |
|---|---|---|
| Area 1 | $101.43 | $173.67 |
| Area 2 | $208.55 (A) | $0.00 (B) |
| Area 3 | $180.01 | $116.53 |
| **Uplift applied if DM put in most economic region**** | **$208.55 (A) - (B)** | |

^ Based on NPV (Augmentation Capex over 10 years / NPV (incremental demand over 10 years driving that augmentation capex); * Based on NPV (Augmentation Capex over 5 years / NPV (incremental demand over 5 years driving that augmentation capex); **Assumes demand response solution lasts at least 10 years.

### 5.3.3. Caveats:

In practice, the benefits attributable to the DM that is undertaken will be dependent on specific factors affecting each individual business, including, but not limited to:

- whether the value of DM differs across a business' service territory;

- whether the value of DM differs over time, hence creating the possibility that a business that maximises the financial benefits from deploying DM under the CESS, may not be maximising the economic benefits that are generated from that DM over its expected useful life; and
- the extent to which DM is being incentivised by the price signals that pertain to other parts of the value chain (e.g., wholesale, retail).

The analysis has not sought to exactly model the operation of the CESS (i.e., to model the exact financial benefits that a business accrues from using DM to defer capital investment), nor does the analysis try to reflect the impact that the actual timing of when the DM that is incentivised by the price signals pertaining to other parts of the value chain is actually installed.

# 6. Implementation considerations

## 6.1. Objective

This section of the report discusses several aspects of the implementation and administration of the DMIS that will be important for its ability to both motivate participation by the distribution businesses and link the incentive to performance.

## 6.2. Specific issues of relevance in the implementation and administration of the DMIS

We note that the details of how the DMIS will be implemented and administered have not yet been determined. Examples of issues that are likely to need to be addressed in this regard are:

- should the DMIS incentive to be calculated on a project-specific, project-type or business-specific basis;
- should the incentive should be calculated on an *ex ante* or *ex post* basis;
- what procedures should be used in determining whether the DNSP has delivered the DM as proposed, and what to do if not; and
- how can appropriate sharing of the benefits produced by the DNSP's DM activities be ensured between the distribution business and its customers.

The following sections discuss each of the issues above and the implications of the different approaches applicable to them for the AER's ability to link the DMIS incentive to the tangible performance outcomes

### 6.2.1. Should the DMIS incentive to be calculated on a project-specific, project-type or business-specific basis

A noted above, the calculation of the benefits associated with a specific DM activity is the most accurate means for setting a cost-effective incentive. However, where very similar projects are to be offered (to similar customer groups) there may be some advantages in reduced administrative costs. This could also justify the development of an incentive value for a distribution business for the duration of a regulatory period.

### 6.2.2. Should the incentive be calculated on an *ex ante* or *ex post* basis

Our view is that the incentive should be calculated on an *ex ante* basis to provide the distribution business with certainty regarding the financial return on their DM activity (assuming it is implemented as assumed in the *ex ante* considerations).

Our view is that the availability of the incentive should be highly certain. That is, having calculated the benefit and undertaken action (which is almost certain to entail expenditure) the DNSP should be able to be highly confident that the incentive will be paid.

Where the AER reviews and approves the incentive prior to the distribution business taking action (which is the approach we recommend) this would require either (a) a firm commitment from the AER that the incentive will not be reversed, or (b) very clear and readily documented grounds regarding the conditions under which some reduction or cancelling of the incentive would apply.

### 6.2.3. What procedures should be used in determining whether the DNSP has delivered the DM as proposed, and what to do if not

In our view, this would be addressed by the following considerations:

- Annually, the AER administers the incentive, by confirming from records provided by the distribution business that
  - the amount of DM that has been contracted by the distribution business,
  - the contracted DM meet any relevant criteria that was stipulated as the basis for the incentive payment (e.g., the DM capability must be in place by a certain time or for a certain duration), and
  - that the incentive amount has been calculated correctly.

Approval of those items would trigger approval of a pass-through type event in the revenue requirement for the following year. This approach removes the risk to the customer that an incentive is paid to the distribution business but does not accomplish anything.

(It is worth noting that the distribution business will almost certainly need to consider these same issues in the contractual arrangements it puts in place with the customers, retailers or aggregators that provide DM to it.)

These procedures will also allow the AER to link the DM incentives provided to performance outcomes.

Capturing these sorts of information will also provide:

- a useful and potentially centralised information base of learnings from the DM activities that result from the DMIS, and
- an important means for linking the incentive provided by the DMIS to the performance (and benefits delivered) by the DM activities undertaken by the distribution business receiving the incentive.

### 6.2.4. How can appropriate sharing of the benefits produced by the DNSP's DM activities be ensured between the distribution business and its customers

Using DM as an alternative to supply side solutions will benefit all customers, if it incentivises distribution businesses to balance supply and demand at the least cost. As outlined earlier, this will be related to the accuracy of the DM incentive provided under the Scheme.

Under the current regulatory framework, over time, lower costs flow through to customers in the form of lower prices, via the operation of the CESS and the EBSS schemes. Therefore, if a distribution business invests in DM, in lieu of an investment in a supply-side solution:

- The distribution business will benefit as presumably they will have only made the investment if the DMIS incentive plus the benefit it receives under the CESS scheme exceeds the costs it will incur under the EBSS scheme, and
- Customers will benefit as a result of not having to pay (via higher prices) for an investment that is now not required (or has been downsized or deferred), but instead having to pay the (lower) DM direct costs plus the DM incentive payment.

In short, assuming that the DMIS incentive is paid to the distribution business in any/every year in which it provides option value or the potential to produce a deferral in the longer-term (i.e., outside the current regulatory period), both parties will receive the respective benefit listed above, and no further 'sharing' mechanism should be needed.