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Pricing for the Integration of Distributed Energy Resources

Project Summary Report ***June 2020***

DISCLAIMER

This report summarises the approach and findings of a study that assessed the potential for more cost-reflective pricing to assist in the economically efficient integration of distributed energy resources (DER) with the grid. It was partially funded by the Australian Renewable Energy Agency (ARENA) under its Advancing Renewables Program (ARP).

The information in this report is intended to provide information for use by electricity industry businesses, DER equipment owners and aggregators and electricity regulators, market bodies and relevant government agencies.

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1. Executive summary

1.1. Objective of the study

Distributed energy resources (DER) such as rooftop PV with and without battery storage, electric vehicles and stationery behind the meter batteries, depending on where they are located and when and how they are operated, can either impose or reduce costs on the overall electricity supply chain.

The central focus of this study was the development of price signals that could be used to better integrate DER with the central generation and grid electricity supply chain. Such price signals would need to inform DER owners and their agents (e.g., aggregators) about the costs and benefits that DER can pose for the supply chain and, hopefully, incentivise:

- Investment in DER
  - at the right scale, at the correct location, and at the right time, and
  - at the lea*st cost*; and
- Operation of DER in such a way that it is allocated to its highest value use in its location at any specific time, so as to maximise its economic value.

The price signals developed in the study focus in particular on providing price signals that reflect the benefits that DER can provide to – and the costs it can impose on – the electricity supply chain.

Input to the project was provided from a variety of stakeholder perspectives via two reference groups that reviewed and commented on the various stages of the work as the study progressed.

1.2. Ways DER can reduce costs in the electricity supply benefits[1]

The primary way in which DER can provide benefits to the electricity supply chain is by reducing costs. The study identified the following areas in which DER can do that. Specifically:

DER can reduce network costs in the following areas:

- Direct connection costs
- Extension of the existing shared network
- Augmentation of the existing shared network
- Replacement of the existing shared network
- Costs of managing voltage within required levels within the existing shared network
- Managing bushfire risk[2].

At present, however, the pricing structures used by DNSPs do not reflect DER's ability to reduce these costs.

1 The cost drivers within the electricity supply chain that DER can affect are discussed in our topical report entitled, *Cost drivers: the foundation for pricing DER in the NEM*, April 2019.

2 Bushfire risk is an externality that network businesses generally have regard for in their planning decisions. DER - particularly in the form of stand-alone power systems -- can be a feasible alternative to grid-supplied electricity. As such, bushfire risk and the degree to which it can be reduced by DER is best seen as a component of the connection cost to be faced by an individual customer or the replacement cost of an asset serving one or more customers.

DER can reduce costs in the wholesale market in the following areas:

- The investment in and operation of the generation fleet required to meet aggregate consumer demand, and
- The cost of managing the operation of the wholesale electricity market.

The wholesale market already provides price signals in several of these areas (for example, the wholesale market provides a very transparent price signal for the value of putting energy into the grid, and the FCAS[3] market provides a similarly transparent price signal for the value of the services that can assist in managing system frequency. However, these price signals cannot be readily accessed by DER owners and their agents.

The potential for DER to reduce greenhouse gas emissions associated with the provisions and use of electricity was not explicitly considered in the study precisely because those costs are not directly included in the price of electricity[4].

1.3. Price signals to integrate DER and the grid[5]

In developing alternative pricing structures for the various ways in which DER can provide value by reducing costs within the electricity supply chain we considered four independent parameters:

- The form of the price signal – specifically whether the price signal should be a charge, a rebate or a payment;
- The time at which the service is provided, specifically whether the level of the price signal should be static or dynamic;
- The basis of the price signal, specifically whether it should be based on the short- or the long-run marginal cost of the service being provided; and
- Location, specifically whether and to what extent the price signal should vary by location.

These different parameters were mixed and matched to provide a 'menu' of candidate pricing structures for each of the DER services that had been identified. This mix and match approach resulted in there being anywhere from 2 to 6 candidate pricing structures for each DER service, ranging from simpler structures that are somewhat similar to current pricing approaches, to more sophisticated and complex structures that are considerably different to the approaches currently in use.

The Stakeholder and Market Bodies Reference Groups (SRG and MBRG) were generally very supportive of the suite of pricing approaches that were developed. However, the SRG expressed a general preference for:

- Location-specific, as opposed to DB-wide, DER price signals, with a number of members expressing the view that a DB-wide, or postage-stamped, price signal would deliver very few if any economic benefits, given that future network costs will differ significantly by location; and

3 The Frequency Control Ancillary Services market.

4 The value of DER in reducing carbon emissions is recognized in government policy initiatives such as Victoria's Feed-in Tariff, which includes an explicit value related to the carbon reduction achieved by DER. DER owners receive that benefit but it does not reduce costs in the electricity supply chain.

5 A full description of the pricing structures that were developed to signal the ways in which DER can reduce cost in the electricity supply chain is provided in our topical report entitled, *Pricing for the Integration of Distributed Energy Resources: Pricing Structures*, October 2019.

- Posted price signals, as opposed to "market-driven" outcomes through which DER service providers would offer services into a market (and a dispatch schedule and market-clearing price would be established via that process). Posted price signals were felt to be preferable, particularly in the short-to-medium term due to their relative simplicity.

Examples of the pricing structures that reflect the preferences of the SRG and MBRG are provided in Section 4 of this report. The full set of candidate pricing structures can be viewed in our report entitled *Pricing structures to assist the economically efficient integration of DER* (April 2019).

The SRG and MBRG also noted that price signals reflecting the value of DER to the electricity supply chain would, in most cases, be responded to by third-party aggregators on behalf of DER owners, rather than the DER owners themselves. This has implications for the acceptable level of complexity of the pricing structures, as the value proposition of such third-party aggregators can be expected to be their ability to understand how DER technologies operate, monitor the price signals available to those technologies and operate the DER technologies of their customers on their behalf (or provide advice to DER owners that prefer to operate their technologies themselves).

1.4. Benefits and costs of pricing structures that reflect the value of DER[6]

A high-level assessment was conducted of the costs and benefits of the pricing structures developed in the study. The results indicated that the benefits of offering these types of price signals can be expected to exceed the costs. The table below shows the results at the state level.

Summary of estimated costs and benefits

Potential benefits*	VIC	NSW	QLD	SA
Transmission and distribution augmentation	$58.5m	$27.7m	$44.0m	$43.7m
Voltage benefits	$14.7m	$14.2	$1.9m	$6.9m
Less				
Est. upfront and on-going costs	$15.5m	$9.3	$6.2m	$3.1m
Net benefits (costs)	**$57.7m**	**$32.6m**	**$39.6m**	**$47.6m**

*All potential benefits are in NPV terms, based on a pre-tax real WACC of 5% and a 10-year evaluation period. Totals may not add due to rounding.

It is important to note that the assessment itself was quite conservative in that it did not quantify all of the potential benefits that could be provided by DER. Network cost reductions in voltage management and asset replacement were not quantified due to their highly situation specific nature, and wholesale market and FCAS cost reductions were not included due to the need for the sophisticated modelling required for their estimation, which was beyond the scope of this study.

6 Details of the cost/benefit assessment are provided in our topical report entitled, *Pricing for the Integration of Distributed Energy Resources: 'Fit' with Market Rules, International Experience and Cost-Benefit Assessment*, April 2020.

1.5. Degree of the 'fit' of price signals for DER services with the market Rules[7]

The study also included a review of the degree to which the DER pricing structures that were developed 'fit' with the current market rules. This review concluded that the economic, market-based approach of the National Electricity Rules (NER) is generally supportive of DER integration.

The only aspect of Chapter 6 that poses a barrier to the use of some of the pricing structures identified in the study is Rule 6.1.4 which prohibits a distribution business from charging a network user "for the export of electricity generated by the user into the distribution network". It should be noted, however, that this Rule does not preclude the use of fixed or demand charges in relation to connection services. It is also the case that the DEIP Access and Pricing work package is considering alternative pricing arrangements and intends to put forward a Rule Change request that may include a means for addressing this barrier.

Other aspects of the rules for participation and network pricing were found to be limiting at least somewhat the effective integration of DER with the grid. Some key changes have been made or are being considered that will enhance DER integration, when and if adopted:

- 5-Minute settlement – Valuing supply side energy and DER on a five-minute basis will allow dispatchable DER to gain additional income for short-term supply against dispatch peaks. This will particularly benefit assets that can be dispatched on very short notice to meet price peaks.
- DER Aggregation – The Rule changes that established the Small Generator Aggregator and Market Ancillary Service Provider market participant categories (which came into effect in 2013 and 2017 respectively) and that are being considered currently to establish a Demand Response Service Providers market participant category provide potential pathways for allowing third parties to bring a more focused approach to the development and integration of DER.
- Current Rule change processes and reviews have the potential to also be helpful as long as the changes are made with DER in mind. It is our understanding that the post-2025 market design being developed by the Energy Security Board (ESB) is considering these issues. A fully two-sided market would remove the need for specialised pricing and participation mechanisms for demand response. AEMO's VPP Demonstration Program will likely provide key insights into the operational impacts and benefits realisation of DER in the wholesale, network and retail parts of the electricity supply chain.

7 A fuller discussion of this topic is provided in our topical report entitled, *Pricing for the Integration of Distributed Energy Resources: 'Fit' with Market Rules, International Experience and Cost-Benefit Assessment*, April 2020.

2. Project background, objective, scope and organisation

2.1. Project background objective

From an economic perspective, the benefits accruing from the increasing uptake of DER in the National Electricity Market (NEM) will be maximised if the price signals and other aspects of the market arrangements incentivise:

- DER investment:
  - at the right scale, at the correct location, and at the right time (allocative efficiency), and
  - at the *least cost* (productive efficiency); and
- DER operation in such a way that it is allocated to its highest value use in its location at any specific time, so as to maximise its economic value (allocative efficiency).

Having appropriate price signals for incentivising both efficient investment in, and operation of, DER are fundamental to the achievement of the National Electricity Objective. The corollary is that an uncoordinated approach to DER deployment (i.e., one not driven by the underlying economic benefits and costs of DER) will almost certainly lead to DER being installed at an inappropriate scale, and potentially in the wrong locations and at the wrong times, as well as it being operated in a manner that does not maximise economic efficiency.

Accordingly, the overall objective of this study is to determine how price signals can be structured and presented so as to best reflect the value that DER at customer sites or elsewhere within the distribution can provide to the electricity value chain so that DER investment is driven by market forces, maximised at the appropriate points in the energy delivery chain and developed at the right scale within the NEM[8].

2.2. Project scope and limits

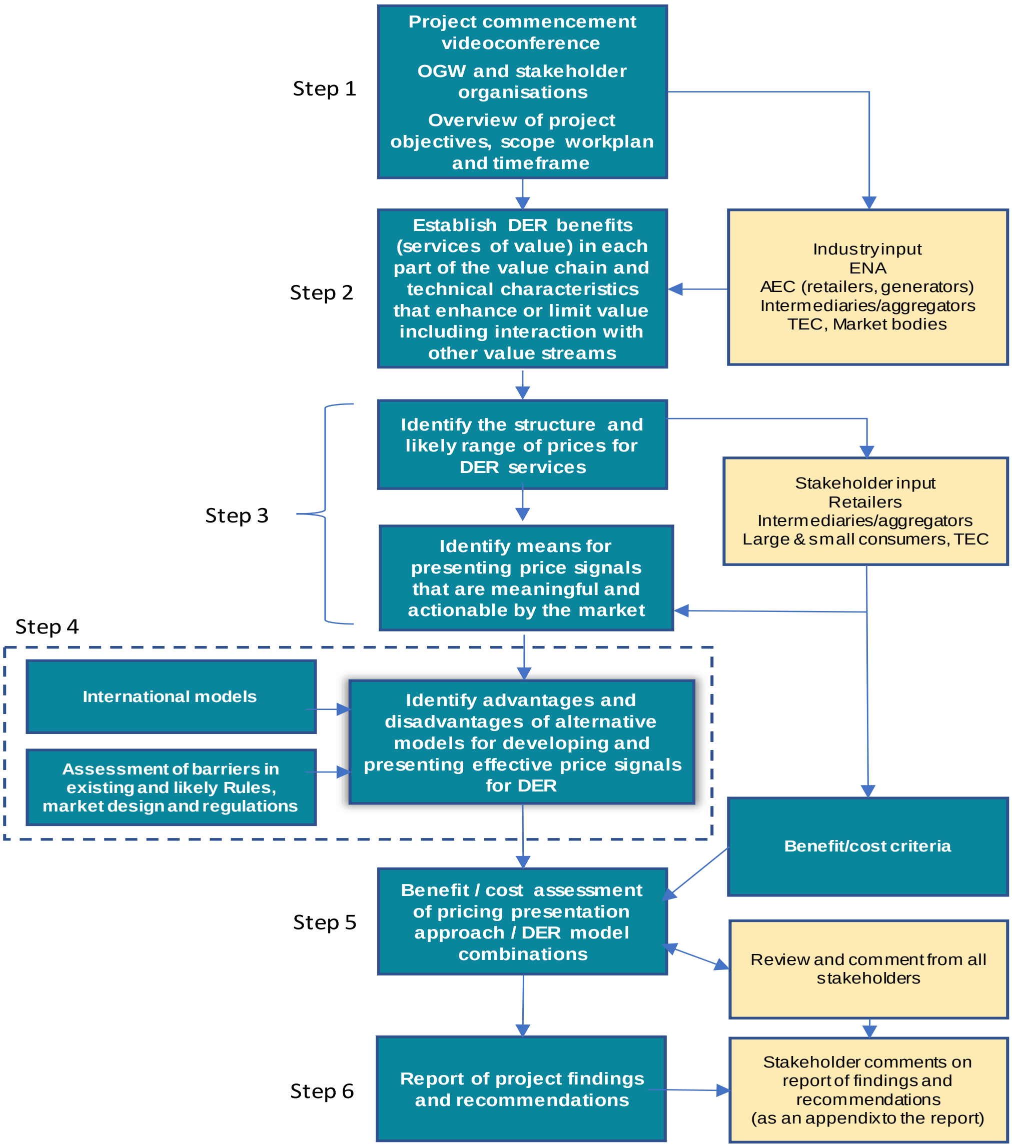
2.2.1. Study scope

The study was organised in six major steps, as shown in the figure on the following page, and includes a significant amount of stakeholder engagement and input from industry, consumer groups, market intermediaries and market bodies. The six primary steps within the study are:

- Commencement of the project with a workshop to embed the stakeholder processes to be used through the remainder of the work (Step 1).
- Identification of the services that DER can provide to each part of the electricity supply chain with specific attention to those services that are not already valued/priced (Step 2).
- Development of the value range of each service that is not currently priced in the market, along with the units in which the value should be denominated and a description of the factors that govern the technical feasibility of the use of DER for the provision of each service and the extent to which the provision of each service may interact with other services or value streams (Step 3a).

8 For the purpose of this study, DER includes decisions on the use of energy, including load shifting and curtailment (DR), as well as co-generation, tri-generation, and embedded and behind-the-meter renewable energy generation technologies and storage.

Figure 1: Overview of the project scope



- Translation of the values into price signals that can be readily understood and responded to by market participants, market intermediaries, DER investors and end customers (Step 3b).
- An assessment of the degree to which the current and likely near-term developments in the market design, Rules, market arrangements and regulatory framework will support the use of these price signals or will need to be modified to do so, incorporating learnings from other markets that are farther along in the integration of DER (Step 4).
- Assessment of the pricing options in terms of the magnitude of the value of the benefits they are likely to be able to realise as compared to the costs required to obtain them, using a set of criteria that conform with the National Energy Objective to assess their relative ability to increase economically efficient deployment and operation of DER and the complexity, costs and difficulty of implementing them (Step 5).
- Reporting of results to stakeholders for review and comment, and wider dissemination (Step 6).

2.3. Study limits

2.3.1. Scope limitations

It should be noted that this study concerns the development and use of price signals related to the benefits that the deployment and use of distributed energy resources (DER) can provide to the electricity supply chain, where 'benefit' is defined as a reduction in the cost incurred somewhere in the electricity supply chain. As such, the price signals being developed in this study almost exclusively address the export of energy generated by DER. The study does not address electricity charges for the consumption of mains delivered electricity to end-use facilities where DER systems are installed.

In addition, the study is not trying to design price signals for end-use customers. Prices for end-use customers are the responsibility of retailers and in some cases aggregators and other market intermediaries. We recognise that many if not the vast majority of end-use customers (and particularly small end-use customers) will not be interested in receiving or technically capable of responding to complex and potentially highly time-varying price signals. However, technologies exist that can be deployed by retailers and market intermediaries (and possibly in future by end-use customers themselves) that can integrate relevant information and automate the response of DER systems in ways that deliver benefits to the electricity supply chain and the DER owner. While price signals of the type developed in this study may not be used all DER owners, the absence of such price signals will severely limit the aggregate benefit that DER is likely to deliver to the electricity supply system.

2.3.2. Use of the terms DER and DR

For the purpose of this study, the term DER includes demand response (DR). This is appropriate because the value of both DER and DR lies in their ability to respond to price signals in ways that can reduce the costs incurred in the central electricity supply chain (i.e. the large-scale generation sector and the transmission and distribution networks). Because of this the structure of price signals that are appropriate for DER will also be appropriate for DR. We have therefore used the term DER as inclusive of DR.

However, there is also an important practical difference between DR and most other forms of DER (e.g., rooftop PV systems and behind-the-meter batteries). That is that DR can seldom if ever be directly measured, while DER can. Metering can establish exactly how much electricity a DER system exports. By contrast, while metering can be useful in establishing the amount of DR delivered, that amount is virtually always defined with reference to the amount of electricity that would have been consumed under business-as-usual conditions (i.e., if the DR had not been provided). This implies a counterfactual which has to be constructed; DR cannot be directly measured.

This difference does not require a difference in price signals or their structure, but it does require different approaches for measuring the output of DR as compared to DER.

2.4. Project organisation

The substantive work undertaken in the project was performed by Oakley Greenwood staff. A significant level of consultation was provided through the use of two bodies: a Stakeholder Reference Group comprised of electricity industry, consumer and third-party businesses and organisations; and a Market Bodies Reference Group. The composition of both reference groups is provided in Appendix A.

3. Cost drivers: the foundation for pricing DER in the NEM

3.1. Context and approach

The use of distributed energy resources (DER) can potentially impact each part of the electricity supply chain. However, the key to the economically efficient integration of DER into the electricity market and grid requires an understanding of the value DER can provide; that is, how the use of DER can affect – and particularly reduce – the costs of the electricity supply chain and then developing price signals that reflect those cost impacts.

As such, the purpose of this part of the project was to identify the key cost drivers within both network and wholesale generation sectors of the electricity supply chain in order to determine:

- whether and under what conditions DER can reduce (or may increase) those costs, and
- how those cost impacts can be reflected in price signals that can be (a) readily understood and acted upon by DER asset owners and/or their agents, and (b) implemented at a cost that does not exceed the value of the benefit they can be expected to provide.

More specifically, the study attempted to describe:

- how each of the cost drivers operates to affect cost in the value chain;
- the locational and temporal dimensions of each cost driver (that is, whether it affects cost everywhere always, everywhere but only sometimes, any time but only in certain places, or only certain places at certain times); and
- how DER can impact the cost driver and any impact that might have on other cost drivers within that or other parts of the supply chain.

The impact of DER on externalities associated with the electricity supply chain (for example greenhouse gas emissions, particulate emissions, land use) was not considered in the study precisely because those costs are not directly included in the price of electricity unless government policy specifically requires their inclusion (and sets the associated value to be included)[9].

3.2. Incorporating a signal for the value of DER in electricity prices

To be as efficient as possible in signalling the value of DER electricity prices should incentivise:

- **Efficient consumption behaviour:** We want to design price signals that incentivise customers to consume electricity from the grid if the marginal benefit to them of consuming that unit of electricity equals or exceeds the marginal cost[10] to society of providing that unit of electricity to that customer via the grid;

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9 Some externality costs may be captured in the electricity prices. For example, where generation facility operators or other parts of the supply chain need to carry insurance for potential damages caused by the environmental impacts of their operations, this would represent at least some internalisation of the potential costs of those sources of damage. This would be the case, for example, for pipeline operators in respect to the potential for environmental damage from oil pipeline leaks, or upstream gas and oil producers in the case of groundwater pollution from shale gas fracking or environmental damage from ocean drilling. While those insurance costs – and the compensation provided to affected parties – may or may not be an accurate quantification of the economic costs imposed on affected parties, at least some level of cost associated with these externalities (i.e., the cost of insuring against them) will be incorporated into the price of electricity, thereby providing an advantage to a resource that does not impose the potential for those impacts.

10 Noting that the marginal cost of supplying electricity services may vary depending on a range of factors, such as the location or the time of day/week/season/year at which the consumption occurs. It is also important to note that "marginal cost" is a forward-looking concept, and hence relates to future costs, not sunk costs.

- **Efficient export behaviour:** We want to design price signals that incentivise customers to export electricity to the grid where and when the marginal benefit to society stemming from that export exceeds the marginal opportunity cost[11] to the customer who is exporting that energy to the grid; and
- **Efficient connection decisions:** We want to design price signals that incentivise customers to connect to, or remain connected to, the grid if the future costs to society of providing them with grid-enabled electricity services is less than the next mor expensive alternative[12].

In sum, for a future cost to be signalled to a customer via a cost-reflective variable price, the customers' response to that price signal (whether through changing their consumption behaviour or through their subsequent decisions regarding what energy-using or producing equipment to purchase) must actually reduce that future cost. If a change in the customer's future behaviour will change the costs of the electricity supply change, a cost-reflective variable charge will not be an appropriate price signal.

So, for example, if the driver of a network business' future capital expenditure is spatial peak demand, and this future cost could be impacted by the behaviour of end customers (e.g., if they reduce their co-incident peak demands, the business can reduce its future augmentation spend), then this future cost should be signalled to customers via a variable charge that is structured to reflect that cost driver.

Other cost drivers that cannot be influenced by (or are not driven by) a customers' future consumption behaviour (e.g., the recovery of sunk investments, fixed administrative costs and the direct costs of connecting a customer) should not be signalled via a variable price signal, simply because any change in the customers' future consumption behaviour incentivised by that price signal will not affect those future costs.

3.3. Network cost drivers

The study identified the following cost drivers of network businesses as those that DER can affect:

- Direct connection costs
- Extension of the existing shared network
- Augmentation of the existing shared network
- Replacement of the existing shared network
- Costs of managing voltage within required levels within the existing shared network
- Managing bushfire risk[13].

11 This reflects the value that the customer would have generated, had it used that exported energy in its next best, alternative, use. For example, a customer's decision to export a kWh of energy to the grid may deprive them from being able to use that energy to run their air-conditioner on a hot day.

12 The AEMC's current project entitled "Updating the regulatory frameworks for distributor-led stand-alone power systems" (EMO0038) is considering these sorts of issues where a stand-alone power system could provide customers located at some distance from the network with electricity supply at lower costs than being connected to the grid.

13 Bushfire risk is an externality that network businesses generally have regard for in their planning decisions. DER - particularly in the form of stand-alone power systems -- can be a feasible alternative to grid-supplied electricity. As such, bushfire risk and the degree to which it can be reduced by DER is best seen as a component of the connection cost to be faced by an individual customer or the replacement cost of an asset serving one or more customers.

The following sections provide the key points about the nature of each of these cost drivers and the implications of the nature of each cost for how it should be reflected in price signals to the customer.

3.3.1. Direct connection costs

- There are almost always costs associated with connecting a new customer to the existing shared network.
- These costs are solely driven by the customer's connection decisions regarding their location, the type of equipment installed and the customer's energy usage and export requirements. Importantly, these costs cannot be changed in any way by other customers connected to the shared network.
- Therefore, the customers should be charged up-front for these direct connection costs.
- This would incentivise connecting customers to make efficient upfront investments in DER, as, everything else being equal, they would invest in DER up to the point where the marginal benefit (being the reduction in their direct connection costs) exceeds the marginal cost.

3.3.2. Extension of the shared network

- Network businesses often also need to extend their existing shared network in order to service new developments/new growth corridors etc. This could be done incrementally, sequentially with new development, or in advance of new development.
- There is an economic cost to the utility of undertaking these shared network extensions. These network extension costs are generally driven by the location and expected sizing and timing of new developments in new service areas.
- There is the potential for those prospective new developments to make investments in DER that contribute to the defraying or complete avoidance of these types of network extension costs, for example, if a new development were to be serviced via a micro-grid with on-site DER, the network business may avoid (or defer) the need to extend its existing network to that location.
- As such, network extension costs should in theory be signalled up-front and in advance of prospective new developments in new service areas so that those costs are reflected in developers' servicing decisions (i.e., whether to invest in on-site DER or not).

3.3.3. Shared network augmentation costs

- The shared network is comprised of those parts of the network that serve more than one customer – for example, the wires, transformers and substations in the low-voltage system that serve end-use customers, as well as the higher voltage lines and zone substations in the distribution system and the transmission system that bring electricity from the generators to customers.
- At some point of growth in electricity demand in any particular area of the network, the capacity of the equipment in that area will need to be augmented – to serve the additional demand.
- A variable price signal is the most efficient means for signalling the forward-looking costs of an augmentation (and any additional operating costs that would be associated with that augmented capacity) that is needed to serve additional electricity demand or to accommodate future levels of DER export.
- In this regard, it is important to note that DER can both:

- Reduce the growth in peak demand on an asset farther up in the distribution system that is otherwise reaching its limit to supply customers below it (for example, the load on a distribution transformer and the distribution feeders that serve it).
- Increase demand on those assets where the exported energy exceeds the total demand of the customers served by the local area network assets.

3.3.4. Replacement costs

- Network assets have a useful life and need to be replaced at the end of that time.
- Where the amount of DER available is such that it is able to offset the entire load of the shared network asset that is due for replacement, it would allow the network business to avoid the replacement of that network asset in total.
- This economic benefit – being the avoided cost of replacement – should be reflected in either the servicing solutions considered by distribution businesses at the time of replacement, or, to the extent that the replacement asset serves a single or a small group of customers the avoidable cost could be signalled to the applicable end customers in order for them to make efficient investment decisions in SAPS.
- DER can in some instances allow the replacement asset to be downsized which, while it may not avoid the cost of the replacement, may lower it.
- It should be noted that timing of network asset replacement is predominately driven by condition and risk factors unrelated to the loads placed on the asset (or the behaviour of end customers), and therefore the take-up of DFER or its use is unlikely to change the timing at which assets are replaced.

3.3.5. Costs of managing shared network voltage within required levels

- Network businesses are required, by regulation, to supply electricity within specified voltage bands.
- Where the network does not maintain voltage within that range it incurs risks and potential costs from customer complaints and the costs of investigating those complaints, and responsibility for damage to customers' equipment.
- Traditionally, networks have been designed to manage voltage *drops*, not voltage increases. The voltage on LV circuits tends to drop the further away from a transformer a customer is located. However, PV, particularly when located at the ends of LV circuits, can cause voltage to rise with distance[14].
- Network businesses can manage voltage issues to some degree using existing assets, for example by adjusting tap settings down to lower voltages, hence providing more scope for accommodating the higher voltages that come with increased export of energy back into the network at certain times of the day.
- Customers can also potentially contribute to the management of this issue. For example, on-site storage could be used to store the excess energy that a customer's PV system generates for use (or discharge) at a later time, thus either contributing to the alleviation of voltage rises (outside of limits) during periods of high DER production or by alleviating voltage drops (outside of limits) during periods of high underlying demand.

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14 The impact of PV on voltage and the relationship of distance to this impact is complex.

- Theoretically, if a network were to send a price signal regarding the management of voltage fluctuations on the network, customers would be faced with the correct economic price signals to inform their investments in, and operation of, DER equipment.

3.4. Wholesale electricity market cost drivers

The study found that there are two major areas in which costs are incurred and could potentially be affected by DER:

- The investment and operating costs of the generation fleet required to meet aggregate consumer demand
- The cost of managing the operation of the wholesale electricity market.

3.4.1. Cost drivers of investment in and operation of the wholesale electricity generation fleet[15]

The wholesale energy market involves costs for investment in electricity generators and the efficient dispatch of available generation plant to meet aggregate consumer demand.

The energy-only design of the NEM means that both of these types of costs must be met through a combination of pool price income, settlement of financial contracts (which are essentially derivatives of expected pool prices) and to a lesser extent bilateral, physical contracts. The wholesale electricity spot market and the contract market provide price signals for the first of these two.

DER can potentially reduce the investment and operational costs of meeting aggregate consumer demand by providing a lower cost of supply during dispatch and also by being contracted for future supplies of energy. However, in the past DER has not been able to access these price signals directly. In general, only two sources of price signals have been available to DER owners: feed-in tariffs offered by retailers or mandated by governments, or other arrangements offered by retailers to customer (such as poo price pass through, special tariffs for interruptibility and pool price saving sharing schemes).

The Wholesale Demand Response Rule Change currently being considered by the AEMC would, if approved, allow DR to be offered into the wholesale electricity market on terms and conditions – and with payment arrangements – similar to that of large-scale generators[16].

In addition, the Retailer Reliability Obligation (RRO) which came into effect in July 2019 can provide an incentive (though not a direct price signal) to retailers and some large energy users to contract or invest in dispatchable and 'on demand' resources. In the event that AEMO in the course of its annual electricity supply demand forecasting process identifies a material gap in reliability within a NEM region three years and three months out, it will apply to the AER to trigger the RRO. When triggered, the RRO requires liable entities be able to show they have sufficient qualifying contracts to cover their share of demand. Qualifying contracts can include DER.

In summary, the market already provides price signals for approaches that can reduce the capital and operating costs of the wholesale electricity sector in meeting aggregate consumer demand and recent and pending changes in market Rules will provide significantly better access to those price signals for DER.

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15 Note that some of the material in this section includes updated information on developments that have taken place since the time that this part of the study was conducted.

16 See https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism. More accurately, the Rule Change would have DR treated as a scheduled load, but in that form it would have access to and be paid the spot price for electricity when dispatched.

3.4.2. Cost drivers for the management of the wholesale electricity market

Management of the operation of the wholesale market system itself has costs that need to be efficiently met by the market system operator. These include:

- the provision of emergency reserves to ensure sufficient supply during low probability events that are outside of participant planning;
- management of system frequency; and
- ensuring appropriate reactive power and system strength.

Each of these is discussed below. The market already provides price signals for the first two, and these price signals are becoming more accessible to DER.

Emergency reserves

- The market operator has to ensure the correct amount of reserves in the market. The level of reserves required is forecast and calculated by AEMO on the basis of the USE standard set by the Reliability Panel.
- Ideally, the correct level of reserves should be met by normal market operations. To the extent that the level is not achieved, AEMO must intervene based on its best judgement of the likely shortfall.
- DER (particularly DR through load reduction or the use of behind-the-meter standby generation) has been proven to be a good source of emergency reserves. Other dispatchable sources of DER – including the use of battery storage – are also prime candidates for providing this service.

Ancillary services

- The market operator must ensure that sufficient ancillary services are available to the market. These include:
  - Frequency Control Ancillary Services (FCAS), which ensures that system frequency is maintained within a specified margin of 50 Hz as load increases and decreases.
  - Frequency regulation services, which are associated with small deviations in supply.
- FCAS resources must:
  - Be dispatchable and able to respond to a frequency signal when activated, and
  - Have high speed metering to measure the response.
- DER is a good source of FCAS, and several types of DER – including DR, standby generation batteries (including batteries teams with renewable energy generation) are already accessing the FCAS market.

Reactive power and system strength

- Reactive power is required to ensure that power flows efficiently through the network. The requirement for this service is highly locational and is typically met through a combination of generation, reactors and capacitors and, most recently power electronics that are associated with a source of power.

- System strength is required to manage alterations in demand in power systems. Some forms of DER can provide the services required to maintain system strength. Fault level protection can be provided by power electronics paired with a stable power source such as a battery, and batteries can also provide inertia or fast frequency response. The market does not provide explicit price signals for either of these services.

4. Pricing structures to assist the economically efficient integration of DER

The previous section of this report summarised and described the types of services that DER can provide to the electricity value chain. This section explores how the value of those services could best be reflected in the structure and nature of price signals provided by the various parts of electricity supply chain to investors in and owners/operators of DER.

4.1. Principles of efficient pricing

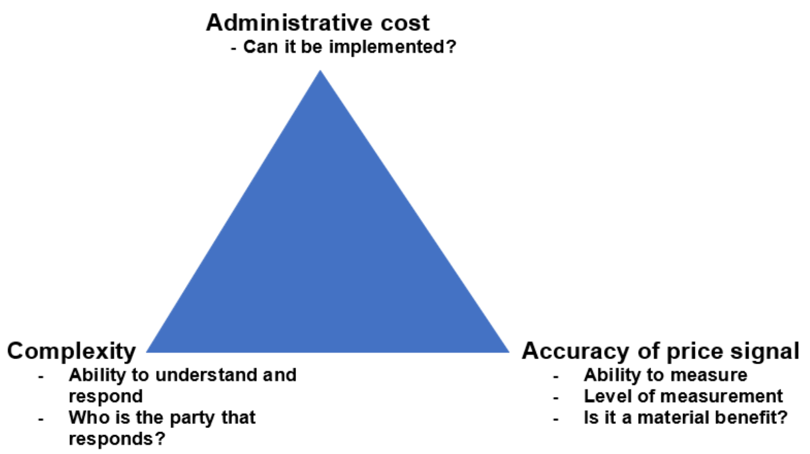
The design and operation of the wholesale electricity market is based on competitive bids from generators that the market operator assess and then dispatches those resources that will, within the dispatch period, minimise the cost of meeting aggregate consumer demand.

The regulatory framework includes a number of explicit statements that guide the pricing of network services, the most important of which are:

- The revenue to be collected from (and therefore the price of network services to) each tariff class must be between the stand-alone cost of serving the customers within that tariff class and the avoidable cost of not serving those customers.
- Each tariff must be based on the long-run marginal cost of providing the service to the customers assigned to that tariff.
- The revenue expected to be recovered from each tariff must reflect the Distribution Network Service Provider's total efficient costs of serving the customers assigned to that tariff.
- When changing its tariff, the Distribution Network Service Provider must consider the impact on customers of the change from the previous year including the degree to which the affected customers can (a) choose the tariff they are on and/or (b) mitigate the impact of the change in the tariff changes through their usage decisions.
- The structure of each tariff must be reasonably capable of being understood by the customers assigned to it.

More generally, there is almost always a range of potential price signals that could be introduced in order to facilitate more efficient outcomes and that could be perceived as being consistent with the Rules and economic efficiency. Developing efficient pricing structures involves making trade-offs, as depicted in Figure 2.

Figure 2: Pricing trade-off considerations



While the three scales shown in Figure 2 may be the ones on which the most significant trade-offs need to be considered, other non-economic factors such as community, customer and Government acceptability generally also need to be taken account of.

4.2. Approach used in developing pricing structures to reflect DER benefits

In developing alternative pricing structures for the various ways in which DER can provide value by reducing costs within the electricity supply chain we considered four independent parameters:

- The form of the price signal – specifically whether the price signal should be a charge, a rebate or a payment;
- The time at which the service is provided, specifically whether the level of the price signal should be static or dynamic;
- The basis of the price signal, specifically whether it should be based on the short- or the long-run marginal cost of the service being provided; and
- Location, specifically whether and to what extent the price signal should vary by location.

These different parameters were mixed and matched to provide a 'menu' of candidate pricing structures for each of the DER services that had been identified. This mix and match approach resulted in there being anywhere from 2 to 6 candidate pricing structures for each DER service, ranging from simpler structures with more similarity to current pricing approaches to more sophisticated and complex structures that were considerably different to the approaches currently in use.

The Stakeholder and Market Bodies Reference Groups (SRG and MBRG) were generally very supportive of the suite of pricing approaches that were developed. However, the SRG expressed a general preference for:

- Location-specific, as opposed to DB-wide, DER price signals, with a number of members expressing the view that a DB-wide, or postage-stamped, price signal would deliver very few if any economic benefits, given that future network costs will differ significantly by location; and
- Posted price signals, as opposed to "market-driven" outcomes through which DER service providers would offer services into a market (and a dispatch schedule and market-clearing price would be established via that process). Posted price signals were felt to be preferable, particularly in the short-to-medium term due to their relative simplicity.

Reflecting this, the sections that follow concentrate on those pricing structures that are closer to the preferences of the SRG and MBRG. The full set of candidate pricing structures can be viewed in our report entitled *Pricing structures to assist the economically efficient integration of DER* (April 2019).

However, the SRG and MBRG also agreed that price signals reflecting the value of DER to the electricity supply chain would, in most cases, be responded to by third-party aggregators on behalf of DER owners, rather than the DER owners themselves. This reduces the importance of the guiding principle mentioned above that the structure of a tariff should be reasonably capable of being understood by the customers assigned to it. To the extent that DER price signals are more likely to be aimed at and responded to be third-party aggregators as agents of DER technology owners, the evolution of DER price signals to their more sophisticated forms may be quicker than it would otherwise be.

4.3. Pricing structures to signal DER costs and benefits to the distribution network

The following sections summarise the objectives and candidate pricing structures that could be used to signal the ways in which DER can reduce costs for networks.

4.3.1. Direct connection costs

Everything else being equal, this price signal should incentivise customers to:

- Install DER where it economically reduces upfront direct connection cost
- This includes:
  - Customers making efficient decisions to NOT in fact connect to the grid in the first place and instead, adopt a SAPS solution.
  - Customers making efficient decisions to invest in DER that reduces the cost of their direct connection costs.

Table 1: Pricing structures to signal DER impacts on direct connection costs

Charges, rebates and payments	Static / Dynamic Price	Approach to developing price level (e.g., LRMC//Market)	Vary by location	Comment
Direct connection charge	Dynamic	Forecast actual costs	Yes	This would involve all direct connection charges being charged to the connecting customer. A connection charge reflects the costs the DB incurs in connecting a customer to their existing shared network, and which only that customers' upfront connection decision can influence (i.e., no other party is able to influence that cost). This would incentivise efficient investments in DER.
Deep(full) connection charge[17]	Dynamic	Forecast actual costs	Yes	This would include the direct connection costs plus any impact that a customer's connection decision would have on the timing of the distribution business' forecast investment in the shared network (i.e., as a result of development X, augmentation of asset Y needs to be 'brought forward' by 5 years, relative to the DB's original, least-cost planning scenario). Note that if a connection, or a development is "out of sequence", the connecting customer would be charged the bring-forward costs stemming from that out of-sequence development. To the extent that development in that area was planned for at that time, any future shared network augmentation costs should already be reflected in the DUoS tariffs charged to customers. This would incentivise efficient investments in DER.

17 This could be converted into a **rebate** to a connecting customer with DER, via the DB estimating the impact that a customer's investment in DER would have on their shallow / deep connection costs, as opposed to the customer doing it themselves and then deciding what is the most economic solution.

4.3.2. Extension of existing shared network

Everything else being equal, we want a price signal that incentivises customers to, amongst other things, invest in DER upfront if that reduces the costs of extending the shared network.

Table 2: Pricing structures to signal DER impacts on the cost of extending the existing shared network[18]

Charges, rebates and payments	Static / Dynamic Price	Approach to developing price level (e.g., LRMC//Market)	Vary by location	Comment
Area-based extension rebate (1)	Static	Area-based estimate of benefit to DB of an individual connecting customer installing DER	Yes	A rebate to an individual customer reflecting the impact that that customer's upfront investment in DER is expected to have on the timing and/or size of any investments that the distribution business has forecast as being required in extending the shared network to service them.
Area-based extension rebate (2)	Static	Area-based estimate of benefit to DB assuming some broader take-up rate of DER in that area by customers being serviced by extension asset.	Yes	A rebate to a customer reflecting the impact that that customer's upfront DER investment is expected to have on the timing and/or size of any investments that the distribution business is forecasting to have to make in extending the shared network. Further to this assumption, the rebate assumes that other customers in the area would also take-up some DER in the future.

Note that the choice between the two approaches may be a function of the DB's planning assumptions (e.g., does it assume, for the purposes of sizing an extension asset, that all future customers have DER or not). Rebates and/or charging can be used to manage this issue.

4.3.3. Shared augmentation costs

Everything else being equal, we want a price signal that incentivises customers to, amongst other things:

- Install batteries in areas where they are able support the network efficiently.
- Discharge in-situ batteries during periods where they are of the most benefit to the network (which is when the network is, or is likely to be, constrained due to high consumer demand).
- Efficiently ration the discharge of batteries where the network is constrained (e.g., high wholesale price events leading to rapid increase in the discharge of batteries to the grid).
- Orientate their PV system, having regard to the impact that that decision will have on the provision of network support (e.g., incentivise west-facing orientation).
- Consume electricity (to the extent that the DER provider also consumes) where the marginal benefit exceeds the marginal value that the DER provider could otherwise derive from providing network support[19].

18 Future augmentations of assets that were originally extension assets are covered under "shared network augmentations

19 It should be noted that, under certain supply/demand scenarios, the opportunity cost of consuming during a period where network support is being financially rewarded is the lost or reduced value the DER provider will receive from being unable to or only able to export less electricity to the grid.

However, the pricing structure to be used will need to have regard to whether shared network augementation costs are driven by peak demand, energy at risk or too much export. Somewhat different pricing arrangements may be required to align with the different underlying cost driver in each case. Moreover, pricing structures, at least in theory, should also send price signals regarding costs that are expect to be incurred in upgrading the network to accommodate future levels of exported energy from DER (e.g., high wholesale price events leading to rapid increase in the discharge of batteries to the grid). The principle being that where (export) capacity is scarce, capacity should be allocated to its highest value use. The following tables highlight pricing options for each such situation.

Table 3 shows pricing structures that can be used to signal the value DER can provide in avoiding shared augmentation costs; Table 4, on the next page, provides pricing structures that can be used to signal the costs that excess exports can impose on the shared network.

Table 3: Pricing structures to signal DER impacts on shared augmentation costs driven by energy at risk or peak demand

Charges, rebates and payments	Static / Dynamic Price	Approach to developing price level (e.g., LRMC//Market)	Vary by location	Comment
Area-based Static “Network-Support” tariff	Static	LRMC of managing peak demand by area NOTE: Definition of area up to DNSP	Yes	DB sets a (static) **rebate** for the **energy** discharged during a **small,** set number of hours/months (e.g., 4-6pm during summer months), reflecting LRMC of managing peak demand in the local network area during the periods where capacity constraints **generally** occur in that area.
Area-based Callable “Network-support” tariff	Application is Dynamic / Price is static	LRMC of managing peak demand in LV network in that area	Yes	Events “called” by network business in advance (e.g., 2-hours in advance) - by area - as opposed to it being based on a pre-set time of day/month combination. NOTE: Rebate amount is still pre-set by area.

Table 4: Pricing structures to signal DER impacts on shared augmentation costs driven by excess exports

Charges, rebates and payments	Static / Dynamic Price	Approach to developing price level (e.g., LRMC//Market)	Vary by location	Comment
Area-based Callable “Network export” tariff	Application is Dynamic / Price is static	LRMC of managing peak demand (for export services) in that area	Yes	Events “called” by network business in advance (NOTE: Likely to be short notice, given factors driving such an outcome - e.g., high prices outside of high demand periods). Would only be called for areas “at risk”. NOTE: The actual export tariff amount would be pre-set by area.
Access rights	Various	Cap and trade, with ability to pay for augmentation, with rights to the new capacity	Yes	This is in the Rules (Rules 5.3 and 5.5) but has not been effectively implemented for generation sources due to fairness and other concerns. Can be physical and financial.

4.3.4. Replacement costs

Everything else being equal, we want a price signal that incentivises customers to invest in DER where it may, in the long run, reduce a distribution business' replacement costs. An example of this might be on long rural feeders where it may be more efficient to use a SAPS system in lieu of replacing the existing network (e.g., SWER).

Table 5: Pricing structures to signal DER impacts on network asset replacement costs

Charges, rebates and payments	Static / Dynamic Price	Approach to developing price level (e.g., LRMC//Market)	Vary by location	Comment
Rebate for disconnection	Static	Avoidable cost of supply	Yes	Publish a rebate for customers in certain areas where replacements are: • Likely to be required in the near-term; and • Likely to be uneconomic, related to an alternative distributed solution The rebate amount would be linked to the DB's avoidable cost of supply (which should in theory be calculated under the Rules)

4.3.5. Costs of managing voltage within required levels on shared network

Everything else being equal, we want a price signal that incentivises customers to, amongst other things:

- Charge batteries during otherwise high voltage events (i.e., to soak up energy that would have been otherwise exported to the grid, causing high voltage issues).
- Discharge batteries during otherwise low voltage events.
- Increase on-site consumption (in lieu of exporting PV) during otherwise high-voltage events.
- Decrease on-site consumption (and in turn, increase PV export) during otherwise low voltage events.
- Orientate PV to account for the impact PV has on voltage (e.g., incentivise west-facing orientation).

It should be noted that there are automated means for doing this that would mean that 'calls' would not need to be made, and dispatch decisions could be made with less lead time. But there would need to be an agreement with the customer and equipment installed. This is the subject of a number of trials and small-scale programs.

Table 6: Pricing structures to signal DER impacts on the cost of managing voltage

Charges, rebates and payments	Static / Dynamic Price	Approach to developing price level (e.g., LRMC//Market)	Vary by location	Comment
At-risk feeder Static Voltage Support tariff	Static	LRMC of managing voltage by at-risk feeder	Yes	As above - but differentiated by at-risk feeder (and no price signal for feeders where no voltage issues foreseen)

Charges, rebates and payments	Static / Dynamic Price	Approach to developing price level (e.g., LRMC//Market)	Vary by location	Comment
"Callable" voltage support tariff	Application is Dynamic / Price is static	LRMC of managing voltage by feeder	Yes	Events "called" by network business in advance (e.g., 2-hours), by feeder, as opposed to being based on a pre-set time of day/month combination. NOTE: Tariff/rebate amount is still pre-set, at a feeder level.

4.4. Pricing structures for DER integration with the various cost/benefit streams in the wholesale market integration

The two primary components of the wholesale electricity market have been designed to be economically efficient. The wholesale spot market is based on generator bids, which must include the amount of electricity the associated unit price, that are used to set the clearing price and dispatch instructions for every five-minute interval. Similarly, participants in the FCAS market provide bids for the amount and unit price for whichever of the eight separate FCAS services they are offering to provide in each interval.

Direct participation in the wholesale market has historically only been available to very large customers, and very few such customers have interacted with the wholesale market in that way. More recently, retailers have made pool-price pass through tariffs available to both larger and small customers[20]. The vast majority of customers, however, have no visibility of the wholesale market price, but rather pay a relatively static price for the electricity they use, with then retailer using the contract market to manage the volatility of the wholesale spot price.

In any case, these arrangements have all concerned pricing arrangements for customers' consumption. The only prices that have been available for electricity exported by small-scale DER have been feed-in tariffs.

DER (including DR) can potentially reduce investment and operational costs in the wholesale market both by providing a lower cost of supply during dispatch and also by being contracted for future supplies of energy, thereby avoiding investment[21]. Alternative pricing structures could be used to provide small-scale DER owners (or aggregators) with price signals that reflect the costs/prices within he wholesale market, and thereby provide a means for DER to compete in that market with potential benefits for all electricity users.

20 Retailers have made such arrangements to large customers, and more recently Flow Power has made these arrangements available to a wider range of commercial and industrial customers. Amber Electricity is (to our knowledge) the only retailer making pool-price pass through available to residential and small commercial customers.

21 DER can also reduce system losses by reducing central system demand, thereby increasing the productive efficiency of the market.

Table 7: Pricing structures to integrate DER in the wholesale market

Charges, rebates and payments	Static / Dynamic Price	Approach to developing price level (e.g., LRMC//Market)	Vary by location	Comment
Integrate DER pricing into dispatch - pool impacts (expanded status quo)	Dynamic	SRMC impact • Avoided fuels and market costs LRMC impact • Dispatch of DER will be picked up in SOO and other forecasts and replace investment in other supply	Regional (vary with losses and constraints)	Allow FRMP to offer DER on a firm dispatch basis into the NEM dispatch process • Retailer to be the FRMP (simplest case) • Multiple FRMPs at a site to allow Aggregators/DER providers or customers to participate as well as retailers (requires Rule change) • Contracts between FRMP and customers or DER providers to be unregulated.
Status quo but supported by efficient consumption and export tariffs for end users	Static or dynamic	As above with additional LRMC benefit that FRMP can incorporate contracts into its portfolio and reduce investments.	Possible	Retailers (as FRMP) charge efficient charges and can therefore customers can value DER correctly for capacity/demand and energy benefits. Aggregators, DER providers and customers supply services to the FRMP via unregulated contracts. FRMP to incorporate into its risk management process
Financial contracts	Static	Primarily LRMC to avoid investment but also SRMC as pure price risk management.	No	Allow DER providers as FRMPs to participate in the Exchange based and OTC contract markets, allowing the FRMP to incorporate the capacity and energy into its risk management process

The primary issue for DER is gaining access to these price signals. As noted, retailers can provide these sorts of pricing arrangements to customers, but do not have to do so, and in most cases, have not done so. This is complicated by the fact that small-scale DER located on the customer's side of the meter (including DR) can only access the wholesale market through arrangements provided by the retailer serving the facility at which the DER capability is located. However, Rule Changes that have been made in the last several years and various technology and business model trials that have been undertaken have begun to change this[22].

22 Relevant Rule Change examples include those that have established Small Generator Aggregators and Market Ancillary Service Providers (which came into effect in 2013 and 2017 respectively) and are being considered currently to establish Demand Response Service Providers, as defined market participants. A key example of a relevant trial is AEMO's VPP Demonstration Program. Further discussion is provided in Section 6.1.1 below.

5. Cost-benefit assessment of candidate DER pricing structures

An assessment was undertaken of the costs and benefits of the pricing structures developed in Step 3 of the project. This section of the report provides information on the approach taken in the cost/benefit analysis and its results.

5.1. Overview of approach used

Any approach for estimating the economic benefits of adopting more efficient pricing arrangements for DER services will necessarily require a significant amount of judgement and the adoption of a number of high-level, simplifying assumptions.

However, at its core, it required estimation of:

- How many DER facilities will be installed under the more efficient pricing arrangements that are being modelled[23], and how those facilities will be utilised under those more efficient ('alternative') pricing arrangements, *as compared to* how many facilities would be installed and how they would be utilised under the base-case pricing arrangements. More specifically, this involves:
  - Determining the incremental change in the number and size of the facilities that will be installed, and
  - Determining how the DER facilities that are forecast to be installed will interact with the grid under both existing and the alternative pricing arrangements.
- The impact that the above changes are likely to have on network businesses' costs, and costs in other parts of the value chain.

5.2. Benefits and costs included in the analysis

5.2.1. Benefits included in the analysis

Table 8 describes the benefits that were included in the analysis and how they were calculated.

Table 8: Benefits (cost reductions) from adoption of alternative DER pricing arrangements

Services	Information sources and approach
Network augmentation	Where available (and current), we multiplied the published LRMC estimates for the applicable DNSP business by the incremental impact of DER on peak demand due to the alternative pricing arrangements as compared to the base case (from the modelling above); *plus* Where available, we multiplied the published applicable locational TUoS charge by the incremental impact of DER on peak demand due to the alternative pricing arrangements as compared to the base case (from the modelling above).

23 It should be noted that while the analysis is not prescriptive regarding the final design, structure or level of the pricing arrangements that would be put in place, it does assume that the pricing arrangement would reflect the LRMC of any costs that the DER can reduce in the value chain in both a temporal and a geographic sense. As an example, we assume that a network-based DER export price signal would be like an area-specific critical peak demand charge as compared to a static time-of-use energy charge.

Services	Information sources and approach
Voltage-related expenditure	We have assumed that appropriate DER pricing arrangements would incentivise the use of battery storage systems to manage voltage issues. In particular, we have assumed that (a conservative) 25% of the installed capacity of batteries in any particular local government area (LGA)[24] would be incentivised to be "set aside"[25] on certain days when voltage issues are likely to be prevalent (i.e., "abnormally high" output levels from in situ PV systems are expected, and mild temperature conditions prevail, leading to low underlying loads on the network due to the absence of temperature-sensitive loads such as air-conditioners). This in turn is assumed to reduce the amount of PV-generated electricity injected into the distribution system over a 2-hour period, and subsequently also manages the voltage issues that would have occurred during the middle of the day due to the PV export. The magnitude of the network cost reduction is based on proportioning down DNSP forecasts of DER integration expenditure (where known, and extrapolated from known information where not[26]) by the reduction in exported energy (which is in effect the base case, less the amount that is assumed to be captured by the battery). For the avoidance of doubt, it should be noted that we have not had regard for the forecast penetration levels of DER at the LGA level over time in this analysis. As a result, it could be that forecast PV generation in a particular LGA may not, over the forecast horizon, lead to any voltage issues in the first place. We have also not had regard for the specific location of the particular PV system (i.e., whether the customer installing the battery is located at the beginning, middle or end of the feeder).

Table 9 describes the benefits that were not included in the analysis and why they were omitted.

Table 9: Potential benefits not included in the cost-benefit assessment and reasons for their omission

Services	Description and reasons for non-inclusion
Direct connection cost reduction	The cost of connecting a customer to the existing shared network is dependent on a number of customer-specific factors, including, but not limited to, the distance between the shared network and their connection point, their load, and the geographic location (which would also impact the cost of the Standalone Power System (SAPS) that would need to be installed, due to, for example, the number of PV arrays that would need to be installed). Due to the bespoke nature of the expenditure, we have not attempted to model this benefit.
Network extension cost reduction	Similar to the above, the quantum of network extensions is ultimately related to the location of connecting customers, and whether they are "out of sequence", which cannot be readily forecast in either the base case or alternative pricing cases.

24 The geographic level at which the assessment of DER take-up in response to the pricing structures was assessed in the study.

25 It should be noted that this may simply involve the owner of the battery exporting their energy earlier in the day when an over-voltage related price signal is in place, instead of storing it in their battery. This in turn frees up space in the battery to take exported energy during the middle of the day, when voltage issues are more likely to occur.

26 Based on publicly available information from regulatory submissions and some regulatory decisions, this has generally been in a range between $5m and $10m per year. Where we have not been able to readily find information for a particular distribution business, we have adopted a figure in this range.

Services	Description and reasons for non-inclusion
Network replacement cost reduction	We have not modelled the potential economic benefit of more efficient levels of replacement expenditure, because: • The timing of these costs is not expected to be materially affected by a change in demand or energy consumption; rather, these costs are predominately driven by condition and risk factors unrelated to the loads placed on the asset; • Demand reductions need to be of a minimum scale to lead to any downsizing relative to the base case (noting that capacity is built in increments, so material reductions need to occur for downsizing to occur); and • Downsizing replacement assets leads to a reduction in economies of scale (i.e., halving the size of a replacement asset almost always leads to less than a 50% reduction in the cost), hence further reducing the economic benefits. We note that this is not to suggest that there is no benefit, rather, that in the main, the benefit is likely to be moderate, relative to other potential benefits.
Wholesale market benefits	As noted in the Pricing presentation and paper, efficient pricing is already available through the wholesale energy market. The translation of these prices to customers via retailers is not readily observable, although we were provided with good anecdotal examples during the study[27]. It is therefore difficult to establish the base case for a cost benefit example and we have not modelled these benefits. In addition, a key change that we have identified, allowing aggregators into the market cannot be readily assess in a cost benefit study of this type.
Wholesale market operator benefits	We have noted above that changes to the ancillary services markets and also the contracting of reserves by AEMO are already underway.

5.2.2. Costs included in the analysis

In assessing the costs that would be incurred by network businesses we have assumed that a DNSP would incur costs to both develop and implement these alternative pricing structures, but these would not be expected to be either particularly large, or to involve information or business processes that are particularly different from those already being undertaken by these businesses. Specifically, we have assumed the following:

- $1m per DNSP to develop the alternative pricing structures proposed above
- $500k per annum per DNSP to administer, maintain and communicate the tariffs to the market

Our rationale for the order of magnitude of these estimates is that the distribution businesses are already generating much of the information required to develop and implement more efficient DER price signals, and moreover, the communication of such a tariff would broadly align with existing practices. For example, DNSPs are already:

- Generating the cost required to augment their system at both the system and location-specific level. This can be used to provide a price signal for the ability for DER to defer demand-related augmentation; and

- Forecasting the impact that increased penetration of PV is likely to have on distribution system voltage in different parts of their network. This type of information - forecast cost, by area, and forecast voltage excursions (relative to standard) – could be used to inform the level and structure of a voltage-related price signal[28].

It is worth noting that, in our view, the implementation of the proposed alternative pricing structures would not impose any additional costs for either metering at the DER level or network visibility of voltage/thermal constraints on the LV network. This is because:

- The interval metering that would be required for the administration of these alternative price signals is already required when these systems are installed, and we are not assuming that these price signals would affect the total number of DER systems installed , but rather their location and use.
- It is also the case that over-voltage constraints (which are generally due to DER export at times of relatively low demand at the local network level) are likely to occur only where the density of DER systems (or their export) reaches a threshold of customer numbers (or aggregate customer load) within that area. Both the number of customers installing DER and the nameplate capacity of those systems is already known to local distribution business. In addition, the interval metering that is required to be installed on these systems can provide information on the voltage condition at the host premises of these systems[29]. The DNSP can use this information to assess the likely impact of the aggregate voltage condition of these premises on the likely voltage condition at the local area asset level.

5.3. Results

Table 10 provide a summary of the results of the high-level cost-benefit analysis.

Table 10: Summary of estimated costs and benefits

Potential benefits*	VIC	NSW	QLD	SA
Transmission and distribution augmentation	$58.5m	$27.7m	$44.0m	$43.7m
Voltage benefits	$14.7m	$14.2	$1.9m	$6.9m
Less				
Est. upfront and on-going costs	$15.5m	$9.3	$6.2m	$3.1m
Net benefits (costs)	**$57.7m**	**$32.6m**	**$39.6m**	**$47.6m**

*All potential benefits are in NPV terms, based on a pre-tax real WACC of 5% and a 10-year evaluation period. Totals may not add due to rounding.

28 We note that standards can be used to set a ceiling on the over-voltage possible from PV systems as their penetration on a feeder increases - AS4777:2015 is one such example. However, a price signal is likely to be more economically efficient. The choice between them, on a practical level, requires consideration of their relative costs, complexity and aggregate impact.

29 Information on voltage is available from Type 4 meters, but as it is not included in the data that is automatically provided by the metering data provider to the DNSP, access to it and the price for that access would be a subject of negotiation between the DNSP and (most likely) the relevant metering coordinator. An alternative that could be considered by the DNSP would be the installation of voltage measurement equipment on the LV side of transformers or at other points on the LV meters. We have not costed access to the interval metering data or the installation of grid-side voltage measurement equipment as either will be highly situation specific.

The results indicate that the benefits of offering these types of price signals can be expected to exceed the costs. However, we note that we have been conservative in developing the costs and benefits of developing and offering these price signals. In particular, as shown in Table 9, several sources of material potential value have not been quantified in the analysis:

- Perhaps most important in this regard is that we have not modelled the upstream impact of the alternative network pricing structures. Those impacts – particularly in the wholesale and FCAS markets could be significant. These impacts were not modelled as they would have required market simulation modelling which was beyond the scope of this study.
- We have also not included the benefits that could accrue from cost reductions for direct connections and network extensions. These were excluded because they are dependent on a number of customer-specific and timing factors.

It should also be noted that the costs of developing and implementing the alternative network pricing structures developed in this study would enable all of the benefits identified. As a result, it is highly likely that the actual net benefits that would be expected to be realised from these pricing structures would be higher than suggested in Table 10.

It is also critical to realise that the costs and benefits of DER will vary over time (and from place to place), and the result of any CBA will be highly dependent on what the value of the relevant costs and benefits are or were thought to be at the time the analysis was undertaken. For example, if this analysis had been undertaken five or six years ago, we would have ascribed a much greater benefit to cost-reflective network prices due to their impact in deferring network augmentation. This would have been the case simply because forecast demand (and therefore the amount of capex required for augmentation) was much greater. By contrast, the voltage issues occurring on the network due to high penetrations of PV – and the benefits of addressing them – are significantly greater now than would have been considered to be the case five to six years ago.

6. 'Fit' of pricing structures with NEM Rules and regulations

This section of the report summarises the findings of Step 4 the project scope of work. It provides:

- A discussion of the degree to which the DER pricing structures summarised in Section 4 above 'fit' with the current market rules, and
- A review of selected international experience in the use of price signals to integrate DER with the traditional electricity supply chain.

6.1. Review of the 'fit' of price signals for DER services with the market Rules

The following chapters within the National Electricity Rules (NER)[30] were identified as those of primary relevance[31] to the ability for pricing structures that reflect the value that DER can provide to various parts of the electricity supply chain:

- Chapter 2: Registered Participants and Participation.
- Chapter 3: Market Rules, which deals with wholesale market dispatch and settlement.
- Chapter 4: Power System Security and the related Chapter 4A: Retailer Reliability Obligation.
- Chapter 5: Network Connection, Access, Planning and Expansion.
- Chapter 6: Economic Regulation of Distribution Services (and the corresponding Chapters 6A: Economic Regulation of Transmission Services and Chapter 6B: Retail markets).
- Chapter 7: Metering.

6.1.1. Chapter 2: Registered Participants and Participation

Until recently, small-scale DER located on the customer's side of the meter (including DR), has only been able to access the wholesale market through arrangements provided by the retailer serving the facility at which the DER capability is located. Rule Changes that have been made in the last several years have begun to change this and to enhance the channels through which DER can access and respond to these price signals that are available in the wholesale market. Relevant examples include the Rule Changes:

- that have established Small Generator Aggregators and Market Ancillary Service Providers (which came into effect in 2013 and 2017 respectively), and
- that are being considered currently to establish Demand Response Service Providers

as defined market participants.

More recently AEMO, in conjunction with the Australian Renewable Energy Agency (ARENA), the Australian Energy Market Commission (AEMC), the Australian Energy Regulator (AER), and members of the Distributed Energy Integration Program (DEIP) has established a VPP Demonstration Program. AEMO's website[32] states that the program will:

30 It should be noted that the NER deal primarily with the wholesale market and network provision. The National Electricity Retail Rules and jurisdictional regulations also place limitations on efficient pricing in the electricity market. Those Rules and regulations were not

31 Other chapters include administrative matters (Chapter 8), either derogate specific aspects of the Rules (Chapters 8 and 9) or manage implementation of Rules (Chapter 11).

32 https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/pilots-and-trials/virtual-power-plant-vpp-demonstrations

allow VPPs to demonstrate their capability to deliver services in contingency FCAS and energy markets. The VPP Demonstrations will allow participating VPPs to trial a new specification to deliver contingency FCAS, and AEMO will observe how VPPs respond to energy market price signals as non-scheduled resources. By trialling VPP operations while their aggregated fleets remain of a small scale, the VPP Demonstrations aim to inform the effective integration of VPPs into the NEM before they reach large scale.

The program specifically aims, among other things, to:

- Allow VPPs to demonstrate their capability to deliver multiple value streams across FCAS, energy and potential network support services.
- Provide AEMO with operational visibility to help AEMO consider how to integrate VPPs effectively into the NEM.
- Assess current regulatory arrangements affecting participation of VPPs in energy and FCAS markets, and inform new or amended arrangements where appropriate.

The program published it first knowledge sharing report in March 2020[33] which includes early lessons learned in the following areas:

- Operational capability for market participation
- Value stream realisation
- Early assessment of regulatory arrangements
- Technology development.

6.1.2. Chapter 3: Market Rules

The market Rules in Chapter 3, in themselves, do not limit the integration of DER. This is because all parties allowed participation under Chapter 2 or connected under Chapter 5, are treated equally, according to their class, in dispatch and settlement processes.

The recent change in the Rules to settle the market on a 5-minute interval basis will improve the value of dispatchable DER supplied to the market, assisting in its integration.

The market chapter also deals with two other key aspects of the market for DER integration: ancillary services and market interventions.

DER can be and is being incorporated into the FCAS markets (in the form of DR). The requirement that resources must comprise at least 1MW within the associated NEM region has resulted in there being relatively few opportunities for participation in ancillary services markets for currently available DER technologies (i.e., PV and, battery systems) except where they have been aggregated. It is expected that DER participation in this market will grow.

DR has also featured in AEMO's Reliability and Emergency Reserve Trader (RERT), which is a market intervention mechanism. Dispatchability is a key requirement of the RERT and it is expected that DER that can be dispatched will not face any particular barriers in being able to participate in the RERT.

6.1.3. Chapter 4: Power System Security and Chapter 4A: Retailer Reliability Obligation

The power system security operations of the market fully incorporate DER where the DER can provide the service.

33 https://aemo.com.au/-/media/files/electricity/nem/der/2019/vpp-demonstrations/aemo-knowledge-sharing-stage-1-report.pdf?la=en

In addition, the introduction of the Retailer Reliability Obligation (RRO) will increase the integration of DER into the NEM. The RRO requires retailers, under specific circumstances, to provide evidence of contractual or physical arrangements that will ensure they can meet the peak demand of their customers. Contracts with responsive loads (DR) or embedded generation or storage (DER) can qualify as sources of the evidence required.

6.1.4. Chapter 5: Network Connection, Access, Planning and Expansion

The provision of network access and the development of networks under the NER is meant to be an economically efficient process. In particular, the connection of customers and generators is, in theory, treated equally. In practice, however, the full application of this chapter has been limited by conflicting Rules in Chapter 6, jurisdictional processes and the practices of Network Service Providers.

The key Rules for DER integration in Chapter 5, are:

- Rule 5.3, which allows an NSP to charge fully reflective costs for the provision of a network connection. This is typically done with regard to larger customers, but generally not for smaller customers due to:
  - The associated administrative costs and complexity, and
  - Network practice to not provide generator access nor to augment the network to facilitate generator access.
- Rule 5.3AA, provides for embedded generators to pay the full cost of their connection including their use of the network system and any augmentation of the network that their operation may engender. It also allows the embedded generator to negotiate a reduced charge based on non-firm access and prescribes a compensation regime that allows for parties to fully participate in dispatch despite non-firm access. This Rule has not, to our knowledge, been applied as, most likely because:
  - It conflicts with Rules in Chapter 6, notably 6.1.4, which are discussed below, and
  - There are significant practical difficulties in applying this Rule to small embedded generators.

6.1.5. Chapter 6: Economic Regulation of Distribution Services

Chapter 6 and the related chapters 6A and 6B deal with the economic regulation of transmission and distribution networks as well as the arrangements between networks and retailers.

While the Rules require the pricing of network services to become more cost-reflective, the speed with which this can be pursued has been limited by the availability of smart metering and regulatory mechanisms that seek to protect customers from unduly large price shocks that could result from very rapid increases in the cost-reflectivity of electricity pricing.

The only aspect of Chapter 6 that poses a barrier to the use of some of the pricing structures identified in the study is Rule 6.1.4 which prohibits a DNSP from charging a network user "for the export of electricity generated by the user into the distribution network". It should be noted, however, that this Rule does not preclude the use of fixed or demand charges in relation to connection services. It is also the case that the DEIP Access and Pricing work package is considering alternative pricing arrangements and intends to put forward a Rule Change request that may include a means for addressing this barrier.

6.1.6. Chapter 7: Metering

Cost-reflective pricing requires appropriate metering.

Chapter 7 of the NER currently requires accurate metering to be installed at all new connections and where meters are replaced. This will eventually mean that effectively all sites in the NEM will have remotely read interval meters. Mechanisms that could result in a faster rollout of interval metering would be very helpful in this regard.

A related issue is the ability of the industry to use the capabilities of smart metering to support cost-reflective pricing. At present there is nothing in the rules that provides assurance of this, and the jurisdictions have the power to overrule pricing structures proposed by the networks and retailers they license.

6.1.7. Summary and proposal

The study found that the NER is generally supportive of DER integration through its economic, market approach. Specific aspects of the rules for participation and network pricing are, however limiting effective integration. Some key changes are being considered or made that will enhance DER integration, when and if adopted:

- 5-Minute settlement. Valuing supply side energy and DER on a five-minute basis will allow dispatchable DER to gain additional income for short-term supply against dispatch peaks. This will particularly benefit assets that can be dispatched on very short notice to meet price peaks.
- DER Aggregation[34]. The inclusion of a DER Aggregator participant in the WDR Rule change augurs well for the market as it will allow a more focused approach to the development and integration of DER.
- Current Rule change processes and reviews have the potential to also be helpful as long as the changes are made with DER in mind. It is our understanding that the post-2025 market design being developed by the Energy Security Board (ESB) is considering these issues. A fully two-sided market would remove the need for specialised pricing and participation mechanisms for demand response. The VPP Demonstration Program will likely provide key insights into the operational impacts and benefits realisation of DER in the wholesale, network and retail parts of the electricity supply chain.

6.2. Relevant international experience

Three key areas relevant to the integration of DER with the large-scale generation and network portions of the traditional electricity supply chain were examined in a number of overseas markets. The specific areas of interest were:

- The pricing approaches that were used,
- The level of direct DER integration achieved, and
- How performance was measured.

Direct study was made of two overseas markets:

- PJM, which is a multi-state market in the North East of the USA, encompassing **P**ennsylvania, New **J**ersey, **M**aryland, District of Columbia, Delaware, Ohio, Virginia, West Virginia, Tennessee, Kentucky, Indiana, Illinois, Michigan and parts of North Carolina, and
- France,

34 Note that an aggregator will be able to aggregate the operation of demand response, distributed generation and storage.

In addition, several other studies of the experience of DER integration was undertaken. These included studies conducted by CIGRE[35], the Brattle Group[36] and the Regulatory Assistance Project[37].

The key findings are provided below.

6.2.1. Pricing approaches used

- The principles for effective rate design are well known and are consistent, in the main, with the principles in the NER;
- The application of the principles relies on effective metering or measurement of the necessary parameters, although some countries have been able to incorporate some of the signals into simple pricing regimes; and
- The use of tariffs that apply the full set of principles has not been widely adopted and certainly not for small customers.

This is consistent with the Australian experience where, even with the correct principles and measurement tools, efficient pricing is not always adopted.

6.2.2. Direct DER integration

- A number of markets include direct trading of DER products between customers and their retailers, but full integration is more possible where centrally mediated products are defined and managed through market bodies.
- The use of intermediaries – and particularly aggregators – is an effective tool for increasing the use of DER and integrating it with the supply chain.

6.2.3. Performance measurement

Very different measurement issues pertain to different types of DER. The most significant difference is that between DR and most other forms of DER.

- Measurement of DR is problematic because it is comprised of the difference between what the load did in response to a price signal as compared to what it would have done in the absence of that price signal. Essentially, the measurement of DR requires both metered data and some form of counterfactual. Many different approaches have developed for the construction of suitably accurate, non-biased and administratively feasible counterfactual methodologies[38].

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35 A Chuang et al, “Cost of Electric Service, allocation methods and residential rate trends” 2018, CIGRE Technical Brochure 747, www.e-Cigre.org.

36 Hledik et al, “The National Potential for Load Flexibility - Value and Market Potential Through 2030”, the Brattle Group, 2019, www.brattle.com.

37 RAP “A Renewable Electricity System and the Value of Flexible Resources”, presentation to The 6th National Conference on Next Generation Demand Response by the Regulatory Assurance Project. 2019.

38 *Baselining the ARENA-AEMO Demand Response RERT Trial* (https://arena.gov.au/assets/2019/09/baselining-arena-aemo-demand-response-rert-trial.pdf) provides a discussion of a number of these approaches. The AEMC has defined an approach for use in the wholesale market in its Final Determination regarding the Wholesale Demand Response Mechanism (https://www.aemc.gov.au/sites/default/files/documents/final_determination_-_for_publication.pdf)

- Measurement of DER other than DR can be relatively straight forward where the DER is dispatchable. Where that is then case, metering on the DER can be used to identify (a) the commencement of export, (b) the cessation of export and/or (c) the commencement of consumption in the case of DER being used as a 'sink'. Non-dispatchable DER (e.g., rooftop PV without battery storage and controls) would generally not be considered to be a form of DER that can respond to the price signals considered in this study.

7. Next steps

We would recommend that a DER focused review of the NER should be undertaken to identify areas that may otherwise escape review and limit integration. This would be a similar approach that was taken for the review of Technical Standards, in 1999[39], which focused on the actual grid requirements rather that the characteristics of the facility that provided the services to meet the requirements.

In addition, we would recommend that existing and future programs undertaken to assess the potential for DER to be better integrated with the central generation and network portions of the electricity supply chain include trials of the ability of the various pricing structures developed in this study to reduce supply chain costs.

39 The review of generator technical standard undertaken by the National Electricity Code Administrator that was required by the initial National Electricity Code. The review undertook a full ground up review of the need for and therefore the approach to defining technical standards.

Appendix A: Study reference groups

A.1: Stakeholder reference group

- Australian Energy Council Limited
- Clean Energy Council
- Enel X
- Energy Networks Association Limited
- Energy Consumers Australia Limited
- GreenSync Pty Ltd
- OC Energy Pty Ltd[40]
- Powerlink
- Reposit Power
- SA Power Networks
- TasNetworks
- Total Environment Centre Inc

A.2: Market bodies reference group

- Australian Energy Market Commission
- Australian Energy Market Operator Limited
- Australian Energy Regulator
- Energy Security Board

40 Left the reference group part way through the project due to it having been acquired by a new owner.