Oakley Greenwood

Cost Drivers: The foundation for pricing DER in the NEM

prepared for:
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DISCLAIMER

This document has been prepared to provide a starting point for the conversation that will be had in the second meeting of the Stakeholder Reference Group of the ARENA-funded study into the use of price signals as a means for integrating the use of distributed energy resources (DER) within Australia's National Electricity Market (NEM). It is not intended for any other audience or purpose, and Oakley Greenwood disclaims liability for the use of any information in this document by any party for any purpose other than the intended purpose.

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Table of contents

1. Introduction

1.1. Purpose

The use of distributed energy resources (DER) can impact all parts of the electricity supply chain. The key to the economically efficient integration of DER into the electricity market and grid requires an understanding of how the use of DER affects the costs of the electricity supply chain and then developing price signals that reflect those cost impacts.

As such, the purpose of this paper is to identify the key factors that drive costs within each part of the electricity supply chain. This will provide the foundation for the consideration of:

- 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 produce.

1.2. Approach

Accordingly, the paper addresses the cost drivers of the following parts of the value chain:

- Networks.
- Wholesale electricity market.

Each of these cost drivers is discussed in more detail in the following sections of this report. More specifically, we have attempted to describe:

- how each aspect drives cost in that part of the value chain;
- the locational and temporal dimensions of the cost driver (everywhere always, everywhere but only sometimes, any time but only certain places, only certain places at certain times); and
- how DER could can impact the cost driver and any impact that might have on other cost drivers within this or other parts of the supply chain.

A short discussion of externalities within the consideration of cost drivers is also provided.

1.3. The questions for the Stakeholder Reference Group (SRG)

The paper is meant to provide a starting point for the conversation that will be had in the second meeting of the Stakeholder Reference Group. As such, the key questions for SRG members to consider in reviewing this paper are:

- Is this list of cost drivers correct and complete?
- Are the cost drivers described and assessed correctly?
- Is the description of the ways in which DER can address the cost drivers correct and complete?

1.4. Comments from the SRG

Comments received from the Stakeholder Reference Group and the discussion at the SRG meeting on 4 March are appended to each section in this paper.

Some comments received are more appropriately dealt with in the later sections of the study and these will be retained for later use. A summary listing of these comments is attached as Appendix A.

2. The use of cost impacts as the basis for the development of economically efficient electricity prices

2.1. Definition of economic efficiency

Section 7 of the National Electricity Law (NEL) contains the National Electricity Objective (NEO). It states that:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to–*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system*

The NEO guides all of the Australian Energy Market Commission's (AEMC) decisions regarding rule changes, the Australian Energy Regulator's (AER) and Australian Energy Market Operator's (AEMO) decisions on the application of the Rules, as well as the decisions of the Australian Competition Tribunal (ACT). Underpinning the NEO is the concept of economic efficiency, which has three sub-components: *productive*, *allocative* and *dynamic* efficiency

Components of economic efficiency – key points

Economic efficiency (which underpins and is required by the NEO) is comprised of:

- **Productive Efficiency:** ('*promote efficient investment in*') The least cost (efficient) mix of resources (e.g., capital and operating) should be used to meet customers' demand for electricity services.
- **Allocative Efficiency:** ('*efficient….use of, electricity services*') The efficient amount of electricity should be consumed by customers, which, amongst other things, requires that variable charges for electricity services reflect the forward looking marginal costs of providing those services (cost reflective) so that customers only consume electricity services where the benefit to the consumer outweighs the cost to society of providing those services; and
- **Dynamic Efficiency:** ('*for the long-term interests of consumers of electricity with respect to…price*') Businesses should be incentivised to seek out efficiency gains over time, and improve performance where the benefits exceed the costs, such that efficiency is promoted in the long-term.

2.2. Allocative efficiency and what it means for electricity pricing

For the purposes of designing electricity tariffs, the most important of the components of economic efficiency is **allocative efficiency**.

In simple terms, for allocatively efficient outcomes to occur, electricity prices – both for the *consumption* of electricity from the grid, and *export* of electricity to the grid[1] – must incentivise, as a minimum, the following:

- **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[2] to society of providing that unit of electricity to that customer via the grid;
- **Efficient export behaviour:** We want to design price signals that incentivise customers to export electricity to the grid, if the marginal benefit to society stemming from the exporting of that energy to the grid exceeds the marginal opportunity cost[3] 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, in totality and everything else being equal, the future costs to society of providing them with grid-enabled electricity services is more efficient (cheaper) than the next best alternative (e.g., standalone power system, going without power).

Using consumption decisions to demonstrate the relationship between pricing structures / levels and allocative efficiency, suppose the variable price of grid-enabled electricity were to deviate from its marginal cost of supply. If this were the case, customers will consume either:

- Too much grid-enabled electricity, which will occur if the marginal price is less than its true marginal cost to society (i.e., some customers will consume grid-enabled electricity services despite the fact that the cost of providing them with an additional unit of that service attribute exceeds the marginal benefit[4] that they receive from consuming that service attribute), or
- Not enough grid-enabled electricity, which will occur if the marginal price is greater than its true marginal cost of supply (i.e., some customers will *NOT* consume grid-enabled electricity services despite the fact that the cost of providing them with an incremental unit of that service attribute *is less than* the marginal benefit that they would receive from consuming that additional unit).

The impact that the above scenarios might have on the amount of grid-enabled electricity demanded by customers (and hence the impact on efficiency) will depend on a customer's elasticity of demand – which reflects the relationship between a customer's demand for grid-enabled electricity and the price of electricity.

This loss in efficiency is termed a **deadweight loss** and is diagrammatically represented below.

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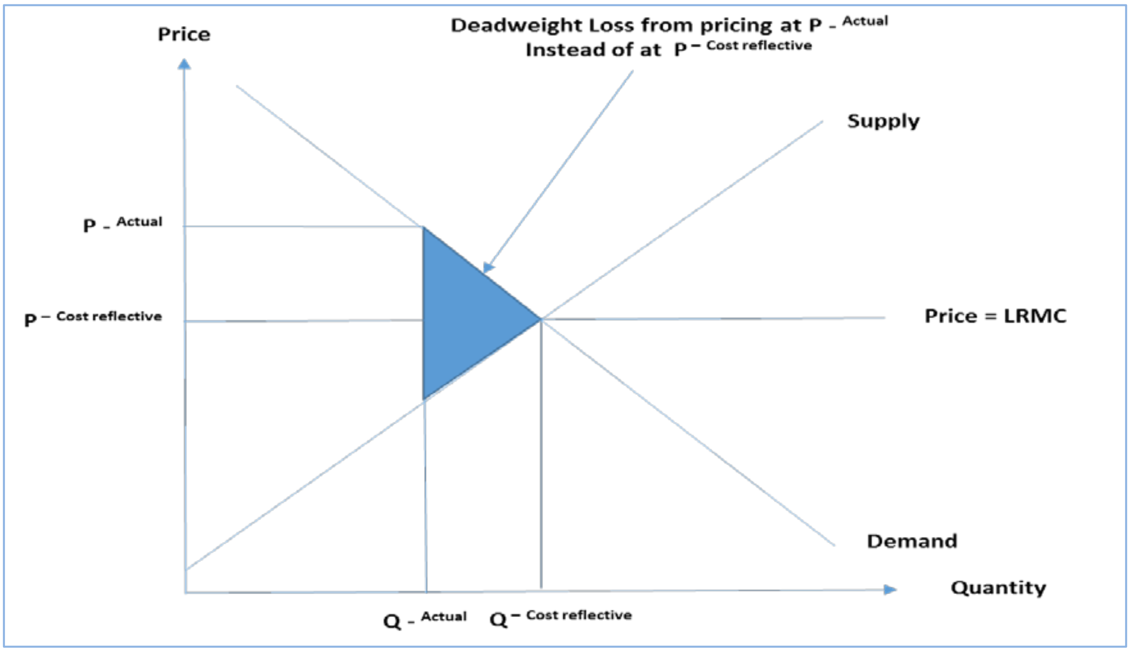
1 Although the service may not relate to energy per se, for example, it may be related to network support.

2 Noting that the marginal cost of supplying electricity services may vary depending on a range of factors, such as the location at which the consumption takes place, or the time of day/week/season/year at which the consumption occurs, however it is important to note that "marginal cost" is a forward-looking concept, and hence relates to future costs, not sunk costs (amongst other things).

3 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. The customer's opportunity cost in this case is the value of that energy in that next best, alternative use (i.e., running their air-conditioner).

4 In theory, this marginal benefit would reflect the lessor of a) the value they place on that energy if consumed, and b) the marginal cost of adopting alternative means of servicing those energy requirements (e.g., via the use of DER).

Deadweight loss assuming a unitary elastic demand curve



Source: OGW

The above figure illustrates the concept by visually illustrating the deadweight loss stemming from an electricity business pricing at a level (P – Actual) rather than at cost reflective levels (P – Cost reflective). It can be seen that this higher price leads to a reduction in the quantity demanded (from Q – Cost reflective to Q – Actual), which creates the blue triangle, which represents the deadweight loss (and which also represents the reduction in allocative efficiency of that price relative to the cost-reflective level). Note that in the above diagram, demand for the service is unitary elastic (it is 45 degrees to the horizontal), which simply means that a change in price causes a proportional change in demand.

The more inelastic a product[5] is (i.e., the steeper) its demand curve, and hence, the smaller the effect any price change has on the demand for that product, or the smaller the difference between the actual price and cost reflective price, the smaller will be the loss in economic efficiency from adopting prices that **are not cost reflective**. At the extreme, if demand for a service attribute is perfectly inelastic[6] (the demand curve is vertical) then there is no deadweight loss associated with adopting a price that deviates from the true marginal cost of supply of that service attribute, simply because there is no impact on the level of demand for that product.

Following on from the above, improvements in economic efficiency do not automatically follow from a move to cost reflective variable prices – whether for the consumption of energy from the grid or export of energy to the grid. Rather, economic efficiency is only improved *if the economic benefits - measured by the reduction in deadweight loss* - exceed the administrative and implementation costs (e.g., metering costs, communication costs, billing system changes) required to move to that more cost-reflective pricing regime.

5 In the case of electricity services, a 'product' could also be electricity consumption at different times of the day, week, month, or year – that is, the elasticity may vary across those dimensions.

6 If the demand for a product is 'perfectly inelastic' it means that the same amount of that good will be demanded no matter what price is charged. In practice, elasticity is generally considered within a particular range of prices.

This has particular importance when considering changes to the design of electricity tariffs, including those that seek to promote efficient investment in and use of DER facilities, because:

- Almost all studies into the elasticity of demand for electricity services indicate that it is relatively inelastic (i.e., less than unitary elastic but not perfectly inelastic); and
- There may be significant costs (e.g,. changes in metrology, communication costs) associated with introducing certain tariff structures/designs. For example, adopting a dynamic market-based approach for signalling the value of exported energy to the network may lead to more cost-reflective price signals, however, it is likely to come with significant administrative costs.

2.3. What costs should be signalled to customers through variable tariffs?

Whilst it is appropriate that businesses be allowed to recover (via tariffs) all of the efficient costs that they incur in providing electricity services to their customers, not all of these efficient costs should be reflected in *variable* price signals. Rather, some legitimate, efficient, costs should be signalled and recovered via some other non-distortionary means (e.g., fixed charges), quite simply, because those costs will not vary with the amount of electricity that customers demand in the future.

Therefore, 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 that future cost does not change in response to the change in customers' demand that has been incentivised by that price signal, then that future cost should not be signalled to customers via a variable charge. Rather, it should be recovered in a manner that least distorts future consumption and investment decisions, which generally means through some form of fixed charge[7].

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.

SRG comments and OGW responses

SRG Comment	OGW Response
Not clear why we are focusing on costs. By definition, DER is an economic resource and so should have an associated cost and a benefit.	Our overarching objective is to ensure that customers invest in DER up to the point where the marginal economic benefit equals the marginal economic cost of the DER. A key component of the marginal economic benefit accruing from investing in (and operating) DER is that its operation **reduces the cost of providing grid-enabled electricity costs.**

7 Noting that even the structuring of fixed charges needs to give consideration to the impact that those charges may have on customers' future consumption or investment decisions. In particular, fixed charges should not be structured in a way that may lead to a customer inefficiently disconnecting from the network.

SRG Comment	OGW Response
	Because the purpose of this project is related to "what price signals should be sent by the electricity supply chain to DER asset owners to ensure they only make investments where the benefits of investing in DER exceed the costs", a consideration of the impact of the DER on supply chain cost must underpin the price signals. This is why we are first focusing on the "costs" of grid-enabled electricity provision. Finally, if a service's price is not linked to its forward-looking costs of supply, customers may inadvertently make inefficient (too many, too few) investments in (or operation of) DER, leading to an inefficient mix of resources being used to provide electricity services in totality. For example, customer might invest in DER when it was in fact cheaper (economically) to procure energy from the grid, or vice versa, they might consume energy from the grid when it is in fact cheaper to utilise DER.
The analysis should also consider the fixed and variable components of costs. Fixed costs will not be impacted by temporal or locational drivers . . . Much of the network costs are fixed and therefore not variable. You should also consider the Pricing Principles (NER 6.18.5) which promote efficient use of the network.	Whilst fixed costs are no doubt "real" costs, you are correct in saying they will not be impacted by temporal or locational drivers. Our discussion of cost drivers in section 3 implicitly considers the difference between fixed and variable cost components, because it only focuses on the grid-enabled cost drivers that we thought were able to be influenced by future (marginal) changes in either future energy consumption or future DER levels. That is, we only focused on variable costs. Please note that we attempted to make this clear in footnote 8 of the paper, where we stated "*for the avoidance of doubt, it is noted that there are various other "corporate" related costs that businesses incur, such as finance, HR etc. These are not discussed in this section, simply because there is no relationship between these costs and marginal changes in either future energy consumption or future DER levels.*" The reference to the Pricing Principles will be relevant when it comes to the structuring of tariffs, which is related to future streams of work. That said, the Rules are underpinned by economic theory, namely that prices reflect the forward-looking costs (using LRMC), and should sit between stand-alone and avoidable costs, which we believe aligns with our discussion of cost drivers.
Economic efficiency is related, but not underpinning. The underpinning concept is 'electricity consumer welfare' (i.e. long term interest of *consumers*). Consumer welfare and economic efficiency are not the same thing" . . . "Given the NEO is centered on consumer welfare, not economic productivity, the price needs to exceed the VOLL to produce a loss, it just needs to be higher than its long run efficient cost. E.g. price is $10, cost is $1 and VOLL is $15 (on a long run basis). The $9 is basically economic rent."	We are comfortable with our interpretation, given that we believe it aligns with the wording of the NEO, as well as interpretations previously provided by the AEMC, the Australian Competition Tribunal as well as the statements underpinning the creation of the National Electricity Law. For example, the AEMC has previously stated that "*the NEO is an economic concept and is intended to be interpreted as promoting efficiency in the long-term interests of consumers*")[8]. The AEMC's more detailed description of its interpretation (in the same document) further elaborates on what it means by economic efficiency, and in doing so, it breaks down its discussion into productive, allocative and dynamic efficiency, as we have done. The National Electricity Law (NEL) Second Reading Speech also provides guidance in how to interpret the NEO[9]:

8 AEMC, "Applying the energy objectives", page 12

9 *National Electricity (South Australia) (New National Electricity Law) Amendment Bill*, p. 2.

SRG Comment	OGW Response
	"The market objective is an economic concept and should be interpreted as such. For example, investment in and use of electricity services will be efficient when services are supplied in the long run at least cost, resources including infrastructure are used to deliver the greatest possible benefit and there is innovation and investment in response to changes in consumer needs and productive opportunities. *The long term interest of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised.* ***If the National Electricity Market is efficient in an economic sense the long term economic interests of consumers in respect of price, quality, reliability, safety and security of electricity services will be maximised [emphasis added].****"* The Australian Competition Tribunal (ACT) has provided the following interpretation of the NEO[10]: *"The national electricity objective provides the overarching economic objective for regulation under the NEL: the promotion of efficient investment and efficient operation and use of, electricity services for the long term interests of consumers.* ***Consumers will benefit in the long run if resources are used efficiently, that is if resources are allocated to the delivery of goods and services in accordance with consumer preferences at least cost****. As reflected in the revenue and pricing principles,* ***this in turn requires prices to reflect the long run cost of supply*** *and to support efficient investment, providing investors with a return which covers the opportunity cost of capital required to deliver the services* ***[emphasis added].****"*
Not sure this [deadweight loss] needs to be described but just need to be sensitive to the fact that pricing should be efficient (currently a hot topic in light of concern over retail margins) and note that the NEO is centred specifically on consumer welfare (so distribution matters).	See the answer to the previous question.
All aspects of efficiency are important. Although allocative efficiency is an important consideration, key objectives of work on more efficient pricing have been to improve productive and dynamic efficiency by incentivising a lower cost mix of investment in networks, centralised generation and DER (i.e., reducing total system costs).	For the avoidance of doubt, we are not suggesting that all aspects of efficiency aren't important or would not be affected by changing how DER is priced into the market. However, pricing structures and levels first and foremost affect how markets allocate resources. There is no central body that does this; it is the market, responding to price signals that does this. To the extent that these prices are incorrect in either their structure of level (despite the business that is sending them potentially being "productively efficient", given the level of demand for their services), then a misallocation of resources will be occurring in the broader electricity market, which by definition, relates to allocative efficiency. Clearly, a by-product of this mis-allocation of resources is that as an industry, we are not productively efficient, however this is a second-order impact stemming from the absence of allocative efficiency.

10 Australian Competition Tribunal - *Application by EnergyAustralia and Others [2009] ACompT 8 - Corrigendum*, p. 10

SRG Comment	OGW Response
Note that the CoGaTI Review recommends that TUOS (congestion pricing) apply to new generation. Some parallels exist for DER, especially when network build occurs to increase DER hosting capacity. https://www.aemc.gov.au/sites/default/files/2018-12/Information%20sheet_2.PDF	We agree that there may be some parallels here; in fact, the underlying principles and framework that apply to the development of the COGATI framework should be similar to that of pricing of DER. For example, one of the key issues COGATI is presumably trying to overcome is the absence of a forward-looking, cost-reflective transmission price signal/s to generators in the NEM. Everything else being equal, this means that businesses investing in generation only focus on one thing: their own generation costs (because this is what is priced), rather than the overall economic costs (their generation costs PLUS the costs that they are imposing on the transmission business to accommodate their connection). This means that we can't be assured that based on the current price signals, the market will arrange itself such that the overall economic cost (of generation and transmission) will be efficient. Similarly, for DER, the absence of, or incorrect signalling of, the forward-looking costs of distribution services could yield inefficient location, sizing, timing or operation of investments in DER for the same reasons.
It is worth describing the relationship between short run and long run prices up front. Pricing is generally thought of in terms of the latter (e.g. AER) but this paper seems focused exclusively on the former.	Pricing related issues will be discussed in latter stages of the project. However, it is true that there is a difference between short and long-run **costs**. Whilst we have focused primarily on long-run costs in the report (e.g., a period of time where capital is assumed to be flexible, whereas in the short-run, capital is assumed to be inflexible), in the absence of any capacity constraints, short-run marginal costs are in effect the operating costs of the cost drivers we mentioned in the report. For example, the short-run marginal cost of providing grid-enabled electricity (outside of capacity constrained periods) includes things such as generation fuel costs, electricity losses, and very small operating costs to transport energy through the networks to end customers and to send bills to those customers. Where capacity is constrained, the short-run marginal cost also needs to reflect the opportunity cost of not being able to supply customers (e.g., the value of lost load).
It is also important to differentiate between Revenue, Price and Cost allocators. I note that the NER requires tariffs to reflect costs however the causal allocators can have big impacts. Allocator factors often considered include RAB, Customer numbers, Energy Volume, Transmission Demand for Distribution Zones, or a Weighted average of the above. Also don't under estimate how government policies (externalities) can impact this also (i.e. CSO in QLD).	As discussed earlier, we have focused on the cost drivers that we thought were related to (or would be impacted by) marginal changes in either future energy consumption or future DER levels. To our mind, the reference to using "allocation factors" is almost exclusively related to the allocation of fixed or sunk costs. From an economic perspective, this should be done in a manner that least distorts future consumption and investment behaviour, which is operationalised in the Rules via the standalone/avoidable cost test. Whilst there is little doubt that government policies (including those that have no relationship to externalities) affect the allocation of costs, it is our view that the NEO, in and of itself, excludes consideration of these "social policy" driven factors when setting prices. Hence, future parts of this project will not attempt to take into account "social policy" objectives. Please note that this in no way should be interpreted as saying that the Commonwealth or State Governments cannot, and have not previously, imposed constraints on the prices that may otherwise have been adopted in accordance with the NEO, in order to deliver outcomes that are consistent with their social policy objectives (e.g., moratorium on cost-reflective prices in Victoria after the rollout of AMI meters).

SRG Comment	OGW Response
I am not sure the context of the Deadweight Loss discussion in this chapter. I think it would be better to discuss causal allocators and how elastic demand is to cost…. Re framing this in relation to consumer welfare, can rephrase as CRP only beneficial when the benefits exceed the costs…. As per my prior comment on economic rent, overemphasising DWL and economic efficiency distracts from the central objective which is consumer welfare.	The context for the deadweight loss (DWL) is that it fundamentally informs how we will go about determining the economic benefits (in accordance with the NEO) that might accrue from any move to more efficient tariff structures for DER. This type of assessment will be a key part of the overall project (i.e., put another way, we will not simply be developing theoretically cost-reflective price structures; rather we will be assessing the cost of implementing different tariff structures against the changes in the DWL). Regarding the reference to "*overemphasising DWL and economic efficiency distracts from the central objective which is consumer welfare*", please see our previous commentary in relation to our interpretation of the NEO.
Please consider the AER decision on SAPN developing a PV specific tariff. Choice and competition may lead the AER to determine that some tariffs are discriminatory and some customers choosing tariffs that are in their best interest or not that of the cost recovery of the network.	We will address pricing-related issues in latter stages of the project.
This is an empirical statement[11] that needs to be substantiated. E.g. there is a narrative by the ACCC that high prices are contributing to the off-shoring of energy intensive industries. My hypothesis would be that elasticity is highly variable between customer segments . . . ..Worth pointing out how this is changing with technology. The past is not always a good indicator of the future. Even if elasticity for total electricity consumption is quite inelastic, non-cost reflective prices can still lead to significant losses in economic efficiency through inefficient decisions to increase the use of DER and reduce the use of grid-supplied electricity in a way that increases total system costs to supply the same total amount of electricity.	We agree with the observation that this is an empirical statement. We will look to investigate this in further detail in the next stages of the project, which looks in detail at the costs and benefits of adopting different pricing structures for DER. We also agree that the elasticity of demand for grid-based electricity services has, and will continue to change as technology changes, and that it will differ by customer segment. All that said, we would note that just because higher electricity prices might lead to "off-shoring" or even "demand reductions", it doesn't necessarily mean that the elasticity of demand is technically classified as being "elastic". The combination of all of those effects may still be such that the elasticity of demand is still technically classified as being inelastic (i.e., the percentage change in demand is less than the percentage change in price).
Effectively we've got inefficient dispatch as a consequence of inefficient price signals. (Directly analogous to disorderly bidding in the wholesale market, which is caused by inefficient price signals).	We completely agree with this comment. To the extent that we have inefficient price signals pertaining to grid-based electricity, we will get inefficient dispatch of DER into the market.
If we are talking about economic first principles, the concept of 'scarcity pricing' (or 'congestion pricing') seems relevant here. Supply is limited so consumers could set the price they are willing to pay. If consumers are willing to pay a high enough price at peak times, then that can become a transparent signal for investment in new supply. This is considered in the AEMC COGATI Review and the Open Energy Networks model which has parallels here. I am not saying this is a solution but ultimately, whatever pricing we come up with it will be a compromise on a purest market model like that.	We will address pricing-related issues in latter stages of the project, but as a general observation, we would agree with this statement, if a short-run marginal cost based pricing approach were to be adopted.

11 This comment is referring to a statement we made on page 7 of our report about most studies suggesting electricity is a relatively inelastic product.

SRG Comment	OGW Response
In the context of the heading: "What costs should be signalled to customers through variable tariffs", it was noted by one respondent: "I think this word is ambiguous. Who are the customers? End consumers of electricity? Or prosumers? I think "users of the network" is better - generic and accurate."	Noted. We will bring the issue of who sees and can respond to the price signal out in the next stages of the project.
Need to clarify the manner of fixing, i.e., daily supply charge versus flat rate tariff.[12]	We will address pricing-related issues in latter stages of the project.

12 This comment is referring to a statement we made on page 7 of report that fixed and sunk costs "*should be recovered in a manner that least distorts future consumption and investment decisions, which generally means through some form of fixed charge*". For completeness, we also stated in footnote 7 that: "*Noting that even the structuring of fixed charges needs to give consideration to the impact that those charges may have on customers' future consumption or investment decisions. In particular, fixed charges should not be structured in a way that may lead to a customer inefficiently disconnecting from the network.*"

3. Network cost drivers

As part of our literature review, we have identified the following as *key* drivers[13] of *future* network costs:

- 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[14].

3.1. Direct connection costs

Direct connection costs – key points

- There are almost always costs associated with connecting a new customer to the existing shared network.
- Customers should be charged **up-front** for any direct connection costs, being those costs that are only able to be affected by an individual customer's connection decision.
- This would facilitate the connecting customer making 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.

When a new customer connects to an existing electricity network, there will almost certainly be some assets required, and hence costs borne, in connecting that customer to the existing shared network. The assets required may be as simple as a service cable and a metering installation, where a new residential customer is located adjacent to an existing low voltage network with some spare capacity, through to the construction of multiple low voltage assets (e.g., multiple poles and associated LV cable) and a distribution sub-station to provide a dedicated service a new relatively large commercial customer.

As the name suggests, these costs are driven by the **specific connection characteristics of the connecting customer**, hence they are solely driven by that customer's connection decisions regarding both their location, type of equipment installed and their energy usage and export requirements.

13 For the avoidance of doubt, it is noted that there are various other "corporate" related costs that businesses that incur, such as finance, HR etc. These are not discussed in this section, simply because there is no relationship between these costs and marginal changes in either future energy consumption or future DER levels.

14 We have included this externality in the network section, as this is a risk that network businesses generally already have regard for in their planning decisions.

Consequentially, the incurrence of these costs cannot be ameliorated by the decisions or actions of other customers connected to the shared network (even in and around the area where the customer is to be located), for example, it is not possible for another nearby customer to reduce their load to create capacity for that new customer to utilise.

From a pricing perspective, this latter feature is important, as it means that these upfront direct connection costs should be charged 'upfront'[15] directly to the connecting customer, as opposed to being signalled to all customers via a variable electricity/demand charge. The simple reason for this approach is that it is only that connecting customer that can influence those future connection costs, and those costs can only be ameliorated at the time of their connection.

If customers were charged upfront for these types of costs, then, everything else being equal, they would face a price signal that matches the marginal economic cost associated with their connection decision, at the time the costs are incurred. From a DER perspective, this means that a DER proponent can monetise all of the economic benefits (from a connection perspective) that stem from any decision to invest in DER.

This would facilitate the connecting customer making 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 connection costs) exceeds the marginal cost of the DER.

SRG Comments and OGW responses

SRG comment	OGW response
Questions were raised regarding the statement that direct connection costs "cannot be ameliorated by the decisions or actions of other customers connected to the shared network". Examples included where another customer changes their load/generation profile to reduce the connection cost of a new customer, and where networks employ dynamic connection envelopes which impact the ability of other customers to export DER energy.	Both of these are possible, but do not affect cost of the physical assets (e.g., the service line and potential maximum demand (or export) of the customer) or any fixed administration or fixed O&M costs imposed by the new customer on the network. Both of the examples offered will affect shared network costs which are discussed below.
Connection charges should acknowledge where new technology such as smart inverters allow flexibility in the impact of the DER on the network.	We agree that this flexibility could be reflected in the connection charge. It could also be taken up in a connection standard. It is worth noting that neither approach would affect existing installations.

15 The cost, and therefore the charge is applied up-front, however it is possible for the connecting party and the network to decided how the charge is recovered. This is a financing decision and does not change the economic incidence of the cost and the correct application of the charge.

3.2. Extension of the existing shared network

Extension of the existing shared network – key points

- New developments/service areas that require the shared network to be extended should be provided with an **up-front** price signal that reflects the size and timing of those up-front extension costs.
- The signalling of these network extension costs upfront would facilitate prospective new developments making 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 the NPV of the upfront extension costs) exceeds the marginal cost of the DER.
- Due to the bespoke nature of the costs, some form of area-specific developer or new customer connection charge may be appropriate.

Following on from the above, 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).

SRG Comments and OGW responses

SRG comment	OGW response
One commentator felt that the approach expressed here was appropriate for greenfield developments but not for brownfield developments.	It is not clear from the comment why this would be the case; however, we can explore this in more detail in latter stages of the project.

3.3. Shared network augmentation costs

Shared network costs – key points

- The efficient investment in, and use of, DER requires both efficient **variable** consumption and export tariffs.
- The structure of these variable tariffs should, in theory, reflect the fact that some shared network assets are driven by deterministic planning criteria, whilst others are driven by probabilistic planning.
- These variable tariffs should reflect the **forward-looking** costs of augmenting the shared network (and any incremental operating costs), which will most likely:
  - Vary by location/region; and
  - Differ depending on whether consumption or export is occurring.
- Where the network needs to be upgraded to accommodate future levels of exported energy from DER, then this should in theory, also be signalled to all DER facilities via a cost-reflective variable tariff.

Electricity transmission and distribution networks are used to convey electricity from where it is generated to where it is consumed. The *capacity* of the shared network that network businesses construct to serve their customers will be a function of **some measure** (see below) of the level of demand that they expect to be placed on those assets during periods of peak (or high) usage.

For the avoidance of doubt, in this context, we are referring to the augmentation of the existing shared network – that is, those assets that are used to serve **more than one customer** - hence a peak (or high) demand period reflects the time when **coincident** peak demands occur (i.e., the maximum peak recorded on that network asset, as opposed to the aggregated 'anytime' peaks of each of the individual customers that are served by that asset).

This feature means that any **future** augmentation cost will need to be signalled to more than one customer (due to the shared nature of the asset). Moreover, as there is no contractual / firm access regime in place, this should be done via cost-reflective variable tariffs that adjust over time as the loadings on an asset change (i.e., which in turn affects the supply/demand balance, and hence the timing/sizing of future augmentation).

The shared network can generally be categorised by the types of equipment that are used to convey electricity to end customers. For example, the shared network includes, but is not limited to:

- Transmission assets;
- Zone substations;
- Sub-transmission feeders;
- Distribution feeders;
- Distribution substations; and
- Low voltage assets (e.g., LV feeders, transformers).

This categorisation – which reflects the different voltages at which electricity is conveyed - is important, as, depending on the jurisdiction, there may be subtle differences as to how businesses decide when to augment an asset, and hence, the underlying driver of future augmentation costs.

For example, for assets that convey electricity at lower voltages (distribution feeders > low voltage assets), businesses tend to adopt **deterministic planning** criteria. For higher voltages (transmission network > sub-transmission network), businesses generally adopt **probabilistic planning** criteria to inform when they will need to augment those assets.

In its most simple form, deterministic planning means that once the coincident demands placed upon an asset are forecast to reach a pre-determined level (which will generally reflect the capacity of the asset under peak load conditions, or N-1 peak load conditions), the asset is deemed to require augmentation.

Probabilistic planning is more complex, as it requires the network business to assess how much "energy is at risk" if an asset were to fail. The value of that energy (based on the amount of energy multiplied by some measure of the marginal value of lost load) determines the total 'value of lost load' (i.e., the economic cost stemming from having to invoke involuntary load shedding). If this cost exceeds the cost of augmenting that asset in that year (i.e., its annualised cost), then it would be economic to replace that asset in that year. If the 'value of lost load' does not exceed the cost of augmenting an asset in a year, then the asset would not be replaced.

As the name suggests, 'energy at risk' is a function of the amount of energy that would not be supplied, assuming an asset failure under certain conditions (e.g., a major transformer outage, which, for example, one distributor defines as "an outage that has a duration of 2.6 months, typically due to a significant failure within the transformer[16]"), therefore it is our understanding that this not just a function of the maximum coincident level of **demand** placed on an asset (i.e., the maximum KW). This means that two assets that are currently of the same capacity, and which are forecast to bear the same coincident peak demands into the future, may have different amounts of energy at risk, simply due to the different consumption characteristics (load profiles) of the customers served by those assets.

The differentiation between deterministic and probabilistic planning is in theory, important from a pricing perspective. In particular, the cost driver for assets whose future augmentation costs are driven by deterministic planning is likely to be co-incident peak demand, hence this should be the focus of any efficient pricing arrangement. That is, the tariff structure needs to send a price signal that correlates with when the demand on the asset (or group of assets) peaks, not when an individual customer records their peak.

In comparison, the cost driver for assets whose future costs are driven by probabilistic planning is energy consumed during the 'at risk' period, hence energy (albeit over a very small space of time, potentially 20-40 hours a year) should be the focus of any pricing arrangement.

Any such pricing arrangement should flow through to the way both the consumption of energy is priced, as well as the export of energy is priced, as both drive the efficient investment in, and operation of, DER services. Moreover, forward-looking augmentation costs will vary significantly by area, hence in theory, area-specific consumption and export variable charges would be required.

16 Powercor, Distribution Annual Planning Report, December 2017, page 26

Finally, the pricing of energy that is exported from a DER facility is further complicated by the following factors:

- DER located at a particular part of the system is likely to only alleviate the augmentation requirements of assets further up the system (e.g., higher voltage levels), hence, in theory, this would need to be reflected in the way DER is priced. For example, batteries that inject into the LV network during co-incident peak periods may alleviate the need to augment the distribution transformer, distribution feeders etc (because it avoids the need to transport energy through those assets), however, the same "flow of energy" may still occur on the LV network[17]; and
- The injection of DER may, in and of itself, necessitate the need to augment the shared network, which should in theory be signalled to DER providers.

SRG Comments and OGW responses

SRG comment	OGW response
'Congestion' and 'harmonics management and power quality' should be added as cost drivers in the network portion of the supply chain.	Congestion' is essentially the cause of the need for 'augmentation of the shared network', and therefore should be covered by that cost driver. Harmonics management and power quality are areas that can require networks to incur costs, and therefore should be addressed in the study.
The potential value of locational price signals has generally been 'glossed over due to the political difficulty" they entail.	It is clear that augmentation costs are fundamentally spatial, and as such, locational price signals provide the most cost-reflective means for signalling demand-side actions that either bring forward or defer or avoid the need for augmentation. We note that many of the programs that have been undertaken or contemplated by DNSPs provide incentives for demand-side activities that defer the need for augmentation, and those incentives are, in effect, price signals. This project is seeking to develop means for providing such price signals for DER. This could take the form of a price signal for the value that DER can provide in a particular location where augmentation is anticipated and can be valued, or where the impact and value of DER can be assessed over the long term across a DNSP's service area. A locational price signal will be more cost-reflective and therefore produce better results in rewarding investment and operating decisions that result in DER being provided in the places and at the times that produce the most economic benefit. We note the report of the committee examining the Coordination of Generation and Transmission Investment (COGATI), which has signalled the need for locational pricing, couple with access charging.
On the other hand, it was also observed that "the suggestion that DER should pay for augmentation costs attributable to injection into the grid seems implausible and unnecessary".	We note that at present Rule 6.1.4 actually prohibits a distribution business from charging a customer for the use of the system for the export of electricity generated by the user into the distribution network. However, to the extent that such export brings forward the need for augmentation of the network, it is imposing a cost on the network, which could be signalled to the customer through a locational price signal.

17 For the avoidance of doubt, even this is somewhat of a simplification, as it may depend on the location of the DER on the LV network. For example, DER towards or at the end of a LV feeder may alleviate the need to augment the LV feeder.

SRG comment	OGW response
Should firm access be considered? Despite its acknowledged and significant technical and political challenges, it is, on paper, an elegant solution.	Firm financial access was included in the National Electricity Code and subsequently in the National Electricity Rules. The process was not effectively used and has been removed at the transmission level (although the parallel Rule (5.5) still exists for distribution connections, despite being inconsistent with Rule 6.1.4. We note that the COGATI review has suggested that some form of access charging and potentially firm access is required for effective coordination of network and generation. We agree that it is an option that should be considered.
In practice, both deterministic and probabilistic planning approaches are likely to give similar tariff structures, since at-risk periods are typically high system peak (i.e. coincident peak) days.	We agree that both approaches are likely to result in the pricing signal focussing on the same days, but the time period of the price signal and its dimension (kW vs kWh) might differ. Moreover, applying one (e.g., maximum kW) when the other is of relevance could exacerbate inefficient outcomes (e.g., customers slightly lower their MD as a result of the price signal, but retain this MD over significant portions of the day due to the absence of the kWh charge during the energy at risk period, thus increasing the overall energy at risk)
If "pricing of energy" in regard to DER potentially includes charging customers for DER exports, the current access model (e.g., no firm access and no GTOUS charges) will pose significant complications. Addressing these would need to be part of a broader review of access and charging rather than treating DER differently to other forms of generation.	We do not disagree with this comment. We note that if consideration begins with the impact of an action on the demand-side on cost, the question will naturally arise of when that action potentially increases cost as well as when it decreases cost.
It would be useful to get a sense of the likely relative size of the various network costs. Shared costs are almost certainty the hardest to recover "correctly". If they are also likely to be the biggest bucket, it would be helpful to know.	The decision regarding whether to implement any particular pricing approach hinges on whether its likely benefits in terms of increased efficiency outweigh the administrative costs of delivering it. This will be considered in the next phase of the project, but it is also likely that the relative size of different categories of network cost will change over time.
The concept of scarcity pricing - in which prices signal the need for further investment rather reflect an assumption that future investment will in fact be needed - as an alternative to the use of forward-looking costs as a signal of augmentation costs.	We note that the adoption of locational pricing would achieve this.
One commentator felt that our reference to "cost-reflective variable tariffs that adjust over time as the loadings on an asset change" was jumping to a conclusion and suggested that other alternatives be considered.	We will certainly consider alternatives. We note that variable charges can be applied to demand as well as energy consumption.

3.4. Replacement costs

Replacement of shared network assets – key points

- Where the amount of DER is such that it is able to offset the entire load of the shared network asset that is due for replacement, then it would allow the network business to avoid adopting a network replacement solution in totality.
- 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 locus of control is with customers, then this avoided cost needs to be signalled to end customers in order for them to make efficient investment decisions in SAPS.

The efficient *timing* of an electricity network's **forecast replacement expenditure** is generally not materially affected by the demands (or behaviours) that are placed on the network by end customers[18]: rather, it is predominately driven by condition and risk factors unrelated to the loads placed on the asset (or behaviours of end customers). This means that the efficient *timing* is unlikely to be able to be materially influenced by end customer behaviour, including the use of DER.

That said, the *sizing* and other *technical features* of the replacement solution *may* be influenced in part by the decisions and behaviours exhibited by downstream parties. For example, the *sizing* of a replacement transformer is likely to be linked to the demands expected to be placed on that transformer. However, the benefit, in this context, is the incremental change in costs between the "fully" sized transformer, and the "downsized" transformer, which will be significantly impacted by the economies of scale (or the loss thereof, in this case) associated with making that investment. This diminishes the economic benefit accruing to the adoption of DER that *incrementally* changes the loads that are placed on an asset.

However, where the amount of DER is such that it is able to reliably offset the **entire load** of the shared network asset that is due for replacement, then it would allow the network business to avoid adopting a network replacement solution in totality[19]. This economic benefit – being the avoided cost of replacement – needs to be reflected in the analysis of servicing solutions that are adopted.

18 In saying this, we have assumed that the timing of a network business' replacement expenditure will generally be driven by that business' assessment of the forward-looking operating and maintenance costs of continuing to operate an existing asset, as well as the probability times consequence of that asset failing. Operating and maintenance costs are predominately a function of maintaining the availability of the asset, not energy throughput or peak demand. The probability of an asset failing is almost de-linked from the end-customer behaviour, rather, it is a function of age, condition, location and other factors that affect its useful life. The consequence of failure is a function of the attributes of the customers served by that asset, as well as other features of the design of the network in that area that may allow load to be switched and served by other parts of the transmission network (or distribution network). Overall, none of the factors driving the timing of replacement of an existing, in situ transmission or distribution asset, is likely to be able to be materially influenced by end customer behaviour (including their adoption of DER) in our opinion.

19 An example of this is happening in Western Australia, where Western Power is trialling the use of Stand Along Power Systems as an alternative to replacing ageing infrastructure.

This is easy, if and where one body (e.g., the distribution business) is charged with centrally planning the provision of electricity services to a customer or group of customers. This is because that central body can reflect, within its project evaluation, that avoided cost benefit. If the AEMC's draft rule change on stand alone power systems (SAPS)[20] is adopted, namely that the national electricity law and rules be amended to remove existing barriers to distribution businesses providing SAPS as a regulated service, then this is likely to be a reasonable basis for facilitating the take up of SAPS systems in lieu of traditional grid-based replacement solutions.

Where this is not the case, and hence the locus of control sits with the end customer (that is, they need to decide to adopt a SAPS solution in lieu of their existing grid-based supply), the avoided cost of replacing the existing network should be signalled to end customers in order for them to make efficient investment decisions in SAPS solutions.

SRG Comments and OGW responses

SRG comment	OGW response
Clarification was sought regarding the scenario being referred to in the last paragraph of this section.	This section is referring to a SAPS solution being installed by a third party or an individual customer as opposed to being undertaken by the DNSP to substitute SAPS solutions for an entire asset needing replacement. As such, the value would need to reflect the value of any individual SAPS or aggregate load reduction of a number of SAPS in terms of the incremental reduction that their installation would produce on the cost of the asset required to serve the remining connected load. There would also probably need to be a time dimension as the installation of the SAPS to be undertaken would need to be known prior to installation (or possibly commitment to) the replacement asset.
Consideration should be given to the case in which DER allows a replacement to be deferred – in which case the cost reduction is related to the cost of capital.	To the extent that DER can defer the need for replacement of an asset we agree.

3.5. Costs of managing voltage within required levels within the existing shared network

Managing voltage issues on network assets – key points

- Theoretically, if the 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.

Network businesses are required, by regulation, to supply electricity within specified voltage bands. These specified bands will reflect not only the underlying physics, but also an assessment of the costs and benefits to the network business and its customer base of supplying a different (i.e., wider or narrower) voltage band.

20 A SAPS system is a form of DER.

Traditionally, networks have been designed to manage voltage *drops*, not voltage increases, and generally, the voltage on LV circuits tends to drop the further away from a transformer a customer is located. PV, particularly when located at the ends of LV circuits, can cause voltage to rise with distance[21].

Where a network business supplies electricity that is outside of its stipulated voltage band, it:

- Increases the risks that customers' equipment may be put at risk
- Is in technical breach of its requirements as they pertain to voltage limits,
- Increases the risk that customers will complain about the voltages that they are receiving, consuming network business' staff time as well as imposing an economic cost on those customers,
- Increases the risk that the network business will have to attend the site of the voltage complaint to investigate, and in many cases, install a temporary data logger on-site and on the LV side of the transformer, and
- Increases the risks that the network business will have to undertake remedial works and/or honour claims from customers regarding damage inflicted on behind the meter equipment and/or appliances.

Whilst the business 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.

SRG comments and OGW responses

SRG comment	OGW response
It was noted by an SRG Member that since 2015 AS 4777.2 2 has included standards for Volt-Watt and Volt-VAr response. These capabilities assist with voltage management of the grid. One (or both) of these are mandatory in some DNSPs, but not all. The ENA National Connection Guidelines propose that they should be mandatory. AEMO is also proposing an update to AS 4777.2 to make them mandatory. This is an important part of the contribution of DERs to network management and it would be worth acknowledging this approach in the Working Paper.	In our view, the decision to impose a standard such as this should include a cost-benefit assessment. In our understanding, a standard of this type would require Volt-Watt and/or Volt-VAr response capability (a) to be included in DER equipment that is connected to the network, and (b) be capable of being activated at pre-set thresholds or (possibly) remotely by the network. If such response capability were to be made available by a standard, there would be no need for a price signal to motivate the provision of this service. A price signal might be required where either (a) the capability of the response was mandated (or available) but not the response itself, or (b) the network wanted to secure levels of voltage control that could be provided by DER equipment beyond the level resulting from the thresholds set by the standard. The price signal could be structured as either or both an avoidable connection charge for DER asset owners allowing remote control of their equipment or a price paid to DER asset owners that respond to calls for voltage control.

21 The impact of PV on voltage and the relationship of distance to this impact is complex. In the next phase of the study we will be seeking engineering input on the relevant technical constraints and limitations regarding the integration of DER with the grid.

3.6. Managing bushfire risk

Bushfire risk – key points

- To the extent that investments in DER are made directly by customers, in response to the broader suite of electricity price signals, then the difference in the relative risk of a grid-based connection as compared to a DER-based electricity service igniting a bushfire, should be signalled to customers to the extent possible.

There are many historical examples of electricity networks starting bushfires. Moreover:

- The way electricity networks are designed (e.g., underground versus overhead) impacts their risk of starting a bushfire; and
- DER (e.g., via the provision of SAPS systems) is a feasible alternative to the provision of grid-supplied energy to some customers, and this solution is likely to impose a different level of bushfire risk on the community as compared to a grid-based solution.

As such, the efficient take-up of DER (e.g., via a SAPS system) requires that the relative difference in bushfire risk imposed upon the broader community between the two broad types of solutions be reflected into the servicing option that is selected. This is relatively straight-forward, if and where one body (e.g., the distribution business) is charged with centrally planning the provision of electricity services to a customer or group of customers. This is because that central body can reflect, within its project evaluation, this bushfire risk.

However, to the extent that investments in DER are in fact made directly by customers, in response to the broader suite of electricity price signals, then the difference in the relative risk of a grid-based connection as compared to a DER-based electricity service igniting a bushfire, would need to be signalled to customers. An example of where this is likely to be the case is where a new customer is considering connecting to an existing shared network. The signalling of the direct connection charges has already been discussed in earlier sections of this report; however, to the extent that a DER solution has a lower risk of igniting a bushfire as compared to the direct connection asset, then that risk should be signalled to customers upfront, in a similar manner to what was discussed in the context of direct connection charges.

SRG comments and OGW responses

SRG comment	OGW response
One commentator noted that the actual cost driver here is the cost of compliance (which could include insurance costs) with jurisdictional technical regulations regarding bushfire risk rather than the cost of a bushfire per se.	The actual economic cost driver is the economic cost stemming from a bushfire. There may be technical regulations that are applied, however these should be underpinned by the underlying economic cost. ~
Clarification was sought as to whether the last sentence of this section meant that connection changes might be higher for customers living in bushfire-prone areas.	That was not the intention of that sentence. Rather, the intent was that if the use of a DER solution reduced the risk of that customer igniting a bushfire, the value of that risk reduction should be signalled to the customer. This could be through various means, including: charging higher connection costs to that customer (to reflect the increased potential for the connection to ignite a bushfire, which could then be mitigated by the decision to install a DER solution), or subsidising the installation of a SAPS to reflect the value of the benefit it would provide in terms of bushfire risk mitigation.

	We recognise that the valuation of the bushfire risk reduction produced by the installation of a particular DER in a specific place is complex and could be a small number. As a result, it would be important to develop threshold conditions that would need to be met to make undertaking the calculation and presentation of such a price signal worthwhile.
This section seems to assume that the DNSP must use a grid-connection but should price it so that the consumer is incentivised to obtain its own SAPS solution if it is cheaper. But if SAPS are a cheaper solution than maintaining a grid-connection, then a more efficient outcome is for the DNSP to use a SAPS solution instead of a grid connection.	The question in our view with regard to this situation is whether the DNSP should 'decide' for the customer, or whether the pricing of the options should allow the customer to decide, with any extra cost involved in the grid connection option (in the situation where a SAPS solution would be cheaper for the network) being visible to and passed on to the customer.

4. Wholesale electricity market cost drivers

4.1. Cost drivers for investment in and operation of the wholesale electricity market

Investment in and operation of the wholesale electricity market – key points

- The wholesale energy market must pay for investment in plant and the efficient dispatch of available plant.
- In the NEM, the energy-only design means that both of these costs must be met through pool trading, financial contracts, and to a lesser extent some bilateral, physical contracts
- One means for integrating DER with centralised generation and the grid would be via the pool, which could optimise the sources to meet the investment and operational costs associated with aggregate demand.
- DER can potentially reduce these investment and operational costs both by providing a lower cost of supply during dispatch and also by being contracted for future supplies of energy (including DR).

Historically, the provision of energy to end users began as sets of localised generation and isolated grids. Over time, due to economic efficiencies, such as sharing capacity and increasing reliability, the grid has become heavily interconnected with a focus on centralised supply and networks for delivery of the energy. Even so, demand response, focusing on load reductions and the use of on-site generation, has been used as part of the tools for managing supply and demand.

For a variety of reasons, price signalling has not generally followed clear economic signals in the past[22] but recent developments in distributed energy and metering has focused discussion on the full integration of demand side options, particularly for small and medium customers.

While demand side trading is currently restricted in the NEM to arrangements between the serving retailer and the customer, markets need not be involved, but to allow the full development of demand side options, they must be included in the market arrangements as much as is possible, having regard to the costs of market participation[23].

Markets for electricity have focused on the two key elements for ensuring cost effective supply of energy:

- Ensuring adequate supply of energy (Investment). The assurance that there is enough capacity available to supply the energy required by users at their location; and
- Optimising the use of the energy supply options (Dispatch). Ensuring that the most efficient combination of energy sources is used to supply the energy at the moment of consumption.

22 CIGRE working group C5.16 examined efficient price allocation in markets around the world. The group noted that, while the principles for allocating costs were well known, they were often not applied due to efficiency, social and political factors. Technical Brochure 747 “Costs of electric service, allocation methods, and residential rate trends”, December 2018, CIGRE www.e-CIGRE.org.

23 CIGRE working group C5.19 studied the integration of demand response, reductions of energy use at a site and noted that when third parties can trade in DR, and the DR is integrated into market dispatch, the amount of DR is increased. Technical Brochure 651 “Report on regulatory aspects of the Demand Response within Electricity Markets”, March 2016, CIGRE, www.e-CIGRE.org.

4.1.1. Costs of investment

The costs incurred during investment are:

- Cost of construction and commissioning, including augmenting, the plant itself;
- Costs of land purchase or leasing;
- Connection charges, including any direct charge for augmentation or modification to the shared network – this has been discussed in the section on networks; and
- Establishment costs for market participation (bidding and dispatch facilities etc).

These costs are incurred ahead of the actual supply of the energy and therefore are incurred on the basis of expected demand.

DER can avoid or reduce these costs by providing alternate sources of forecastable supply.

4.1.2. Costs of operation

The costs of operation for supply are:

- Fuel costs for the production of the energy;
- Maintenance and repair costs for the plant; and
- Licence and participation costs.

These costs are incurred during the operation of the plant.

DER can reduce these costs by providing a cheaper alternative to the dispatch of centralised plant.

How the NEM signals these costs

The NEM consists of two complementary parts that combine to efficiently dispatch energy while also signalling the need for additional investment in generation capacity. The efficient dispatch of currently available energy sources is managed via the energy market pool and the associated spot price, while the signalling of investment is via the financial derivative market, which is used to manage the risk of future prices and therefore signals the need for investment.

The NEM pool efficiently optimises the provision of energy from all supplies offered into dispatch and settles each connection point based on the energy used at the connection point in each half-hour period and the price of energy in that half hour.

Market theory[24] suggests that a freely operating energy market, like the NEM, will establish and maintain sufficient energy supply, including necessary reserves to meet demand. For example:

> *" … under ideal conditions, electricity spot markets provide efficient outcomes in both the short and the long term, meaning that they lead to optimal investment in generation capacity, both in terms of generation capacity and generation technology portfolio."* CIGRE TB 647.

24 CIGRE working group C5.17 examined the literature at length as well as surveying countries on their use of capacity remuneration mechanisms to enhance reliability of their markets. The results are published in Technical Brochure 647, available from e-CIGRE (www.e-CIGRE.org). The Working Group noted that energy only markets allow customers and providers to contract to meeting their needs, which should result in economically efficient outcomes.

One concern with energy-only markets is that any restriction on their operations (i.e., any deviation from "ideal conditions" by constraining the ability of the market to reach the correct equilibrium price and dispatch) can lead to a sub-economic outcome. One deviation is the imposition of price caps that limit efficient price signalling, particularly for investment.

Most markets have a price cap but the cap in most markets is set above the level required to efficiently signal investment. For example, the NEM establishes the level of the Market Price Cap based on an assessment of the required price level that will provide sufficient investment to meet customer demand, defined in terms of the acceptable level of Unserved Energy[25] (USE) in the market.

The NEM Market Price Cap, currently set at $14,500/MWh, is determined by the Reliability panel based on the Unserved Energy Standard, which requires that less than 0.002% of energy demand should be unserved. This standard is also the trigger for AEMO interventions, discussed under Market Operations below.

4.1.3. Cost recovery in the NEM

The NEM is an energy-only market, which means that the total cost of investment in, and operation of, supply sources must be met through energy price, which is a combination of the pool price income and the financial derivatives settled with reference to the pool.

In addition, retailers contract directly for some resources, including demand response and local generation. Some of these purchases are due to legislated imposts for the purchase of DER (primarily feed in tariffs for PV).

Pool prices and associated contracts are established on a zonal basis in the NEM, with each zone aligned with state jurisdictional boundaries (the ACT is included in NSW for NEM pricing).

Physical contracts for DR or local generation are bilateral between the retailers and the selling entity, which could be an aggregator and the contract is located at the site (or group of sites that are aggregated) of the trade.

4.1.4. Possible role for DER

DER will always be able to be offered through physical contracts between energy purchasers (most likely retailers) and DER providers, but as noted in footnote 23, some overseas markets have found that the most efficient integration occurs if the DER is offered into the energy pool and the associated contract markets. The pool, and the contract trading, integrate the price of DER with other forms of energy and optimise the use of the various options.

DER could be integrated into the dispatch market, where the DER can set the price if it is the most efficient form of energy at the price boundary, if the cost of participation is below the economic benefits achieved. At all other levels where it is not at the price boundary its dispatch would still lower system demand, and potentially the price, by displacing higher priced plant.

For non-dispatchable plant, the benefit is the reduction of energy at a site, which makes the available energy available for other sites. Currently the value of the reduction accrues to the registered retailer at the site at the pool price. With the correct measurement tools and a market mechanism to value the DER, this DER could earn spot price for the reduction amount.

25 The Unserved Energy Standard is a deterministic, planning standard and is not derived from an assessment of the customer value of maintaining supply, which is represented by the Value of Consumer Reliability or the Value of Loss Load. As it forms the basis of the Market Price Cap, any loss of efficiency due to the market being capped is not currently assessed against the economic losses due to customer loss of supply.

DER can be very effective for reducing costs in the energy market as it is usually smaller scale and more modular, which means that it can be established in smaller increments to closely match the energy requirements thereby avoiding larger capital investments that may prove uneconomic over time.

SRG comments and OGW responses

SRG comment	OGW Response
Retailers effectively act as brokers for DER providers	This is a valid point. As noted in the paper, the use of DER could be direct or via intermediaries or retailers. Integration does not necessarily mean that DER providers need to participate directly in the market.
The wholesale demand response mechanism would integrate DER and push prices down	The paper notes that participation via the market is an option. Increased sources of energy to meet demand, including not using it in some locations to free it up for others, should reduce prices.
Correct valuation could allow competition for DER between retailers rather than a need for market participation.	This is an alternative that is available now. With correct valuation of DER retailers could provide a more efficient means of integration. Adding the market alternative, unless it is too costly or burdensome, would simply improve the competition by adding brokers and direct access.
Can the market signal demand differently from DER (including DR capable demand)?	This has occurred in some jurisdictions where the loads and the DER can be isolated for metering and settlement purposes. The key issues is structuring the signals so that they are efficient and practical. For loads that cannot respond to signals, it would not be effective to use a pricing regime. These aspects will be examined later in the study.
The costs could be grouped differently, such as: • Reduce required investment in generation capacity by reducing demand peaks • Share the flexing burden with generation in light of the growth in variable low-cost sources • Assist the process of scheduling and contracting energy assets from day to day by providing additional flexible resources into the mix • Provide non-energy services: o Participate in the frequency control ancillary services markets o Through mandatory obligations (e.g. AS4777.2) to assist frequency recovery following a disturbance	This grouping is a variation on the categories in this paper, using the services that DER could provide. Our intention is to understand the costs and potential services and then build pricing structures and arrangements to allow DER to provide cost effective services.
Is there a need to include the cost of risk in the paper.	This was discussed in the meeting, noting that risk is added to a cost to account for unknown variations. Therefore, reducing risk would reduce the level of a cost. Risk does not change a cost factor, just the value allowed for a cost in advance.

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

Apart from the efficient exchange of energy between market participants, the operation of the wholesale market system itself has requirements that need to be efficiently met by the market system operator. These costs are:

- the assurance of emergency reserves for ensuring sufficient supply during low probability events that are outside of participant planning;

- management of system frequency; and
- ensuring appropriate reactive power and system strength.

4.2.1. Assuring adequate emergency reserves

Ensuring adequate 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.

Emergency reserves

AEMO is required to purchase emergency reserves by the market rules. This requirement was established at market start due to concerns that sufficient supply might not always be available due to market signals alone[26]. Recently its use has been to ensure reliable supply in the face of a reduction of dispatchable plant due to plant shutdowns.

DER is naturally suited to the provision of reserves as the set up and carrying cost can be low[27]. The role DER can play in reducing the costs incurred in the market for adequate reserves is discussed below.

In most cases, emergency reserves, in the few instances they have been established, are maintained but not used. AEMO is required to meet the reserve levels set by the Reliability Panel, which are generally around ensuring that any region can meet the loss of the most significant source of supply on a very high demand day. The key requirement for reserve is that it be:

- Dispatchable – AEMO must be able to call on the reserve and be assured that the quantity requested is delivered at the time requested; and
- Tradeable – a tradeable amount of means a block of sufficient quantity to make difference to the market outcomes. The tradeable amount needs to be a quantity where the dispatch of

26 AEMO has a comprehensive set of tools to provide information to the market participants so that, as much as possible, participants provide sufficient reserves and AEMO is not required to intervene by deploying emergency reserves. AEMO provides a 10-year forecast of expected market supply demand balance, then assessments of the adequacy of supply from 2 years out to two days ahead of the dispatch day. From 2 days out to 5-minutes before dispatch, AEMO provides both expected prices and expected dispatch of plant. In the last two days before dispatch, if AEMO foresees a shortfall, it publishes Lack of Reserve notices. The market is therefore fully informed of the need for capacity.

27 Demand reduction can be considered to have a low carrying cost because the facility, once established, does not impose a cost when it is not being used as the site continues its normal operation. When called, the value of the DER is the contract price and would reflect the value of not using the energy at the site, which demonstrates allocative efficiency. This compares with the cost of constructing facilities, maintaining them and holding fuel for occasional use, which is the case for supply side reserve provision. Note that this does not apply that setting up the DR capability is necessarily low cost.

the DER provides more value that the costs of dispatching the DER[28]. Currently, AEMO sets the minimum quantity (tradeable parcel size) at 5MW.

Given the short notice available to contract capacity (12 months) and the fact that the reserve is contracted outside of the NEM market process, DER has traditionally been the most effective form of emergency reserves. This is because it can often be developed quickly when compared to the time required to build and commission new generation plant and the holding cost of the DR based reserve is generally low (see footnote 27).

While some DER sites may be able to provide a tradeable parcel, it is likely to be relatively few. Smaller sources of DER will need to be aggregated together to create a tradeable parcel. Aggregation is a key requirement for full DER participation in the reserve market.

Role of DER

Some DER, notably reduction in load, is well placed to provide reserves due to its low carrying costs (discussed in footnote 27), while other DER can contribute by being a more cost-effective supplier of reserves. In addition, experience with emergency reserves in the NEM has shown that the and the ability to develop the capability can be developed relatively quickly.

DER does have the issue that it may not be able to meet the procurement requirements for reserve; size of the capacity parcel and dispatchability. These issues are capable of being addressed.

4.2.2. Ancillary services

Providing ancillary services

- The market operator must ensure that sufficient ancillary services are available to the market.
- DER is a good source of Frequency Control Ancillary Services (FCAS) and some integration is already occurring.
- Some forms of DER, batteries and distributed generation are able to provide other ancillary services.

AEMO is required to purchase services to ensure the market remains secure. These services are generally called ancillary services. The relevant types for this paper are:

- Frequency Control Ancillary Services (FCAS). System frequency is a proxy for the balance between supply and demand. In a balanced state in the NEM, the system frequency is 50Hz and is established by the speed of rotating plant. When the load on the system increases, rotating plant slows down and frequency drops, triggering a response to increase generation to restore the frequency. These services are provided by a market that is dispatched every 5 minutes; and

28 In the NEM, plant below 5MW are not normally required to register as their connection does not materially impact the NEM. They must, however, notify their network service provider as their operation can have local effects. Plant below 30MW are not required to take part in central dispatch unless their operation materially impacts the stability of the system. This exemption from participating in dispatch is set at a higher level for intermittent plant, unless local constraints become an issue. Where plant is not dispatched by AEMO, its operations are captured in the forecast errors for demand.

- Non-market ancillary services, reactive power and system strength.
  - Reactive power is a source of support to the system that allows energy to effectively flow through networks; and
  - System strength includes a few factors, including fault levels (akin to pressure in pipe) and inertia, the ability of a system to withstand disturbances.

4.2.3. Management of system frequency

The grid must be maintained within defined frequency bands to meet the standards required of parties attached to the grid. In addition, the further system frequency deviates from the standard, the harder it is to return the system to the standard frequency.

Frequency disturbances have a variety of causes, from simple change in demand across a day and within dispatch periods to actual loss of generating plants or loads. The simple changes in demand are covered by small deviations in supply and are referred to as regulating services. The larger deviations are covered by plant or DER being available to meet the sudden changes in supply or demand.

For example, the loss of a generating unit requires immediate response to arrest the loss of frequency and a longer-term response to restore the frequency by replacing the lost generation. The differing requirements are met with different services but all entail monitoring and providing energy at a trigger point.

At the limit, customers provide the ultimate frequency response through involuntary load shedding, either on command or via under-frequency relays that shed load automatically.

DER is well placed to provide a cheaper source of frequency response and is already being incorporated into the NEM markets for FCAS. To provide the service a DER source must:

- Be dispatchable and able to respond to a frequency signal when activated, and
- Have high speed metering to measure the response.

DER has been incorporated into FCAS reserves markets in Australia and overseas and virtually all forms of DER, including DR, distributed generation and, in particular, batteries (standalone or in vehicles) can provide cost effective and technically effective FCAS.

4.2.4. Ensuring appropriate reactive power and system strength

Reactive power

Large electrical systems require the provision of reactive power to ensure that power flows efficiently through the network. This service is highly locational and is met with a combination of generation, reactors and capacitors and, most recently power electronics (associated with a source of power).

DER could provide reactive support with the necessary power electronics but only DER that includes a stable and available source of power for the power electronics can provide this service.

System strength

Power systems require a level of system strength to manage the alterations in demand. There are two main components:

- Fault levels: like water in a hose, a certain pressure must be maintained to allow the hose to deliver water. If the pressure is too low, the water won't flow, if too high the hose will burst. DER is capable, with power electronics, to provide a source of system strength. But a stable power source, such as a battery or generator is required.

- Inertia or Fast Frequency Response. When disturbances occur, an electrical system needs some time (milliseconds) for FCAS to respond. Rotating plant in the system provides inertia, slowing the drop in frequency until FCAS is engaged to restore the system. Until recently, the amount of rotating plant in the NEM was sufficient to provide the required amount of inertia. Some sources of DER can provide a service that can substantially replicate inertia, Fast Frequency Response, using power electronics backed by a power source. For example, the TESLA battery in SA has been successful in supplying Fast Frequency Response into the NEM.

SRG Comments and OGW responses

SRG comment	OGW Response
The paper should refer to the service from DER in relation to inertia issues in the market as Fast Frequency response.	This is correct and the paper has been updated to note the differences. The system and some connected plant have the property of inertia and a certain level is required for system strength. Fast Frequency Response can be used to support the inertia in a system.
DER would not be very useful for reactive power, system strength of SRAS.	This is currently true. In the meeting, however, it was noted that inverter technology is evolving and that market support services are becoming available. It was also stated that AS4777, the relevant standard is being updated.
Some additional sections could be added: • Lack of visibility (cost of) • Lack of controllability • Efficacy of emergency mechanisms compromised • Predictability of behaviour in response to disturbances • Mass behaviour (e.g. all switching on/off on time-of-use tariffs) and associated ramps	The first two items in the list could increase the cost of reserves as AEMO would need to hold more to manage the system and the last two could add to costs by requiring AEMO to hold higher levels of ancillary services. Therefore, the actions of removing these issues would reduce costs but only the costs already identified. The third, or middle, item is increasingly being considered a problem and may be a cost to the system. Currently, the technical standards that apply to connections should prevent plant connecting where there is a risk to system security. However, some countries are now identifying that the co-location of uncontrolled DER within loads has the potential to harm system restoration. Controllable inverters are now available and may be required for future PV systems to prevent this issue worsening.

5. Externalities

5.1. Externalities and pricing

The term 'externality' refers to a cost (or in some cases a benefit) associated with an economic transaction regarding a good or service that is not included in the price of that good or service. As such, an externality is a cost that affects a party who did not choose to incur that cost.

Where the price of a good or service does not include costs or benefits that might be imposed on or accrued by third parties, that price will not be as allocatively efficient as it could be. That is, we will get too much of a good being consumed (if there is a negative externality), or too little of a good being consumed (if there is a positive externality).

Because the producer of the good or service in question does not bear the cost of any associated externality these costs do not need to be recovered in the price of the good or service. In fact, voluntarily including externality costs by a producer would put the producer at a potential commercial disadvantage.

This is why economists suggest that governments adopt policies that lead to the party whose actions impose (lead to the creation of) the externality to internalise those externality costs (or benefits). More generally, it is really only governments that have the power – through taxation, legislation and other powers such as licensing – to determine the cost of any relevant externality and ensure it is incorporated within the costs incurred (and therefore the prices charged) by the party whose actions give rise to the externality. that to n

5.2. Externalities associated with different sources of electricity generation

In the case of the electricity sector, relevant externalities primarily include the environmental and other costs to society arising anywhere in the supply chain that are not included in the price of electricity. Examples include the environmental and public health damage and other costs to society associated with:

- the extraction and transport of fuels;
- the fabrication, construction of electricity generation facilities; and
- the CO2 and other emissions from the combustion of fossil fuels.

Both fossil-fuelled and renewable energy-based electricity generation give rise to externalities, though of different types and levels of impact.

A portion of some of the externality costs may be captured in the price of building or operating a plant. For example, to the extent that 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 represents 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.

5.3. Treatment of externalities in this study

As noted above, in most cases, the estimation of the costs imposed by externalities and the incorporation of those costs in the prices (including taxes) charged for the goods and services that give rise to those externalities relies on government policy or action.

Given this, in this step of the project we will note the extent to which specific externalities are associated with the various parts of the electricity supply chain, but will not seek to value those externalities as they do not (at present) affect the costs incurred by the supply chain[29].

These physical impacts will be noted in the cost-benefit assessment to be conducted in Step 5, and Step 4 will include discussion of both the price and non-price mechanisms used in other jurisdictions for taking the externality impacts of various electricity generation technologies into account in electricity sector policies and regulations.

29 It should be noted that in some cases, the costs of externalities (or some estimate of them) have been included in the costs incurred by the electricity supply chain. The insurance costs mentioned above, and the risk of bushfires addressed in Section 2 are examples.

Appendix A Comments received that will be used later in the study

A.1 Comments from SRG members related to pricing structures

There were six comments relating to how pricing structures should be applied to integrate DER into the markets. These comments were:

- Need to consider how costs can be converted to price signals.
- Not sure why we are talking about costs, pricing will resolve for both costs and benefits.
- The concepts of scarcity pricing and congestion pricing seem relevant here.
- Need to consider fixed and variable costs
- So, are we ruling out critical peak demand pricing?
- Network tariffs for DER connection should be set at the avoidable costs not the standalone costs.
- Need to be clear about fixed charges and how they are set.

We agree that establishing efficient pricing structures is a necessary step, which we will do in the next phase, but we believe that we need to get an agreed position on the costs of the system and how DER will impact these costs.

The pricing structure should align with the impact on costs, given practical and technical considerations.

One commentator noted that all pricing arrangements have inevitable limitations; none are perfect.

A.2 Comments related to the application of prices

SRG members noted that network tariffs were not applied directly to customers in Australia, in the main. This is true and retailers and intermediaries apply a combination of the network impacts, the wholesale impacts and their own marketing views to the structures that apply to customers. The comments were:

- Prices/tariffs are charged to retailers and not to customers directly.
- Should up-front costs be charged to developers for putting electricity through a development?
- Note that it is the price, not the cost of supply that matters. The price can reflect a cross subsidy which is borne by another party (e.g. solar).
- Retailers [and other intermediaries] can simplify or otherwise alter the tariff, which will impact the signals. Retailers can meet their own needs rather than the network.
- Need to consider price signals for off the grid customers – the prices still need to be efficient and reflect costs but it should be easier when the supply is more direct.
- I think we need to reflect on the definition of a tariff. We need to consider where DER is providing a positive contribution to the utilisation and recovery of network costs (i.e. high voltage means higher revenues through the meter). We should consider Machine to Machine Tariffs or Controls mechanisms which may not need to be metered (ie. Volts vs VARs).

We take the view that, if the prices are efficient and correctly aligned with costs, then the intermediary or retailer sees the true costs and can act on them via alternate means. Whether prices are directed to the customer or to a machine with parameters set for the customer, the prices need to be efficient.

The costs will be more apparent in the off-grid case, but pricing would still be a matter of practicality as well as efficiency.

For example, the provision of a DER response on high price days may be worth more to a retailer than the market price cap as it is only charged for the actual DER provided and for the short period it is actually used, which can be cheaper than retaining a Cap across the entire period. This is efficient because it replaces the supply source that backs the Cap.

A.3 Comments related to current pricing mechanisms in the NER

It was noted that the:

- The structures reflected in Chapters 5 and 6 of the NER require consideration of the pricing principles, which promote efficient use of the network.
- Consideration should also be given to how the AER treats Cost Accounting Method for each business through the Cost Allocation Guidelines.
- The AER decision on SAPN developing a PV-specific tariff should also be noted and considered. Choice and competition may lead the AER to determine that some tariffs are discriminatory and may lead to customers choosing a tariff that is in their best interest or at least not in the best interest of the cost recovery of the network.

These aspects will be considered later in the study.

A.4 Pricing clarifications

The comment "price signalling has not generally followed clear economic signals in the past", which was referenced to the CIGRE work on prices, was queried. The specific question was whether retailers tended to charge flat tariffs. The CIGRE Technical Brochure 747 "Costs of electric service, allocation methods, and residential rate trends", surveyed tariffs across sixteen countries and noted that in over half of the markets flat or simple prices were charged. The reasons were primarily metering and simplicity. It was noted, however, that many European countries charged demand tariffs on an up-front basis.

Appendix B AEMO graphic from page 21 of Power System Requirements, March 2018

Figure 3 Summary of required system services, and capability of technologies to provide them

Service description				Supply side		Network						Demand side		
				Centralised generation		Transfer between regions		Transfer within regions	Stabilising devices			Load	Decentralised resources	
System Attribute	Requirement	Service	Spatial level of need	Synchronous generator	Non-synchronous generator	DC interconnection	AC interconnection	Transmission and distribution networks	Grid reactor, grid capacitor, static VAR compensator	Static synchronous compensator	Synchronous condenser [1]	Large industrial, residential, commercial	Solar PV	Battery storage
Resource adequacy	Provision of sufficient supply to match demand from customers	Bulk energy	System wide	●	●	➔	➔	➔	○	○	○	●	●	●
		Strategic reserves	System wide	● [2a]	◐ [3a]	➔	➔	➔	○	○	○	●	◐ [3b]	◐ [3b]
	Capability to respond to large continuing changes in energy requirements	Operating reserves	System wide	● [2b]	◐ [3a]	➔	➔	➔	○	○	○	●	◐ [3b]	◐ [3b]
	Services to transport energy generated to customers	Transmission & distribution services	Local	● [4]	● [4]	●	●	●	●	●	●	● [4]	◐	◐
Frequency management	Ability to set frequency	Grid formation	Regional	●	◐ [5]	⇨ [5]	●	●	○	○	○	○	○	◐ [5]
	Maintain frequency within limits	Inertial response	Regional	●	◐ [6]	◐ [6]	➔	➔	○	◐ [7]	●	○ [8]	○	◐ [6]
		Primary frequency control	Regional	●	● [9]	➔	➔	➔	○	○	○	●	●	● [9]
		Secondary frequency control	Regional	●	● [9]	➔	➔	➔	○	○	○	●	●	● [9]
		Tertiary frequency control	Regional	●	● [9]	➔	➔	➔	○	○	○	●	●	● [9]
Voltage management	Maintain voltages within limits	Fast response voltage control	Local	●	●	●	○	○	●	●	●	●	◐	●
		Slow response voltage control	Local	●	●	●	○	○	●	●	●	●	◐	●
		System strength	Local	●	○	○	⇨	➔	○	○	●	○	○	○
System restoration	Ability to restore the system	System restart services	Local	●	◐ [10]	◐ [10]	●	➔	○	○	○	○	○	◐ [10]
		Load restoration	Local	●	●	●	●	⇨	●	●	●	●	◐	◐

1 This includes generators with ability to operate in synchronous condenser mode.
2a While many synchronous generators can provide energy reserves, some less firm technologies (solar thermal or pumped hydro storage) will be limited by the amount of energy storage they include.
2b While many synchronous generators can provide flexibility services, coal generators are limited in their ability to provide such services.
3a Limited by duration for which service can be delivered.
3b Limited by duration for which service can be delivered; existing controllability is limited.
4 The provision of local voltage support from generators and loads can improve the network transport capability near their respective connection points.
5 Grid forming power electronic converters are available and have been proven on small power systems. Development of grid forming converters for large power systems is an emerging area of international research.
6 Some fast frequency response capabilities can provide emulated inertia response, but are not yet proven as a total replacement for synchronous inertia.
7 Static synchronous compensators with energy storage devices are being trialled as an emerging provider of inertial response.
8 Except for load relief.
9 Includes fast frequency response capabilities.
10 System restoration services from variable non-synchronous generators is an emerging area of international research. If they are grid scale, batteries are likely to provide some system restoration support

Ability to provide service		
●	◐	○
Fully capable	Partial or emerging	Unable
➔	⇨	
Enables delivery	Partial or limited delivery	

Note: Classifications are indicative of the general ability of each technology type. The extent to which technologies can provide each service must be assessed on the specifics of each individual system.