Energy Transformation Taskforce

DER Roadmap

Regulatory Settings Summary

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Glossary

Term	Definition
AA4	Western Power Access Arrangement Period 2017-2022
Access Code	Electricity Networks Access Code 2004
AEMO	Australian Energy Market Operator
Aggregator	A party which facilitates the grouping of DER to act as a single entity when engaging in power system markets (both wholesale and retail) or selling services to the system operator(s).
Code of Conduct	Code of Conduct for the Supply of Electricity to Small Use Customers
DER	Distributed Energy Resources
DSS	Dispatch Support Service
EIA	*Electricity Industry Act 2004*
EPWA	Energy Policy WA
ERA	Economic Regulation Authority
ESS	Essential System Services
EV	Electric Vehicle
LFAS	Load Following Ancillary Services
LRRAS	Load Rejection Reserve Ancillary Services
NFIT	New Facilities Investment Test
PV	(Solar) photovoltaic
RCM	Reserve Capacity Mechanism
REBS	Renewable Energy Buyback Scheme
SRAS	Spinning Reserve Ancillary Services
SRS	System Restart Service
STEM	Short Term Energy Market
SWIS	South West Interconnected System
TOU	Time of Use
WEM	Wholesale Electricity Market

Executive summary

Distributed Energy Resources, or 'DER', are smaller–scale devices that can either use, generate or store electricity, and form a part of the local distribution system, serving homes and businesses.

DER covers a wide range of existing and new technologies and services which can deliver value across different parts of the electricity supply chain. This document provides a summary of how DER are connected, managed and rewarded under the current regulatory arrangements applicable in the South West Interconnected System (SWIS). It also explores coordination and alignment between the various regulatory instruments across the wholesale, network and retail segments of the supply chain.

The document considers the effectiveness of these mechanisms to support the efficient uptake, operation and use of DER, and identifies gaps. The purpose of this analysis is to inform the development of the DER Roadmap by the Energy Transformation Taskforce, which will help manage the transition of the SWIS to a high DER future.

The analysis of the current arrangements is based on the four key themes adopted in the DER Roadmap:

1. Technology integration
2. Tariffs and investment signals
3. DER participation
4. Customer protection and engagement

Key findings for each theme are summarised below. The body of the report provides a more detailed discussion, including the practical impact of existing arrangements on DER deployment.

Technology integration

DER technology is constantly adapting and improving, however, there does not appear to be a comprehensive and consistent approach to understanding the number, type and capability of DER installations across the network.

Generally, the technical framework for connecting DER only contemplates passive interaction with the wider electricity system and its markets. It does not provide for the connection of DER to achieve active control to provide additional value to the electricity system.

There are complicated registration and technical requirements relating to how battery storage can participate in the wholesale market (individually or aggregated) and existing tariff arrangements discourage the connection of battery storage, limiting its value to owners and the wider network. It is also not clear whether Western Power can own and deploy battery storage in its own right as a network service provider and leverage additional value from the battery.

Tariffs and investment signals

There are several mechanisms across the supply chain that reward DER in different contexts. This covers both direct payments for DER related services and cost savings experienced by customers who invest in DER.

However, there is limited alignment between the impact DER has on the system, and how DER is valued and rewarded. For instance, the current regulatory arrangements, including tariff structures, do not encourage efficient investment in battery storage and battery storage owners are not able to maximise the value of their investment. The existing flat tariff structure provides little incentive to consumers to shift consumption to the middle of the day in order to mitigate the impact of high rooftop solar photovoltaic (PV) output and low demand on the system.

Efficient adoption of DER is more likely to emerge if there is common agreement on how to value different DER types and the services they can provide. A lack of coordinated integration and established valuation mechanisms makes it more difficult for parties to provide energy and other services from DER.

Despite DER being able to provide multiple services that could be of value to the Western Power network, there is no regulatory mechanism which explicitly requires the calculation of network value from small-scale generation in all situations. In addition, there is limited prescription governing the calculation of any payment to the DER provider. This is often left to negotiation between Western Power and the DER provider.

The regulatory framework currently seeks to deal with the potential of distributed generation (amongst other 'non-network solutions') to defer future network capital expenditure, and value net benefits for the system. In short, Western Power's investments should already consider opportunities for least cost solutions across the value chain, not just least cost for the provision of network services. However, the methods for assessing and valuing these 'net benefits' lack prescription. Practically, this is likely to result in limited consideration and thus limited use of DER solutions as an alternative to network investment.

DER participation

Scale is not an explicit barrier to obtaining value from DER. In theory, generators above 5kW are permitted to register with the Australian Energy Market Operator (AEMO) and some of the potential barriers to participation, such as prudential requirements, are scaled. However, smaller generators are likely to find it more difficult to participate in some markets, such as the Reserve Capacity Mechanism (RCM), due to technical, incentive and valuation limitations outlined above, as well as other administrative requirements.

It is difficult for an individual DER installation to access multiple payments, limiting adoption and constraining innovation (i.e. where a DER provider or aggregator may need to contract with multiple parties, such as the network provider and a market participant, in order to achieve a positive rate of return, the risk may outweigh the potential benefits). For these reasons, a viable market has not yet emerged for DER aggregators to participate and provide services across the supply chain.

The integration of DER aggregators with market dispatch systems will be central to DER participation. However, the technical standards, communication protocols and processes for achieving system integration that will underpin DER dispatch via aggregators are undefined at present and will require pilots to demonstrate capability.

Customer protection and engagement

Where there are barriers to the full value of DER being extracted, customers will pay more than necessary for their electricity. While DER is creating challenges for the electricity system, the proliferation of DER also provides an opportunity to test new approaches to the generation, transportation and supply of electricity. By removing barriers to the efficient deployment and utilisation of DER, customers will, over time, benefit from lower cost energy and new services.

It is important that the consumer protection framework keeps up with changes in the nature of the supply of electricity. The current regulatory arrangements, which allows many service providers to benefit from an exemption from the licensing framework and associated obligations, does not provide customers with sufficient protections in relation to the development of new business models. In particular, energy-specific consumer protections that cover important issues such as disconnections and hardship do not currently apply to energy service providers that are exempt from requiring a retail or distribution license.

Summary

A core finding is that existing arrangements do not deliver accurate valuation of the services DER can provide across the electricity supply chain. Further, the processes and mechanisms for DER services participating across the value chain are either overly complex with a high degree of risk, or non-existent. Finally, appropriate consumer protections may not readily apply to emerging DER related business models and as such may not adequately protect customers signing up to such models.

Table A provides a summary of the regulatory setting assessment across the wholesale, network and retail supply segments, broken down under four key themes: technology integration, tariffs and investment signals, DER participation and customer protection and engagement.

This document provides a summary of DER-related regulatory issues as an input to the DER Roadmap development. Recommended changes to regulatory settings will be broadly identified by the DER Roadmap and progressed as part of implementation of the Roadmap.

Table A – Summary of SWIS regulatory settings for DER

	Wholesale	Network	Retail
Technology integration	• Wholesale Electricity Market (WEM) distinguishes between generation & demand response. • Batteries not able to participate in some services.	• Connection of behind the meter DER is typically provided on a firm access basis. • Limited information exchanged between Western Power and potential DER providers to identify potential DER opportunities. • Western Power ownership of energy storage not clear.	• No common definition for DER. • Solar PVs, batteries, electric vehicles and demand response treated differently under different frameworks.
Tariffs and investment signals	• Capacity mechanism – RCM values each MW of capacity (generation or demand side) available to satisfy reliability criterion equally based on an estimated cost of additional capacity. • WEM – market value or regulated price.	• Network tariffs provide little signal of the costs being imposed on the network. • Limited consideration of the value of DER. Framework provides some incentives/ requirements to consider and value DER in some circumstances (regulatory test, requirements for efficient investment and cost recovery mechanisms) but not all. • Discounted network tariff for efficient connections (using DER) provided for in the Electricity Networks Access Code 2004, but rarely, if ever, used. • Western Power is able to pay DER for network support, but faces technical constraints, extra risks and potentially limited incentives.	• Retail tariffs deliver limited signalling of the value of DER/load shifting at different times of day. • Uniform Tariff Policy limits signalling of value of DER at different locations. • For rooftop solar PV, the Renewable Energy Buyback Scheme (REBS) rate is unlikely to reflect value of solar PV to the system including at different times of day.
DER participation	• Reserve capacity security deposit required. • Auditing requirements as per the WEM rules. • DER aggregators largely not contemplated.	• Limited information on network constraints including timing and location. • Technical framework delivers passive DER installations, not active DER that can be more easily leveraged for network support.	• Eligible customers receive REBS, however installations are passive participants in the system. • Grid connection of batteries discouraged through tariff structures and zero export connection requirements.
Customer protection and engagement	• Risk of REBS price and structure incorrectly valuing DER.	• Risks of failure to meet reliability standards may prevent Western Power from engaging DER. • Alternatively, shifting these risks to the DER provider is likely to be a barrier to deployment.	• Risks to customers around non-performance of system and opt-out arrangements. An example may be a customer's ability to opt-out of an agreement (e.g. a power purchase agreement). • DER providers do not contribute to retail costs, such as hardship schemes.

1. Introduction

1.1 Background

Distributed Energy Resources (DER) are generally defined as devices which are located at a customer's premises and can inject power into the local distribution system (including embedded networks), such as embedded generation or battery storage resources, or which assist in the management of load at the premises. These resources operate for the purpose of supplying all or a portion of the customer's electricity load and may also be capable of supplying power into the system or alternatively providing a load management service for customers.

DER could therefore include such technologies as solar photovoltaic (PV), combined heat and power or cogeneration systems, micro-grids, wind turbines, micro turbines, back-up generators and energy storage. Some parties may also consider demand response or energy efficiency to be DER, given that they could in some circumstances have the same value as injecting power into the network.

The rapid pace of adoption and innovation of DER provides opportunities for multiple parties across the electricity supply chain, including customers, to approach the production, transportation and consumption of electricity in a whole new way. DER, in the form of solar PV, has already transformed the way in which many customers engage with energy. Customers are no longer confined to drawing energy from the grid; it is now cost effective for them to produce their own energy. As the cost of electric vehicles (EVs) and battery storage falls, customers will have new opportunities to benefit from installing and using these other types of DER.

While DER, particularly renewable energy generation, are currently imposing technical challenges for power system security, other forms of DER have the potential to mitigate them, including energy storage, electric vehicles, home energy management systems, and demand management systems for commercial and industrial (C&I) consumers.

The proliferation of DER also provides new opportunities for Western Power to use these technologies to support its network. Grid-scale storage would assist in resolving some of the anticipated system and network stability issues arising from the strong uptake of solar PV and the consequent 'duck curve'. Western Power could also leverage DER assets owned by other parties to support its own network operations, in return for a payment. There are opportunities for DER owners to extract greater value from their investments by providing such services.

Despite the opportunities available from DER, in practice it is currently difficult for customers, Western Power, Synergy and other retailers and energy service providers to extract the full value. There are a range of barriers in the regulatory and policy frameworks that currently inhibit either the uptake of, or extraction of, value from DER. Typically this is not intentional.

Rather, the regulatory and policy frameworks were developed to meet the requirements of the traditional electricity supply model, characterised by a one-way flow of electricity from large, centralised fossil fuel generators, through transmission and distribution networks to the customer. Consequently, the frameworks are not fit-for-purpose for the new supply model that is developing – a supply model of decentralised, customer-owned renewable generation and two-way flows across the network.

The focus of this *DER Roadmap Regulatory Settings Summary* is to identify and summarise the aspects of the current regulatory and policy frameworks that influence DER in the South West Interconnected System (SWIS). This analysis considers the effectiveness of these mechanisms in practice, to support the efficient uptake, operation and use of DER, and identifies gaps that might need to be addressed in the DER Roadmap.

Hence, this Regulatory Settings Summary also provides important context for the DER Roadmap. It provides a baseline scenario against which potential changes to the regulatory and policy frameworks can be assessed.

1.2 Approach

This document considers how the four themes of the DER Roadmap – technology integration; tariffs and investment signals; DER participation; and customer protection and engagement – are reflected in the policy and regulatory frameworks across the three components of the electricity supply chain (wholesale, network and retail).

In addition, the following four questions, largely corresponding to the four themes, are considered:

1. *How is DER defined and identified?* This question considers whether the regulatory framework provides a consistent definition of DER, and whether that definition is appropriate and captures all potential applications of DER. Also relevant is how DER might be identified by Western Power as providing a potential source of network support.
2. *How is DER valued and rewarded*? This question considers the incentives that potential DER providers and end users (such as households) have to invest in and operate their DER in a way that optimises DER through supporting the wider system.
3. *Are costs for DER participation proportionate*? This question considers whether there are any barriers to DER participation (such as transaction costs and inherent cross-subsidies) that may either outweigh the benefits or inhibit access to the potential rewards of DER.
4. *Are risks appropriately identified and managed*? This question considers what risks might arise in the provision or procurement of DER and whether those risks are appropriately managed.

In addition, the following factors have been considered in assessing the current frameworks.

- System security and reliability – ensuring availability of enough dispatchable energy to keep the lights on and the network operating within technical limits
- Efficient solutions are identified and implemented – keep prices no higher than necessary to deliver a reliable and secure supply to customers
- Technology neutrality – the regulatory framework is agnostic with respect to the technology deployed, instead focusing on the most efficient solution that meets technical requirements
- Regulatory flexibility – reduce regulatory barriers to efficient new technology solutions and alternative business models

A broad definition of the scope of DER has been applied in this assessment:

> *Smaller-scale devices that can either use, generate, or store electricity and form a part of the local distribution system which serves homes and businesses, as well as demand response.*[1]

1.3 Purpose and structure of this document

The purpose of this analysis is to inform the development of the DER Roadmap by the Energy Transformation Taskforce that will help manage the transition of the SWIS to a future with more

[1] Where demand response is considered as a change in consumption of a customer in response to a signal seeking to better match the demand for electricity with the supply.

dispersed and variable generation and a lower carbon footprint. It should therefore be read in the context of the DER Roadmap.

This document first sets out an overview of the legislative framework that underpins the policy and regulatory frameworks that will influence investment in and operation of DER.

The subsequent sections set out the specific mechanisms that will influence the use of DER across each component of the supply chain – wholesale, network and retail – and assesses the effectiveness of those mechanisms. As part of this assessment, potential gaps in the frameworks are identified.

This document provides a summary of issues identified but does not consider how issues should be addressed. Where regulatory settings are a barrier to efficient uptake and use of DER, detailed recommendations for making changes will be developed through the different workstreams of Energy Policy WA (EPWA) and the Energy Transformation Taskforce, including:

- the DER Roadmap and associated implementation work plan;
- the Energy Transformation Taskforce's Foundations Regulatory Frameworks workstreams:
    - Improving Access to the Western Power Network;
    - Delivering the Future Power System (e.g. considering arrangements for essential system services); and
- EPWA's review of licensing provisions and associated customer protections.

2. Legislative framework in the SWIS

The legislative framework underpinning the regulatory framework for the SWIS is extensive and complex. The following table provides a summary of the legislation and subordinate rules and regulations that materially influence DER.

Table 2.1 Key Legislative Instruments in the SWIS

Legislative instrument	Description	Relevance to DER
Electricity Industry Act 2004 (EIA)	Provides the overarching regulatory framework for electricity, including access to network infrastructure, operation of the wholesale market and protections for customers. The EIA is supported by a series of codes, rules and regulations.	The EIA provides the governing framework for the regulation and operation of the electricity supply chain. As such, it ultimately influences every facet of DER.
Electricity Networks Access Code 2004	Provides the framework for the regulation of certain electricity networks, including Western Power in the SWIS, by the Economic Regulation Authority (ERA). The objective of the Access Code is to promote the economically efficient investment in, and operation and use of, networks and services of networks in Western Australia, to promote competition.	Among other things, the Access Code governs: • connection, which will influence the ability to connect DER to the distribution network and the standards that the equipment must meet in order to connect; • the structure of network tariffs, which will influence efficient investment in and use of DER by its owner/operator – efficient price signals are required to optimise investment in DER and incentivise participation in relevant markets; and • network planning and operation, which will influence the ability and incentives for Western Power to use DER as an alternative to network investment. This will depend on how Western Power is able to recover its DER-related costs compared to network investment.
Technical Rules	Sit under the Access Code. The Technical Rules detail the technical requirements to be met by: 1. Western Power; and 2. by Users who connect facilities to the transmission and distribution systems which make up the Western Power Network. Prospective Users or existing Users who wish to connect facilities (or modify existing connections) to the transmission and distribution systems must first	Set out the detailed technical requirements that DER is required to meet to connect to Western Power's network. Allows WP to refuse a small system connection if it considers the power system performance standards will not be met as a consequence of the operation of the power system.

	submit an access application to Western Power in accordance with the Access Code.	
Code of Conduct for the Supply of Electricity to Small Use Customers	Regulates and controls the conduct of retailers, distributors and electricity marketing agents who supply electricity to residential and small business customers to provide consumer protections.	Adherence to the Code of Conduct is limited to licensed participants. The Code therefore does not apply to commercial activities that are outside the scope of an electricity licence, which can include certain DER services (e.g. Virtual Power Plant products) offered by parties without a retail electricity licence.
Electricity Industry Metering Code	Sets out the rights, obligations and responsibilities of participants associated with the measurement of electricity and the provision of metering services, the rules for the provision of metering installations at connection points, and the rules for the provision of metering services, standing data and energy data.	The Metering Code will impact the type of meter required for DER, the data that must be collected and to what standard/level of granularity. The Metering Code also governs access to data, which will be important for customers and third parties seeking to optimise the use of DER.
Electricity Act 1945	Technical and safety issues relating to electrical installation, are governed by the *Electricity Act 1945* and supporting Regulations	All electrical work, including design, construction, operation and maintenance, must be carried out in accordance with the Act and associated regulations. Includes the installation of DER. The Act also specifies the permissible network voltage band.
Electricity Industry (Licence Conditions) Regulations 2005	Imposes obligations on certain licence holders e.g. in relation to the purchase of renewable energy from certain customers and requiring compliance with certain codes	Gives effect to the requirement for Synergy to offer to purchase electricity generated through small renewable energy systems from some customers.
Wholesale Electricity Market Rules	Govern the market and the operation of the SWIS, including the wholesale sale and purchase of electricity, Reserve Capacity, and Ancillary Services	Determines the value of DER in the various components of the wholesale market, and conditions for participation in that market.

3. Wholesale market mechanisms influencing DER

3.1 Introduction

This section focuses on the use of DER in the wholesale market. The Wholesale Electricity Market (WEM) supports the sale and procurement of electricity in the SWIS. The WEM comprises of mechanisms that, together, ensure that the demand for electricity can be met. These mechanisms include:

- Reserve Capacity Mechanism (RCM);
- forward energy markets: Short Term Trading Market;
- real-time Balancing Market; and
- Essential System Services (ESS).

Each of these is discussed below.

In order to participate in the WEM, an entity must be registered with AEMO. Registered market participants are subject to a set of obligations under the WEM Rules, including prudential requirements to reduce the risk that they are not able to meet their settlement obligations.

3.1.1 Reserve Capacity Mechanism

The RCM places an obligation on market customers (retailers and major users) to contract for 'capacity credits' to cover their share of the total capacity necessary to meet system requirements at times of annual peak system load. The AEMO is responsible for determining the capacity requirement.

A capacity credit is a notional construct that reflects 1MW of capacity. Suppliers of registered capacity can be either:

- generators, including distributed generators. If there is a shortage in supply, these generators can be called upon to operate in order to meet demand; or
- demand side resources. The demand side management mechanism effectively pays electricity users to be on standby to reduce electricity demand upon request during peak periods.

In order to provide capacity credits, a facility must be certified by AEMO. This requires a review of the technical capability of the facility and whether the capability will be available when needed. The extent to which capability is available when needed determines the maximum quantity of capacity credits that can be allocated to the facility. A market customer can either procure capacity credits bilaterally from capacity providers or purchase them from AEMO.

If insufficient capacity credits are traded bilaterally to meet requirements, AEMO will run an auction to procure more to cover the remaining requirements of market customers. The price paid by AEMO for this capacity – the Reserve Capacity Price – is derived from a pricing formula established in the WEM Rules. Under the WEM Rules, capacity is procured by AEMO at this administered price, rather than a price determined by the market.

The RCM pricing formula has recently undergone significant reform to send clearer signals on the value of capacity at different levels of capacity excess. There are now sharper pricing signals to capacity providers regarding when additional capacity is required, and to discourage inefficient over-investment in capacity[2].

To fund capacity procured through the RCM, each Market Customer is assigned an Individual Reserve Capacity Requirement (IRCR) obligation based on their contributions to the system peak. For small customers, the IRCR is smeared across regulated tariffs and does not provide any signals under current tariff structures.

For large electricity consumers, the IRCR contribution will vary depending on their metered use on previous designated system peak days. Using DER to reduce load can reduce capacity related costs, or energy charges, in the short term, but also reduce the IRCR over the longer term. However, the 12 month calculation introduces a period lag to the realisation of any IRCR benefits that DER can provide.

3.1.2 Forward energy markets

Most energy and capacity trading occurs bilaterally between generators and retailers. It is up to the contracting parties to agree the terms and conditions, including the timeframe and price. This market is not centrally managed, but bilateral contract positions are registered with AEMO and netted-out as part of market settlement processes.

The Short-Term Energy Market (STEM) allows market participants to trade around their bilateral energy position on a day-ahead basis. The STEM is administered by AEMO. A STEM auction is run for each trading interval of the next day, determining a STEM clearing price and clearing quantities.

3.1.3 Balancing Market

The Balancing Market is a mandatory, gross pool into which all generators with capacity credits must offer their full ‘available’ capability. Every half-hour, the Balancing Market ‘clears’ energy to meet expected demand over the half-hour trading interval, using forecasts of load and generation levels without accounting for information about constraints on the network (as demonstrated in AEMO’s network model).

3.1.4 Essential System Services

ESS are essential for maintaining security and reliability of supply. For example, they assure management of voltage and frequency quality and respond to contingency events on the power system. AEMO is required to determine, procure, and schedule required ESS. There are currently five types of ESS in the WEM:

- *Load Following Ancillary Services* (LFAS) is the primary mechanism to ensure supply and demand are balanced in real time. The LFAS market identifies facilities to provide LFAS on a half-hour basis. It runs four times each day, generating LFAS selections for a specified six-hour period. Participants must reflect their LFAS position in their Balancing Market offers.
- *Spinning Reserve Ancillary Services* (SRAS) holds online capacity (generation and load) in reserve to respond rapidly in the event of an unexpected loss of generation (e.g. a generation unit ‘tripping’).
- *Load Rejection Reserve Ancillary Services* (LRRAS) requires generators to be maintained in a state where they can rapidly decrease their output should a system fault result in the loss of load.

[2] https://www.wa.gov.au/government/collections/improving-reserve-capacity-pricing-signals

- *Dispatch Support Service* (DSS) ensures voltage levels around the power system are maintained, and includes other services required to support the security and reliability of the power system that are not covered by other balancing or ESS.
- *System Restart Service* (SRS) allows parts of the power system to be re-energised by black start equipped generation capacity following a full (or partial) black out.

Currently there is only a market for LFAS. In order to participate in the LFAS market, a facility must be certified by AEMO as being capable of providing LFAS. SRAS, LRRAS and DSS are procured by AEMO via contracts with individual market participants. This process, including setting costs, is overseen by the ERA. AEMO procures SRS via an expression of interest process.

Synergy is the default provider of LFAS, SRAS and LRRAS, with costs recovered via an administered price for SRAS and LRRAS[3]. Market participants other than Synergy will only be appointed when the contract price offered is lower than the administered price for the service.

Not all DER will be capable of providing each of the above services. Each ESS needs to be able to meet certain technical requirements, which may exclude some DER from participating. However, provided it meets the necessary technical requirements, there do not appear to be any further barriers to individual DER providing ESS. It is not clear how aggregated DER across multiple sites will register and become accredited under the ESS framework.

The Energy Transformation Taskforce's Foundation Regulatory Frameworks work stream will introduce security-constrained energy market and new ESS arrangements in the WEM from 1 October 2022.[4] These new market arrangements may provide opportunities for future involvement by DER.

3.2 Technology integration

The technical and registration requirements for DER participation in the WEM, RCM and ESS markets, particularly where facilitated by aggregators, are unclear.

In theory, any new generation facility with a name plate rating above 5kW can potentially be registered as a generating facility and participate in the WEM, provided it meets AEMO's registration requirements and any technical requirements for a market or service. However, in practice, the registration and prudential requirements necessary for participation make it unlikely that any generation or load without some degree of scale will be able to operate in the WEM. This is discussed further below. The current arrangements also do not contemplate participation by aggregated, smaller facilities.

Further, there are restrictions on how storage technology can participate in the WEM as an individual facility. This is because the registration requirements are inconsistent with how a storage facility would operate and there are complicated technical requirements to consider.[5]

From a technical perspective, participation in these markets using aggregators will require a common set of standards and protocols to ensure multiple DER within a portfolio are able to comply with market dispatch capability requirements. Pilots and trials will be required to demonstrate the technical capability of DER to provide services within these markets.

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[3] LFAS prices are set in the LFAS market.

[4] See https://www.wa.gov.au/organisation/energy-policy-wa/energy-transformation-strategy

[5] See AEMO, Participation Guideline for Energy Storage Systems in the WEM, May 2019.

In addition to the above, as the penetration of DER increases within the system, the SRS within the ESS framework will need to be evaluated to consider the impact of the DER fleet within the restart process. High amounts of unmanaged DER will impact the load and restart generation requirements necessary to complete the system restart process.

Findings:

- Whilst in theory most individual DERs could participate in the various markets (subject to meeting defined requirements), market participation requires review and clarification, particularly when considering DER aggregated across multiple sites.
- Storage technology faces constraints on participation in the WEM as an individual facility.
- Pilots will be required to demonstrate the technical capability (including integration with market systems) of DER to provide services within the WEM.
- The impact of increasing DER on the provision of some ESS requires further technical review.

3.3 Tariffs and investment signals

DER services can generally be valued through existing market mechanisms, including the Reserve Capacity Mechanism (RCM).

3.3.1 Valuing capacity under the RCM

The annual price paid by the AEMO for reserve capacity is derived from a pricing formula established in the WEM Rules. Under the Rules, capacity is procured by AEMO at an administered price, rather than a price determined by the market.

AEMO is responsible for calculating the Benchmark Reserve Capacity Price (BRCP) in accordance with a market procedure. It must then be approved by the ERA. The BRCP is based on the stand-alone fixed costs incurred by a benchmark new entrant plant.

A new capacity price curve will continue to be based around the benchmark cost of an efficient new entrant. The price curve comprises three inflection points:

- *Price Cap* – the capacity value associated with no capacity surplus, to be set at 1.3 times the BRCP.
- *Absolute zero point* – the point where the amount of excess capacity is deemed to be sufficiently high for the capacity price to be zero, set at a 30 per cent level of excess capacity.
- *Economic zero point* – a level of capacity surplus and price at which no additional resources should enter the system under a very wide range of market conditions, set at a capacity price equal to 50 per cent of the BRCP and at a level of excess capacity of 10 per cent.

Transitional arrangements apply from the 2019 Capacity Cycle and will involve a price band for existing generation facilities between $114,000 and $140,000 per megawatt (CPI adjusted) for a period of ten years. New entrants have the option to take the ‘floating’ capacity price in each capacity year or to lock in the price in the year of entry for five years.

The reserve capacity price paid to generators for the 2019-20 capacity year is $126,683/MW.

Demand response was previously valued consistently with generation. However, during the transition to the new capacity price formula, which began in 2016, demand side management capacity was priced differently to generation capacity to better align the economic value of DSM as a contribution to system reliability at the time.

While this approach was adopted for the transition period, EPWA has indicated that it is preferable for demand side resources to receive the same price as other forms of capacity, and that the RCM should move towards equivalent pricing.

EPWA has also noted that it is important to ensure the availability of this type of capacity resource. To assist with this, particularly where there is a risk of the demand side resource not being available, EPWA has recommended that demand side management resources be required to provide a Reserve Capacity Security deposit each year of capacity certification, with scope for the requirement to be waived where resources can demonstrate availability.

The reserve capacity price for demand side management for the 2019-20 capacity year is $16,990/MW.

Upon implementation of the new capacity price curve, demand side management will receive the same capacity price as other forms of capacity.

3.3.2 Valuing DER in other components of the WEM

As noted previously, DER is generally valued in the same way as other generation. For the forward markets, Balancing Market and LFAS market this value is determined via a competitive process, either via auction or bilateral negotiation. However, for the remaining ESS markets, the value of these services is determined via administered or contract prices.

> Findings:
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> - Currently DER services are largely able to be valued through existing market mechanisms in theory, however as noted previously, there are technical and administrative barriers to participation in these markets.

3.4 DER participation

3.4.1 Registration

Participation in the WEM requires registration with AEMO as a market participant and registered facility. This comes with obligations which impose some transaction costs associated with participating in the market. These are likely to be proportionally higher for small scheme participants.

Further to this, the dispatch of DER via aggregators within the WEM, RCM and ESS markets will require integration with market systems. Given the inherent complexity in dispatching customer-owned DER across multiple sites and using varied communication technologies and protocols, pilots and trials will likely be necessary to demonstrate integration.

3.4.2 Prudential requirements

Market participants must meet prudential requirements for participating in the market. There are two aspects to the prudential requirements:

- *Credit limit* – this is the maximum net amount that a market participant is likely to owe AEMO over a two-month period between being scheduled and being settled in the market, where this amount is not expected to be exceeded more than once in a 48-month period.
- *Credit support* – this is a guarantee of unconditional payment of a set level of funds to AEMO where the guarantor of this payment cannot be a Rule Participant and must have a satisfactory credit rating.

While the prudential requirements are scaled to reflect the risks associated with individual market participants, the requirement to secure credit support could be a limiting factor for some potential DER providers seeking to participate in the wholesale market.

> Findings:
>
> - Scale is not an explicit barrier to obtaining value from DER, but smaller generation is likely to find it more difficult to participate in the wholesale market due to administrative, technical and other requirements.
> - Pilots and trials will be critical in testing DER participation from a market integration perspective

3.5 Customer protection and engagement

Risks for customers arising from the WEM include:

- Over- or under-compensation of capacity. Where capacity is over-compensated, it is customers that will ultimately pay a higher price. On the other hand, the level of compensation must be sufficiently high to attract capacity when needed.
- Capacity not being available when called upon. This could create system security and reliability issues.
- Market distortions leading to inefficient outcomes and higher costs for customers.

Recent changes to the RCM have sought to address the first two of these issues. The way in which the price for capacity is calculated is being amended to better reflect the value of incremental new capacity. One of the drivers for this amendment was acknowledgement that in the past, the mechanism may have been over-compensating capacity providers and incentivising excess capacity.

In respect of the second risk, the reforms have sought to address this issue, specific to demand response, by placing greater requirements on market participants. In particular, demand side management resources must:

- provide a security deposit each year of certification; and
- be subject to more stringent auditing requirements.

In respect of market distortions, dispatch is not currently co-optimised across energy and ESS markets. Rather, these markets are operated separately. This means that generators may game the markets by offering into relatively higher priced markets, increasing costs for customers. A co-optimised market will leave capacity providers commercially indifferent as to what service they are dispatched to provide. This issue is being addressed by the Energy Transformation Taskforce via the Foundation Regulatory Frameworks work stream.

4. Network mechanisms influencing DER

4.1 Introduction

This section focuses on the relationship between DER and the transmission and distribution networks under the regulatory arrangements applicable to Western Power.

4.1.1 Overview of the regulatory framework

Western Power owns and operates both the distribution and transmission networks in the SWIS. As a monopoly provider of network services, Western Power is subject to economic regulation. This is given effect through an Access Arrangement, which sets out the terms and conditions, including prices, for third parties seeking to access the network.

An Access Arrangement period typically spans five years. At the end of an Access Arrangement period, Western Power is required to submit proposed revisions to the Access Arrangement and Access Arrangement Information to the ERA. The ERA is then required to consider Western Power's proposed revisions to the Access Arrangement and decide to approve or not approve the proposed revisions.

Mechanisms within the Access Arrangement, its governing legislation, and associated codes and rules influence the incentive on Western Power to utilise DER as an alternative to network solutions as well as the incentive on network users to invest and operate DER. These are summarised in the following tables, which identify and describe each mechanism and explain how the mechanism influences DER.

Together, these mechanisms seek to govern how Western Power:

- is required to operate and invest in its network;
- recovers its costs; and
- supports DER and recognises the potential for DER to reduce Western Power's own system costs and incentivise investment in and use of DER.

4.1.2 Interaction between network provider and DER

The incorporation of DER into distribution networks has important effects on the traditional operation of those networks. Existing distribution networks have been designed to be passive, transporting electricity from the transmission grid to end customers with a minimal level of control, monitoring and supervision. Distribution networks were not designed to accommodate generation at lower voltages.

DER introduces new challenges for Western Power, but also opportunities for both consumers and Western Power that reflect the economic benefits arising from local generation and more active networks.

There are multiple ways where the decisions and behaviour of Western Power can influence, directly and indirectly, the uptake and utilisation of DER. These include:

a) the diversity and structure of network tariffs, which provide signals about investment in and use of DER;

b) through buying DER as a network service and sharing with DER providers the financial benefits of deferring network investments;

c) operation of the network, impacting on how DER is used;

d) setting the rules under which DER can connect to the network; and

e) metering arrangements to help inform the value, as well as monitor and manage the use, of DER.

4.1.3 DER access and pricing

The table below provides a summary of the four different arrangements relating to DER network access and pricing, including a description of the arrangement and how it influences efficient outcomes for DER.

Table 4.1 DER access and pricing arrangements

Mechanism/Arrangement	Description	How it influences DER
Connection of DER	The Technical Rules set out the technical requirements and standards that network users wishing to connect generation (and load) facilities to Western Power's network must meet. These connection requirements can differ by the nature and size of the connection. This can determine whether the costs are levied directly on the connecting customer or socialised across the general customer base.	The Technical Rules address connecting DER to the network and are quite broad. They allow Western Power to impose performance requirements and refuse DER connection where connection would adversely impact on performance standards. There are no export reliability standards nor access guarantees for the new 'export' distribution service of accepting customer exports onto the grid. Thus, an exporting DER customer's access to the network can be uncertain.
Network tariffs	Western Power is free to structure its network tariffs how it sees fit, provided the tariffs comply with the objectives of pricing methods set out in the Access Code. The primary objective requires tariffs to recover the forward-looking efficient costs of providing network services. Secondary objectives relate to considering the impact of tariffs on network users. Clause 7.7 prescribes postage stamp pricing for customers with contracts for services lower than 1MVA.	In practice, network pricing averages costs across many users. This means that individual network users may not be exposed to the actual costs they impose on the network, particularly at different times of day and in different locations, limiting the ability to signal the value of DER through network tariffs.
Prudent discounts	The Access Code allows Western Power to offer discounts to certain users where it is efficient to do so.	May provide an incentive for customers with DER to remain connected to the network and provide services that help support the network.
Discounted network tariffs for distributed generation	The Access Code requires Western Power to provide a discounted tariff for users that are connecting distributed generating plant to the network where their connection results in a reduction in Western Power's costs due to the location of the connection.	This mechanism should encourage investment in DER in locations that provide value to Western Power in terms of reduced network costs. The calculation methodology may be too general to accurately capture the true value of the distributed generation.

4.2 Technology integration

4.2.1 What is considered DER?

Western Power explicitly recognises a range of types of DER, in the form of embedded generation, that may seek approval to connect to the network. Embedded generation includes solar PV, battery storage and electric vehicles where the EV charger is connected to the grid. The technical requirements for connecting these types of generation to the network are set out in the Technical Rules.

The legislative and supporting frameworks are less specific about the types of technology that may connect to the network or be used by Western Power in operating its network. For example, the definition for "alternative options" in relation to a network augmentation includes (but is presumably not limited to) demand-side management and generation solutions.

Similarly, under the D-factor scheme[6], Western Power can retrospectively recover costs associated with demand management initiatives or network control services where they are employed to defer capital expenditure. Network Control Services are defined as demand-side management or generation solutions (such as distributed generating plant) that can be a substitute for network augmentation.

In turn, DER can be defined quite broadly to include tools that contribute to demand management as well as generation solutions. This interpretation may include advanced meters used for load control.

However, the EIA defines network infrastructure facilities as "electrical equipment that is used only in order to transfer electricity to or from an electricity network" and "the wires, apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity". It is not clear whether batteries would fall within this definition and therefore whether Western Power is permitted to own such assets.

4.2.2 How are DER solutions identified?

Western Power has two options to employ DER as an alternative to network solutions.

1. Investing in DER solutions itself, in which case at least some of the associated costs will be capital costs.
2. Contracting with another party to provide DER solutions, in which case the associated costs will primarily be operating costs.

While Western Power may be able to identify potential DER solutions it can provide itself, it may not be able to identify the full range of DER solutions that could be provided by another party ('DER provider').

The regulatory test requires Western Power to value DER in certain circumstances as an alternative to a major augmentation. The regulatory test assessment is to consider "whether a proposed major augmentation to a covered network maximises the net benefit after considering alternative options".

[6] The D-factor is an adjustment to account for any additional operating expenditure that Western Power incurs as a result of deferring a capital expenditure project, and any additional operating or capital expenditure incurred in relation to demand management initiatives. See section 4.3.5 for more information.

The regulatory test also requires that Western Power "use its reasonable endeavours to ensure that it makes sufficient information available in a timely manner in respect of a proposed major augmentation to maximise the opportunity for potential alternative options to be viable". Further, submissions must be invited on reasonable alternative options to the proposed major augmentation. This can be done as part of Western Power's Access Arrangement approval process or as a separate process. However, there are practical challenges for DER providers submitting credible alternatives to WP through the regulatory test process.

This requirement to provide sufficient information to potential DER providers is not a comprehensive one. Further, without consultation with DER providers themselves, Western Power may not be aware of the type of information and level of detail required for alternative options providers to respond with viable proposals.

The regulatory test is only required to be applied to investments that are over a defined cost threshold and only new (not replacement) expenditure. Consequently, there may be other opportunities for DER to efficiently replace network expenditure that are not currently being utilised. Western Power is not required to provide comprehensive plans of its system that may assist potential DER providers in identifying upcoming network constraints or other issues that may benefit from a DER solution.

While alternative options may be identified outside of the regulatory test process, there does not appear to be a comprehensive tool for identifying potential DER solutions.

4.2.3 Impact of technology on the network

The Technical Rules are the primary mechanism that Western Power has for controlling the impact of electrical equipment on its network. The Technical Rules contain specific requirements for the connection of small generating units (less than 10MW) to the distribution system – whether renewable or non-renewable – as well as specific requirements for energy systems that are connecting via an inverter (such as household solar PV). These latter requirements are discussed further in the context of the retail market.

The Technical Rules give Western Power the ability to impose performance requirements on connecting parties and refuse DER connection where connection would adversely impact on power system performance standards.

The connection framework is based on the current reliability standards which apply to conventional distribution services, supplying consumer load. There are no corresponding export reliability standards nor access guarantees for the new 'export' distribution service. Thus, an exporting DER consumer's 'access' to the network can be uncertain.

Findings:

- It is not clear in existing legislation whether Western Power is permitted to own energy storage.
- Proponents of a credible DER alternative option may not have sufficient information or opportunity to engage effectively with Western Power.
- There is no export reliability standard that Western Power is required to meet.

4.3 Tariffs and investment signals

This section considers the aspects of the regulatory arrangements that require Western Power to value DER and its incentive to implement DER solutions.

4.3.1 Form of regulation

The form of the regulatory incentive framework may influence Western Power's incentives to adopt DER solutions. Until recently, the amount of revenue that Western Power could earn from providing regulated services was capped. However, Western Power has now shifted to a price cap form of regulation, which instead limits the prices that Western Power can charge. A key difference between the two mechanisms is who bears the risk that forecast demand, upon which cost allowances are set at the beginning of the regulatory period, differs from actual demand.

Both a price cap and a revenue cap are intended to encourage Western Power to reduce its costs by fixing either the revenue or price it can earn for a period and allowing Western Power to benefit from any cost savings it is able to achieve. However, the two forms of regulation may provide different incentives for Western Power to adopt DER solutions.

Under a revenue cap, it is customers that bear the risk that actual demand is less than forecast demand – Western Power will still recover the same amount of revenue.

On the other hand, under a price cap it is Western Power that bears the volume risk. If demand is lower than expected, Western Power's revenue will also be lower than expected. Consequently, Western Power may have less incentive under a price cap to adopt solutions that reduce demand across its network, potentially hindering the uptake of DER solutions.

However, it is important to note that the form of control cannot be considered solely through the lens of the use of DER by Western Power. The ERA considered a range of factors in deciding to shift the form of regulation to a price cap. A critical factor was the ERA's view that exposing Western Power to demand risk would provide stronger incentives to develop more efficient tariffs, particularly in relation to the balance between fixed and variable charges. As discussed further below, better price signals should, in turn, provide incentives for customers to more efficiently invest in and use their DER.

4.3.2 The regulatory test

As noted previously, the regulatory test requires Western Power to value DER in certain circumstances when assessing alternative options for a major augmentation, including net benefits across the value chain.

In assessing the net benefits, Western Power would need to identify the value that DER may provide. The net benefits to be considered are to those who generate, transport and consume electricity in Western Power's network and any interconnected system. In principle, therefore, Western Power can consider the wider benefits from a particular DER solution which could accrue to the users of its network, not simply to Western Power itself.

Under the regulatory test, DER would typically be considered as a means to defer network investment, as "an alternative to a major augmentation". However, given that the net benefits to be assessed may be broader than just the network, Western Power could also assess other potential benefits of DER, such as improving system security or reducing ESS dispatch requirements in the WEM.

Despite the potentially broad interpretation of the requirements of the regulatory test, there is no explicit requirement for benefits to be interpreted this broadly. The way in which the regulatory test is articulated in the Access Code is not specific about the types of costs and benefits that should be considered in applying the test. Rather, there appears to be significant discretion provided in how net benefits are calculated.

The ERA published a Guideline for application of the Regulatory Test in 2008[7]. This also provides very little guidance on how to value or treat DER type benefits, which were not a significant feature of the electricity system when the Guideline was developed.

Effectively the value of DER under the regulatory test is capped at the avoided costs associated with the network option.

Although the regulatory test provides a potentially useful mechanism for valuing DER, there are several issues that may inhibit its effectiveness.

- As noted previously, the regulatory test only applies to new, not replacement, capital expenditure and only over a certain threshold.
- There may be insufficient information for potential DER providers to respond with plausible DER alternatives.

Aside from being a regulatory requirement, it is not clear how the regulatory test provides an incentive for Western Power to implement non-network solutions. Indeed, as discussed further below, there may be some disincentives to Western Power implementing non-network solutions.

4.3.3 Recovery of capital costs for Western Power-owned DER solutions

As noted above, DER solutions may be implemented by either Western Power itself or by a third party DER provider. Where Western Power is implementing a DER solution this could include, for example, advanced metering and distribution network-connected storage. In this instance, the DER solution must pass various hurdles for Western Power to be able to recover the costs.

Western Power must be able to demonstrate that the investment passes the New Facilities Investment Test (NFIT) for the capital expenditure to be included in its Regulated Asset Base (RAB). The NFIT comprises of two parts, an ‘efficiency test’ and a test of whether new facilities investments provide benefits that justify the addition of the investment to the RAB.

The first part, the efficiency test, assesses whether the new facilities investment exceeds the amount that would be invested by a service provider that is efficiently minimising costs, taking account of economies of scale or scope, increments in which new capacity can be added and forecasts of sales of services.

The second part provides for new facilities investments to be added if one or more of three tests are satisfied.

1. The ’incremental revenue test’ is satisfied if the new facility is expected to at least recover the new facilities investment, unless a modified test has been approved by the ERA.
2. The ’net benefits test’ is satisfied if the new facility provides a net benefit over a reasonable period that justifies the approval of higher reference tariffs.

[7] https://www.erawa.com.au/cproot/6414/2/20080222%20Guideline%20for%20Application%20of%20the%20Regulatory%20Test.pdf

3. The ’safety and reliability test’ is satisfied if the new facility is necessary to maintain the safety and reliability of the covered network or its ability to provide contracted covered services.

The NFIT therefore requires Western Power to evaluate the costs and benefits of any potential investment in DER assets to demonstrate that the investment is efficient and meets one of the other three tests.

Part of the reason it may be difficult to justify DER investments such as community battery storage is that it is difficult to extract the full potential value of DER, particularly where coordination with other parties is required. For example, the ring-fencing objective prevents Western Power from carrying on a related business, which means Western Power is unable to generate, purchase or sell electricity other than under limited circumstances.

The NFIT could make it difficult for Western Power to justify capital investment in certain DER assets even where there may be wider community benefits, or reluctant to implement them if there is any regulatory risk.

4.3.4 Recovery of operating costs for third party DER

Western Power must also consider the value of DER where it procures a DER solution from another party in order to recover the associated operating costs. The Access Code recognises that if Western Power employs a non-network solution it will need to recover the additional non-network (operating) costs associated with the non-network solution. The associated test is similar to that for capital expenditure. That is, Western Power is permitted to recover the operating costs associated with procuring DER provided that those costs are efficiently incurred and at least one of the following conditions is satisfied. Either:

- the additional revenue for the alternative option is expected to at least recover the alternative option non-capital costs; or
- the alternative option provides a net benefit in the covered network over a reasonable time period that justifies higher reference tariffs; or
- the alternative option is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

Again, like capital expenditure, there is a risk that although operating expenditure may be approved by the ERA to procure DER in one Access Arrangement period, it may not be approved in a subsequent period. This may temper Western Power’s appetite to enter into extended agreements with DER providers.

4.3.5 D-factor

The D-factor scheme was approved in Western Power’s second Access Arrangement and has operated since then. The D-factor is an adjustment to account for any additional operating expenditure that Western Power incurs as a result of deferring a capital expenditure project, and any additional operating or capital expenditure incurred in relation to demand management initiatives.

In its decision on Western Power’s most recent Access Arrangement (Western Power’s fourth Access Arrangement, or ‘AA4’), the ERA noted that the D-factor is not intended to provide incentives for Western Power to pursue demand management activities. Rather it was introduced to remove the apparent disincentive for Western Power to seek efficiency in capital costs where an increase in non-capital costs was necessary to achieve the efficiency.

The D-factor scheme can therefore be seen as a mechanism that is intended to level the playing field between network investment and non-network solutions such as demand management initiatives.

4.3.6 Network tariffs

Network tariffs are necessary to recover the costs of investing in and operating the network. The structure of network tariffs can provide a signal to network users of how their use of the network influences costs. This, in turn, can provide incentives for customers to use the network in ways that lower network costs, including how they invest in and use DER.

Western Power is free to structure its network tariffs how it sees fit, provided the tariffs comply with the objectives of pricing methods set out in the Access Code. The primary objectives are that tariffs recover the forward-looking efficient costs of providing regulated network services and an individual user's tariff is between the incremental cost and stand-alone cost of providing the service.

Secondary objectives are that:

- charges only differ between users where their average cost to serve differs;
- tariff structures take into consideration the Access Code objective and the reasonable requirements of users;
- annual changes in tariffs are predicable; and
- price shocks are avoided.

In addition to the above, clause 7.7 of the Access Code prescribes postage stamp pricing. That is, tariffs do not differ based on location on the network and associated costs to serve. For residential and small use customers, where the vast bulk of DER is currently installed, network costs are averaged across customers regardless of their actual network usage. This means that individual customers may not be exposed to the actual costs they impose on the network, particularly at different times of day and in different locations, limiting the ability to signal the impacts or value of DER through network tariffs.

Moves towards greater cost-reflectivity in network tariffs can help to better reflect and reward the network value from DER.

It is challenging to design network tariffs that better reflect costs and fully capture the network savings available from DER. Most network tariffs are based on the long-run marginal cost of the network, allowing DER to be captured by valuing the benefits of deferring network investment that would otherwise be required to meet additional demand. However, this does not recognise other potential benefits from DER such as operational cost savings and improved reliability outcomes. DER can also create network value through deferring the need to replace existing assets.

There is also a risk under the current arrangements that retailers do not pass through the full cost reflective network charges and DER customers may not receive a share in the wider benefits provided by DER.

4.3.7 Prudent discounts

The Access Code allows Western Power to discriminate between users and offer discounts to certain users where it is efficient to do so. Western Power's policy, set out in AA4, states that Western Power may offer a prudent discount if the network user is able to demonstrate that another supply option will provide a comparable service at a lower price than that offered by Western Power's reference services and reference tariffs. Where this is the case, Western Power's discounted price offer will be set to reflect the higher of:

a) the cost of the other option; or

b) the incremental cost of service provision.

Where customers can access this discount, it may provide an incentive for customers with DER to remain connected to the network and potentially provide services that help support the network, rather than potentially disconnecting from the network.

4.3.8 Discounted network tariff

The Access Code requires Western Power to provide a discounted tariff for users that are connecting distributed generating plant to a covered network where their connection results in a reduction in Western Power's costs due to the location of the connection.

The Access Code does not specify how the discount should be calculated, but just requires the discount to reflect "a share" of any cost reductions. It also requires Western Power to provide further detail as part of its Access Arrangement. In practice, these provisions are rarely, if ever used. Further, the mechanism is not symmetrical, in that it does not consider scenarios where distributed generating plant imposes additional costs.

4.3.9 Bilateral payment for DER services

Where DER is procured from another party, Western Power and the DER provider will need to negotiate the payment for the provision of the services. As noted above, the expenditure will need to meet the requirements set out in the Access Code for Western Power to be able to recover the costs. This still leaves a range of possible payments, from the cost to the DER provider of providing the service through to the next most efficient alternative solution.

4.3.10 Incentives outside of the regulatory framework

It is important to note that Western Power may face incentives that are not a direct consequence of the regulatory framework. Capital investment solutions can be favoured due to engineering preferences and a tendency to adopt approaches that have been successful in the past, preferring known risks over unknown ones. Increased exposure to DER options is likely to mitigate this over time.

In some other jurisdictions, the adoption of mechanisms that explicitly incentivise investment in non-network solutions are, in part, intended to compensate for cultural incentives that may otherwise steer the networks towards more traditional network solutions.

Findings:

- While exposing Western Power to demand forecast risk could lead to more efficient network tariff design, it may also reduce Western Power's incentives to adopt solutions that result in reduced demand.
- Western Power is broadly required to value potential DER solutions as part of consideration of non-network solutions in options assessment under the NFIT. However, limited guidance is provided to Western Power on how to value the benefits of DER or on its requirements to engage with DER providers. In practice, this limits the use of non-network solutions, particularly innovative DER options.
- It may be difficult for Western Power to justify and so recover the costs of certain DER investments, particularly where it is difficult to extract the full potential value of the asset.
- Where the connection of generation to the distribution network results in lower costs for Western Power, the cost savings can be passed through to the DER provider. However, the mechanism is rarely used, and doesn't allow for Western Power to recover additional costs imposed by DER.
- Where DER is procured from a third party, it may be challenging for the DER provider to negotiate favourable terms and conditions with Western Power (as the sole buyer of network services). The importance of getting the right arrangements in place for contracting of DER by networks will increase under a high-DER future where certain DER services are more frequently and dynamically required under a Distribution Services Operator (DSO) type framework.

4.4 DER participation

4.4.1 Transactions costs for DER providers

There are several transaction costs that may inhibit participation by DER providers in providing alternatives to network solutions.

First, as discussed above, there is limited information provided by Western Power on where constraints are arising or are likely to arise. While Western Power is required to provide information in relation to major augmentations and consult on its plans in order to elicit alternative solutions, the Access Code is not comprehensive in its requirements for information provision. Rather, it is up to Western Power to use it's "reasonable endeavours".

It may not be straightforward for potential DER providers to engage with Western Power at the appropriate stage in Western Power's planning and investment process. Further, the Access Code does not provide any requirements for Western Power to provide transparency in the way that it assesses DER options.

Second, it may be costly for potential DER providers to put together a proposal in enough detail to support a business case for their proposed solution. Further, if there is a perception that Western Power is likely to adopt a network solution, there may be a reluctance to invest the necessary time and funds into fully scoping and preparing a compelling business case.

Third, bilateral negotiations can be expensive, particularly where there are limited contractual precedents for the provision of DER services. Negotiations over the terms and conditions can be challenging, particularly in relation to key issues such as price, service standards and how the risks associated with the contracted services are shared between the parties (discussed further below).

In terms of price, in most instances there is limited prescription governing the calculation of the payment to the DER provider. This is often left to negotiation with Western Power, with the potential exception of where a distributed generator is eligible for a network tariff discount due to their facility contributing to reduced costs for Western Power. However, even in this instance it is not clear to what extent the calculation of the discount is transparent.

In summary, there are likely to be significant transaction costs associated with negotiating DER contracts. The regulatory framework provides limited guidance in this regard, and Western Power is likely to have a significant information advantage over potential DER providers. Further, where there is limited information available on the nature of the network issues to be resolved, the transaction costs associated with obtaining this information in order to design a potential DER solution will be higher.

4.4.2 Ability to enter into long term procurement contracts

Potential DER providers are likely to require Western Power to enter into a long-term agreement that allows them to recover the cost of any associated DER assets. However, Western Power has its expenditure reassessed every five years when its Access Arrangement is revised, with the prospective risk of the ERA disallowing the expenditure associated with a DER contract. Consequently, Western Power may be reluctant to enter into multi-year agreements that extend over multiple access periods.

4.4.3 Issue of expenditure volatility associated with non-network investments

Under current arrangements, network investment plans are assessed by the ERA every five years, with allowed expenditure levels being set for the next five years. This provides Western Power with an incentive to seek cost savings, since it can retain a proportion of any savings on the allowed expenditure. However, Western Power is also exposed to potential losses if it exceeds its allowed expenditure. The level of certainty that the business has in the allowed expenditure level to cover its true costs will influence its investment decisions.

The cost profile of a non-network project can differ significantly compared with capital infrastructure. With capital infrastructure, most of the costs are upfront and a business manages the expenditure risk during the construction phase. However, for certain types of non-network projects, the cost profile can be quite varied over a five-year period, particularly if the DER option is dependent on network and weather conditions. As a result, the costs associated with DER may be difficult to forecast. For example, if the DER program involves a peak time rebate, a network business would have to forecast the number of times such rebates will be triggered over the period. This could involve estimating the number of days where there are extreme temperatures over a five-year period.

Under some mechanisms, Western Power can pass through annual amounts in its approved prices and hence the volatility is reflected in the customer prices. However, if the non-network option is a proponent led project (where Western Power contracts with a DER provider) and included in allowed operational expenditure, then Western Power may be exposed to the volatility in actual costs over the regulatory period.

Findings:

- Limited information on network constraints, the cost of preparing a compelling business case and costs associated with bilateral negotiations on the terms and conditions of services may inhibit participation by DER providers in offering alternatives to network solutions.
- The provision of DER services by aggregators will be more likely to emerge if there is common agreement on how to calculate the value from the DER. Transactions are less likely to occur if there is disagreement on the amount of payment required.
- Western Power may not be able to enter into long-term agreements if it is uncertain of recovering its costs in subsequent access periods.
- Requiring Western Power to manage the expenditure risk associated with certain DER projects could put these projects at a comparative disadvantage compared with capital infrastructure projects because the cost profile of non-network projects can differ significantly from those of capital infrastructure.

4.5 Customer protection and engagement

There are risks that must be managed through the DER contracting process in relation to non-network solutions which, if not appropriately managed, could adversely impact customers. Broadly, these relate to customers receiving a stable supply of electricity at an efficient price.

Critically, Western Power is required to meet network reliability standards that ensure customers have access to an uninterrupted and safe supply of electricity. Failure to meet these standards can attract high penalties for Western Power, as well as causing interruptions to customer supply.

Many DER solutions are still relatively new and are yet to be comprehensively tried and tested. Western Power may have concerns that a DER solution could be less reliable than a network-based solution and, at worst, could result in Western Power not meeting its reliability standards. In turn, unless this risk can be managed, Western Power may not be comfortable with DER solutions and so would be less likely to enter into such contracts. While this may provide customers with a higher probability of receiving an uninterrupted supply, this approach comes with a commensurate cost that customers may not be willing to pay.

One solution is for Western Power to shift the risk of Western Power not meeting its reliability standards onto the DER provider. However, this approach may act as a barrier to DER solutions where potential providers are not prepared to, or are unable to, take on the financial consequences of Western Power not meeting its reliability obligations.

This issue of risk is not fully addressed under the Access Code and so could continue to act as a barrier to DER contracting.

Findings:

- Unless risks can be appropriately allocated and effectively managed, customers are unlikely to benefit from potentially more efficient DER solutions to network issues.

5. Retail mechanisms influencing DER

This section focuses on DER in the retail market. This primarily covers household and small business customers and certain other customers.

Synergy is the sole electricity retailer for small use customers in the SWIS. The State Government regulates the price that Synergy can charge to its small retail customers. The key retail mechanisms and arrangements that influence the uptake and operation of DER by small customers are summarised in the table below.

Table 5.1 Retail arrangements and DER

Mechanism / Arrangement	Description	How it influences DER
Retail tariffs	Currently most small use customers are on a flat-rate regulated tariff, although limited time of use tariff is also available.	The structure of the charges that customers face will influence their consumption behaviour and the value to them of investing in DER. This could either dampen or reinforce the DER signal in network tariffs.
Uniform tariff policy	Small use customers are charged the same retail tariff rate regardless of location.	Prevents the use of a location-based pricing signal to indicate the value of DER, such as for high cost rural customers. However, in higher cost areas it also ensures customers face a strong incentive to remain connected.
Renewable Energy Buyback Scheme (REBS)	Requires Synergy to offer to purchase electricity generated through some small renewable energy systems. REBS is available to residential customers who consume not more than 50MWh per annum, non-profit organisations and educational institutions that have a small renewable energy system between 500W and 5kW.	Provides an incentive for households and certain other customers to install renewable energy systems by allowing them to sell any excess generation back into the grid for a fixed price. A fixed REBS rate does not reflect the underlying value of DER generation, or changes in the value of energy over the course of the day. The structure encourages customers to maximise the size of the system to the scheme limit, regardless of their own usage needs.
Metering	Advanced metering infrastructure is being rolled out on a new and replacement basis by WP. Alternatively, customers must pay for their own advanced meter where they want access to certain products and services – typically through the Metering Model Service Level Agreement.	Advanced meters have the potential to improve the efficiency of investment in DER for customers. Advanced meters also provide the necessary data and technology to allow customers to participate in markets for DER.
Access to data	Customers or their representatives have the right to access their data free of charge twice per year.	Access to data is essential for customers to understand their current consumption behaviour and how they may benefit from installing DER or changing tariff.
Licensing scheme	Requires licensed retailers to meet various obligations, including via the code of conduct which provides critical customer protections to small customers.	DER-only providers are generally exempt from the licensing scheme, so associated customer protection obligations do not apply. The description and scope of DER services will determine the extent of any customer protections.

5.1 Technology integration

5.1.1 How is DER defined?

The *Electricity Industry (Licence Conditions) Regulations 2005* require Synergy to offer to purchase electricity generated through small renewable energy systems in certain circumstances through REBS.

The Licence Conditions Regulations define a small renewable energy system as:

- a system of photovoltaic arrays;
- a system of wind turbines;
- a hydro power system; or
- another system for the generation of electricity from a renewable energy source, that has a generating capacity exceeding 500W but not exceeding 5kW.

To install a solar power system a customer will need to have a bi-directional energy meter that is capable of separately measuring and recording electricity flows in each direction – how much energy is consumed from the grid vs. how much excess energy is exported back to the grid.

While not clear, it appears that the definition does not include battery storage. Consistent with this interpretation, Synergy will not provide any payments to customers for battery storage. Rather, if a customer currently eligible for REBS connects a battery that is capable of exporting to the network, the customer is no longer eligible to receive a payment for their export. Given the ability of EVs to act in a similar way to batteries by either drawing from or sending electricity to the grid, restrictions may also apply to the participation of EVs in this scheme.[8] With EVs, a complicating factor is the temporary and movable nature of connections.

In addition, the Code of Conduct is linked to the licencing scheme and does not appear to specifically cover DER, nor more generally does it contemplate protections for small customers who have generation or storage on their premises. Rather, it focuses on the supply of energy from the grid.

5.1.2 How is DER identified?

Customers must apply to Western Power for the connection of embedded generation, such as solar PV and battery storage. This provides oversight by Western Power of the embedded generation connected to the network, although it does not provide Western Power with any control over how that asset is used.

To qualify for the REBS, a customer must apply to Synergy. There is a $21.50 fee (inclusive of GST) for the application.

EVs that charge from a standard power socket do not require permission from Western Power. Rather, these types of EVs are simply treated like any other appliance over which Western Power has no oversight. However, in order to access faster charging capability, and to allow the EV to be

[8] Notably the NSW IPART set the benchmark rate to allow payments for exports in the early evening to encourage battery storage and export at peak times. Potentially exports from EVs would also be allowed.
https://www.ipart.nsw.gov.au/Home/Industries/Energy/Reviews/Electricity/Solar-feed-in-tariffs-201819

used as a battery capable of exporting energy to the grid, customers must undergo a standard connection approval process for connecting the charge point to the network.

Findings:

- It is not clear whether the licensing regulations in relation to REBS extends to battery storage.

5.2 Tariffs and investment signals

5.2.1 Renewable Energy Buyback Scheme

Currently the primary mechanism for customers to receive payments for their DER is via REBS. In the SWIS, Synergy is required to offer eligible customers with renewable energy systems a payment, allowing them to sell their excess energy back into the grid. REBS is available to residential customers who consume not more than 50MWh per annum, non-profit organisations and educational institutions that have a small renewable energy system up to 5kW inverter capacity.

Customers also need to have an approved, bi-directional meter installed, or an existing compatible meter reprogrammed, at their own cost. All necessary approvals to connect the system to the grid and transfer electricity into the grid must also be obtained from Western Power.

Customers may also be required to fund the installation of communications capability on the meter if Western Power deems it necessary. This is typically required where Western Power does not have access to the meter.

If a customer also has a battery installed as part of their system, the customer will continue to be eligible for REBS provided that the battery has an export limit of 0kW. This means that the battery cannot be used for export.

Synergy is responsible for establishing the terms and conditions (including rates) for buying excess energy and is responsible for running the REBS. The Coordinator for Energy approves the terms and conditions of Synergy's buyback offer. In assessing whether the contracts, including the buyback rate, are ‘fair and reasonable’, the Coordinator for Energy considers:

- the wholesale cost of electricity for the retailer;
- line-loss reductions provided by distributed renewable energy;
- peak reductions provided by distributed renewable energy;
- capacity benefits provided by renewable energy; and
- the costs to retailers in running the REBS.

In practice, it is likely to be difficult to fully reflect each of these components in a single, flat tariff to all solar PV owners. The value of DER to the network depends on the time of day that the DER is generating as well as the location of the DER. Better reflecting the value of renewable energy would therefore require a rate that varies with both time of day and location.

For example, a rate that paid less during the middle of the day would encourage a customer to shift their consumption to the middle of the day and self-consume the power generated at this time. A higher rate during the late afternoon when the network is typically under the most strain would encourage people to reduce their own consumption or use locally stored energy at this time, helping to support the grid by sending their generation into the grid.

There is very little guidance in the Electricity Industry (Licence Conditions) Regulations 2005 with respect to the structure or level of the REBS rate. There is no requirement for the rate to be flat, although any change to a time of use rate may require a change to the metering configuration and significant investment in customer education. One challenge to consider is how to balance making the payment simple for customers to understand versus additional complexity to better reflect the value of this type of DER.

Further, where the value of the REBS is influenced by factors other than a strict assessment of market value, there is a risk that the REBS becomes a poor signal of the value of DER to the market. Where the REBS rate is high relative to the market value of DER, this can result in overinvestment by customers in DER (by over-sizing systems relative to individual needs). Conversely, if the REBS rate is too low, there will be inefficiently low levels of investment in DER by customers.

The REBS rate in the SWIS is currently 7.1350c/kWh for both residential and non-residential customers. This compares to Synergy's estimate of the 2018-19 market value of the energy it buys of 4.667c/kWh.

Higher feed-in tariffs (of up to 40c/kWh) apply for certain customers that entered into the net feed-in tariff scheme between 1 July 2010 to 1 August 2011. The net feed-in tariff is distinct from the REBS and is administered by Synergy on behalf of the state government. These more generous tariffs end 10 years after installation.

The current payment amount and structure of REBS is unlikely to be a major factor in DER investment and behaviour by customers, as the flat-rate consumption tariff incentivises customers to maximise self-consumption. However, as a single clearing price, the REBS rate is overpaying at certain times and is limited in driving efficient DER outcomes.

Amendments to the REBS rate and structure, in combination with network and retail tariff structures, would better signal efficient DER investments and subsequent DER usage behaviours by customers.

5.2.2 Retail tariffs

The structure of the charges that customers face for using grid-based energy will influence their consumption behaviour. In turn, this will influence network costs.

For residential customers, Synergy offers two different tariffs for grid energy:

- a flat tariff (A1); and
- a time of use (TOU) tariff ("Smart Home Plan").

Synergy is also currently trialling a tariff specifically aimed at customers with EVs ("Electric Vehicle Home Plan").

Most customers are on the A1 tariff. Customers pay a flat rate for all their consumption, plus a fixed daily charge. The flat tariff does not provide customers with any signal of the cost of providing electricity at different times of day or in different locations. From a customer's perspective, the value of the network is the same in all locations and at all times of the day. Therefore, customers have no incentive to shift their consumption at times that would reduce overall costs. Additionally, the A1 tariff does not fully recover the cost to service these customers. This gap has been funded by the State Government.

Further, household customers on the A1 tariff with DER have no signal as to the relative value of their DER versus consuming electricity from the grid at different times of day or in different locations.

It is also worth noting that, when considering grid versus solar energy, households see two rates: the variable rate of the A1 tariff (currently 28.8229c/kWh for residential customers) and the REBS rate (7.1350c/kWh). Customers perceive these two rates as payment for the provision of the same service, i.e. energy. However, it is important to note that the variable A1 tariff also encompasses other costs including network charges, renewable energy certificates, retail costs and the cost of the retailer's contracting position for wholesale energy and reserve capacity.

Without appropriate price signals, household customers have no incentive to use or export DER generation in ways that are valuable to the system. The flat A1 tariff (and REBS) may even encourage customers to exacerbate system issues by overinvesting in solar PV and facing their PV panels north (maximising total generation) rather than west (which would better support the system at peak times).

The Smart Home Plan's TOU tariffs provide some degree of cost signalling to customers of the value of the energy at different times of day. Under the current structure, this tariff encourages customers to shift their load to between 9pm and 7am and discourages them from consuming between 3pm and 9pm on weekdays. Customers with solar PV on a TOU tariff would have an incentive to draw on their solar during network peak demand noting, however, that generation from solar PV will have passed its peak by this time.

If customers were on a TOU tariff prior to installing solar, this tariff may encourage them to face their solar panels west to maximise solar production coinciding with the network peak. However, overall, this tariff provides little incentive to use or store PV during the shoulder period between 7am and 3pm as the rate is very close to the main residential A1 tariff.

The Electric Vehicle Home Plan tariff trial is designed to incentivise customers to charge their EV between 11pm and 4am. The EV tariff is lower than the standard residential A1 tariff during an off-peak period and the same during the Standard home period. To be eligible for an EV tariff the customer must pay to install a compatible meter/have an existing meter reprogrammed. However, there are other incentives for this trial, including a $200 incentive payment pro-rated across the first year and 60 free kilometres per month.

None of these tariffs provide any incentive to shift consumption to the middle of the day when PV output will generally be highest.

A move towards greater cost reflectivity in network and retail tariffs would assist in better reflecting and rewarding the value from DER. However, it is important to note that this is not a solution in and of itself. Additional measures will be required to allow the full value of DER to be captured across the supply chain.

Further, Synergy may not fully pass through the signal provided in network tariffs. The network tariff could be either heightened or dampened as it is bundled with wholesale and other costs into a retail tariff. Despite this, Synergy currently has a similar profile to the network tariff for its TOU tariff, as shown in the table below.

Table 5.2: Comparison of the network and retail TOU tariffs

	Daily charge (c/day)	On-peak 3pm-9pm (c/kWh)	Shoulder 7am-3pm (c/kWh)	Off-peak 9pm-7am (c/kWh)	Ratio of on-peak to off-peak
Network tariff	86.85	14.60	14.60	3.32	4.40

Retail tariff	103.33	54.81	28.71	15.10	3.63
Retail tariff net of network tariff	16.48	40.22	14.11	11.78	3.41

Western Power's RT3 and Synergy's "Smart Home Plan" time of use tariffs for 2019/20.

To be eligible for a TOU or EV tariff a customer must pay to install a compatible meter[9] or have an existing meter reprogrammed. This may be a disincentive for some customers to switch to different types of tariffs.

5.2.3 Uniform tariff policy

Under the uniform tariff policy, small use customers in the SWIS (those that consume less than 50 MWh per annum) are charged the same rate for their applicable tariff, regardless of location. This extends to customers in remote and regional parts of the State, where the costs to supply electricity are often considerably higher.[10] The extra costs of supplying electricity to these areas are funded by:

- the Tariff Equalisation Contribution, recovered through electricity distribution network charges in the SWIS[11]; and
- a subsidy provided by the Western Australian Government to Horizon Power.

This approach means that customers living in more expensive to serve locations are not charged more than their lower-cost counterparts.

As described above, it also means that there is no locational signal to incentivise customers to invest in DER in parts of the network where DER would be highly valued.

The uniform tariff policy effectively prohibits Western Power and Synergy from using location-based signals of network value via residential tariffs.

[9] However, compatible advanced metering infrastructure is being rolled out on a new and replacement basis by Western Power.

[10] The uniform tariff policy also applies to customers of Horizon Power.

[11] Customers below 4380MWh per annum in Horizon Power areas also have access to regulated subsidised tariffs under the Tariff Equalisation Contribution.

Findings:

- The existing retail consumption tariff and REBS framework discourages the connection of battery storage to the network. This means that neither customers or Western Power can maximise the potential value of battery storage in supporting the network. The REBS framework also discourages customers from installing a solar PV system with capacity over 5kW.
- The current, flat REBS rate that applies to all eligible customers cannot accurately signal the value of DER to the network, which will depend on the time of day that the DER is generating as well as the location of the DER. Better reflecting the value of renewable energy would require a rate that varies with both time of day and location.
- Most customers are currently on a flat retail tariff and, as such, have no incentive to shift their consumption to times that would lower overall costs. Similarly, household customers on a flat tariff with DER have no signal as to the relative value of their DER versus consuming electricity from the grid at different times of day or in different locations.
- A move towards greater cost reflectivity in network tariffs would assist in better reflecting and rewarding the network value from DER. However, this is not a solution in and of itself. Additional measures will be required to allow the full value of DER to be captured across the supply chain.

5.3 DER participation

5.3.1 Metering

Only a relatively small number of household and small business customers in the SWIS currently have advanced meters installed. Advanced meters are an enabling technology that can facilitate numerous services that provide benefits to both customers and network businesses. As such, advanced metering infrastructure is often viewed as a first step to enabling a smart grid and markets for DER.

Advanced meters have the potential to improve the efficiency of investment in DER for customers, as well as provide the necessary data and technology to allow customers to participate in markets for DER. Critically, advanced metering provides a more granular level of information in near real-time on consumption decisions, allowing the development of tailored advice on DER to customers. This information is necessary for customers to optimise both their investment in and use of DER.

As noted above, the type of meter a customer has will also influence their ability to take up certain retail tariffs which, in turn, will influence a customer’s incentive to install DER and how the DER is operated.

Western Power and retailers would also benefit from having access to more granular information to better understand their customers’ consumption behaviour. This, in turn, informs how customer behaviour influences network costs. Advanced metering infrastructure can also be used to provide a range of services that would help Western Power monitor and operate its network, including load control and notification of power outages or distortions in the quality of electricity supply.

Advanced meters are currently being installed on a new and replacement basis by Western Power. If a customer wishes to have access to a product or service that requires an advanced meter, such as a TOU tariff, they are required to fund the cost of installing the necessary metering equipment. This poses a barrier to some customers taking up certain DER and supporting products, including TOU tariffs.

The cost of the meter will depend on the nature of the metering requirements. A single phase 240V meter for an existing home is currently $138.24. A three phase 415V meter for an existing home is currently $235.04. These upfront costs may be prohibitive for some customers, particularly where the value of shifting to a TOU tariff is not clear. It should be noted that these rates are currently being reviewed as part of Western Power’s proposed update to its Metering Model Service Level Agreement, in conjunction with its advanced metering infrastructure program.

5.3.2 Access to data

Linked to improved metering technology, access to data is essential for customers to understand their current consumption behaviour and how they may benefit from installing solar PV or storage or switching to a different tariff.

Under the Metering Code, Western Power owns all energy data and standing data. However, under the Code of Conduct small customers have the right to request their consumption data. Western Power must provide consumption data at no charge where the consumption data is for a period of less than two years before the date of the request and where the customer has not already requested data more than twice in the previous 12 months.

If payment is required to access data, the Code of Conduct does not provide much guidance on the appropriate level of payment, other than to note that the payment may be “for the distributor’s reasonable charge for providing data”. Further, the Code of Conduct does not specify the format the data must be provided in.

Third parties may also access data on behalf of a customer. To do so requires:

- registration with Western Power;
- verifiable consent from the customer, which must be renewed at a minimum every 12 months; and
- paying fees to register and for Western Power to verify and process customer consent forms.

The nature of the available data will depend on the type of meter that a customer has and how it is configured. For example, a customer with an accumulation meter will only be able to access his or her total consumption at each meter read. A customer with an appropriately configured advanced meter should be able to access their consumption data over much more granular time periods.

For customers with solar PV, metering is currently provided on a net basis. That is, the meter only records energy sent out into the grid, not gross energy generated. Consequently, customers would need to have a device installed directly on their solar PV system in order to measure gross generation, which would come at a cost.

The ACCC Consumer Data Right (CDR) arrangements, which are expected to be finalised soon, will provide more certainty and governance on how customer data access is shared[12].

The CDR is a competition and consumer reform which will allow consumers to require a company such as their energy retailer to share their data with an accredited service provider such as a comparison site to get more tailored, competitive services. Consumers will need to consent and authorise their data to be shared under the CDR. The ability to securely share energy data with

[12] https://www.accc.gov.au/focus-areas/consumer-data-right-cdr-0

trusted parties may promote competition between energy service providers, leading to better prices and more innovation of products and services.

While this may assist customers in accessing their data and more comprehensive energy services, it will not solve the problem that the quality, granularity and type of data available will be dictated by the customer's metering technology.

5.3.3 Cost of connecting embedded generation

The cost of connecting embedded generation to the network is primarily driven by the nature of the generation system, including the size of solar panels or battery and the inverter. For systems connected via an inverter under a certain threshold, Western Power does not charge an application fee. All other systems will incur both an enquiry fee and an application fee, and potentially a processing fee. However, it is unlikely that these types of systems would be installed by households.

The standards that inverters are required to meet are set out in the Technical Rules. The current inverter standards do not require any ability for Western Power to control the generating system (e.g. reducing its output or switching it off where network security and reliability is at risk).

However, if required to support a stable grid, it may be necessary to require the connection of smart inverters which either provide Western Power with control over the operation or connection of the generating system or that autonomously respond to local conditions.

While smart inverters may not necessarily impose a significantly greater financial cost to connect to the network, requiring the use of smart inverters would impose transaction costs on customers in the sense that they would have less control in respect of how they access DER value.

This discussion assumes that the network can accommodate additional embedded generation. While this has been the case in Western Power's network to date, some parts of the network may not be able to absorb much more solar PV or other forms of distributed generation without affecting the safe, reliable and secure operation of the system.

Where Western Power is concerned about its ability to maintain system security, it can refuse a connection under the Technical Rules. This may ultimately prove an insurmountable barrier to installing DER for customers in certain parts of Western Power's network without network augmentation or another mechanism for minimising any adverse impact on the network.

5.3.4 Cost of joining REBS

As noted earlier, for customers with solar PV, the cost of participating in REBS is currently low. Customers are required to pay an administrative fee to Synergy of $21.50.

Findings:

- The upfront cost of installing a meter may provide a disincentive for customers to adopt certain tariff structures that might better support the efficient use of the DER by signalling the value of DER to the network at different times of day. This issue is currently being reviewed as part of Western Power's proposed update to its Metering Model Service Level Agreement, in conjunction with its advanced metering infrastructure program.
- While customers currently have a mechanism to access historical consumption data, the usefulness of the data will be limited by the customer's meter functionality. The data sets usefulness may also be limited by the format and timeframes in which it is provided.
- Connection of embedded generation is currently processed on a "first come, first served" basis. If a local network is not able to support the further connection of solar PV, augmentation costs may apply and, in some cases, customers may be limited in how they connect their generation to the grid (e.g. zero net export requirements may be applied).

5.4 Customer protection and engagement

The primary risk to customers from participating in DER schemes is that their generation system does not function as expected, meaning they have less available for self-consumption, or are not paid for their energy exports or cannot maximise the value of those exports. For example, the solar panels may not have been installed to maximise the efficiency of the system, the system could have been over- or under-sized for their needs or there could be a fault with the system.

These types of risks are not covered by the energy-specific consumer protection frameworks. However, customers may have certain protections under the Australian Consumer Law, particularly in relation to faulty products.

Currently only licensed distributors, licensed retailers and electricity marketing agents are subject to energy-specific consumer protection obligations. The key instrument is the Code of Conduct. The Code of Conduct provides critical customer protections to small customers (who use less than 160 MWh per annum) in relation to the supply of electricity, including issues such as billing and payment requirements, obligations to assist customers who are having difficulty paying their bill and obligations in relation to disconnection and reconnection of a customer's premises. Licenced entities are also required to participate in the Energy and Water Ombudsman's scheme.

Entities that are exempt from becoming a licensed retailer are, by extension, also exempt from complying with the Code of Conduct. They are also exempt from paying licensing and market fees as well as participating in the Ombudsman scheme. Entities that sell energy to customers via on-site generation such as rooftop solar PV are generally exempt from the licensing arrangements, although these are currently under review by Energy Policy WA. This means that, while these entities may be able to supply energy to a customer, they are not subject to the same arrangements as a retailer supplying a customer with energy from the grid.

Findings:

- Entities that sell energy to customers via on-site generation are generally exempt from the licensing arrangements, meaning they are also exempt from complying with energy-specific consumer protection obligations.