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Seed Advisory

Smart Energy Hubs: accelerating growth in C&I flexible demand participation

Stage One Knowledge Sharing Report

30 March 2023

Important notices

Report purpose

This report is a key deliverable from the Smart Energy Hubs project. The purpose of this report is to assist in the following objectives from a knowledge sharing perspective:

- Deliver targeted regulatory reforms to existing demand response related schemes that benefit demand response providers and increase the value of consumer energy resources.
- Generate awareness and interest from regulators, market bodies, State and Federal Governments to increase the value of flexible demand services before 2025 through the market challenges they can address.

Stakeholder acknowledgement

The preparation of this report required consultation and involvement of a broad group of stakeholders. We would like to acknowledge their valuable time and input as part of this project.

It is important to note that the contents of this report do not necessarily reflect the views of every stakeholder we consulted and consensus was not sought nor received.

ARENA acknowledgement and disclaimer

This Project received funding from the Australian Renewable Energy Agency (ARENA) as part of ARENA's Advancing Renewables Program.

The views expressed herein are not necessarily the views of the Australian Government, and the Australian Government does not accept responsibility for any information or advice contained herein.

Report authors

This report was authored by Peter Eben, a Director of Seed Advisory and Ruth Guest, a Director of Evolution Energy Advisory.

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Glossary

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
C&I	Commercial and Industrial
CER	Consumer Energy Resources
CIS	Capacity Investment Scheme
DAPR	Distribution Annual Planning Report
DEIP	Distributed Energy Integration Program
DER	Distributed Energy Resources
DMIA	Demand Management Innovation Allowance
DNSP	Distribution Network Service Provider
DRSP	Demand Response Service Provider
DOE	Dynamic Operating Envelope
DR	Demand Response
DSP	Demand Side Participation
EDPR	Electricity Distribution Price Review
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
EUAA	Energy Users Association of Australia
FRMP	Financially Responsible Market Participant
FTA	Flexible Trading Arrangements
MSL	Minimum System Load
MW	Megawatt
NEM	National Electricity Market

Term	Definition
NER	National Electricity Rules
NSP	Network Service Provider
PDRS	Peak Demand Reduction Scheme
RERT	Reliability and Emergency Reserve Trader
RIT-D	Regulatory Investment Test - Distribution
SEH	Smart Energy Hub
SGA	Small Generation Aggregator
WDRM	Wholesale Demand Response Mechanism

1 Executive Summary

1.1 Introduction

Shell Energy has received funding from ARENA to deliver a project aimed at commercialising Smart Energy Hubs with a focus on commercial and industrial (C&I) customers with weather or temperature sensitive loads, e.g., shopping centres, supermarkets and distribution centres.

Smart Energy Hubs are a mix of technologies and capabilities that integrate and optimise energy supply, generation, energy management and flexible demand. The intention is to optimise the entire energy usage and supply for a business to produce more significant energy efficiency gains and reduce emissions and costs.

As part of the project, Seed Advisory (Seed) is working with Shell Energy as an independent and expert third-party energy market advisor to assist with the delivery of knowledge sharing from the project.

Seed's role is to deliver two specific independent and public knowledge sharing deliverables:

- Stage One: regulatory reform report - this report (due March 2023).
- Stage Two: final knowledge sharing report - due at the conclusion of the project (October 2024).

1.2 Scope of work and approach

Scope of work

This report reflects work undertaken to identify:

- up to three short term reform options that will facilitate an increase in participation of C&I flexible demand in existing market schemes. Specifically the Wholesale Demand Response Mechanism, Reliability and Emergency Reserve Trader, Small Generation Aggregator and Peak Demand Reduction Scheme); and
- also the identification of up to three new market and / or network services for trial by Shell Energy as part of Stage Two of the Smart Energy Hubs project.

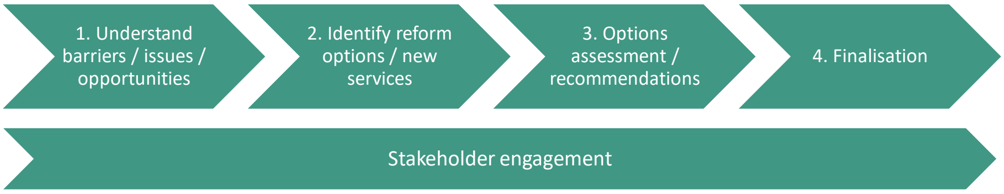
Our scope included high level consideration of the longer-term reform work program under way (see Section 4) to ensure alignment with any of our short-term recommendations.

Detail on the scope of work including specific exclusions is included in Section 3.1.

Approach

The project approach is outlined in Section 3.2 and Figure 1.1. Our approach comprised four stages for delivery underpinned by stakeholder consultation across each stage.

Figure 1.1: Approach overview



In brief our approach involved:

- Understanding and identifying issues and barriers to growing participation of C&I flexible demand (refer Section 5.2).
- Identifying reform options and potential new services to address issues and barriers and increase C&I flexible demand participation (refer Section 7).
- Prioritising the options and new services (refer Section 8).
- Making recommendations on priority options and next steps for Shell Energy to trial in the SEH project (refer Sections 8 and 9).

Stakeholder consultation

This project involved broad stakeholder consultation throughout all key stages of the project. We completed four rounds of consultation, an initial one-on-one early engagement round with policy and thought leaders to confirm our scope and priorities, and then three subsequent group based consultations by industry segment with approximately 30 stakeholders in each round.

The purpose of the consultation was to ensure stakeholders' insights and perspectives informed:

- our approach;
- the understanding of issues and barriers;
- the identification of options to resolve issues and barriers; and
- the development of our priority recommendations.

It is important to note that the contents of this report do not necessarily reflect the views of every stakeholder we consulted, and consensus was not sought nor received.

Our approach to Stakeholder engagement is discussed in further detail in Section 3.3 and Appendix A.

1.3 Analytical approach

Our identification of issues and barriers and their potential options utilised an overarching analytical framework (refer Section 5).

The key elements of the framework include:

- An outline of the generic physical and financial / transactional requirements for provision of a flexible demand service used to capture barriers and issues. We note that cultural factors are not an explicit requirement in our framework, however these are implicit and considered in, for example, the ability to effectively participate and appropriate market / network protections and safeguards.

- A recognition that the identification of potential solutions (reform options and new services) was necessarily based on the identified barriers and issues. These were therefore not identified based on a pre-determined framework.
- A consideration of costs, benefits, risk and time to implement when assessing the identified reform options and potential new services. In developing our reform and new service recommendations we did not complete cost benefit analyses.

1.4 Key findings

Introduction

Our analysis and stakeholder consultation confirmed that:

- the current schemes are generally able to facilitate C&I participation in flexible demand;
- uptake for flexible demand is acknowledged as relatively low;
- the C&I segment presents a significant growth opportunity;
- changes to the schemes are needed to encourage participation and growth in the C&I segment; and
- longer term reforms are being progressed across the industry, however these have long lead times and an opportunity exists to accelerate growth with more immediate impact.
  - The recently announced Commonwealth Government's Capacity Investment Scheme (CIS) proposal aims to provide a national framework that drives new renewable dispatchable capacity and ensure reliability.
    Some stakeholders have noted that if flexible demand is disadvantaged compared to generation side or storage technologies in any capacity scheme or is not eligible for this type of underwriting scheme it has the potential to economically impact demand response in favour of new generation or storage and detrimentally affect the business case for flexible demand, stymying its growth in the market.

Barriers and issues

Through the stakeholder consultation we've identified a range of barriers and issues including:

- there is no one 'key issue', rather a broad range of issues and barriers.
- most barriers are financial or transactional and not physical in nature.
- cultural barriers were evidenced by the lack of understanding and education and awareness by customers (and even some market participants) and exacerbated by lack of customer focused language in key regulatory and market documents.
- participants require an ability to maximise the opportunity to provide multiple services, i.e., value stack.
- there is a lack of consistency across the schemes (such as baselining approaches, registrations and aggregation models) and therefore a need for harmonisation.
- a better balance (and hence trade off) is needed between risk, accuracy and simplicity.
  - Stakeholders have commented that demand response is different to generation, it is the provision of a service rather than the sale of a commodity.
- there is a lack of transparency and challenges with negotiating and securing contracts to provide network services.

Potential reform options

We identified 20 potential reform options across four broad categories:

- Education and awareness options to address barriers relate to a lack of understanding and information.
- Harmonisation options to address additional cost and complexity due to a lack of consistency across existing schemes.
- Value stack maximisation options to enable participants and customers to maximise the return on investment.
- Risk, accuracy and simplicity trade off options to achieve a better balance amongst competing objectives.

These options were considered with a view to identifying quick wins and short term opportunities that can be demonstrated and trialled through the SEH project and align with the NEM's longer term reforms.

Potential new services

Our analysis identified four 'new' network services and two new market services that flexible demand could provide.

The increased penetration of CER has impacted, and will continue to impact, the efficient operation of networks e.g., voltage instability, minimum demand, negative flows and increased need for network augmentation. New services to address each of these issues were identified.

Similarly at a market level new services related to minimum demand and negative prices were identified.

Priority reforms and new services

All stakeholders agreed that education and awareness related opportunities covering all flexible demand schemes and services are critical. However these were acknowledged to be best progressed by participants, governments and regulators outside of the Smart Energy Hubs Project.

Our assessment has led to three (3) recommended priority reforms to be trialled in Stage Two of the Smart Energy Hubs Project:

- Risk, accuracy and simplicity trade off: Expand the wholesale demand response mechanism and the reliability and emergency reserve trader schemes by broadening participation criteria through the creation of new baselines, and potentially deeming mechanisms, in particular for temperature sensitive and more volatile loads.
- Value stack maximisation: Remove misconceptions to enable additional value stacking across specific schemes - wholesale demand response mechanism and network services; and reliability and emergency reserve trader and network services. Some stakeholders have reservations in relation to the costs of 'double dipping' which need to be better understood.
- Harmonisation: Develop consistent aggregation models for network services to streamline the customer acquisition process, reduce transaction costs and enable easier participation.

We have also recommended three (3) network services to be trialled and developed in Stage Two of the Smart Energy Hubs Project:

- Voltage support, minimum demand and negative flows which are growing issues needing to be addressed by networks.
- These three services also align with our consistent aggregation model related priority reform recommendation.

1.5 Next steps

The recommended reforms and new services will be trialled by Shell Energy in Stage Two of the Smart Energy Hubs Project.

Our scope for Stage Two of the Smart Energy Hubs Project is to monitor the progress of recommended reforms and services against success measures and prepare a public and independent knowledge sharing report that covers:

- The key outcomes of identified and progressed priority reforms from this report.
- The value created from the new services trialled by Shell Energy.
- Assessing the general appetite (based on stakeholder feedback) to compensate for the new services beyond the trial and at a larger scale.
- Regularly engaging with key stakeholders to share insights and ensure their input is captured.

2 Introduction

2.1 Background

The Australian Renewable Energy Agency (ARENA) has developed and is continuing to grow a portfolio of projects specifically targeted at accelerating the opportunities offered by flexible demand. This includes projects that can provide new flexible demand capacity either through 'load shaping' or 'load shifting' to help align customer electricity demand with variable renewable energy supply.

Flexible demand is the voluntary altering or shifting of electricity use by customers, which can help to keep a power grid stable by balancing its supply and demand of electricity. It can help to make electricity systems flexible and reliable, which is beneficial if they contain increasing shares of variable renewable energy.

Traditionally, flexible demand has been used to efficiently manage the electricity system during peak demand periods. This can be in real time as a response to market signals, generation shortfalls or network constraints.

Flexible demand is an increasingly viable alternative to investing in network infrastructure and large-scale batteries and may balance supply and demand more efficiently and cost-effectively. However, flexible demand is more than just demand response and will require new technologies, market processes and ways of engaging with energy users.

Section 2.3 provides a brief overview of flexible demand in the National Electricity Market (NEM).

2.2 Purpose of this report

Shell Energy has received funding from ARENA to deliver a project aimed at commercialising Smart Energy Hubs for approximately 40 Commercial and Industrial (C&I) sites, with a focus on customers with weather or temperature sensitive loads e.g., shopping centres, supermarkets and distribution centres. The project aims to demonstrate new flexible demand capacity of 21.5MW.

The project commenced in mid-July 2022 and is delivered over two stages, Stage One (the focus of this report) is intended to be complete by March 2023. Stage Two (the focus of a subsequent report) is intended to complete by the end of October 2024. Section 2.4 provides a brief overview of the Smart Energy Hubs Project.

As part of the project, Shell Energy is working with Seed Advisory (Seed) as an independent and expert third party energy market advisor to assist with the delivery of knowledge sharing from the project.

Seed's role will be to deliver two specific independent knowledge sharing deliverables:

- Stage One: regulatory reform report - this report.
- Stage Two: final knowledge sharing report - due at the conclusion of the project.

The purpose of this report is to assist in the following objectives from a knowledge sharing perspective:

- Deliver targeted regulatory reforms to existing demand response related schemes that benefit demand response providers and increase the value of consumer energy resources.
- Generate awareness and interest from regulators, market bodies, State and Federal Governments to increase the value of flexible demand services before 2025 through the market challenges it can address.

Detail on the scope and approach for this report is in Section 3.

2.3 Flexible demand in the NEM

This section provides a broad overview of flexible demand in the NEM, the emerging and increasing issues that they can contribute to resolve, and an outline of the existing schemes and mechanisms.

Necessarily, and where practical, this section (and report) is focused on flexible demand that is available for distribution network connected commercial and industrial customers.

Whilst there are existing schemes that enable the provision of flexible demand, the NEM is currently undergoing significant transformation and reform. This includes potential changes to regulations and broader market design for providing flexible demand related services. Section 4 summarises key longer term reforms and reform proposals currently in progress.

We note that many C&I customers provide flexible demand directly with their retailer through products such as pool price pass through. The provision of flexible demand directly with a retailer is not within the scope of this report and will not be assessed nor considered directly in our recommendations.

2.3.1 Market challenges flexible demand may address

Flexible demand has the potential to help address several increasing and emerging issues in the NEM. Local issues are typically addressed by network services, whereas regional issues utilise market mechanisms. A brief description of these issues is provided.

Maximum demand

Maximum demand must be managed to ensure available generation and the hosting capacity of networks are capable of serving it.

Increasing maximum demand is not a new issue, with schemes such as Reliability and Emergency Reserve Trader (RERT), Wholesale Demand Response Mechanism (WDRM) and Peak Demand Reduction Scheme (PDRS), as well as some network tariffs, specifically designed to address this issue.

Maximum operational demand typically occurs at the end of a hot summer day while air-conditioners continue to be run, and distributed PV generation is low. In Tasmania, maximum demand typically occurs in winter, with both morning and evening maximum operational demand events caused by residential consumers heating their premises.

AEMO's Electricity Statement of Opportunities (ESOO) maximum demand forecast represents uncontrolled or unconstrained demand without considering schemes that could reduce system load during peak periods including RERT, WDRM or demand side participation. The 2022 ESOO forecasts maximum operational demand to be higher and grow over the next five years to 2026-27 in all regions compared to 2021. Non-coordinated, customer-controlled battery and EV charging has the potential to add to peak demand stress on the system.

https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/2022-electricity-statement-of-opportunities.pdf

Minimum demand

Minimum demand is an issue that is increasing in frequency and prevalence. AEMO's ESOO minimum operational demand forecast represents uncontrolled or unconstrained demand, free of schemes that might increase operational demand e.g., coordinated storage and EV charging, scheduled loads such as pumping load, and demand response in periods of excess generation.

The strongest influence on minimum operational demand is distributed PV uptake. As consumers generate more of their own electricity this creates a significant reduction in demand for electricity generated from grid scale generators during periods of low underlying demand. Minimum net demand must be met to facilitate stable operation and provision of ancillary services from grid scale generation.

The 2022 ESOO forecasts minimum operational demand to be lower and decline rapidly over the next five years to 2026-27 in all mainland regions compared to 2021. This is caused primarily by a forecast uptake of distributed PV that is faster than underlying demand growth.

Negative flows

Negative flows, sometimes referred to as reverse power flows are a local network phenomenon caused by the issues that underpin minimum demand. At its extreme in a local area of the network the low net demand issue can cause negative flow i.e., electricity flow from low to high voltage. As minimum demand issues increase so too will negative flow related issues.

Negative flow is often unpredictable and can cause quality of supply issues, e.g., voltage rise and drop situations in various parts of the network that require simultaneous management to adhere to statutory limits to customers. This represents a significant challenge in the operation of the distribution network. Negative flow can also detrimentally impact a transformer requiring design changes to assure that its operating life is not materially impacted[1].

Examples of negative flow can be found in networks' planning documentation, for example see Endeavour Energy's DAPR.
https://www.aer.gov.au/system/files/Endeavour%20Energy%20-%2010.12%20Distribution%20Annual%20Planning%20Report%20%28DAPR%29%20-%20December%202022%20-%20Public.pdf

1 https://energycentral.com/system/files/ece/nodes/463672/der_reverse_power_flow_impacts.pdf

Voltage Management

The Victorian Government's Department of Environment, Land, Water and Planning (DELWP) Voltage Management in Distribution Networks consultation paper identifies an underlying decline in network voltages in the region. This paper also identifies that across the NEM there are issues with periods of high voltage or voltages outside of the required range.

As rooftop solar penetration increases and new kinds of CER become more prevalent, e.g., household batteries and EV, there will be a growing need for distribution businesses to manage the impacts solar exports have on network voltage. Failure to manage voltage can negatively impact:

- Electricity consumption
- Network capacity
- GHG emissions
- Appliances

https://engage.vic.gov.au/voltage-management-in-distribution-networks-consultation-paper

2.3.2 Overview of flexible demand

There is a significant quantity of publicly available data on the potential scale and value of flexible demand in the NEM. Table 2.1 is a sub-set of this information intended to inform the current and potential opportunity for flexible demand in the NEM and create context for the value proposition of the recommended reforms and services in this report.

Table 2.1 Current operational data and potential value for flexible demand in the NEM

Data	Value	Data Source	Comments
Demand serviced by distributed solar generation Q4 2022	3 GW	AEMO QED Q4 2022[2]	Underlying demand (22.4 GW) less the operational demand (19.4 GW). We note this is all solar not just C&I solar.
Capacity of distribution connected solar and battery at C&I sites	3.1 GW	AEMO Distributed Energy Resource Register (DERR) December 2022[3]	Total capacity of DERR (solar and battery) at December 2022 is 14.6 GW
Number of C&I connections on tariff or other DR arrangements	~9,500	AEMO Electricity Statement of Opportunities 2022[4]	Data sourced by AEMO from Demand Side Participation (DSP)[5] submissions. We note that approximately 60 per cent of connections are

[2] https://aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed
[3] https://aemo.com.au/energy-systems/electricity/der-register/data-der
[4] https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/2022-electricity-statement-of-opportunities.pdf
[5] https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach/forecasting-and-planning-guidelines/demand-side-participation-information-guidelines

Data	Value	Data Source	Comments
			'not specified'. This will likely mean the C&I figure quoted is understated. Approximately 67 per cent of commercial customers are noted as being on fixed tariffs whilst 70 per cent of industrial customers are noted as being on market exposed tariffs.
Estimate of flexible demand potential of C&I in the NEM	1.8 GW	Race for 2030: Flexible Demand and Demand Control report[6]	Citing an Energetics report: Overview of the demand response market in Australia
Size of the network benefits prize from efficient DER integration (2020-2040)	$2.3bn central scenario $11.3bn step change scenario	ESB: Potential network benefits from more efficient DER integration, June 2021[7]	Report by Baringa Partners, value represents the avoidance of unnecessary network infrastructure build and solar PV curtailment with reference to the ESOO 2020 scenarios
Net Present Value consumer cost savings of load flexibility to the NEM	$6bn baseline case scenario $18bn high DER uptake	ARENA Load Flexibility Study Technical Summary [8]	Net present value consumer cost savings is the cost of avoided new build and 'inframarginal rent' that generators capture during peak pricing events.
Approved AER 2021-2026 EDPR DER integration capital expenditure	$240M	Victorian Government DEECA's voltage management consultation paper[9]	This value reflects the current approved spend on network issues with services and avoid network infrastructure spend.

The following observations can be made from the identified data:

- There is a significant and growing volume of demand and unscheduled generation that has the capability to be flexibly changed to meet the needs of the NEM.
- There is significant value in the avoidance of unnecessary dispatchable generation / storage and network infrastructure build that can be captured by changing demand at the right time and in the right location.

[6] https://www.racefor2030.com.au/wp-content/uploads/2021/10/RACE-B4-OA-Final-report.pdf
[7] https://www.datocms-assets.com/32572/1629948077-baringaesbpublishable-reportconsolidatedfinal-reportv5-0.pdf
[8] https://arena.gov.au/assets/2022/02/load-flexibility-study-technical-summary.pdf
[9] https://engage.vic.gov.au/voltage-management-in-distribution-networks-consultation-paper

- Tariff based structures for demand response assist with peak demand and price issues but do not adequately cater for issues such as minimum demand, network constraints and voltage management.
- Emergency reserve schemes (out of market) capture significant volumes (2 GW) of demand response compared to in market demand response schemes (<100 MW) suggesting that in market schemes need modification to increase participation.

Information on participation in each of the schemes, e.g., WDRM and RERT is provided in Section 2.3.3.

2.3.3 Existing schemes for flexible demand

Wholesale demand response mechanism

The Wholesale Demand Response Mechanism (WDRM) started on 24 October 2021. The WDRM is an 'on market' demand response program managed by AEMO that operates in all NEM jurisdictions. WDRM allows demand side (or consumer) participation in the wholesale electricity market for every trading interval, currently five minutes.

WDRM operates by enabling 'Demand Response Service Providers' (DRSP) to classify and aggregate the demand response capability of large market loads and small generating units for dispatch through the NEM's standard bidding and scheduling processes. The level of demand response provided is the actual meter data measured against a baseline estimate. The DRSP receives payment for the dispatched response at the prevailing electricity spot price for the relevant period.

In June 2022 AEMO published its first annual report into the WDRM[10]. As at June 2022 the WDRM had one registered DRSP, 25 registered National Metering Identifiers (NMI) covering New South Wales, Victoria and South Australia with a total registered capacity of 61.6MW. As at January 2023[11] there were 28 registered NMIs with a capacity of 65MW.

In the first 8 months of operation there were 16 days where WDRM was utilised for a total of 319MWh.

In AEMO's words: *"In terms of WDR operations, there has been a slow build of WDR capacity registered since the start of the mechanism. After a summer with few WDR events, there have been an increasing number of WDR events over the winter period."*

Further details on the operation of WDRM can be found on AEMO's webpage below.

https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/wdrm

Reliability and emergency reserve trader

The Reliability and Emergency Reserve Trader (RERT) is an 'off market' function conferred on AEMO to maintain power system reliability and system security using reserve contracts. It operates in all NEM jurisdictions.

[10] Wholesale Demand Response Annual Report, June 2022, AEMO

[11] Based on AEMO's published registration and exemption list as at 17 January 2023

As part of its functions to maintain system reliability AEMO regularly assesses whether forecast reliability and security meets the relevant NEM standard. If AEMO observes that the standard is breached and considers there is no market resolution to it, then AEMO may choose to procure reserve under the RERT.

To procure reserve AEMO maintains a panel of RERT providers that can provide short notice (between three hours and seven days) and medium notice (between ten weeks and seven days) reserve. The RERT providers have contracts with provisions to be paid for availability, pre-activation (for non-scheduled reserves only), usage, and early termination. There are no payments made for being on the RERT panel. Panel members for short notice RERT agree on prices when appointed to the panel, whereas panel members for medium notice RERT negotiate prices if and when reserve is required.

In November 2022 AEMO published a quarterly report[12] on RERT for the period 1 July 2022 to 30 September 2022. At the start of Q3 2022 up to 2030 MW of potential short notice reserve capacity was in place under panel agreements.

The total amount paid by AEMO for RERT in Q3 2022 was ~$639,000 for an event that occurred on 5 July 2022 in Queensland that required 63MW of RERT. This equates to a cost of $71,161 / MWh (based on the number of hours the 63MW of RERT was dispatched), of which the activation cost was $18,000 / MWh, which reflects the rate paid for the actual reserves delivered with the balance reflecting the pre-activation payment for having the reserve available and market compensation costs.

Further details on the operation of RERT can be found on AEMO's webpage below.

https://aemo.com.au/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert

Peak demand reduction scheme

The Peak Demand Reduction Scheme (PDRS) is a state based certificate scheme that commenced in November 2022 to reduce peak electricity demand in New South Wales.

The PDRS incentivises households and businesses to reduce energy consumption during hours of peak demand. This is done through a certificate scheme which began in November 2022.

The PDRS sets an energy savings target for electricity retailers (and large energy users) equivalent to their share of electricity sales each year. Participants create or buy Peak Reduction Certificates (PRCs) for eligible activities, such as reducing energy usage during hours of peak demand.

The initial focus of the PDRS is on specific technologies such as air conditioners, heat pump water heaters, refrigerated cabinets, ventilation motors, refrigeration motors, pool pumps and spare fridges and freezers. These technologies were chosen as they are already eligible under the New South Wales Government's energy efficiency scheme.

Currently the eligible activities are typically only applicable to residential and small business consumers. The PDRS is intended to be expanded to include new activities,

[12] Reliability and Emergency Reserve Trader Quarterly Report Q3 2022, November 2022, AEMO

technologies and capabilities in future years which will include commercial and industrial consumers.

Further details on the operation of the PDRS can be found on the NSW Government's Department of Climate and Energy Action webpage below.

https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/peak-demand-reduction-scheme

Small generation aggregators

A small generation aggregator (SGA) is a market participant category in the NEM. An SGA supplies electricity aggregated from one or more small generating units which are exempt (or have been exempted by AEMO) from registration. SGAs are financially responsible for the electricity provided and they can be connected to distribution, transmission or embedded networks.

Currently an SGA can only provide electricity to the NEM including participation in WDRM and not ancillary or other services.

Unlike the schemes outlined above, SGA is not a specific flexible demand or demand response based scheme. Rather it is a mechanism via which parties can aggregate multiple small generating units, access wholesale prices and participate in other schemes at a large scale such as WDRM or RERT.

Further details on the SGA can be found on AEMO's webpage below.

https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/registration/register-as-a-small-generation-aggregator-sga-in-the-nem

Network services

The increasing penetration of variable renewable electricity together with changing consumer demand patterns means electricity distribution networks are becoming increasingly complex to manage with issues such as maximum demand, minimum demand and voltage fluctuations becoming more prevalent.

To address these issues and enable the network to adapt to the changing circumstances the distribution network service providers (DNSP) can either invest in network solutions (e.g. capital expenditure for network augmentation) or non-network solutions (e.g. demand side solutions). For example, in Victoria the electricity networks have received approximately $240 million in approved expenditure for the period 2021 – 2026 to invest in a range of programs to better integrate CER, much of this funding is committed to voltage related initiatives[13].

The procurement of non-network solutions is typically in the form of a contract for the provision of network support services with a provider that can either be a large customer directly or an aggregator representing several customers simultaneously. These network

[13] https://engage.vic.gov.au/voltage-management-in-distribution-networks-consultation-paper (page 22)

services contracts are tendered for by individual electricity networks to meet their specific requirements.

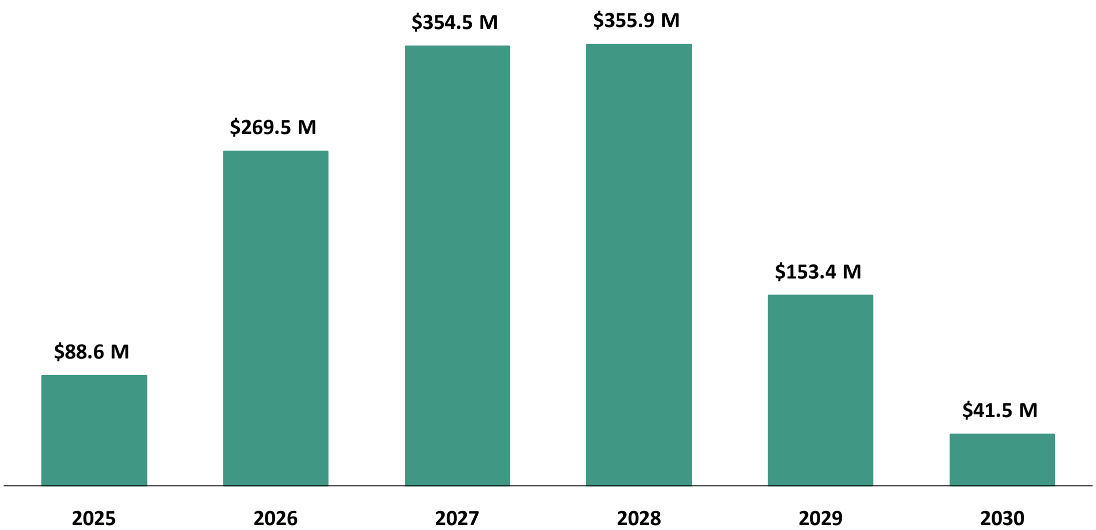
The National Electricity Rules require electricity networks to undertake an annual planning process and prepare an annual planning report covering at least the next five years. An aspect of the planning report includes taking into account non-network options when considering investment options.

If an electricity network requires an investment above $6 million they must undertake a regulatory investment test for distribution (RIT-D) which requires an assessment of the costs and, where appropriate, the benefits of each credible investment option (including non-network options) to address a specific network problem. The assessment identifies the option which maximises net market benefits (or minimises costs where the investment is required to meet reliability standards).

The Energy Networks Association (ENA) together with the University of Technology Sydney have prepared Network Opportunity Maps[14] of annual planning data that identifies opportunities for non-network solutions to address network capacity constraints and reduce costs for customers. The most recent data is based on the planning reviews published in December 2020. We appreciate this data is not fully current, however it is the most up to date aggregate data available.

The chart presented in Figure 2.1 is based on our analysis of the 'network opportunity maps – annual planning data'[15] downloaded February 2023. It highlights the potential deferred distribution network investment over the period 2025 to 2030 in real dollars. In aggregate over the period approximately $1.26 billion in forecast network investment is deferrable by implementing non network options including flexible demand.

Figure 2.1: Potential deferred distribution network investment by year, 2025 – 2030, $m real



[14] https://www.energynetworks.com.au/projects/network-opportunity-maps/

[15] https://www.energynetworks.com.au/miscellaneous/network-opportunity-map-annual-planning-data/

This ENA valuation is supported by an ESB commissioned report[16] in 2021 to review the potential network benefits from more efficient DER integration. This report values avoided augmentation and unnecessary network infrastructure build and avoided solar PV curtailment (with reference to the ESOO 2020 scenarios) at $2 to $13 billion over the 20 years to 2040.

2.4 Smart Energy Hubs

Shell's Smart Energy Hubs are a mix of technologies and capabilities that integrate and optimise energy supply, generation, energy management and demand flexibility. The intention is to optimise the entire energy usage and supply for a business to produce more significant energy efficiency gains and further reduction of emissions and costs.

The Smart Energy Hubs Project is focussed on the temperature sensitive sector in particular shopping centres, supermarkets and distribution centres. The choice of sector is deliberate as it represents a significant near-term opportunity for flexible demand capacity due to the large thermal loads with potential to manage heating and cooling, coupled with the broader industry's strategic imperative to reach net zero emissions and improve sustainability related outcomes where possible

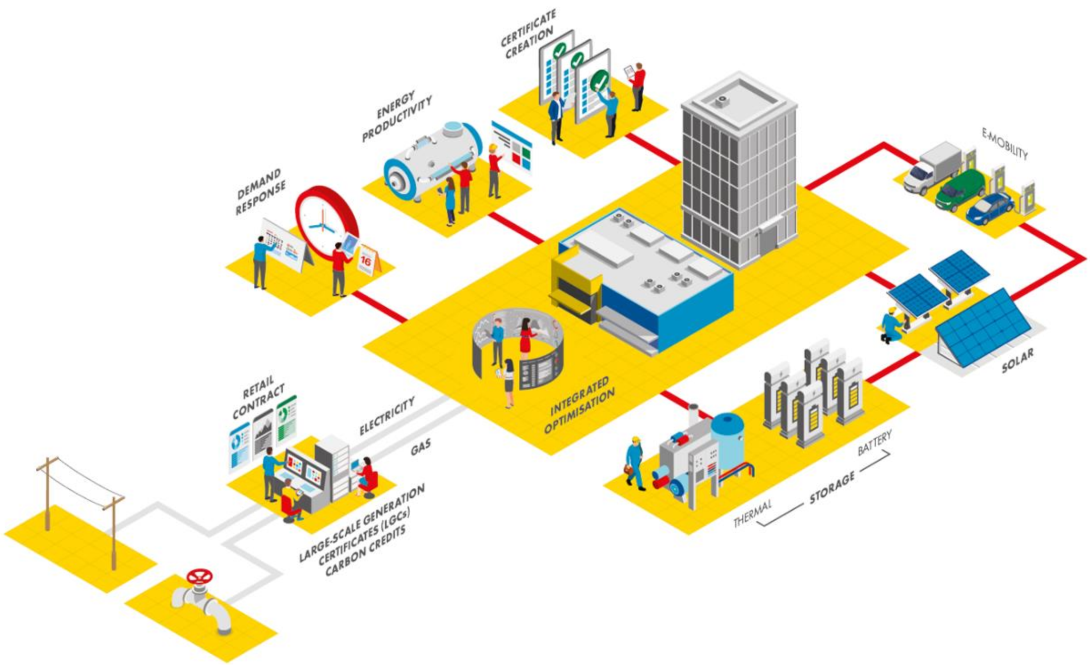
Figure 2.2 illustrates a potential Smart Energy Hub that integrates and optimises one or more of the following:

- energy usage
- solar generation
- battery storage
- thermal storage
- electric vehicles
- demand response
- energy productivity.

The first of Shell's Smart Energy Hubs was launched in September 2022 at Chirnside Park Shopping Centre in Victoria. This site includes a 2MWh battery, a 1,700kVar water cooled central chiller plant and a 650kW solar array which, combined with a whole of site software optimiser, is seeking to co-optimise the distributed energy resource for market benefits, network services and customer savings. It is also seeking to supply up to 70 per cent of its required electricity during peak energy demand periods.

[16] https://www.datocms-assets.com/32572/1629948077-baringaesbpublishable-reportconsolidatedfinal-reportv5-0.pdf

Figure 2.2: Smart Energy Hub Infographic



If successful, the Smart Energy Hubs Project will help:

- improve the understanding of how to commercialise Smart Energy Hubs at scale.
- reduce costs for flexible demand services and firm renewable energy generation across the system through deployment of Smart Energy Hubs across C&I sectors at scale.
- reduce barriers for flexible demand services through stakeholder engagement and revised regulatory mechanisms.
- increase value delivered by flexible demand services through stakeholder engagement and potential new market services that can be formalised.

3 Scope and approach

3.1 Scope of work

This report reflects work undertaken to identify short term options that will facilitate an increase in participation of C&I flexible demand in existing schemes and their potential to provide new market and / or network services. The scope of work included:

- Identification through stakeholder consultation and other analysis of material market issues and barriers to flexible demand participation in the identified schemes i.e., RERT, WDRM, SGA and PDRS.
- Develop potential reform or regulatory change options to address identified issues with a focus on short term and relatively straight forward implementation.
- High level consideration of the following longer-term reform options to ensure alignment with any short-term recommendations. These reforms are described in more detail in Section 4.
  - The 'scheduled lite' reform seeking to address demand forecasting challenges;
  - The 'flexible trading arrangements' (FTA) reform proposal to allow demand responsive third-party participants 'behind the meter';
  - Operational strategies for managing minimum system load (MSL) and dynamic operating envelopes (DOEs); and
  - Network tariff reform opportunities.
- High-level analysis to support the justification of up to three priority reform or regulatory change options that can be trialled by Shell Energy through the SEH project.
- Identification and analysis of up to three new market or network services with potential growth opportunities that can be trialled by Shell Energy through the SEH project.
- Engagement with key stakeholders throughout the program to ensure their input is captured and reflected in the project outcomes.
- Recommendation of actionable reform or regulatory changes and next steps.

To progress this work in a timely fashion the scope was intentionally limited and specifically excluded the following:

- Detailed analysis of the identified schemes i.e., RERT, WDRM, SGA and PDRS or analysis of programs other than those identified.
- Technical support and analysis outside of commercial, regulatory and stakeholder engagement related work, for example, legal, engineering, accounting or taxation.
- Detailed financial models or cost / benefit analysis of recommendations.
- Auditing or validation of information provided by stakeholders or sourced from publicly available documentation.

3.2 Approach

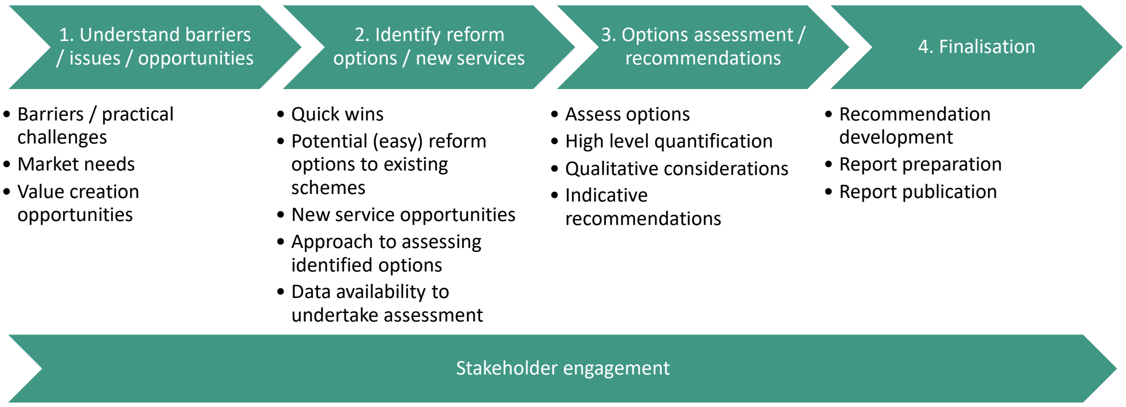
A staged and collaborative working approach was adopted, engaging regularly with stakeholders to gather insights, information and feedback and ensure a 'no surprises', supported set of outcomes and recommendations.

The tasks included in the approach were:

- Developing and implementing a stakeholder engagement plan. Our approach to Stakeholder engagement is discussed in further detail in Section 3.3 and Appendix A.
- Developing an assessment framework for the key issues, barriers and opportunities (refer Section 5).
- Identifying issues and barriers to growing participation of C&I flexible demand (refer Section 5.2).
- Identifying reform options and potential new services to address issues and barriers and increase C&I flexible demand participation (refer Section 7).
- Prioritising the options based on the assessment framework (refer Section 8).
- Making recommendations on priority options and next steps for trial in SEH project (refer Sections 8 and 9).

The project approach is summarised in Figure 3.1 and comprised four stages for delivery underpinned by stakeholder consultation across each stage.

Figure 3.1: The four stages and timelines to deliver the scope of work



The approach and recommendations were developed cognisant of the practicalities and timelines of implementing the identified reform options and the broader work program being undertaken by the industry (refer Section 4).

3.3 Stakeholder consultation overview

This project involved broad stakeholder consultation throughout all key stages of the project. The purpose of the consultation was to ensure stakeholders' insights and perspectives informed our approach, the understanding of barriers, the identification of options and the development of our recommendations.

It is important to note that the contents of this report do not necessarily reflect the views of every stakeholder we consulted and consensus was not sought nor received.

Stakeholder Engagement Plan

The stakeholder engagement plan established the stages, timing and nature of engagements, the industry segmentation adopted and how feedback was captured and fed into outcomes and recommendations. A level of flexibility was maintained to maximise efficiency and cater for follow up with key stakeholders unavailable for planned workshops.

Stakeholder Segmentation

Table 3.1 below outlines the key stakeholders and industry segments across the electricity and flexible demand value chains identified in the plan and engaged during this work. In addition, policy makers and thought leaders were engaged early to ensure that there was comfort with the framing and scope of the work in the context of ongoing market reform progams and priorities.

Table 3.1: Stakeholder segmentation

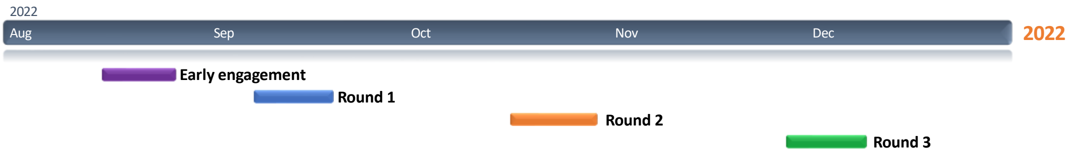
Stakeholder Interest	Industry Segment
Policy Developers	Governments Market bodies Government agencies
Flexible Demand Value Chain	Energy service companies
Electricity Value Chain	Distribution networks Retailers (with C&I customer base) Consumer representatives

Nature of Engagement

All stakeholder engagement occurred via Teams meetings that were scheduled to accommodate the maximum availability of the participants based on polling. Pre-reading was circulated reflecting feedback from previous rounds where available and discussions were facilitated through the presentation of meeting packs.

The stakeholder engagement was undertaken in the stages illustrated in Figure 3.2.

Figure 3.2: Stakeholder engagement - high level timeline



Early one-on-one engagement with policy makers was conducted to confirm the appropriateness of the framework and scope of the project.

Rounds one and two of the consultation were conducted as small workshops within each industry segment, with two workshops for some segments offered to manage group sizing and availability as required.

The third and final round was held as two broader workshops with larger cross segmentation groups to discuss and disseminate draft findings. Additional, follow up meetings were held as required.

Capturing stakeholder feedback

To capture and share stakeholder feedback the following occurred:

- Stakeholders were asked to confirm in subsequent rounds of engagement the broad findings from the prior round. For example, in Round Two stakeholders' feedback was sought on outcomes presented from Round One to confirm accuracy.

- The key stakeholder perspectives and how they have informed the option assessment and recommendations is provided throughout this report.
- For purposes of managing engagement and preparing this report summary notes in a structured format against the key questions and stakeholder segment were recorded. These notes informed the next stage of consultation, option identification and assessment, and this report and are not intended to be further distributed.

All discussions were held under Chatham House Rules[17] and no comments are directly attributed to any individual organisation or person. No confidential information was requested or shared.

Consultation summary

The consultation work ran from the 19 August 2022 to the 16 December 2022 in alignment with the plan illustrated in Figure 3.1 and covered the stages and stakeholders detailed in Table 3.2.

Table 3.2 Stages of engagement and meetings held

Stage	Content of engagement	Stakeholders & segments
Early Engagement	• Frame and scope of the project	• Eight 1:1 consultations • Policy and thought leaders • Governments: NSW, Vic, QLD and Commonwealth • Regulators / market bodies: AER, AEMC, AEMO, ESB
Round One	• Discuss analytical framework • Identify issues and barriers • Market needs and value creation opportunities	• Five small group consultations • 33 stakeholders across key segments • Governments, regulators, market bodies • Retailers, networks, energy services companies
Round Two	• Identify reform options / new services • Available / required data • Assessment methodology	• Five small group consultations • 31 stakeholders across key segments • Governments, regulators, market bodies • Retailers, networks, energy services companies
Round Three	• Present draft recommendations	• Two larger cross sector group discussions • 30 stakeholders across key segments • Governments, regulators, market bodies • Retailers, networks, energy services companies and end user representative bodies

The engagement work covered the seven stakeholder segments identified with 30 plus stakeholders represented in each of Rounds One to Three. During the early engagement eight stakeholders were consulted one-on-one.

Due to the lack of availability of resources from end user representative bodies to participate in the three rounds of consultation, a one-on-one meeting was conducted in early January 2023 to present the findings and ensure that there was a level of comfort with the consultation process and draft recommendations.

Further detail on the dates and participation during the consultation process can be found in the Appendix A.

[17] www.chathamhouse.org

4 Longer term market reforms

The recommendations for reform and new services in this report focus on relatively short term and straight forward change to improve participation of C&I flexible demand. It is important that these do not operate contrary to the intent of the identified longer term reforms currently underway.

Our report is not intended to assess or recommend changes to the longer term reforms. These longer term reforms, detailed in Table 4.1, are particularly important as they may replace or augment the existing schemes identified in Section 2.3.

In addition to the reforms detailed in Table 4.1, the Commonwealth Government, endorsed by the State and Territory Energy Ministers, are developing a Capacity Investment Scheme (CIS) with a first auction scheduled later in 2023. This is a revenue underwriting mechanism for investment in clean dispatchable power. There is limited further detail on this scheme publicly available at the time of writing this report.

Whilst the CIS is not explicitly considered in this report, Section 8.5.1 provides a short commentary on how this, and the schemes detailed in Table 4.1, align with our recommended reforms and new services to increase participation of C&I flexible demand in the NEM.

Table 4.1 Longer term market reforms that have implications for participation of C&I flexible demand

Reform	Reform Type	Timing/ Status	Comment
Flexible trading arrangements	Rule change proposal	Draft determination due August 2023	ESB reform, AEMO is proponent. Implementation timing is uncertain. Seeks to increase flexible demand participation by carving out flexible demand behind the meter. Potential impact for use of SGA in embedded networks.
Scheduled Lite	Rule change proposal	Pending, lodged 10 January 2023	ESB reform, AEMO is proponent with indicative implementation timing late 2024 to 2025. Potential to increase the opportunities for flexible demand 'on market' and reduce the need for RERT.
AEMO minimum operational demand	Procedural / regulatory	implemented	Longer term plans for managing minimum operational demand under development. Likely to present significant opportunity for flexible demand and avoid curtailment of DER solar
Dynamic operating envelopes	Guidelines (AER) Procedures (networks)	Ongoing	DEIP DOE working group has reviewed evolution of DOEs. All electricity networks likely to implement by 2027. Opportunity to increase participation and optimise value of flexible demand

Reform	Reform Type	Timing/ Status	Comment
			within the DOE.
Network Tariff Reform	Rule change Trials and implementation	Determination 2021 Networks are trialing and establishing new tariff structures	AER has oversight to ensure cost reflective pricing and efficient use of capital. This presents an opportunity to optimise value of flexible demand with new incentives and tariff structures.
Project Edge	Trial	Completes August 2023	ARENA funded DER marketplace pilot running from 2020 to 2023. Opportunity to create marketplace for DER services including flexible demand.

Flexible trading arrangements (FTA)

AEMO's FTA rule change proposal was lodged in May 2022 and builds on the work and recommendations of the ESB in its post-2025 market design review and final advice.

The AEMC is currently consulting on the rule change with a draft determination due in August 2023. The final decision and subsequent timeline for implementation is still uncertain.

The rule change would enable residential and business consumers to have their 'behind the meter' consumer energy resources separately identified and settled through a secondary settlement point for CER resources. This means that the consumers' current meters that measure energy flow to and from the grid would be settled by difference (in the same way that a parent meter in an embedded network is settled).

The consumer may have contracts with more than one financially responsible market participant (FRMP) for individual devices or one for less flexible load and another for their flexible load. Alternatively, all resources could be managed by one FRMP, but with different types of pricing. AEMO proposes that the proposed change will remove current barriers to establishing these types of arrangement.

Metering at the secondary settlement point is proposed to be done with a new kind of minor energy flow metering installation. AEMO has also proposed that this new kind of meter should also be used for currently unmetered loads, such as street lights.

This proposal if implemented could facilitate growth in flexible demand where, for example, a business could take up a flexible demand contract for part of their consumption and a regular contract for other less flexible load.

Further information can be found on the AEMC's website at https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading

Scheduled Lite

AEMO's Scheduled Lite rule change proposal was lodged in January 2023 and also builds on the work and recommendations of the ESB in its post-2025 market design review and final advice.

The AEMC has yet to publish its consultation paper so the timings on draft and final decision and subsequent timeline for implementation are still uncertain.

This rule change is intended to enable small to medium sized resources (including demand and generation) to actively participate in market processes or dispatch. These 'distributed resources' refer to a broad range of customers and assets including CER, flexible demand and other unscheduled resources which will commonly participate in Scheduled Lite as an aggregation. The aim is to create value for customers through the integration of CER and flexible demand within the wholesale market.

As a market mechanism, the role of Scheduled Lite is foundational to enabling greater customer side participation in the NEM in the long term through two models:

- Visibility model: provide additional information on the future behaviour and intentions of price-responsive resources in return for a service payment.
- Dispatchability model: participation directly in scheduling and potentially setting the market price, through reduced barriers to participation and a level of incentivization, for example ability to participate in FCAS markets or future services like operating reserves or capacity mechanisms.

These two models in tandem are seeking to:

- maximise the value of distributed resources for consumers and the broader system through increased competition and access to markets by rewarding service provision and lowering barriers to participation in market scheduling processes.
- promote efficient system operation and delivery of electricity services by addressing risks associated with growing operational uncertainty and driving more efficient use of security and reliability measures.
- enhancing the efficiency of long-term investment in electricity services term through greater visibility and active participation of distributed resources in the market and aligning their behaviour with the needs of the system.

Further information can be found on the AEMC's website at
https://www.aemc.gov.au/rule-changes/scheduled-lite-mechanism

AEMO Minimum Operational Demand

Minimum operational demand describes the minimum level of demand that a specific part of the grid can sustain in a secure and reliable state. Minimum operational demand, also known as minimum system load (MSL) is a relatively new phenomenon in the NEM associated with the high level of uptake in CER and in particular rooftop solar.

Minimum operational demand is prevalent in South Australia and Queensland where AEMO manages it through state based regulation that has been introduced to allow AEMO to curtail solar output when minimum operational demand is breached. In SA, for example, AEMO can request action when demand falls below 400 MW.

In the longer term the package of market mechanisms being introduced, of which FTA and Scheduled Lite are foundational steps, should allow CER to be better managed to address the issue of minimum operational demand.

AEMO provides information on managing minimum operational demand in the following fact sheet: https://www.aemo.com.au/-/media/files/learn/fact-sheets/minimum-operational-demand-factsheet.pdf

Dynamic Operating Envelopes (DOE)

Operating envelopes are not new, they are limits that an electricity customer can import and export to the electricity grid at their connection point. These limits are agreed between networks, customers and the AER as part of the customer connection or regulatory process.

Currently, in most cases, operating envelopes are fixed at conservative levels regardless of the capacity of the network because they are static and need to account for 'worst case scenario' conditions.

Dynamic operating envelopes (DOEs) are still in development as a concept. They are intended to allow import and export limits to vary over time and location. DOEs may enable greater flexibility with higher levels of energy exports from customers' solar and battery systems by allowing higher export limits when there is more hosting capacity on the local network. This should increase opportunities for customers to participate in flexible demand related schemes and programs.

The Distributed Energy Integrated Program (DEIP) DOE Outcome's Report[18] identifies that approximately 50% of electricity networks are trialling DOE offerings and all electricity networks are planning for the implementation of DOEs within the next 5 years (by 2027).

Whilst there is a call for a consistent approach it is not recommended that regulatory change is required to facilitate the introduction of DOEs although supporting AER guidelines, e.g., a DOE Service Target Performance Incentive Scheme, will need to be developed. It is noted that the AER has approved South Australia Power Network's adoption of DOEs since 2021.

Further information on DEIP's work on DOEs can be found at: https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/dynamic-operating-envelopes-workstream.

It is worth noting that the operation of DOEs and how they might impact consumer choice are also part of the Project EDGE work scope.

Project EDGE

Project EDGE (Energy Demand and Generation Exchange) is a multi-year, off-market proof-of-concept DER Marketplace that trials the operation of DER to provide both wholesale and local network services within the constraints of the distribution network.

The project is an ARENA funded collaboration between AEMO, AusNet Services and Mondo with participation of three other aggregators - AGL, Discover Energy, and Rheem and Combined Energy Technologies. The trial is based in the AusNet Services distribution

[18] https://arena.gov.au/knowledge-bank/deip-dynamic-operating-envelopes-workstream-outcomes-report

area within Victoria and intends to demonstrate capabilities which can be replicated across other areas of the NEM:

- DER wholesale energy market integration.
- Scalable DER data exchange.
- Local service exchange for network support services.

The project is working to demonstrate how consumer participation in a DER marketplace may be facilitated to provide wholesale and network services and therefore increase the opportunities for flexible demand.

An aggregator, chosen by a consumer, utilises the consumer owned DER to deliver electricity services within the DER marketplace, in exchange for monetary compensation. The wholesale and network services are determined by AEMO, or the electricity network.

Further information on Project EDGE can be found at: https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge

Network Tariff Reforms

Distributors charge network tariffs to retailers who pass them on to their customers. Network tariffs are used to build, operate and maintain the distribution networks. The AER regulates these tariffs to ensure cost effective outcomes for consumers in the delivery of safe and reliable electricity services.

The NER requires distributors to gradually make their tariffs more accurately reflect the costs of serving their customers (i.e. cost reflective). For example, transitioning single rate usage tariffs to reflect different peak and off-peak times (time-of-use tariff). Changes to the NER in 2021[19] removed prohibition of export tariffs to help ensure that DER such as solar PV, batteries and electric vehicles can be integrated onto the grid in a cost reflective and efficient manner. It also required the AER to publish export tariff guidelines.[20]

Network tariff reform is intended to reduce the need for additional investment and the amount of network infrastructure that needs to be maintained. The AER expects distributors to view both tariff reform and network support service procurement as alternatives to expensive network investment with cost reflective tariffs driving broad retailer and consumer responses while targeted procurement can address local needs.

Price signals mitigate constraints in networks by encouraging more efficient use of distribution networks. This helps distributors to integrate more DER onto networks without the need to invest in further capacity. Different prices throughout the day incentivise consumers to use less electricity or export more electricity during evening peaks when demand is high and use more electricity during the day when demand is low. Examples of price signals include:

- time-of-use, demand and export tariffs.
- complementary initiatives such as prices for devices.

[19] https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources
[20] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/export-tariff-guidelines

- Demand management rebates.
- valuing and procuring network support services.

Distributors are required to explain the interrelationship between their tariffs and their regulatory proposals to the AER. Distributors are also required by the AER to consult consumers on an appropriate balance of network investment and price signals to support DER integration. The types of price signals used should reflect :

- the NER pricing principles.
- consumer preferences.
- network requirements.
- jurisdictional context.
- learnings from tariff trials.

The AER has established a clear expectation that distributors design new and innovative tariffs that are informed by tariff trials. This requires working with retailers, aggregators and governments to create new service models. The AER also expects distributors help consumers participate in new energy markets as part of the Energy Security Board's two-sided markets reform work.

Information regarding tariff reform and trials can be found on the AER, and the relevant electricity network websites, for example:

- Essential Energy are introducing bi-directional tariff trials https://www.aer.gov.au/networks-pipelines/network-tariff-reform/tariff-trials, https://www.essentialenergy.com.au/media-centre/newsletter/newsletter-3-breaking-the-duck-curve
- Energex https://www.energex.com.au/home/our-services/pricing-And-tariffs/residential-tariffs-and-prices/residential-network-tariff-trials
- Ausgrid https://www.ausgrid.com.au/Industry/Regulation/Network-prices/Tariff-Reform

More information on network tariff reform can be found on the AER's website: https://www.aer.gov.au/networks-pipelines/network-tariff-reform

5 Analytical approach: identifying barriers & assessing potential solutions

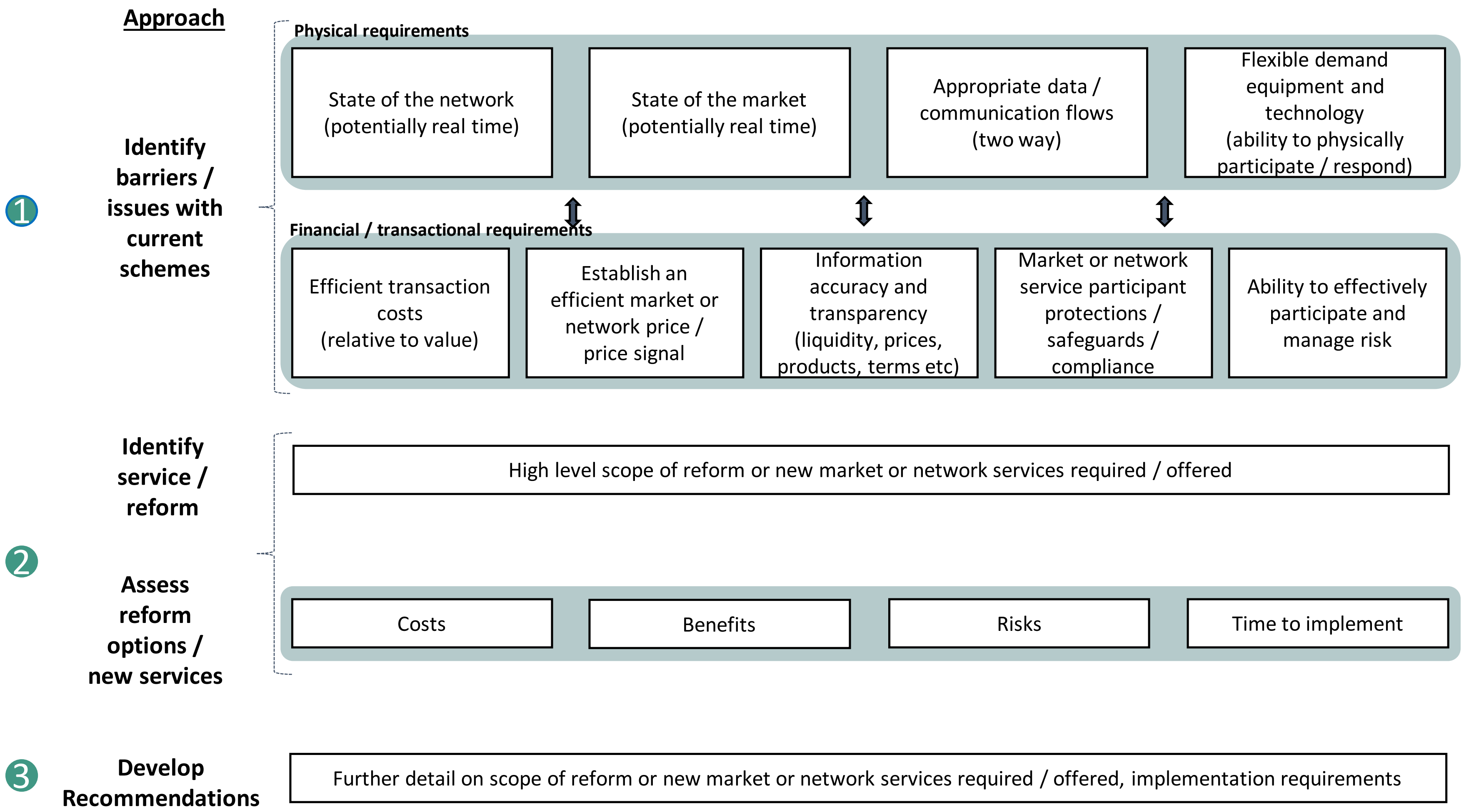
5.1 Overarching analytical framework

Our overarching analytical framework is detailed in Figure 5.1. The key elements of the framework include:

- An alignment with our approach (refer Section 3.2) and the first three stages of work (refer Figure 3.1). The first three stages in our approach directly correspond to the three numbers on the very left of the diagram in Figure 5.1.
- An outline of the generic physical and financial / transactional requirements for provision of a flexible demand service. These requirements were used to capture barriers and issues (refer Section 6) and are considered in further detail in Section 5.2. We note that cultural factors are not an explicit requirement, however these are implicit and considered in other requirements, for example, ability to effectively participate and market / network protections and safeguards.
- A recognition that the identification of potential solutions (reform options and new services) were necessarily based on the identified barriers and issues. They did not utilise a pre-determined framework.
- Our considerations of costs, benefits, risk and time to implement when assessing the identified reform options and potential new services (refer Section 5.3).

The overarching framework was discussed with stakeholders and there was general consensus that it was suitable and appropriate.

Figure 5.1: Overarching analytical framework



5.2 Requirements for flexible demand

This work, Stage One of the of the Smart Energy Hubs Project, was designed to identify potential reform options to specific, existing flexible demand schemes and also potential new market or network flexible demand related services.

The first stage of our approach was to identify barriers or issues with the existing schemes. Table 5.1 provides an outline of the typical requirements for any flexible demand scheme.

The requirements are separated into physical requirements, i.e. those that relate to the physical provision of the flexible demand service, and financial / transactional requirements, i.e. those that relate to pricing, costs and other transactional requirements.

For a flexible demand scheme to operate effectively it must consider all requirements and ensure they are met to the appropriate degree.

Material gaps in meeting key requirements were used to assist in identifying the barriers and issues. We captured the barriers and issues identified with the various schemes against the most relevant and / or important requirement.

Table 5.1: Framework to capture requirements for flexible demand

Requirement	Comment
	Physical Requirement
State of the network	• The provision of a flexible demand service must be cognisant of the local network conditions and requirements, and vice versa. The local network should have visibility of the potential provision of flexible demand services that may impact their network. • Failure to have appropriate visibility may result in unintended adverse consequences or incomplete delivery of the local networks' requirements.
State of the market	• Similar to network conditions and requirements, flexible demand service providers must also be cognisant of the broader market (regional) conditions and requirements and vice versa. • Failure to have appropriate visibility may result in unintended adverse consequences or incomplete delivery of the market's requirements.
Appropriate data / communication flows	• To provide a flexible demand service there must be appropriate (two way) data and communication flows. • In particular those related to the state of the market and / or network and the requirement to provide the physical response, i.e. the flexible demand.
Equipment and technology	• The equipment and technology at the relevant site (including metering) must be capable of providing and validating the flexible demand service as required including response times.
	Financial / Transactional Requirement
Efficient transaction costs	• The provision of flexible demand services must have efficient transaction costs. These relate to the cost of

Requirement	Comment
	contracting or securing the service as well as any other transaction related and compliance costs but exclude capital and equipment costs. • If a flexible demand service has high or inefficient transaction costs then it will discourage participation by service providers and customers.
Efficient price	• There must be an efficient and effective market (or network) price and price signal. • A price that does not reflect the market's view of an efficient outcome or is opaque will discourage participation by service providers or customers, or alternatively result in customers paying more than is needed for a service.
Information accuracy & transparency	• There must be appropriate transparency and availability of all relevant (and non-confidential) market information. This includes prices, volumes, terms and conditions and liquidity. • The information must be accessible in a timely and cost-effective manner. • A lack of such information will again discourage or limit participation by service providers and customers.
Participant protections and safeguards	• There must be appropriate safeguards for existing participants and customers to ensure service providers comply with their requirements. • A lack of safeguards may encourage rogue behaviour that may result in electricity system issues and / or adverse financial outcomes for the market and / or customers.
Managing risk	• Flexible demand service providers and customers must be able to readily participate in the relevant schemes and manage their risk in a cost-effective manner. • Participation will be discouraged by an inability to manage risks and cost effectively and efficiently.

5.3 Potential solutions assessment framework

A qualitative and high level approach to prioritising the reform options and potential new services was taken and did not include a (detailed) cost benefit analysis.

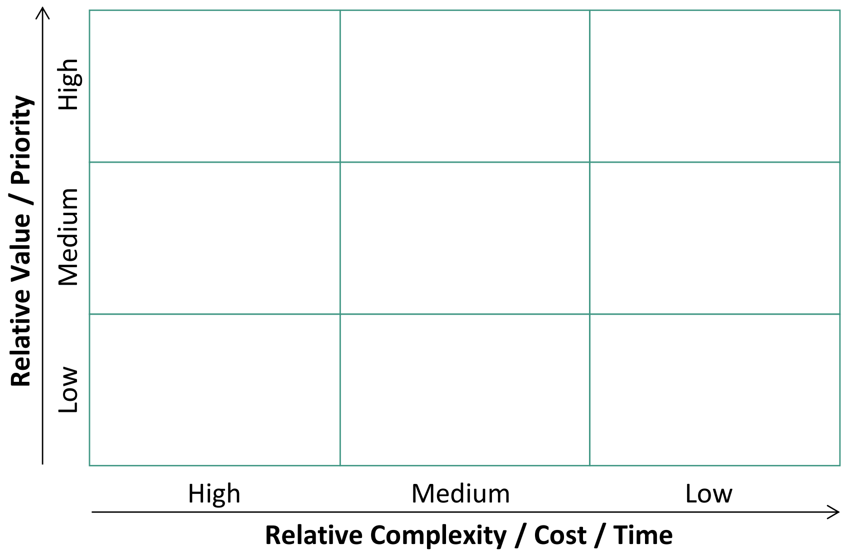
This choice of approach is reflective of three key factors:

- Our reform options and new services are deliberately short term focused and intended to be capable of (relatively) easy implementation and align with the longer term reforms already in progress. There is therefore limited merit in detailed analysis and assessment.
- Our final recommendations are designed to be trialed by Shell during Stage Two of the Smart Energy Hubs Project where further insights into the practicalities, costs and benefits will emerge.
- Limited data availability due to commercial sensitivities and the lack of availability of flexible demand and similar data more generally make a detail cost benefit analysis impractical. We discussed with stakeholders on several occasions where we might access data to assist with our analysis. In the end no specific data sufficient to inform a detailed analysis was provided.

Our approach to assessment, illustrated in Figure 5.1. considered the costs, benefits, risks and time to implement. The assessment framework itself is illustrated in Figure 5.2. We used this matrix framework to prioritise and assess identified reforms and new service options. Each was individually plotted on the matrix with the vertical axis representing the relative value / priority (benefits) of the option and the horizontal axis representing the relative complexity, cost and time of the option.

Options that are closer to the top right hand section of this framework are likely to be of greater net benefit.

Figure 5.2: Assessment framework to prioritise reform options and new services



The initial assessment, and location of the reform or new service on the matrix, was performed based on our experience and perspectives. Each reform or new service assessment was then discussed, validated and if necessary amended through feedback from the stakeholder consultation. Final assessments and recommendations were also discussed with stakeholders.

6 Barriers and issues identified

As outlined in our approach (Section 3) and utliising the framework in Figure 5.1, we identified a series of issues and barriers for flexible demand to participate in existing schemes for discussions with stakeholders for their feedback and to identify further issues and barriers.

The issues and barriers raised by stakeholders were collated and again discussed with them in Round Two consultation to confirm that they were a reasonable representation of discussions and that no material issue or barrier had been omitted.

Section 6.1 is an overview of the barriers and issues identified, Section 6.2 provides greater detail with barriers and issues being assigned to the relevant scheme.

Whilst not specifically a barrier or issue, it became evident from our discussions with stakeholders that there are overarching themes worth noting on C&I flexible demand:

- C&I flexible demand participation is viewed as attractive if the appropriate value can be captured.
- C&I flexible demand provides an easier pathway to the required scale for successful participation compared to small customer markets.
- Significant volumes of demand response is being provided by retailers as the FRMP due to their ability to capture most value streams on offer to flexible demand.
- Some stakeholders noted that consumers may have a closer affiliation with their local area and would therefore be more likely to offer a network service that has a direct meaning to them and their peers than an ‘intangible’ market service.

The information presented in this section is not able to be representative of every stakeholder’s perspective, we appreciate that some stakeholders have differing views and have attempted to capture these where practical.

6.1 Overview of barriers and issues identified

The general observations on barriers and issues for participation across all schemes were:

- There is no one ‘key issue’, rather a broad range of issues and barriers.
- Most barriers are financial or transactional and not physical in nature.
- The main physical issue is a customer’s (in)ability to provide the level of demand response given other business priorities or process restrictions.
- Cultural and other barriers that have been noted in recently published demand response studies were evidenced by the lack of:
  - engagement by customers,
  - customer focused language in key regulatory and market documents.

The following barriers and issues were raised by multiple stakeholders:

- Participants require an ability to maximise the opportunity to capture multiple value streams from flexible demand as there are high fixed and upfront costs associated with providing demand response.
- There is a lack of consistency across schemes and there are also too many schemes which leads to higher transaction costs for successful participation.
- A better balance (and hence trade off) is needed between:

  - (a necessary focus on) risk of inaccuracy and potential cross subsidies; and
  - simplicity and subsequent growth of uptake in demand response.
- There is a need to keep communication and information simple for consumers and participants. Current documentation is too complex and not designed from a consumer perspective.
- There is a lack of transparency and challenges with negotiating and securing contracts to provide network services.
- Demand response is different to generation, it is the provision of a service rather than the sale of a commodity. These differences need to be appreciated when considering demand response scheme design.
- Low participation in RERT may not be an issue, comments included:
  - you 'don't want to promote it too much'
  - 'Is RERT meant to be a value pool for customers?'
  - 'more volume offered in market is better'.
  - more parties seeking to provide RERT results in a better price and therefore lower costs for all consumers.
- Market developments in the current reform program may address some issues, for example:
  - The 'market operating reserve' may address specific RERT issues; and
  - The integrated resource provider and flexible trading arrangements may supersede and address some SGA issues.

6.2 Barriers and issues identified by scheme

Greater detail on the issues and barriers raised, which schemes they relate to, and how they fit with the analytical framework, i.e. physical or financial/transactional, is presented in Table 6.1 to Table 6.10

Table 6.10.

In some schemes no specific issues or barriers were raised, for example, physical requirements in PDRS and network services. This is made clear in the information provided.

Table 6.1: WDRM - physical requirement barriers or issues

Physical Requirement	Identified barrier or issue
State of the network	• None identified
State of the market	• None identified
Appropriate data / communication flows	• Demand Response Service Providers' (DRSP) ability to access meter data can present challenges impacting the ability to acquire new customers. • Networks may not have appropriate access to the required data ahead of time – to inform visibility of events, assist in the ability to forecast and manage their networks. Data is available after the events.
Equipment and technology	• Businesses have other operational priorities creating difficulty in responding in 5 minutes to meet dispatch requirements.

Table 6.2: RERT - physical requirement barriers or issues

Physical Requirement	Identified barrier or issue
State of the network	• None identified
State of the market	• None identified
Appropriate data / communication flows	• "When RERT mechanism is activated AEMO has the steering wheel and everyone else has to get out of the way" – sometimes limited information and control at that point in time to market participants. • The 0RERT portal requires regular updates and can be cumbersome and inefficient to maintain.
Equipment and technology	• Businesses (i.e. end customers) have other operational priorities creating difficulty in providing automated and direct control of their equipment and hence their business processes to third parties.

Table 6.3: PDRS - physical requirement barriers or issues

Physical Requirement	Identified barrier or issue
State of the network	• None identified
State of the market	• None identified
Appropriate data / communication flows	• None identified
Equipment and technology	• None identified

Table 6.4: SGA - physical requirement barriers or issues

Physical Requirement	Identified barrier or issue
State of the network	• None identified
State of the market	• None identified
Appropriate data / communication flows	• There are potential challenges with getting meter data from embedded network related SGA resources. • AEMO is primarily interested in the data associated with the parent connection point and not the child connection points. • “DNSPs not interested in anything past the gate meter.“
Equipment and technology	• There may need to be more regular testing of embedded generators, as some may not be able to run as required without regular testing.

Table 6.5: Network services / support - physical requirement barriers or issues

Physical Requirement	Identified barrier or issue
State of the network	• None identified
State of the market	• None identified
Appropriate data / communication flows	• None identified
Equipment and technology	• None identified

Table 6.6: WDRM - financial or transactional requirement barriers or issues

Financial / Transactional Requirement	Identified barrier or issue
Efficient transaction costs	• There are high upfront establishment costs (capital and acquisition costs) and a need to 'over contract' to meet targeted volumes. • It is too complex for many end customer businesses to assist in registering or to participate – they need a level of energy expertise, their primary focus is not energy. • There are varying demand response based schemes (e.g. WDRM, RERT) which have differing requirements – this increases participation complexity and cost. • There is limited ability to value stack across schemes – e.g. network service and WDRM can be considered exclusive by the electricity network due to 'double dipping' fears.
Efficient price	• There is no certainty of returns for customers in their ability to recover establishment costs. • The market price is not necessarily beneficial for a retailers' portfolio or position. There currently is limited to no incentive to participate by the party with closest customer relationship, i.e. the retailer. • The ex-ante price and volume for customers can be challenging and uncertain. • The price signal is secondary, it is sometimes not a true demand side bid nor operating as fully scheduled load.
Information accuracy and transparency	• There is a lack of awareness by customers of the opportunity represented by WDRM. • There is a lack of simple information to explain how WDRM works for customers and participants. • The baseline is produced ex-post and therefore customers do not know what they are entitled to until after the fact.
Participant protections and safeguards	• The requirements for accuracy and 'no arbitrage' in baselines may be too conservative. • The market must accept and balance imperfections with accuracy requirements. Is overshooting demand response provision really a problem?

Managing risk	• There are strict eligibility criteria: it also excludes more complex sites, e.g. multiple connection points or varying CER.
	• There are high eligibility consumption thresholds – the scheme excludes EV charging.
	• There is a requirement to wait 12 months between RERT and WDRM participation.
	• Limited baselining methodologies and can penalise rational customer behaviour e.g.
	  – CAISO 10 of 10 and impact of recent DR on baseline
	  – no temperature sensitive baselines.
	• There is no aggregation of sites to meet baseline eligibility criteria, i.e. the scheme is for large customers only.
	• There is limited awareness and understanding of rules by consumers and many market participants – hard for customers to know who to talk to.

Financial / Transactional Requirement	Identified barrier or issue
	• Too risky for some consumers relative to value, e.g., regulatory instability deters participation, DRSP (customer) is liable for any shortfall at spot price. • Some businesses (end customers) have difficulty responding in 5 minutes to meet dispatch requirements. • WDRM is effectively a capacity mechanism in an energy market. • FRMP can't capture value from WDRM.

Table 6.7: RERT - financial or transactional requirements barriers or issues

Financial / Transactional Requirement	Identified barrier or issue
Efficient transaction costs	• It is too complex for many end customer businesses to assist in registering or to participate – they need a level of energy expertise, their primary focus is not energy. • There are high upfront establishment costs and a RERT provider needs to 'over contract' to meet targeted volumes. • Varying demand based schemes (e.g. WDRM, RERT) have differing requirements – increases participation complexity and cost. • There is limited ability to value stack – e.g. network and RERT exclusion due to 'double dipping' fears. • The RERT portal requires regular updates and can be cumbersome and inefficient to maintain.
Efficient price	• There is no certainty of returns for customers in their ability to recover establishment costs. • 'Don't know if you will lose or make a fortune'. • AEMO is not price sensitive and can be a price taker, therefore is RERT really an efficient market price or even a market price?
Information accuracy and transparency	• Lack of awareness by customers of the RERT scheme. • There is a lack of simple information to explain how RERT works for customers and participants and what areas are negotiable or not. • A perception of inflexibility in RERT. • Lack of clarity on what other services are permissible when providing RERT, e.g., network services.
Participant protections and safeguards	• Lack of real financial penalty for non-compliance. Only real penalty is to take away pre-activation fee.
Managing risk	• Limited baselining methodologies and can penalise rational customer behaviour e.g. – CAISO 10 of 10 and impact of recent DR on baseline – no temperature sensitive baselines – timing of typical RERT events doesn't align well with baseline methodologies and many customer loads.

Financial / Transactional Requirement	Identified barrier or issue
	• Strict eligibility criteria: requirement for no double dipping can hinder ability for participants to offer network services and RERT. • Limited awareness and understanding of rules by consumers and many market participants – hard for customers to know who to talk to. • RERT contract and participation is complex. • Requirement to wait 12 months between RERT and WDRM participation.

Table 6.8: PDRS - financial or transactional requirements barriers or issues

Financial / Transactional Requirement	Identified barrier or issue
Efficient transaction costs	• State based scheme increases complexity for participants and makes transaction costs higher than they need to be.
Efficient price	• Batteries are treated as a load and a generator which may impact cost allocation mechanisms and economics. • Given the limited scale and eligible activities 'most liable entities (i.e. retailers) will likely pay penalty for first few years.'
Information accuracy and transparency	• Lack of clarity on when new eligible activities will be added. Perception of slow change process and market development.
Participant protections and safeguards	• Requirements for accuracy and 'no arbitrage' may be too conservative.
Managing risk	• Limited eligible activities – acknowledged slow start, growing over time. • Peak period definition may need review including time of day and potentially season given growing winter peak vs summer peak. • C&I customers not currently eligible. • Load shifting not currently eligible. • Batteries are treated as a load and a generator can add new risks. • Retailer (and customer) liability is calculated retrospectively which can impact some retailers and make it more difficult to sell the proposition to customers to participate.

Table 6.9: SGA - financial or transactional related barriers or issues

Financial / Transactional Requirement	Identified barrier or issue
Efficient transaction costs	• SGA is a generator focussed scheme that does not look at the facilities more broadly for a site as a whole.
Efficient price	• An SGA in an embedded network can generally not access any network tariff benefit because tariffs are applied at parent meter.
Information accuracy and transparency	• None identified
Participant protections and safeguards	• None identified
Managing risk	• Potential misalignment with AER's Embedded Network Guidelines – can cause confusion, conflicts and difficulty in maximising participation of behind the meter resources in embedded networks. • Uncertainty of AER treatment of SGA in embedded networks can increase risks for participants. • Some electricity networks may not allow a second connection point on an industrial site so effective use of an SGA may be inhibited due to an electricity networks policy.

Table 6.10: Network services / support - financial or transactional related barriers or issues

Financial / Transactional Requirement	Identified barrier or issue
Efficient transaction costs	• Lack of standardisation across electricity networks for network support processes and agreements. • 'Contracting each service is just too hard.' • Lack of simple aggregator-based network support agreements and acquisition models. Incentivises electricity networks to contract with large single sites. • Impact of RIT-D process and $6m threshold. • 'Hard to build a business case given uncertainty of outcome of bidding for service.' • Perceptions electricity networks are reluctant to pay for a service someone else may already paying for in the market i.e. consider WDRM or RERT double dipping.
Efficient price	• Uncertainty of when service is going to be needed and therefore paid for e.g., upfront payments vs event based payments. • Need further development of pricing models for some networks e.g., critical peak pricing. • Tariff is not always reflective of the value at the right connection point e.g., embedded networks. • The RIT-D process and the $6m threshold can impact the creation of an efficient price and / or price signal.

Financial / Transactional Requirement	Identified barrier or issue
Information accuracy and transparency	• Limited transparency on required services, not a market. • Information asymmetry between electricity networks and customers / DR providers e.g., constraints. • Limited understanding by many end use customers of the value and opportunity of network services.
Participant protections and safeguards	• Trade-off between accuracy / certainty of delivery of service from electricity network's perspective and ability for customers to respond and provide service. • Ring fencing provisions with electricity networks could cause an issue.
Managing risk	• Network services are very location and time specific – some customers have dedicated transformers sized to their loads, so are not able to participate and provide value to the rest of the network. • Potential export restrictions in certain jurisdictions and network areas. • Some customers are tenants and therefore have less ability to control modifications to connections and installation of CER behind the meter. • 'Are networks incentivised to offer the services? Do they have the right culture to offer these services? '

7 Potential reforms and new services

This section identifies (at a high level) a range of potential reforms and new services that address the material barriers and issues identified in Section 6 and qualitatively assesses the value and costs of the potential reforms and new services using the approach identified in Section 5.3.

Our initial identification and assessment was discussed with stakeholders and refined based on feedback, noting that the views in this report do not necessarily reflect the perspectives of all stakeholders as a consensus approach to stakeholder consultation was not utilised.

The refinements post stakeholder consultation include:

- clarifying and amending the high-level definition of the potential reform or new service;
- adjusting the initial assessment of the value, cost, or both; and
- identifying new potential reforms or services and their qualitative value and cost.

This section is a high-level description of the potential reform options and new services. Section 8 provides further detail on the approach to implementation, risks, costs and timeframes for the recommended reform options and new services.

7.1 Categorisation of potential reform options

Our analysis of the issues and barriers in Section 6 highlighted four broad categories of issues and therefore potential reform options:

- **Education and awareness** related options to address barriers related to lack of understanding and information.
- **Harmonisation** related options to address additional cost and complexity due to lack of consistency across existing schemes.
- **Value stack maximisation** related options to enable participants and customers to maximise the return on investment.
- **Risk, accuracy and simplicity trade off** related options to achieve a better balance amongst competing objectives.

Education and awareness

This reform area would be for consumers, market participants, aggregators, regulators and other key stakeholders. It was evident that there is confusion amongst market participants and consumers on the rules and requirements for each scheme and that multiple schemes with often subtle variations added additional layers of complexity.

There is limited to no documentation written from a consumer's perspective, with much of the existing documentation written for a technical audience.

The high degree of opaqueness of the schemes and limited data availability for analysis and insights was also seen as a barrier to growth in participation.

Harmonisation

The current market design has several schemes that seek to utilise flexible demand to achieve specific objectives in particular RERT, WDRM and PDRS. Network services also use flexible demand.

Where practical and possible harmonisation across schemes (and network services) will assist in addressing unnecessary complexity and cost for participants and reduce confusion. An example for harmonisation is baselining methodologies.

Value stack maximisation

There are significant fixed costs associated with installing the appropriate technology and providing flexible demand related services which presents a barrier to uptake and participation.

Where possible and practical there should be an ability to capture additional value streams and incentivise greater participation across schemes. This includes provision of demand response as a direct market participant as well as through one of the identified non-market schemes within this report.

Risk, accuracy and simplicity trade off

The initial scheme designs were appropriately conservative, accepted little risk and designed to achieve specific (initial objectives). However, a continuing conservative approach presents barriers to growth and participation.

As the market matures, and to promote market development, it is reasonable to improve the balance between risk and accuracy and accept that some level of risk and inaccuracy is beneficial for market growth and ultimately all consumers.

The market also needs to establish an initial approach with a higher degree of trust and recognition that demand side schemes may require increased monitoring, reviewing and enforcement of compliance.

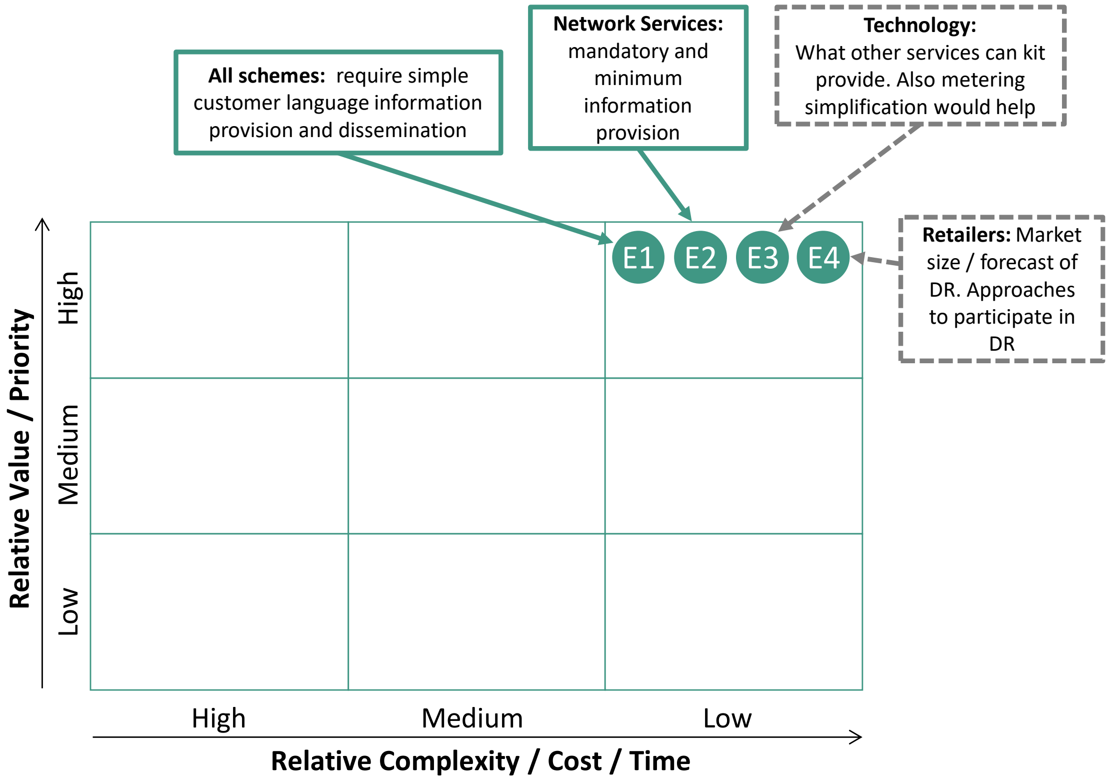
7.2 Education and awareness reforms

Our analysis identified four potential education and awareness related reforms, these are highlighted in Figure 7.1.

Discussions with stakeholders confirmed that all the options are of high relative value as they will assist in addressing the critical barrier of lack of awareness and understanding amongst consumers and market participants. These options will also address issues associated with lack of data and information.

The relative costs were identified as low as these reforms primarily relate to the development, publication / dissemination and maintenance of information to key stakeholders.

Figure 7.1: Potential reforms – Education and Awareness



Note: The potential reforms with the grey dashed boxes were identified during the stakeholder consultation

E1: Provision of customer friendly information for all schemes

This reform involves the development of plain customer language information that will assist with the ease of understanding of how the schemes are intended to operate. The information should seek to map equipment / customer flexibility types to the best scheme, for example, which scheme may be best if customers are able to load shift for specific durations and with specific response times.

It Is likely that this information is best developed and maintained by the relevant bodies that administer and manage the schemes as opposed to being developed by participants or aggregators. Relevant scheme participants and aggregators can and should be required to augment and disseminate this information to customers to provide information on the opportunities available to them and assist in their awareness and ultimately participation.

E2: Provision of customer friendly information and data on network services

This reform involves the development, regular update and provision of minimum and mandatory information in simple plain customer language. Examples include:

- areas of constraints in the network;
- high negative flow risk areas;

- processes to engage with networks for the provision of network services; and
- typical contract terms and conditions.

This information is necessarily best developed and maintained by the relevant network however it should be in a standard format (where practical) across networks.

Retailers and aggregators who participate in these services can and should be required to augment and disseminate this information to customers to provide information on the opportunities available to and assist in their awareness and ultimately participation.

E3: Provision of information on technology requirements for all schemes

This reform recognises the high fixed costs associated with the installation of technology to enable flexible demand and the lack of understanding by many customers of the value that their investment in technology can unlock.

Relevant scheme participants, aggregators and networks should be required to provide mandatory information on all services or schemes that the installed technology at customer's site can support.

There should also be simple information developed by metering technology providers and disseminated by aggregators and participants to streamline and simplify the complexity in metering requirements, specifications and capabilities required to participate in schemes and provide flexible demand.

E4: Provision of information on market size and participation for all schemes

The NER Clause 3.7d currently obliges all market participants to submit demand side participation information to AEMO to further develop and improve its current load forecasting for planning and operational use. This is an annual requirement.

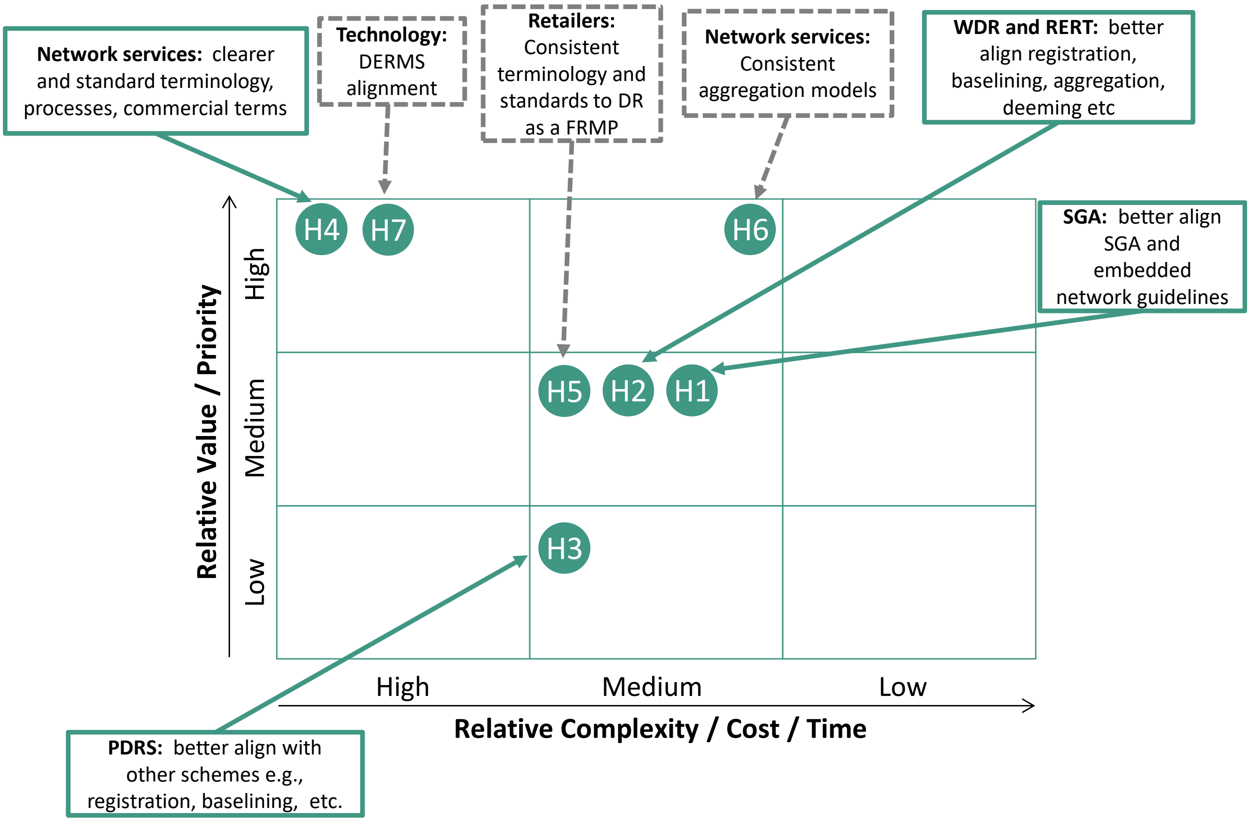
Building and augmenting on this, market participants (retailers and aggregators) should be required to provide more frequent and mandatory information to AEMO on the flexible demand services and schemes they participate in and the scale of their participation (market size). AEMO can disseminate this information not for its own use in load forecasting but rather to address the current opaqueness in the size and potential for flexible demand related markets.

In addition, consistent with E1 and E2 above, retailers and aggregators should be required to provide information to customers on approaches to increase their participation in the various flexible demand related schemes.

7.3 Harmonisation reforms

Our analysis identified seven potential harmonisation related reforms, highlighted in Figure 7.2, three of which were identified through the stakeholder consultation process. Table 7.1 provides further detail on each reform option.

Figure 7.2: Potential reforms – Harmonisation



Note: The potential reforms with the grey dashed boxes were identified during the stakeholder consultation

Table 7.1: Potential harmonisation reforms – further detail

Ref#	Relevant scheme(s)	Further detail	Value / cost rationale
H1	SGA	Increased alignment of SGA and embedded network guidelines. • There currently exists (some) ambiguity between the SGA documentation developed by AEMO and the embedded network guidelines developed and maintained by the AER. • These should be aligned to remove perceived ambiguity and be clear and explicit on what is / is not allowed by an SGA within an embedded network. • This could alternatively be addressed by a joint fact sheet developed and disseminated by the AER and AEMO.	**Value** Medium value relative to other reform options. Whilst large and growing, embedded networks and SGA only represent a proportion of the overall market. **Complexity** Medium complexity as it requires collaboration and work between two market bodies.
H2	WDRM and RERT	There should be increased alignment (where practical) between WDRM and RERT, examples include: • Consistent baselining methodologies and aggregation models noting that	**Value** Medium value relative to other reform options as harmonisation of RERT and WDRM will increase some

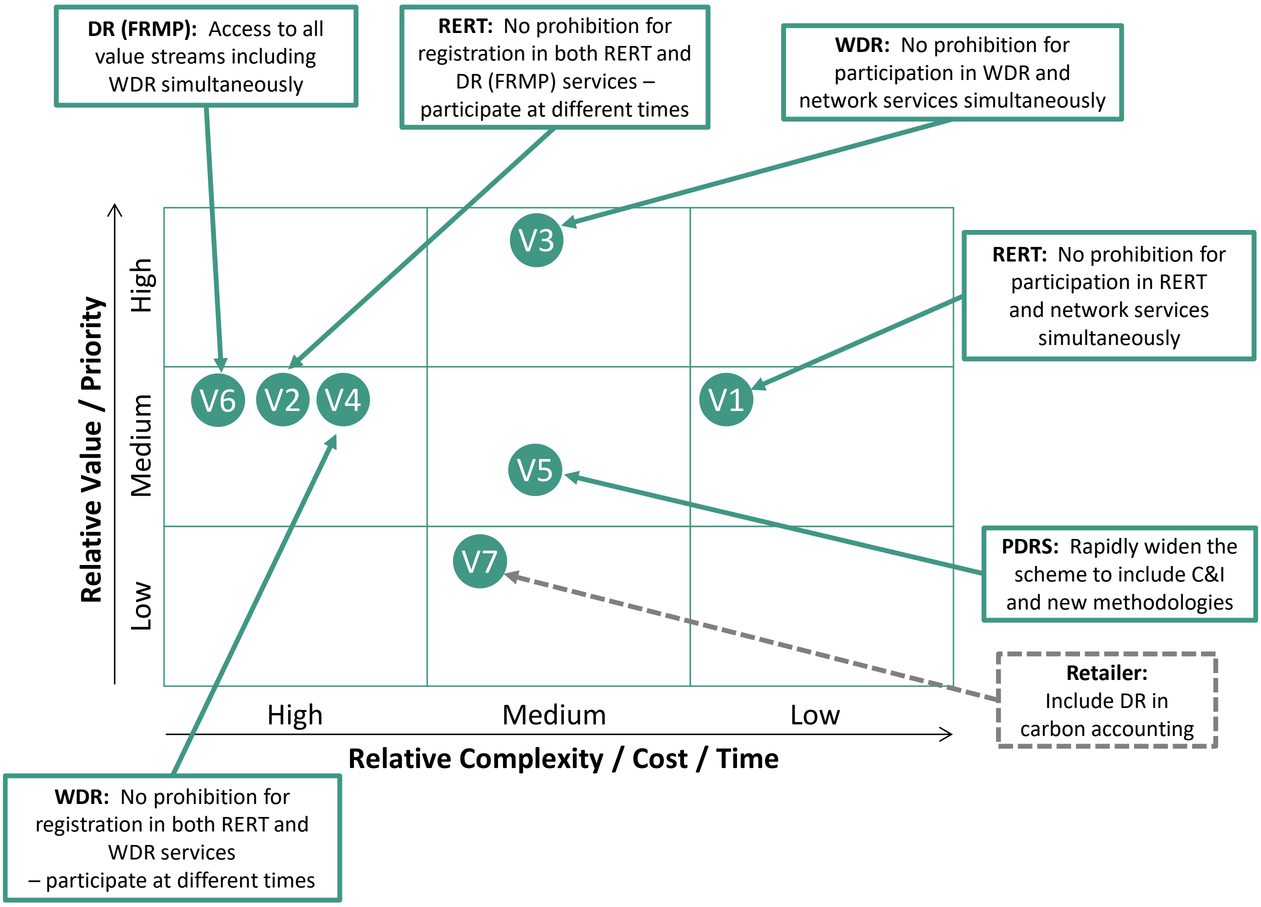
Ref#	Relevant scheme(s)	Further detail	Value / cost rationale
		each scheme requires a different cost recovery approach. • A consistent and single registration model for both – currently participants in both schemes must (at times) provide duplicate information to AEMO. • If a deeming approach is seen as appropriate (refer Section 7.4, reform option R2) any post response compliance program should be identical.	participation but not as much as other reform options. **Complexity** Medium complexity as the schemes are complex, however since both schemes are managed by AEMO there are available efficiencies in harmonization.
H3	PDRS	Where practical PDRS should seek to align to the national schemes, including: • Using the same methodologies for baselining, aggregation and if relevant deeming. • Developing similar information requirements for registration and accreditation.	**Value** Low value relative to other reform options as PDRS is a state based scheme and harmonisation will only marginally increase participation. **Complexity** Medium complexity as PDRS has recently commenced and it may take some additional time before changes are made to align with other schemes.
H4	Network services	Networks should be required to develop clear, and where possible standardised services, including items such as: • terminology • key commercial terms for service provision across networks • network processes for tendering and awarding network services • format of information on services required (Refer Section 7.2 Education and Awareness reform E2) • deeming approach if required and where possible (refer Section 7.4, reform option R2) • baselining methodologies consistent with WDRM and RERT • aggregation models for C&I consistent with WDRM and RERT We note that Project Edge (refer Section 4) is seeking to develop an exchange-based approach to the provision of network services. This could be complementary to, and work in parallel with, a bilateral approach to the provision of network services where some but not complete standardisation is required.	**Value** High value relative to other reform options as there has and will continue to be significant value in the increased provision of network services as an alternative to network augmentation. This has been evidenced in many studies and discussed previously in this report (Sections 2.3 and 4). **Complexity** High complexity as it requires the collaboration and consensus across multiple networks.

Ref#	Relevant scheme(s)	Further detail	Value / cost rationale
H5	Demand response as a retailer	• This would involve a requirement for retailers to develop and utilise consistent terminology and technology standards for the provision of flexible demand directly to customers as the Financially Responsible Market Participant (FRMP). • Recognising that this is a competitive market and service, only some degree of standardisation is warranted and required. • For example, we note that unlike H4 above, this does NOT include standardisation of contractual terms or similar commercial matters.	**Value** Medium value relative to other reform options as, whilst a significant proportion of the flexible demand market is provided directly between retailers and customers, the development of consistent terminology and standards will only provide some growth and efficiencies in the market. **Complexity** Medium complexity as whilst not a large volume of material to harmonise it requires the collaboration and consensus across multiple retailers and aggregators.
H6	Network services	• This involves the development of consistent aggregation models for use in the provision of network services. • This could be viewed as a first step towards the achievement of H4 above. • This will address a current barrier in the practicalities and cost of using smaller sites in aggregate for the provision of network services. There are high transaction costs and lead times associated with this that can be reduced through standardisation.	**Value** High value relative to other reform options given the continued need for and high value of network services to avoid potential augmentation. **Complexity** Medium complexity as whilst it involves collaboration across multiple networks and with multiple aggregators / service providers it is only on a specific and focused matter.
H7	Network services	• This involves the alignment of flexible demand related data capture and management through the development of a consistent and universal DER management system. • This would address the complexity associated with inconsistencies in the approaches and systems used by each network which adds costs and time to all flexible demand participants.	**Value** High value relative to other reform options given the continued need for and high value of network services to avoid potential augmentation. **Complexity** High complexity given the scale and complexity of the systems development required and the need for collaboration across multiple networks.

7.4 Value stack maximisation reforms

Our analysis identified seven potential value stack maximisation related reforms, highlighted in Figure 7.3, one of which was identified as part of the stakeholder consultation process. Table 7.2 provides further detail on each reform option.

Figure 7.3: Potential reforms – Value Stack Maximisation



Note: The potential reforms with the grey dashed boxes were identified during the stakeholder consultation

Table 7.2: Potential value stack maximisation related reforms – further detail

Ref#	Relevant scheme(s)	Further detail	Value / cost rationale
V1	RERT	• This reform is seeking to explicitly allow customers to be registered and contracted for RERT and network services simultaneously. • This is on the basis that each service is providing a specific value for a specific outcome – in one case for the market (RERT) and the other case for a network - and that both services need to be firm. • Whilst there is no explicit prohibition for the	**Value** Medium value relative to other reform options given the limited size of RERT relative to other schemes. **Complexity** Low given there is no current prohibition and that the AER and AEMO have recently

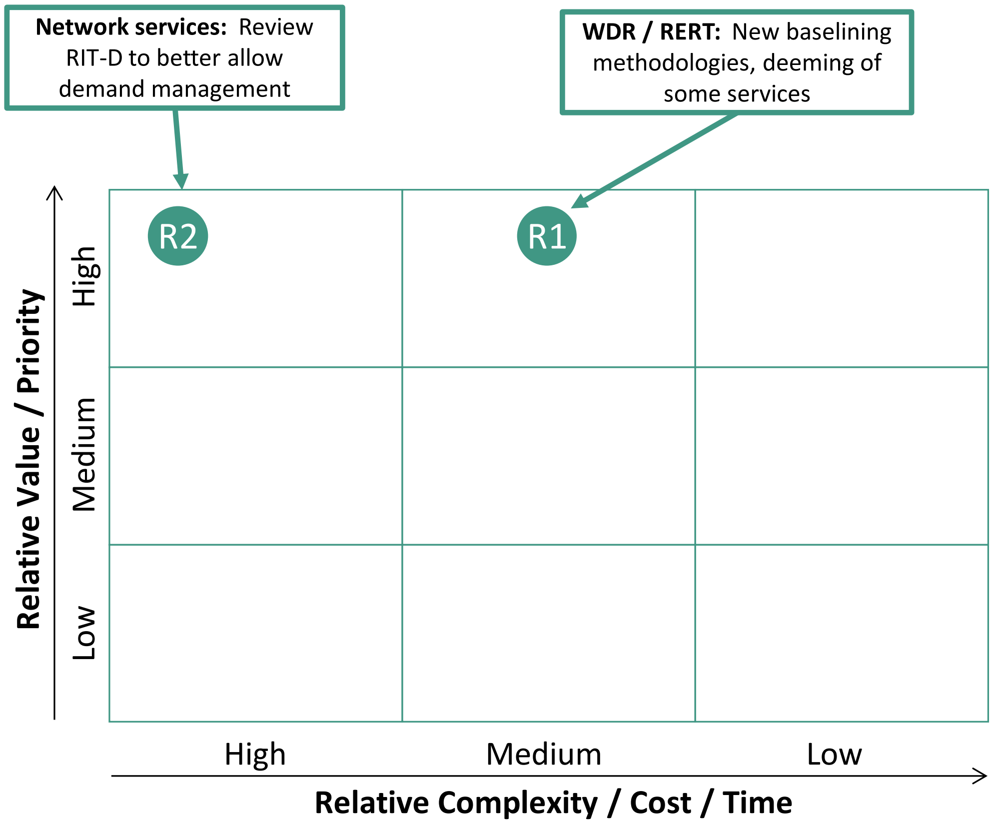
Ref#	Relevant scheme(s)	Further detail	Value / cost rationale
		contracting and provision of these services simultaneously there is some confusion and hesitation by some parties including concerns about potential 'double dipping'. • V1 is complementary and related to reform option V3 below.	approved that networks are able to contract for the provision of RERT services directly.
V2	RERT	• This reform is seeking to explicitly allow customers to be registered and contracted for RERT and flexible demand services with an FRMP simultaneously. • This is on a clear basis that the services must not be provided at the same times. This is expressly prohibited and would cause increased costs to participants and customers. • V2 is complementary and related to reform option V4 below.	**Value** Medium value relative to other reform options given the limited size of RERT relative to other schemes. **Complexity** High given the need to ensure the service is not provided at the same time, and to avoid mixed signals and incentives for participants to double dip and / or increase costs through deliberate withholding of capacity from the market to receive RERT payments at higher prices.
V3	WDRM	• This reform is seeking to explicitly allow customers to be registered and contracted for network services and WDRM simultaneously. • This is on the basis that each service is providing a specific value for a specific outcome – in one case for the market (WDRM) and the other case for a network. • Whilst there is no explicit prohibition for the contracting and provision of these services simultaneously there is some confusion and hesitation by some parties including concerns about potential 'double dipping'. • V3 is complementary and related to reform option V1 above.	**Value** High value relative to other reform options given the scale and opportunity of network services size and the growth potential for WDRM. **Complexity** Medium complexity given whilst there is no current prohibition there are some concerns over double dipping and incentives / costs that would need to be further considered.
V4	WDRM	• This reform is seeking to explicitly allow customers to be registered and contracted for RERT and WDRM simultaneously. • It is conditional on the service being provided at different times including the need for a post process compliance review. • The provision of both on market and off market services simultaneously is expressly prohibited and would cause increased costs to participants and customers. • V4 is complementary and related to reform option V2 above.	**Value** Medium value relative to other reform options given the limited size of RERT relative to other schemes. **Complexity** High complexity given the need to ensure the service is not provided at the same time, and to avoid mixed signals an incentives for participants to double dip and / or increase

Ref#	Relevant scheme(s)	Further detail	Value / cost rationale
			costs through deliberate withholding of capacity from the market to receive RERT payments at higher prices.
V5	PDRS	• As noted in Section 2.3.3 the PDRS has only recently been implemented and is intended to grow over the coming years. • The scheme design initially is limited and does not have any C&I related participation as the current approved methodologies are for residential and small business customers. • This reform involves speeding up the process for broadening access to the scheme, for example, developing C&I related processes, a load shifting methodology etc. • This will increase the growth of the scheme and participation potential. • We note there is a public consultation scheduled for mid 2023 for additional methodologies. There may be an opportunity to consider these changes during this review.	**Value** Medium value relative to other reform options given the limited size of PDRS as a state based scheme with existing targets. **Complexity** Medium as the scheme has only recently commenced and therefore it may take some additional time before changes are made to allow it to broaden.
V6	Retailer directly provided flexible demand	• This reform involves ensuring that an FRMP / aggregator can access all value streams including WDRM, RERT, Network Services and PDRS. • Currently an FRMP provides flexible demand directly as opposed to via WDRM. However, some parties may (for some specific reason) wish to participate in WDRM instead of direct provision of flexible demand.	**Value** Medium value relative to other reform options given the limited number of FRMPs likely to be seeking to participate via WDRM. **Complexity** High given the need to assess the approach to enable FRMPs to participate in WDRM.
V7	All schemes	• This reform involves ensuring that flexible demand and participation in the relevant flexible demand schemes is also able to simultaneously receive the appropriate value from recognising its emissions reduction benefits through demand reduction lowering emissions intensity. • This requires the inclusion of flexible demand activities in the relevant carbon accounting methodologies.	**Value** Low value relative to other reform options given the second order nature of the emissions reduction activities of flexible demand. **Complexity** Medium complexity given the reform involved developing and agreeing carbon reduction methodologies not only nationally but internationally.

7.5 Risk, accuracy and simplicity related reforms

Our analysis identified two potential risk, accuracy and simplicity trade off related reforms, these are highlighted in Figure 7.4.

Figure 7.4: Potential reforms – Risk / Accuracy / Simplicity Trade-off



R1: Develop new baselining methodologies for WDRM and RERT

This reform involves the development of new baselining methodologies within WDRM and RERT and the investigation and potential introduction of deeming methodologies for specific activities if viewed as appropriate. In particular, temperature sensitive loads and potentially volatile loads such as battery or electric vehicle based loads could and should be able to have baselines and / or deeming methodologies developed.

This reform reflects the need for the market to accept that some inaccuracies with new baselines will exist and facilitating future market growth for the net benefit of consumers will require an adoption of a better balance between risk, accuracy and simplicity.

For WDRM, AEMO has currently approved four baseline methodologies that are all based on the CAISO “10 of 10” framework and differentiated by day type. None of the baselines are relevant for volatile or temperature sensitive loads. RERT similarly only allows a small number of baselining methodologies equally based on the CAISO “10 of 10” framework, although AEMO has indicated it will amend the baseline methodology for voltage control based RERT providers[21].

Deeming is not currently an approved approach within RERT or WDRM.

This reform has been assessed as high value given the growth potential for new loads and technology types to participate in WDRM and RERT, in particular temperature sensitive loads, electric vehicle loads and batteries.

The complexity has also been assessed as medium reflecting the need to develop and assess new baselines and potentially deeming. However, the current scheme designs envisage and allow new baselining methodologies to be developed and procedures and approaches to assess and approve new methodologies already exist.

R1: Review the RIT-D to better enable flexible demand / demand management for network services

This reform involves the review of the RIT-D guidelines to ensure they are fit for purpose in relation to the provision of flexible demand as a non-network option.

As discussed in Section 2.3.3 the RIT-D requires networks to investigate non-network options alongside network options for any investment in excess of $6 million.

There have been limited examples of non-network options including flexible demand successfully being identified as the preferred option under a RIT-D. There have been numerous prior reviews and amendments to the RIT-D, however none to our knowledge have explicitly focused on amendments to better enable flexible demand.

This reform has been assessed as high value given the significant value potential for network services and the need for significant network augmentation in the coming years.

The complexity has also been assessed as high given the history of repeated reviews of RIT-D and the need for multiple networks to be involved in any consultation and change process.

7.6 Potential new services

Our analysis identified four 'new' network services and two new market services that flexible demand could provide, these are highlighted in Figure 7.5 and further discussed in Table 7.3.

The increased penetration of CER has impacted, and will continue to impact, the efficient operation of networks e.g., voltage instability, negative flows and increased need for network augmentation.

Flexible demand can assist with addressing key underlying issues such as:

- managing voltage within defined parameters
- rectifying a network abnormality

[21] https://www.aer.gov.au/system/files/Letter%20from%20AEMO%20dated%2024%20November%202022_Redacted.pdf

- preventing the network from exceeding its firm capacity.

The proposed new services involve developing and agreeing a set of terms and conditions for the provision of each service, noting that some degree of standardisation is beneficial. Given the services are not designed to be operated on an exchange it is not necessary for complete standardisation.

The development of the terms and conditions of the service will likely need to consider the requirements of the network services harmonisation reform (H6) in Section 7.3.

As discussed in Section 4, Project Edge is currently investigating and trialling the development of a local exchange to facilitate the growth and development of network services. Many of the network services being trialled could be complementary to, and work in parallel with, a bilateral approach to the provision of network services where less standardisation is required.

During the consultation phase of this project we separately identified 'ahead services' as a specific new service where customers offer confirmed flexible demand at some agreed period ahead, e.g. a day ahead, 6 hours ahead or an hour ahead etc. In this report we have removed this as a new service appreciating that this is a characteristic of all network services, with a degree of firmness and a notice period for provision of the service ahead of time.

Figure 7.5: Potential new market or network services

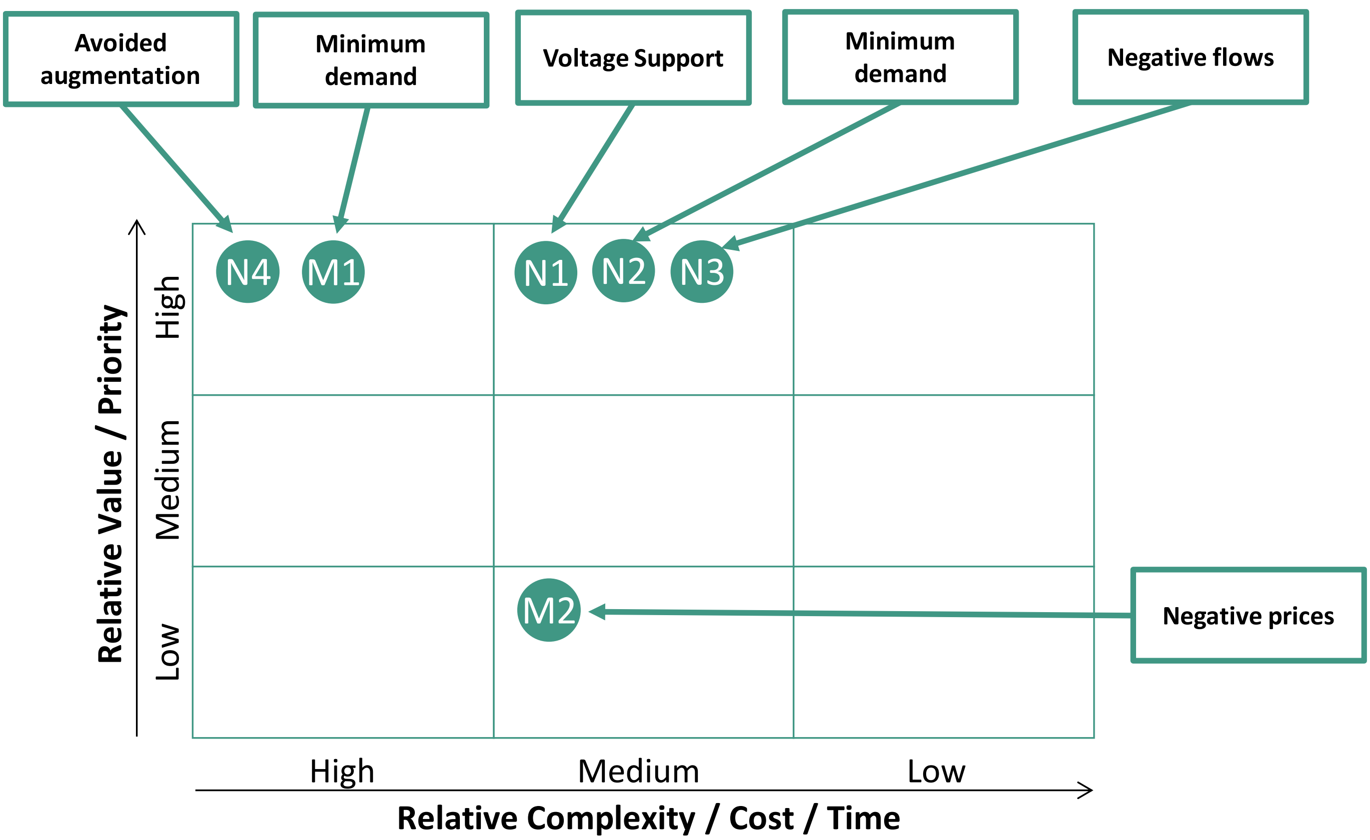


Table 7.3: Potential new services - further detail

Ref#	Market or network service	Further detail	Value / cost rationale
N1	Network	• This would involve the development of a specific service to address voltage management related network issues. • The specific contract terms and service requirements would be agreed and developed between the parties.	**Value** High value given the scale and opportunity for network services to assist in avoiding network augmentation. **Complexity** Medium complexity given the need to agree and develop specific contract terms and conditions. This can leverage the work from Project Edge as well as previous albeit limited network support contracts for similar services.
N2	Network	• Involves the development of a specific service to address minimum demand related issues such as a turn up or load shifting service. • The specific contract terms and service requirements would be agreed and developed between the parties.	Refer above as the rationale for N2 is consistent with N1.
N3	Network	• Involves the development of a specific service to address negative flow related issues such as a turn up or load shifting service. • The specific contract terms and service requirements would be agreed and developed between the parties.	Refer above as the rationale for N3 is consistent with N1.
N4	Network	• Involves the development of a broader service to address avoided augmentation, it would need to align with any RIT-D changes or review (refer Section 7.5 reform R2). • It would consider including reduced replacement expenditure as well as capital expenditure to ensure improved network utilisation and further growth of electricity within the existing network infrastructure is best enabled.	**Value** High value given the scale and opportunity for network services to assist in avoiding network augmentation. **Complexity** High complexity given the similarity to the amendment of the RIT-D and the need to agree how to address significant issues and changes with the AER and multiple networks.
M1	Market	• Involves the amendment of WDRM or the development of a new market service to address minimum demands. • This could include a turn up service or a	**Value** High value given the scale and growing market wide issue of minimum demand.

Ref#	Market or network service	Further detail	Value / cost rationale
		load shifting service. • However, some stakeholders queried if negative prices in the spot market were already sufficient to send a signal to address minimum demand.	**Complexity** High complexity given the need to either develop a new service or substantially amend the WRDM to allow for turn up and load shifting services.
M2	Market	• Involves the amendment of WDRM or the development of a new market service to address negative prices demands. • However, many stakeholders queried if negative prices are an issue for flexible demand to resolve and / or if the existing market price signals are sufficient to resolve any negative price issues.	**Value** Low value given the questionable need for new market service to address this issue. **Complexity** Medium complexity given the need to amend the WDRM or develop a new market service.

8 Recommended reforms and new services

This section details the priority reforms and new services which, based on our assessments in Section 7, we have recommended for trial in Stage Two of the Smart Energy Hubs Project and the justification for our recommendations. Prioritisation of reforms and services was primarily based on their relative value and complexity. We also considered alignment with longer term reforms and the ability for Shell to trial the reform or new service during Stage Two of the project.

The recommended priority reforms and new services, and the rationale to support the priorisation, were sense checked with stakeholders during Round Three consultation. There was a good level of agreement that, based on our criteria, the recommendations were reasonable.

In this section we:

- explain why education and awareness reforms are not taken forward to Stage two (Section 8.1)
- identify the priority reforms and summarise their value and cost/complexity assessment (Section 8.2)
- provide further detail on each reform and implementation considerations (Section 8.3)
- discuss the alignment of each reform with longer term reforms (Section 8.3.1)
- identify the priority new services and summarise the value and cost/complexity assessment (Section 8.4)
- provide further detail on each new service and implementation considerations (Section 8.5)
- discuss the alignment of each reform with longer term reforms (Section 8.5.1).

8.1 Education and awareness is an industry priority

Education and awareness reforms were considered 'no regrets' with high value and low to medium complexity. However, they are not something that can be practically pursued by Shell during Stage Two of the Smart Energy Hubs Project trials. These reforms are best progressed outside of the Smart Energy Hubs Project by appropriate stakeholders.

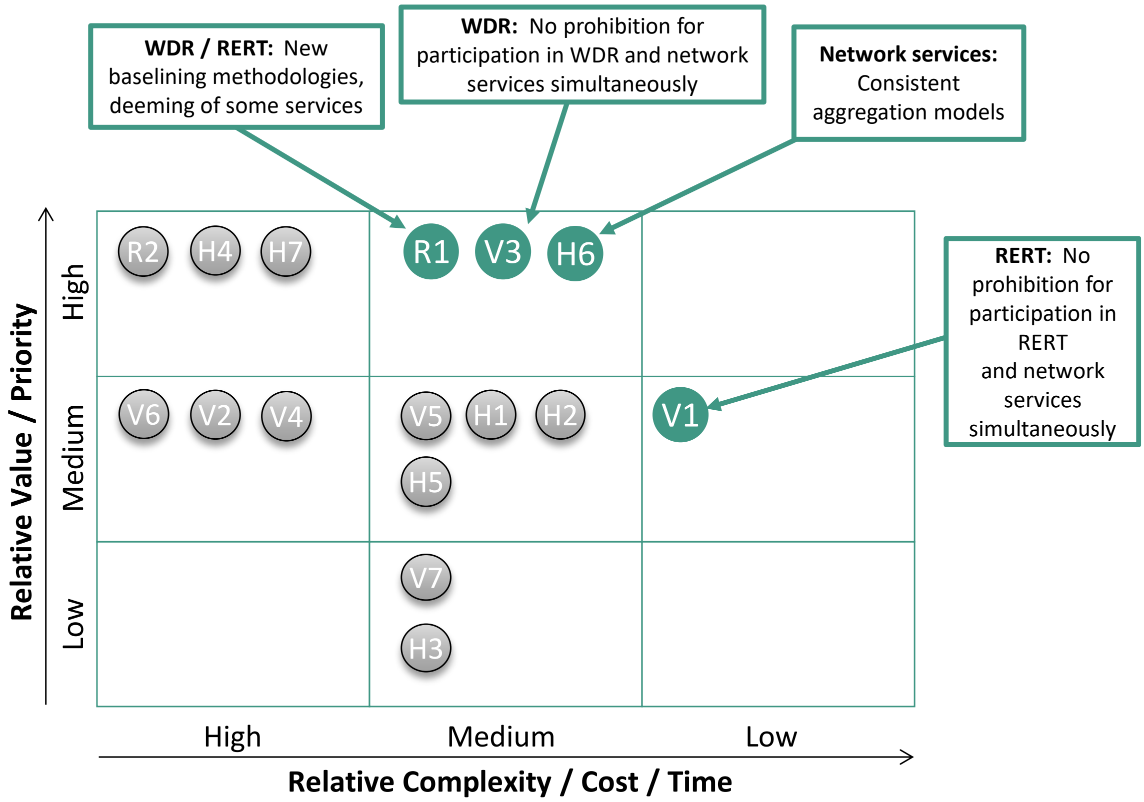
We recommend that market bodies, i.e., AEMC, AEMO and AER and jurisdictional governments come together and explore the best way in which information can be documented and disseminated so that they reach the target consumer audience in a format that can be understood and increases participation. We believe that to get the right level of information to the right people a level of centralised planning and co-ordination is needed. In addition, mandatory requirements may be needed in some cases (refer Section 7.2).

The education and awareness reforms are therefore not considered further in this report nor in Stage Two of the Smart Energy Hubs Project.

8.2 Priority reforms

All the reforms detailed in Section 7.3 to Section 7.5 have been collated into the matrix illustrated in Figure 8.1 and the top four have been identified. Although only three reforms were to be recommended, we consider two of them (V1 and V3) to be sufficiently related to be regarded as a single reform.

Figure 8.1: Priority reforms assessment



The rationale for the prioritisation of each reform is as follows:

R1. New baseline methodologies and deeming

The value of this reform was based on the opportunity for significant growth in WDRM, opening it up to new C&I customer segments, and some growth in RERT. This would result in additional scale and liquidity to reduce costs for all consumers.

New baselines do not require a rule change and in that regard the medium complexity and cost is attributed to the documentation update and systems implementation of the reform. Deeming would require a rule change, but more pressing is the need for a cultural shift as the conservatism towards deeming was evident during stakeholder consultation.

H6. Consistent aggregation models for network services

The value is associated with improved efficiencies in dealing with smaller sites and loads resulting in cost savings for customers, networks and aggregators along with the potential for new customer segment participation.

The cost and complexity reflects the need for collaboration and consensus building across multiple parties, i.e., networks and aggregators.

V3. No prohibition to take part in WDRM and network services simultaneously

The value of this reform is based on the opportunity to access additional value streams and the potential to encourage new customer segment participation. This would result in additional scale and liquidity to reduce costs for all consumers.

The cost and complexity is medium as there is no regulatory or rule change required but a cultural change and shift in mindset is needed.

V1. No prohibition to take part in RERT and network services simultaneously

The rationale for prioritisation here is the same as that for V3.

8.3 Priority reforms – further detail

The following Tables (Table 8.8 to Table 8.6) provide a further narrative on each of the recommended reforms and the implementation considerations assuming a successful trial in Stage Two.

The 'reform further detail' tables describe the required changes and areas for consideration to meet the recommended reform objectives, the anticipated result of the reform that drives the value assessment, and detail of factors that influenced the cost/complexity assessment. The evaluation for this report was necessarily quantitative at this stage based on publicly available data for the current and potential value of flexible demand presented in Section 2.3.2. It is anticipated that during the SEH trial the required data should be accumulated to inform relevant businesses who may wish to undertake a cost benefit analysis (if required) to support any subsequent implementation work.

The 'implementation considerations' tables describe factors to be considered for implementation of each reform post the SEH trials should these prove to have merit. They include the approach to implementation, the decision makers and stakeholders who can drive implementation, the associated risks, barriers and dependencies to be managed during implementation and the likely implementation timeframes.

Table 8.1 Reform Further Detail - New baselining methodologies, deeming of some services in WDRM and RERT (R1)

Reform Further Detail	Value Drivers	Cost / Complexity Drivers
• This would involve extending both the WDRM and RERT schemes to offer new baselines for some types of DR. This includes temperature sensitive loads or loads that are more volatile such as EVs or batteries that do not currently qualify or suit the '10 of 10' rule. • The focus should be on ensuring no material systemic bias as opposed to inaccuracies. For the market to develop there is a need to accept some inaccuracies will exist and achieve a better balance between risk / accuracy/ simplicity. • There should be consideration of the appropriateness of deeming for some services where the practicalities and accuracy of a baseline may not be suitable or obtainable. This could include highly volatile loads such as batteries, where the level of demand response can be validated not by revenue or market facing metering or baselines but rather by confirming the technology has been varied to create the step change in usage (turned on / off) at the appropriate times.	• Increased opportunities for new customer segments and technologies to participate in WDRM / RERT • Enable new participants to access additional value streams and increase liquidity and market size to reduce costs for all consumers.	• Capital and implementation costs of relevant technologies at customer's sites. • Customer acquisition costs for the aggregator / retailer. • Nature, number and complexity of potential new baselining methodologies. • Evaluation and acceptance of new baselining methodologies. • Market system related IT costs and delivery. • The level of risk aversion and hesitation by stakeholders to investigate and potentially adopt deeming as an approach.

Table 8.2 Implementation Considerations - New baselining methodologies, deeming of some services in WDRM and RERT (R1)

Approach to implement	Decision Makers/ Key Stakeholders	Risks (post implementation)	Barriers	Timeframes	Key Dependencies
Baselining • This is largely within AEMO's domain to manage and control the process. • There is no rule change required to develop new baselines. • Follow AEMO's documented process for developing / adopting new baselines and methodology metrics. • There may be a potential new IT build required depending on the nature of the new baseline. **Deeming** • Rule change is likely required to allow WDRM to use a deemed approach - this may be suitable for a sandboxing trial as a possible option prior to full implementation. • Rule change may not be required to allow RERT to use a deemed approach. • Follow AEMO's documented process for developing / adopting new baselines and methodology metrics. • New IT build is most likely required depending on the nature of the deeming.	• AEMO • AEMC	• Limited or no customer uptake on the new baselining / deeming methodologies. • Unexpected systemic bias in the deeming / baselining outcomes.	• Cultural and risk aversion to accepting inaccuracies in the provision of flexible demand / demand response.	• Baselines likely to take less than 6 months if appropriate resources are available and no material IT build is required. • Deeming likely to take 18+ months to allow for rule change and AEMO implementation.	• None identified

Table 8.3 Reform Further Detail –consistent aggregation models for network services (H6)

Reform Further Detail	Value Drivers	Cost / Complexity Drivers
• This could be a key stepping stone towards the larger opportunity identified of harmonising network services more broadly (H4). • This reform would involve focusing on aggregation models specifically to allow multiple sites to meet a single service requirement. • This includes developing a consistent (where practical and possible) set of terminologies, service definitions, commercial terms and conditions and processes for awarding and tendering services specifically in relation to aggregation models. • We note that Project Edge is looking at developing an exchange based solution for aggregation, this reform is complementary to any exchange based solution and reflects the reality that many situations and parties may prefer to interact bilaterally rather than via an exchange. • Also note, where practical / possible the aggregation models developed in this reform should be consistent with those used in WDRM and RERT.	• Provides efficiency in dealing with smaller sites and loads that can more readily participate via an aggregation model. • This results in transaction cost savings for networks and customers / aggregators. • Increases opportunities for new customer segments to provide network services. • This should enable these new participants to access additional value streams and increase liquidity and market participation that should reduce costs for all consumers.	• Nature and complexity of aggregation models and approach to developing consistency. • Requirement for multiple networks to collaborate and reach consensus with multiple aggregators.

Table 8.4 Implementation Considerations - consistent aggregation models for network services (H6)

Approach to implement	Decision Makers/ Key Stakeholders	Risks (post implementation)	Barriers	Timeframes	Key Dependencies
• Establish an ongoing network working group including the ENA to take carriage of the longer term implementation. • Develop a similar working group of aggregators / service providers. • Understand the learnings from the trial and the issues / improvement opportunities. • Collaboratively work towards developing a consistent (where practical and possible) set of terminologies, service definitions, commercial terms and conditions and processes for awarding and tendering services specifically in relation to aggregation models. • Publicise and make sure other parties including customers, regulators and governments are aware of the new aggregation models and how to participate. This aligns with our general finding of the need to improve education and awareness.	• Networks and ENA • Aggregator / service providers	• There may be a need for any aggregation model to evolve as the market more broadly develops and / or new technologies and service definitions are created. • Failure to do so may limit the usefulness of any developed models.	• Inability to reach consensus and the natural tendency for businesses to retain independence and control over their approach to service provision.	• Likely to take 12 months to allow for appropriate discussion, collaboration and consensus development.	• The awareness of the need for and opportunities in providing network services more broadly. • If customers and other parties are not aware of where, when and what type of network services may be required then this will limit the value of any consistent aggregation model.

Table 8.5 Reform Further Detail –no prohibition for participation in WDRM (V3) or RERT (V1) and network services simultaneously

Reform Further Detail	Value Drivers	Cost / Complexity Drivers
• The argument for value stack maximisation aligns with the recovery of fixed costs associated with the provision of DR. • Many of the identified value stack maximisation related reforms are inter-related. • In this case these two priority reforms are intended to allow WDRM (or RERT) and network services to be provided simultaneously on the basis that both need the service to be firm. • We understand that some organisations are already able to simultaneously provide either WDRM and network services or RERT and network services however this is not universally adopted or understood by all participants. • This reform focuses on ensuring there is no prohibition for participation in the relevant schemes simultaneously and that this is clearly communicated to all parties and the starting point for any contractual documentation and / or scheme registration.	• Enables participants to access additional value streams and increase liquidity and market participation that should reduce costs for all consumers. • Increases opportunities for new customer segments to provide these services.	• The level of risk aversion and hesitation by some stakeholders to allow simultaneous participation. This is on the basis that some parties believe that the services are identical and customers should not be paid twice for providing the same service and.reduce costs for all consumers.

Table 8.6 Implementation Considerations - no prohibition for participation in WDRM (V3) or RERT (V1) and network services simultaneously

Approach to implement	Decision Makers/ Key Stakeholders	Risks (post implementation)	Barriers	Timeframes	Key Dependencies
• Develop WDRM / RERT materials and the RERT contract that state there is no prohibition in participating in these schemes whilst offering network services simultaneously. • Develop network services related materials and contractual documentation that state there is no prohibition in participating in WDRM and RERT whilst offering network services simultaneously. • Publicise and make sure other parties including customers, regulators and governments are aware of the position and that no prohibition exists.	• Networks and ENA • AEMO	• That WDRM or RERT and network services are not able to be fully met simultaneously and one or more of the service outcomes is not delivered.	• A belief that the services are identical (or close to) and that this is in effect 'double dipping' by customers. • A belief that the services are not able to be provided simultaneously and that one or more of the service outcomes may not be delivered.	• Likely to take 3 - 6 months to allow for appropriate development and publication of materials.	• None identified

8.3.1 Alignment with longer term market reforms

As part of our prioritisation process we have considered the longer term reforms to ensure that the recommendations are aligned. A high-level assessment based on the intent and nature of each of the reforms was undertaken.

All of the recommendations are considered to align with the long term reform program. For example:

- the development of a consistent aggregation model would be complementary to any large scale network services exchange. In addition, this would also assist with the development of a broader flexible demand market.
- value stacking or participation in multiple schemes simultaneously is aligned with the development of a fully functioning two sided market.
- extending the number of baselining methodologies and increasing uptake of WDRM / RERT will assist with the longer term success of reforms like flexible trading arrangements.

Table 8.7 identifies how longer term reforms are linked or align with our priority reform recommendation. Network tariff reform and DOEs have the potential to increase the capacity and value of participating in the WDRM and RERT however they are not included in the table as we have not identified an overlap between these longer term reforms and the priority reform recommendations that we have made.

Table 8.7: Alignment of reform recommendations with longer term market reforms

Reform option	Scheduled Lite	Flexible Trading Arrangements	Minimum operational demand
R1	As scheduled lite evolves it has the potential to capture fluctuations in energy against predictable demand patterns. Baseline and deeming methodologies at single sites and for aggregations could be part of this solution where the difference to a baseline behaviour is provided.	FTA has the potential to, and should consider, increase eligibility for WDRM participation if behind the meter devices can participate directly. Additional baselines and deeming approaches have the potential to assist in growing participation in WDRM through the FTA reform.	If future reform for operational demand includes export reduction, demand increase or shifting then additional baselines or deeming has the potential to increase eligibility and participation.
H6	Consistent aggregation models in each network will assist in the understanding and appropriate use of data from an aggregation used to manage demand forecasts.	Consistent aggregation models will assist if network services extend to behind the meter devices that will be measured through FTA. Aggregations of behind the meter devices should be considered for current network services and FTA.	Consistent aggregation models will assist AEMO and networks in developing mechanisms for managing and directing additional demand on as required to alleviate minimum operational demand issues.
V3 / V1	Providing greater value	FTA has the potential for	Whilst longer term reforms,

Reform option	Scheduled Lite	Flexible Trading Arrangements	Minimum operational demand
	for flexible demand in RERT and WDRM will likely increase participation and hence provide greater visibility to AEMO which is fully aligned with the intent of the Scheduled Lite reform	additional flexible demand to be eligible to participate in WDRM and RERT through energy from behind the meter devices. Increased participation in these schemes aligns with the intent of V1 and V3.	additional to mechanisms that involve solar PV curtailment, to manage operational demand are under development increased participation in flexible demand aligns with a requirement to change demand profiles.

Capacity Investment Scheme

The Commonwealth Government's Capacity Investment Scheme (CIS) proposal was endorsed by State and Territory Energy Ministers in December 2022. Given the timing this reform has not been considered in our assessment or consultation rounds. However, with a first auction scheduled later in 2023, we believe that it has the potential to significantly impact the growth of flexible demand and merits noting in this report.

The stated aim of the CIS is to provide a national framework that drives new renewable dispatchable capacity and ensure reliability. Public information on the scheme is limited however the wording to date e.g., 'This new revenue underwriting mechanism will unlock $10 billion of investment in clean dispatchable power' indicates that it is targeted towards generation.

If flexible demand is not on a level playing field with generation and storage technologies, or it is not eligible for this type of underwriting scheme, it has the potential to economically disadvantage demand response in favour of new generation and detrimentally impact the business case for flexible demand, stymying its growth in the market.

For further information see: https://www.energy.gov.au/news-media/news/capacity-investment-scheme-power-australian-energy-market-transformation

NSW Firming Long Term Energy Service Agreements (LTESA)

The inclusion of firming infrastructure in the NSW Government's Q2 2023 LTESA tender process administered by AEMO Services was announced in November 2022. Given the timing this has not been considered in our assessment or consultation rounds.

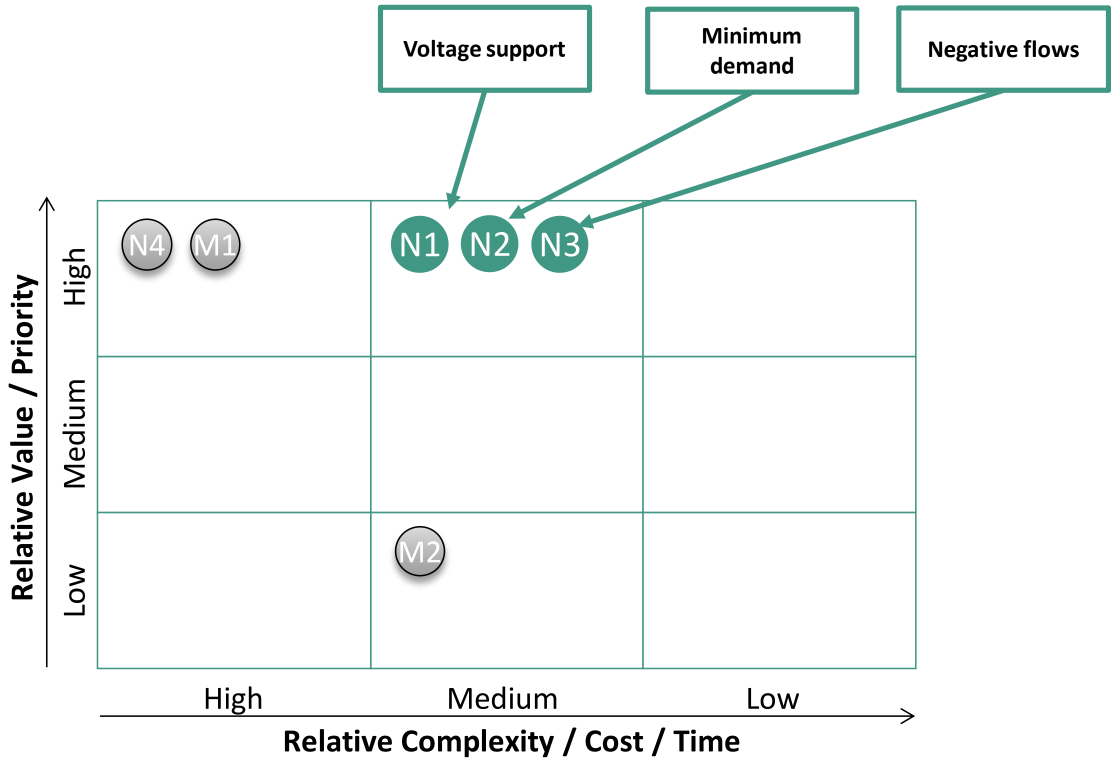
We note that the draft term sheets for participation of demand response in this scheme requires demand response to be scheduled and provided through the WDRM. The requirement for eligibility to be scheduled by AEMO is established in the relevant legislation. This type of restriction has the potential to significantly stymie the potential growth of flexible demand in the NEM through an approach that chooses to require flexible demand to behave like generation. An alternative that would not adversely impact the development of a flexible demand market would be for the capability to be provided via flexible demand and SGA.

For further information see: https://aemoservices.com.au/tenders/firming

8.4 Priority new services

The new services detailed in Section 7.3 are represented in Figure 8.1 and the top three have been identified.

Figure 8.2: Priority new services assessment



The rationale for the prioritisation of each new service is as follows:

N1: Voltage support

The value is high as voltage related issues are materially increasing with continued roll out of non smart inverter based technologies. Improved voltage management via flexible demand will enable better utilisation of the network, increase its capacity thereby deferring or avoiding additional network augmentation costs. It will also enable the installation of greater volumes of new customer energy resources.

The cost and complexity is medium as it is necessary to develop and agree the service specifications and associated terms / conditions between the network and service provider. In this regard, we note Project Edge is developing similar services for transacting via an exchange which could provide a reasonable basis for a first draft for discussion between the parties.

The cost / complexity may also need to identify approaches to ensure the service is innovative and novel to meet the AER's Demand Management Innovation Allowance (DMIA) scheme funding requirements.

N2: Minimum Demand

The value is high with the increased penetration of rooftop solar PV increasing the occurrence of low and at times even negative demand with associated issues in localised areas of networks. Improved demand management will enable better utilisation of the existing network thereby deferring or avoiding additional network augmentation costs. It will also enable the installation of greater volumes of new customer energy resources.

The cost and complexity is medium for the same reasons provided for N1 voltage support.

N3: Negative Flows

The value is high for the same reasons as N2 Minimum Demand. This is an extreme localised case of minimum demand where the flow of energy in the local area is negative. Local feeders / sub stations were not designed to work with negative flows which can cause significant quality of supply issues.

The cost and complexity is medium for the same reasons provided for N1 voltage support.

8.5 Priority new services – further details

The assessment of the recommended voltage support, minimum demand and negative flow network services has led to the identification of significant commonality in how the services can be established. As such, these three services are combined in the rest of this section to avoid repetition. The following Tables (Table 8.8 and Table 8.6) provide a further narrative on the recommended new services and the implementation considerations assuming a successful trial in Stage Two.

Table 8.8, 'new services further detail', describes the required changes and areas for consideration to establish and meet the objectives of the new service, the anticipated benefit of the services that drives the value assessment, and detail of factors that influenced the cost/complexity assessment. The evaluation we completed for this report is necessarily quantitative at this stage based on publicly available data for the current and potential value of flexible demand presented in Section 2.3.2. It is anticipated that during the SEH trial the required data should be accumulated to inform individual network businesses to complete a cost benefit analysis (if required) to support any subsequent implementation work.

Table 8.9, 'implementation considerations', describes factors to be considered for implementation of the new services post the SEH trials should these prove to have merit. They include the approach to implementation, the decision makers and stakeholders who can drive implementation, the associated risks, barriers and dependencies to be managed during implementation and the likely implementation timeframes.

Table 8.8 New Services Further Detail - Voltage Support (N1), Minimum Demand (N2) and Negative Flows (N3)

New Services Further Detail	Value Drivers	Cost / Complexity Drivers
• The increased penetration of CER has and will continue to impact the efficient operation of networks e.g., voltage instability, negative flows and increased the need for network augmentation. • Flexible demand can assist with addressing key underlying issues such as preventing the network from exceeding its firm capacity, rectifying a network abnormality, or managing voltage within defined parameters. • Examples of such network services would include voltage support and demand management (increase or reduction) services. • Appropriate network services should also support high CER enablement, reduced energy consumption, reduced emissions, and minimal adverse impacts on consumers. Ultimately they should be in the long term interests of consumers. • These three new services involve developing and agreeing a set of terms and conditions for the provision of each service, noting that some degree of standardisation is beneficial. Given that this is not proposed to be operated on an exchange it is not necessary for complete standardisation. • Examples of terms and conditions to be agreed include: degree of firmness (ahead related services), number of activations, duration and notice period, pricing parameters, availability parameters, location, approach to measuring service delivery / performance and volume. • The development of the terms and conditions of the service will likely need to consider the requirements of the priority reform 'consistent aggregation models' (H6). • We note that there are currently projects trialling the development of a local services exchange for the provision of similar services (e.g. Project EDGE). These bilateral services are complementary to that work and may be able to be more rapidly implemented to address more immediate local issues.	• More efficient network utilisation • Avoided network augmentation • Increased CER penetration • Ability to capture new value streams for participants	• Identification and analysis of the requirement for new services. • Developing and agreeing the service specifications and associated terms / conditions between the network and aggregator / service provider. • Agreeing and implementing methodologies to monitor and measure service delivery and performance. • There are unlikely to be material IT related costs.

Table 8.9 Implementation Considerations - - Voltage Support (N1), Minimum Demand (N2) and Negative Flows (N3)

Approach to implement	Decision Makers/ Key Stakeholders	Risks (post implementation)	Barriers	Timeframes	Key Dependencies
• Establish an ongoing network working group including the ENA to take carriage of the implementation. • Develop a similar working group of aggregators / service providers. • Understand the learnings from the trial and the issues / improvement opportunities. • Collaboratively work towards developing a consistent (where practical and possible) set of terminologies, service definitions and commercial terms and conditions. This includes working towards satisfying the AER's requirements for the service to be included in the DMIA. • If required, work with the AER to agree any changes to the DMIA's funding requirements to ensure these new services can receive appropriate DMIA funding if required. • Publicise and make sure other parties including customers, regulators and governments are aware of the new service definitions and how to participate. This aligns with the general finding on the need to improve education and awareness.	• Networks and ENA • Aggregators / service providers • AER	• The new services are unable to address the underlying core issues experienced within networks and a high degree of augmentation is still needed.	• Inability to reach consensus and the natural tendency for businesses to retain independence and control over their approach to service provision. • A perceived cultural perspective of networks preferring to address these operational issues via network solutions.	• Likely to take up to 18 months to allow for appropriate discussion, collaboration and consensus development.	• The awareness of the need for and opportunities in providing network services more broadly. If customers and other parties are not aware of where, when and what type of network services may be required then this will limit the value of any new service definition. • The existence of a simple and consistent aggregation model across networks – as discussed in priority reform H6.

8.5.1 Alignment with longer term reforms

The development of new and consistent defined network services for voltage support, minimum demand and negative flows aligns with the NEM's reform program goal of a fully functioning two-sided market.

The longer term reforms in play for networks include network tariff reform, dynamic operating envelopes and minimum operational demand. These new services have no identified impacts or overlap with reforms such as scheduled lite or FTA.

Network tariff reforms align with new network services in that they allow for the innovative development of tariffs that can be one potential pathway for rewarding providers of these new services.

The application of dynamic operating envelopes should work in tandem with new services with the potential to afford service providers greater flexibility at their connection points to meet the required service need.

Minimum demand and negative flow services should be considered in the development of minimum operational demand reform and vice versa to ensure that network services and market reforms to manage this issue are complementary.

We note that Project Edge is currently trialling an exchange mechanism for network services. The services recommended in this report are bi-lateral in nature i.e., between a provider/aggregator and an electricity network. The recommendations for definition and consistency for the new services is complementary to any large-scale network services exchange and provides an alternative route for service provision.

9 Next steps: Stage Two Smart Energy Hubs

This section outlines high level considerations for Shell Energy as they trial our recommendations in Stage Two of the Smart Energy Hubs Project and potential measures of success we will monitor and report on as the trial progresses.

This section also covers our scope, high level timeline and approach to stakeholder consultation for Stage Two of the Smart Energy Hubs Project.

9.1 Trialling our recommendations

9.1.1 No prohibition in participating in WDRM (V3) or RERT (V1) and network services simultaneously

This trial will almost certainly be financial in nature and involve actual simultaneous participation in WDRM and network services or RERT and network services.

To achieve this would require consideration of:

- Working collaboratively with AEMO and the relevant networks in the trial to ensure participation in the relevant schemes simultaneously occurs.
- Ongoing partnering and involvement with AEMO and the relevant networks to increase the robustness and independence of trial results.
- Confirmation that all relevant services can be fully met simultaneously with no material issues observed including understanding the extent of any 'double dipping' and the impact of this in the form of additional costs to consumers.

Potential success criteria

The following are likely indications that the trial has been (at least partially) successful:

- Positive feedback (qualitative) from Shell Energy on their ability to participate simultaneously in the required schemes.
- Positive feedback (qualitative) and perspectives of AEMO, participating networks and customers – in particular that no material issues were observed.
- Analysis to confirm little to no occurrence of 'double dipping' and / or any material associated costs.

9.1.2 Consistent aggregation models for network services (H6)

This trial will be financial in nature and involve development and implementation of a consistent aggregation model with at least two networks.

To achieve this would require consideration of:

- Working collaboratively with the relevant networks in the trial to develop an initial basic set of requirements for a consistent aggregation model.
- A later stage discussion with non-participating networks (likely through the ENA) and other aggregators to enhance the initial aggregation model developed.
- Ongoing partnering and involvement with the relevant networks to increase the robustness and independence of trial results.

Potential success criteria

The following are likely indications that the trial has been (at least partially) successful:

- The successful development and acceptance of a (first cut) consistent aggregation model with at least two networks.
- A largely (pro-forma) and consistent aggregation service provision agreement must be in place with more than one network.
- Identification of key financial and operational efficiencies captured through consistency in approach across at least two networks.
- Positive feedback (qualitative) and perspectives of participating networks and customers in relation to the aggregation model.
- Feedback (qualitative) from other networks (likely through the ENA) and aggregators on their ability to further develop, scale and replicate the aggregation model.

9.1.3 New baselining methodologies, deeming of some services in WDRM and RERT (R1)

This trial will be non-financial in nature, our rationale for this is that implementation of a financial trial may require the AER to approve the use of the regulatory sandbox and would also involve AEMO implementing the new baselines and incurring costs. This may take unnecessary time and effort.

A non-financial trial would equally demonstrate the risks and performance of any new baselining and / or deeming methodologies which is a critical step towards implementation in any event and can be used to fully implement the new baselines and / or deeming approaches.

To achieve this would require consideration of:

- Developing a set of criteria with AEMO to assess the baselining and / or deeming methodologies. These criteria should seek to have a better balance between risk and accuracy than currently exists and acknowledge that demand side involvement would necessarily have additional risk and uncertainty than generation side technologies.
- Developing approaches for new baselining and / or deeming methodologies in conjunction with AEMO.
- Demonstrating and analysing actual load variations against the potential baseline and deeming methodologies. Any flexible demand in this instance would be in response to 'actual' signals from the market, but not via market interfaces or market systems and no settlement would occur.
- Ongoing partnering and involvement with AEMO to increase the robustness and independence of trial results.

Potential success criteria

The following are likely indications that the trial has been (at least partially) successful:

- Development with AEMO of an accepted set of criteria for the trial of the new baseline methodologies and / or deeming approaches.
- Development with AEMO of new baselining methodology(s) and deeming methodology(s).
- Analysis that confirms the baseline / deeming methodologies meet the required criteria.

9.1.4 New Services - Voltage Support (N1), Minimum Demand (N2) and Negative Flows (N3)

This trial will be financial in nature and involve development and implementation of at least one identified new network service with at least two electricity networks.

To achieve this would require consideration of:

- Working collaboratively with the relevant networks to develop an initial, basic, largely common set of terms and conditions for the relevant network service(s).
- Working collaboratively with the relevant networks and the AER to identify how the new service could align with the AER's DMIA scheme funding requirements.
- A later stage discussion with non-participating networks (likely through the ENA) and other aggregators to enhance the initial set of terms and conditions for the relevant network services.
- Ongoing partnering and involvement with the relevant networks to increase the robustness and independence of trial results.

Potential success criteria

The following are likely indications that the trial has been (at least partially) successful:

- The development and acceptance of a (first cut) set of terms and conditions for each relevant network service.
- If required, confirmation that the new service satisfies the DMIA scheme's funding requirement.
- Consistent (where practical) terms and conditions must be in place with at least two networks.
- Confirmation from discussion with Shell Energy, networks and customers that the service provision was consistent with the required terms and conditions.
- Positive (qualitative) feedback and perspectives from participating networks and customers
- Discussions with other stakeholders to gauge general appetite and the ability and interest to further develop, scale and replicate the services across other networks and with other aggregators.

9.2 Our Stage Two scope of work and our approach to stakeholder consultation

Our scope for Stage Two of the Smart Energy Hubs is to prepare a public and independent knowledge sharing report that covers the following:

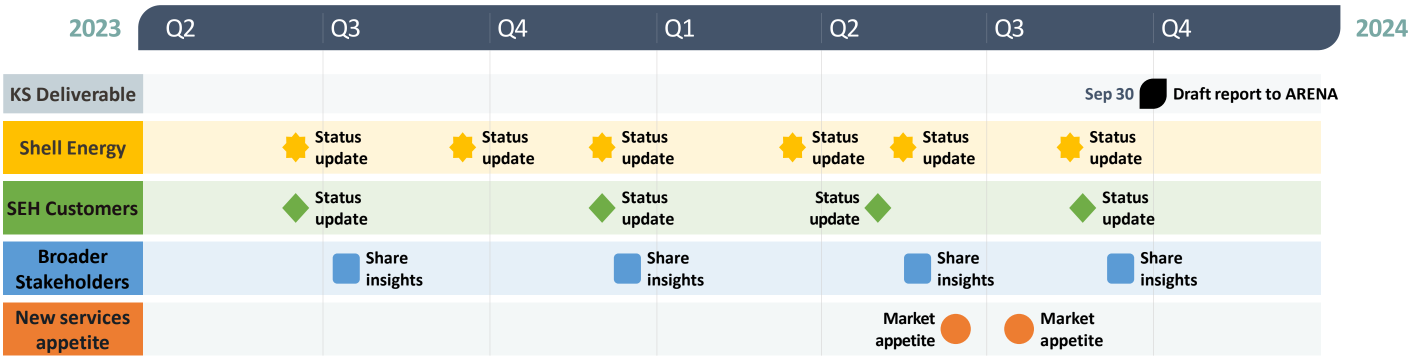
- The key outcomes of identified and progressed priority reforms from this report.
- The value created from the new services identified in this report and subsequently trialled in Stage Two of the SEH project by Shell Energy. This will be based on data provided by Shell Energy.
- Assessing the general appetite (based on stakeholder feedback) to compensate for the new services beyond the trial and at a larger scale.
- Outlining the experience from the Shell Energy trial of the alignment between market-based responses and minimum demand mitigation.

- Summarising the trial's experience on whether current metering and network and/or retail tariff arrangements are contributing to or inhibiting the use of demand flexibility.
- Engaging with key stakeholders throughout the program to share insights and ensure their input is captured at key stages.

9.2.1 Stakeholder consultation

Similar to the development of this report, our Stage Two work will again be informed by stakeholder consultation as outlined in Figure 9.1. We will be providing a complete but draft report to ARENA at the end of September 2024. The report is draft subject to ARENA approval.

Figure 9.1: High level timeline (indicative consultation dates) - Stage Two Smart Energy Hubs



For Stage Two we will be seeking to consult with stakeholders in four broad segments:

- **Shell Energy** – we will be consulting with Shell Energy on their progress with implementing and trialling our recommendations. We will gather data and evidence in areas such as progress, value created from new services and issues identified. We anticipate meeting with Shell Energy on an approximately quarterly basis.
- **SEH Customers** – this includes key stakeholders who are 'effectively' customers of the SEH project, including specific end use customers who have a SEH at their premise, relevant electricity networks who are jointly trialling the recommended new services and AEMO who is a key stakeholder of specific reform recommendations. We will be consulting with these stakeholders to gather data and evidence of their perspectives of the trial and any issues identified. Given potential sensitivities we anticipate meeting with these stakeholders individually or in small groups and on a quarterly basis shortly after we meet with Shell Energy.
- **Broader Stakeholders** – this includes a similar broad spectrum of stakeholders consistent with our approach to Stage One consultation. We will seek to engage with the same stakeholders in Stage Two as we did in Stage One. In Stage Two we will be seeking to meet with these stakeholders in one or possibly (for logistical reasons) two groups. The primary purpose of the discussions with these stakeholders is to inform them of the progress and the information gathered from Shell Energy and the SEH customers. We will also gather any material questions or concerns raised by stakeholders at these sessions and feed this back to Shell Energy as required. We anticipate meeting with these stakeholders on a quarterly basis shortly after we meet with the SEH customer group.

- **New services appetite** – this segment is likely to include electricity networks and the ENA and potentially other aggregators / flexible demand service providers. The purpose of this engagement, deliberately timed towards the end of the Stage Two trial, is to better understand and report on the general appetite for continuing the new services beyond the trial. We anticipate meeting with these stakeholders as a group two times towards the end of the project.

A. Stakeholder consultation – further details

The table below provides details on the organisations consulted by industry segment.

Table A.1: Industry segment and stakeholder organisations consulted

Industry segment	Stakeholder organisations
Governments	• Commonwealth Government – Department of Industry Science and Resources • Victorian Government – Department of Energy Environment and Climate Action • NSW Government – Department of Climate and Energy Action • Queensland Government – Department of Energy and Public Works
Market bodies / Government agencies	• Australian Energy Market Commission • Australian Energy Market Operator • Australian Energy Regulator • Australian Renewable Energy Agency • Energy Security Board
Distribution networks and peak bodies	• Ausgrid • AusNet • Citipower / Powercor / United Energy • Energy Networks Australia • Energy Queensland
Energy retailers and peak bodies	• Australian Energy Council • AGL • EnergyAustralia • Flow Power • Pacific Hydro / Tango Energy • Shell Energy
Flexible demand service companies	• Green Hat Solutions • Greensync • Gridbeyond • Intellihub • Jetcharge • Mondo • PlanetArk Power • PlusES • Viotas
End user representative bodies	• Energy Users Association of Australia

The table below provides details on the dates of the industry consultations undertaken and the number of stakeholders consulted. We note that some stakeholders could not attend the original dates of the sessions and in those instances we consulted with a number of stakeholders one-on-one if required.

Table A.2: Meeting dates and stakeholder numbers by round of consultation

Round	Meeting Dates	Stakeholder numbers
Early Engagement	Eight one-on-one discussions of approximately one hour in duration: • between 19 August 2022 – 26 August 2022	8
One	Six sessions by industry segment of approximately 1.5 hours in duration on the following dates: • 8 September 2022 • 9 September 2022 • 12 September 2022 • 14 September 2022 • 15 September 2022 • 19 September 2022	33
Two	Six sessions by industry segment of approximately 1.5 hours in duration on the following dates: • 28 October 2022 • 3 November 2022 (three sessions) • 8 November 2022 • 10 November 2022	31
Three	Two sessions covering all industry segments of approximately 1.5 hours in duration on the following dates: • 15 December 2022 • 16 December 2022	30

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