Potential network benefits from more efficient DER integration

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Executive summary

The Energy Security Board (ESB) commissioned Baringa Partners (Baringa) to evaluate the potential benefits of an efficient integration of distributed energy resources (DER) – such as rooftop solar photovoltaic (PV), electric vehicles (EVs) and battery storage – into the National Electricity Market (NEM). This is to inform policy development within the demand-side participation workstream of the ESB's Post-2025 Market Design Review.

DER are redefining the energy market. They are rapidly positioning consumers/prosumers as participants in a two-sided market rather than recipients in a one-sided system – where traditionally consumer demand has been viewed as fixed at any particular point in time, and large-scale generation provided the vast majority of the flexibility to ensure demand and supply balance. Further, DER are changing the role of retailers, aggregators and distribution network service providers (DNSPs), as they adjust to meet changing system needs and consumer preferences with increasing DER uptake.

The ESB engaged Baringa to, among other tasks, quantify an updated benefits case for more efficient DER integration. This builds on our existing study for the Open Energy Networks (OpEN) project and incorporates updated DER forecasts from AEMO's 2020 Electricity Statement of Opportunities (ESOO 2020). This report focusses on the network benefit categories of avoided investment in distribution and transmission networks and avoided solar curtailment costs.

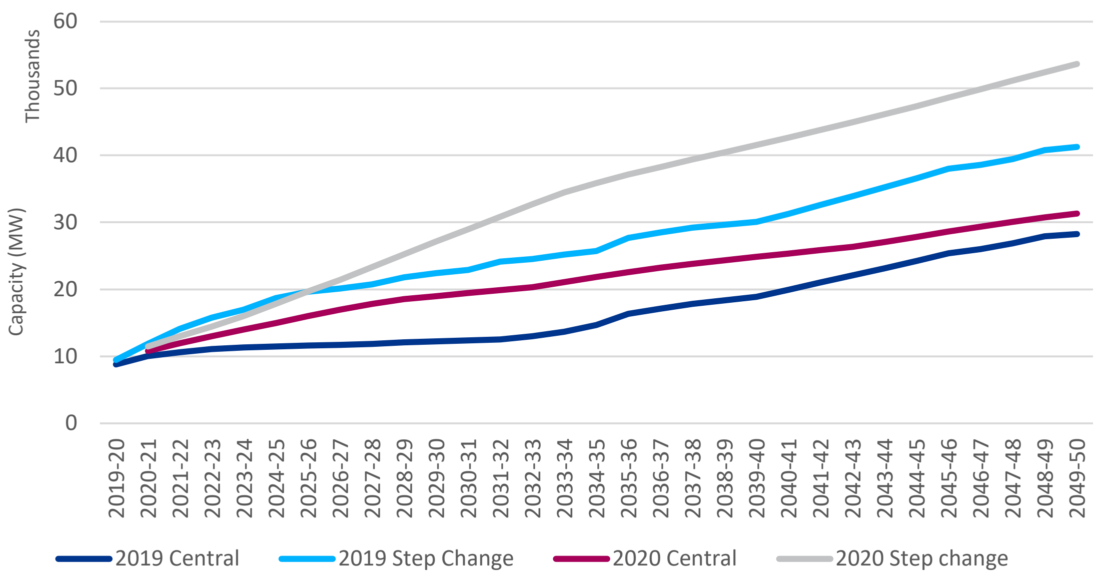
Our modelling results indicate that incorporating the vast uptake of forecast DER into the grid in an unmanaged way could lead to billions of dollars of network infrastructure to accommodate EV demand in excess of current network capacity. It could also lead to significant amounts of unused rooftop solar PV generation as the current network would not be capable of accommodating all this additional solar. We find that continued reform of distribution network tariffs and expanded use of direct procurement of network support services by DNSPs are critical to realising the value of rooftop solar PV and avoiding unnecessary network upgrades.

DER forecasts continue to be revised upwards

Australia already has a world-leading uptake of rooftop solar PV and further DER growth continues to 'surprise'. A common trend is for DER forecasts to continue to be revised upwards each year. Our previous OpEN study was based on DER forecasts from the 2019 ESOO. Between the 2019 and 2020 ESOO publications, AEMO significantly revised upwards its forecasts of DER penetration including rooftop solar PV and EVs across multiple scenarios as shown in the figures below.

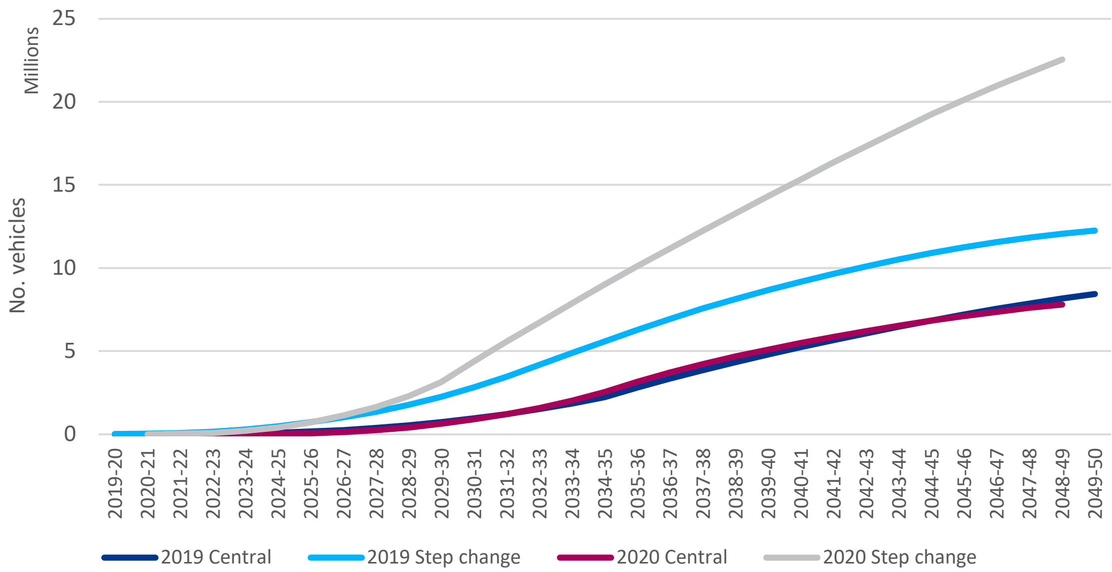
We can see that rooftop solar PV forecasts have materially increased between the 2019 and 2020 forecasts under both the central and step change scenarios. What in the 2019 forecasts was considered a step change level of increase in rooftop solar PV was only one year later in the 2020 forecasts considered close to a central scenario projection.

Figure A NEM rooftop solar forecasts (MW capacity)



In the figure below, we can see the ESOO 2020 step change scenario shows a significant increase in EVs compared with the 2019 step change scenario, with little change to the central case forecasts. The 2020 step change scenario models a move towards a zero emission transport fleet by 2050, which would need to be driven by strong regulation and/or incentives such as bans on sales of new internal combustion engine vehicles.

Figure B NEM electric vehicle uptake forecast (vehicles)



Without a managed approach to the integration of DER and having effective policy settings in place, this increase in DER penetration is expected to result in a need for significant new network infrastructure to accommodate the increase in demand from EVs and wasted energy through curtailing solar PV at times when generation is excess to system needs. The costs of an unmanaged approach to integrating DER can also be conceptualised as the benefits of a managed approach. These benefits ultimately flow through to all consumers through lower energy bills and greater rooftop solar PV output.

Potential 'size of the prize' network benefits from efficient DER integration is very material

We estimated the potential 'size of the prize' which could be achieved if DER is integrated through managed and highly effective approaches. This estimate is 'solution agnostic' in that it is focused on the benefits of avoiding unnecessary network infrastructure build and avoiding unnecessary solar PV curtailment without taking into account the specific policy levers through which this would be achieved. Later below we estimate the effectiveness of current DER policy arrangements in delivering these potential benefits.

Our assessment indicates that there are significant potential benefits from the effective integration of DER. This is the case under both the AEMO central scenario and step change scenario of DER forecasts and is driven by forecasts in rooftop solar PV, EV adoption and embedded storage. Our updated modelling indicates the potential benefits of avoided distribution investment in the central scenario have increased by 92% from $999m to $1.9bn out to 2040. In the step change scenario, the potential benefits of avoided distribution investment have increased by 112% from $3.9bn to $8.4bn. The potential benefits of avoided curtailment costs have increased 50% to $367m in the central scenario, and increased 132% to $1.5bn in the step change scenario. The primary driver of this increase in estimated benefits is factoring in the updated 2020 ESOO DER forecasts.

Combined the distribution benefits have increased by 84% from $1.2bn to $2.3bn in the central scenario, and by 115% from $4.6bn to $9.9bn in the step change scenario. Transmission benefits have also increased with respect to reduced curtailment by 3% in the central scenario and 122% in the step change scenario.[1]

Our estimate of distribution and transmission network benefits, combined, has increased by 41% from $1.7bn to $2.3bn under the central scenario, and increased by 88% from $6bn to $11.3bn under the step change scenario.

Table A 'Size of the prize' of network benefits from efficient DER integration (2020-2040)

Benefit category	Benefit sub-category	ESOO scenario	NPV potential benefits (ESOO 2019) ($m)	NPV potential benefits (ESOO 2020) ($m)	Difference ($m)	% Change
Avoided distribution investment / reduced curtailment costs	Avoided curtailment costs (generation driven)	*Central*	244	367	123	50%
		Step change	652	1,514	862	132%
		Central	999	1,918	919	92%

[1] On the other hand, avoided transmission network benefits have decreased from our previous study. This is due to a refinement in the model methodology we have adopted.

Benefit category	Benefit sub-category	ESOO scenario	NPV potential benefits (ESOO 2019) ($m)	NPV potential benefits (ESOO 2020) ($m)	Difference ($m)	% Change
	Avoided distribution investment (demand driven)	*Step change*	3,958	8,389	4,431	112%
Totals	**Total distribution benefits**	***Central***	**1,243**	**2,285**	**1,042**	**84%**
		Step change	**4,610**	**9,902**	**5,293**	**115%**
Avoided Transmission investment / reduced curtailment costs	**Avoided curtailment costs (generation driven)**	***Central***	**17**	**18**	**1**	**3%**
		Step change	**47**	**104**	**57**	**122%**
	Avoided transmission investment (demand driven)	***Central***	**393**	**20**	**-373**	**-95%**
		Step change	**1,358**	**1,315**	**-43**	**-3%**
Totals	**Total transmission benefits**	***Central***	**410**	**38**	**-372**	**-91%**
		Step change	**1,404**	**1,419**	**15**	**1%**
Total network benefits		***Central***	**1,653**	**2,323**	**670**	**41%**
		Step change	**6,014**	**11,321**	**5,307**	**88%**

Current DER arrangements are making progress but will under-deliver without further reform

There is a range of tariff and non-tariff policy levers available to facilitate DER integration in the distribution network. This includes network tariff reform, direct procurement of network support services by DNSPs, access right reforms including dynamic export limits, technology standards and community batteries.

In this report, we focus on network tariff reform and direct procurement, consistent with our brief from the ESB. These two measures form a useful complement in that cost reflective network tariffs are likely to be deployed across a wider customer base but are typically less targeted to the specific temporal and locational needs of the network, whereas direct procurement is likely to be much more targeted to the temporal and locational needs of the network but less widely deployed. Network tariff reform and direct procurement are both critically important to unlock the full suite of potential benefits of DER integration.

For network tariffs and direct procurement, we describe the current arrangements in these two areas. We then estimate the effectiveness of the current arrangements for these two measures to capture the potential 'size of the prize' of available network benefits in the table above. We perform a qualitative assessment – and then use these findings as an input into a high-level quantitative assessment – of the scope of this ‘size of the prize’ benefits case that is achievable through the current arrangements for network tariff reform and non-tariff direct procurement solutions. We perform this qualitative assessment against a series of criteria we’ve established including the ability of the tariff or non-tariff solutions to reflect temporal and locational network needs, the strength of the response, and how widespread the solution is likely to be applied.

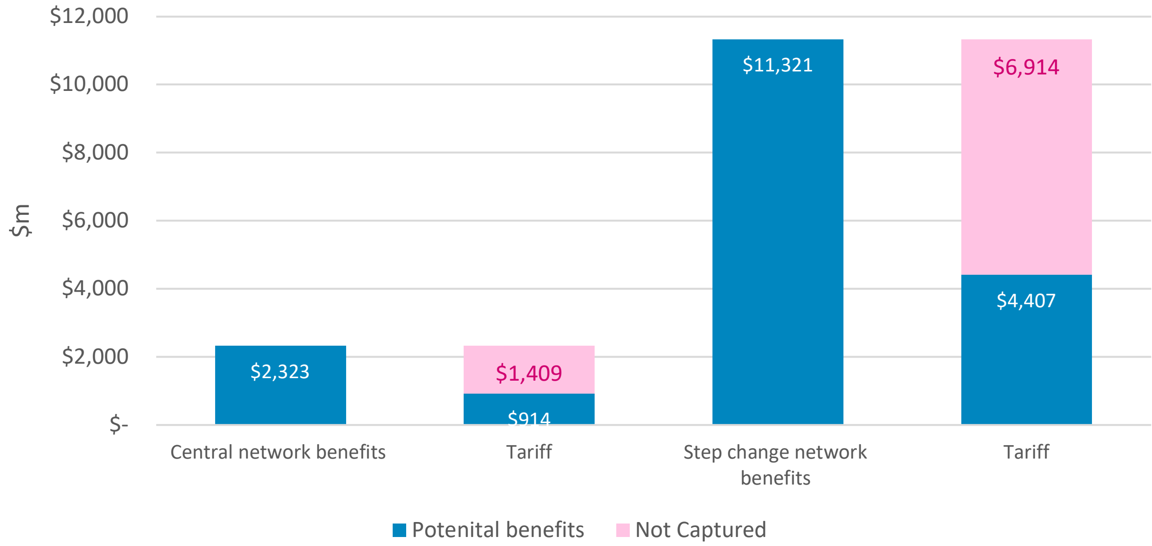
Table B Qualitative assessment of current DER arrangements to deliver network benefits

	Network tariffs	Direct procurement	Network tariffs	Direct procurement
Evaluation criteria	**Demand-driven benefits**		**Generation-driven benefits**	
Ability to signal temporal network needs	🟡	🟢🟢	🟢	🟢🟢
Ability to signal locational network needs	🔴	🟢	🔴	🟢
Strength of response	🟡	🟢	🟡	🟡
Reach	🟢	🔴	🟢🟢	🔴

Note: Assessment in table based on five tier rating from least to most effective: red dot, yellow dot, single green dot, two green dots and three green dots. No criteria scored the highest rating of three green dots.

We find that current arrangements, particularly for network tariff reform, are expected to make some progress towards delivering on the potential benefits of more efficient DER integration. However, also we find that in both the central and step change scenarios, the possible benefits captured by tariff and non-tariff direct procurement assessed under current arrangements still leaves a considerable gap when compared to the potential ‘size of the prize’ from efficient DER integration. Neither tariff or non-tariff direct procurement options are able to fully realise the DER benefits by themselves, which emphasises the need for both tariff and non-tariff reforms to occur.

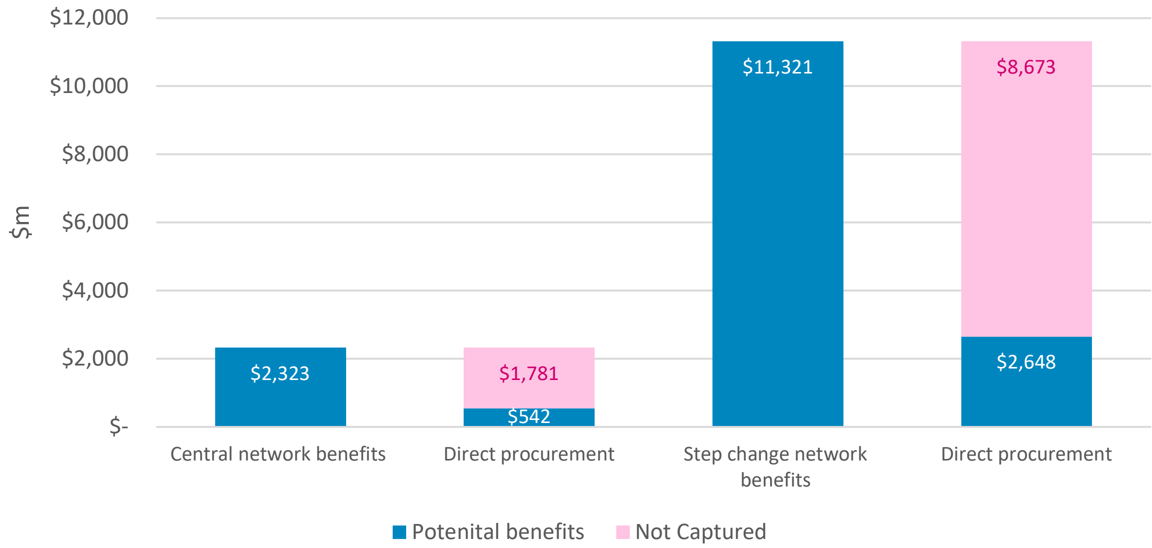
Figure C Benefits captured by network tariff reform under current arrangements



The figure above shows that based upon our assessment of tariff performance to capture benefits, $914m are captured in the central scenario and $4.4bn are captured in the step change scenario. While these benefits are material, under current arrangements, this still leaves a gap of $1.4bn in the central case and $6.9bn of uncaptured benefits in the step change case.

The uncaptured benefits as a result of our qualitative assessment are largely driven by different factors for the tariff and non-tariff options. Tariff performance is impeded by the ability to signal a dynamic temporal and locational price signal and consequently drives a moderate strength of response, though has a broad reach.

Figure D Benefits captured by direct procurement under current arrangements



The figure above shows that based upon our assessment of direct procurement to capture benefits, $542m are captured in the central scenario and $2.6bn are captured in the step change scenario. This leaves a bigger gap of uncaptured benefits compared with the tariff performance where $1.8bn is uncaptured in the central scenario and $8.7bn goes uncaptured in the step change scenario.

Under current arrangements, direct procurement is unable to capture the full scope of benefits largely due to the low level of reach, despite the potential for highly temporally and locationally granular signals.

We find that current arrangements with either network tariff reform or direct procurement are unlikely to realise the majority of potential benefits. The key message therefore is more is needed on network tariff reform, direct procurement and other non-tariff DER solutions to unlock the full potential of effective DER integration and avoid the unnecessary costs of avoidable network investment and solar curtailment that would result from an unmanaged approach to DER integration.

Further reforms to help unlock the potential benefits of efficient DER integration

We suggest further measures and reforms on network tariffs and direct procurement be considered to help unlock the full 'size of the prize' network benefits that could be achieved through more efficient DER integration.

On network tariff reform, we estimate an additional $884m benefits under the central scenario and $4.3bn in the step change scenario could be unlocked when compared with our assessment on current arrangements, if the following approaches were to be adopted:

- Continued rollout of broad-based network tariff reform by DNSPs (sending temporally cost reflective price signals) through the Tariff Structure Statement process by DNSPs and the Australian Energy Regulator (AER). This is so that retailers face a cost reflective network price signal for all customers who own DER, and retailers are incentivised to design retail offers to encourage the use of DER in a managed way – it is particularly important that this is expanded to cover electric vehicles which is not always the case currently. This should also include continued review of distribution areas where it is appropriate to move the lowest off-peak rates to the middle of the day to soak up excess solar PV.
- Completion of the current DER access, pricing and incentive arrangements rule change process by the Australian Energy Market Commission (AEMC), to enable greater flexibility in the rules framework on innovative tariff designs and more encouragement of tariff trials.
- The rule change process should be swiftly followed by trials on the new network tariff structure options that may be made possible by this rule change process, so that those trials can inform tariff structure design in the next round of Tariff Structure Statements. The new network tariff options include network payments as well as charges to imports and exports of electricity by consumers, with the design depending on network circumstances. It also enables consideration of options where network tariffs are based on the aggregate load across a retailer's customer base, which increases the options available for retailers and aggregators to respond to those price signals.

Direct procurement of network services (load and supply flexibility) from DER provides DNSPs with a means to address technical challenges and network needs when and where it is required. At present, the scale of direct procurement and the benefits delivered are limited.

We estimate an additional $602m benefits under the central scenario and $2.9bn could be unlocked in the step change scenario compared with our assessment of current arrangements, if the following approaches were to be adopted:

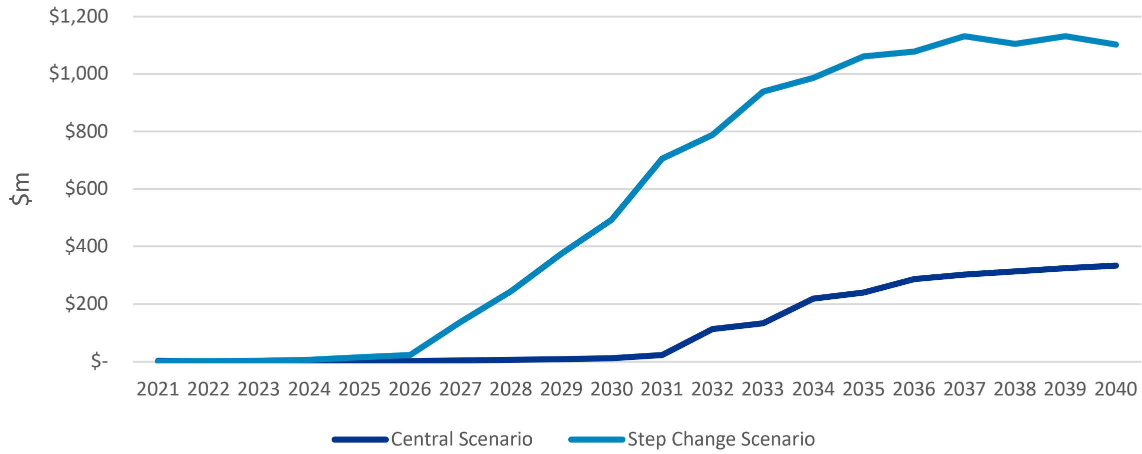
- Expansion of direct procurement trials and deployment projects to engage a wider range of DER technologies, technology providers and aggregators, will be important to working through the technical and commercial challenges of direct procurement, providing a trajectory to wider use of this mechanism in the future.
- Monitoring of the post-allowance financial incentives framework and the regulatory investment test (RIT-D), and the outcomes each is delivering, will help to ensure any real or perceived capex biases are addressed, removing regulatory barriers to implementing direct procurement where efficient to do so.
- Over the last few years, substantial progress has been made to enable aggregated DER to access a broad value stack. Removing remaining barriers such that aggregators can participate in a range of markets, will help to encourage growth in the sector and ultimately more DER participation.
- Network access arrangements for DER, and particularly energy export, impact which DER assets are able to provide network services, as well as the firmness of their ability to participate. Developing access arrangements that align with the needs of aggregators and DNSPs will help to realise more benefits of DER integration through direct procurement.

Delay in reform will reduce the 'size of the prize' benefits that can be realised

As set out earlier in this executive summary, our estimate of the total 'size of the prize' of potential distribution and transmission network benefits from efficient DER integration is $2.3bn under the central scenario and $11.3bn under the step change scenario. The figure below sets out how these potential 'size of the prize' network benefits are forecast to develop over time.

The majority of benefits are forecast to occur over the second half of our forecasting period out to 2040, however, under the step change scenario benefits start to materialise and grow rapidly within the next several years. This is because with the elevated levels of rooftop solar and EV demand under the step change scenario, constraints against existing network capacity start to occur earlier. Further, as our modelling is based on average conditions across a NEM region (i.e. state/territory-wide conditions), it is likely that constraints will occur in some localised areas earlier.

Figure E 'Size of the prize' of network benefits from efficient DER integration over time



We estimate that current arrangements, without further reform, are likely to realise less than half of these potential benefits. Further reforms across network tariffs, direct procurement and other non-tariff DER integration measures will take time to implement. Any significant delays in the commencement of further reforms would reduce the potential 'size of the prize' of network benefits that could be captured, meaning some benefits would become permanently unrealised, particularly if actual DER penetration outcomes develop along the step change scenario trajectory. This is because after certain expenditure on network upgrades are incurred, or after certain solar PV is curtailed in a particular year, these impacts cannot be reversed even if they were avoidable if reforms to more efficiently integrate DER had taken place earlier.

1 Introduction

This chapter sets out the context for this report, including how this report builds upon our previous work for the Open Energy Networks (OpEN) project, and the methodology we used for this report. The methodology for the benefits quantification is explained further in appendix A.

1.1 DER integration

Distributed energy resources (DER) are redefining the energy market. They are rapidly positioning consumers/prosumers as participants in a two-sided market rather than recipients in a one-sided system – where traditionally consumer demand has been viewed as fixed at any particular point in time, and generation provided the vast majority of flexibility to ensure demand and supply balance. Further, DER are changing the role of retailers, aggregators and distribution network service providers (DNSPs), as they adjust to meet changing system needs and consumer preferences with increasing DER uptake.

The integration of DER such as rooftop solar photovoltaic (PV), electric vehicles (EVs) and battery storage, poses both challenges and opportunities for the market, including for DNSPs.

DNSPs are responsible for operating and maintaining the local networks to which DER assets connect. This requires them to manage local network capacity, while maintaining network reliability and security and minimising investment costs. DER growth is creating significant, and potentially costly, technical challenges to operating the distribution network. However, DER can also offer the information and flexibility to better manage network conditions. With strategic integration, DER offer unique opportunities for DNSPs to efficiently and effectively manage their networks and defer costly network reinforcements as the National Electricity Market (NEM) continues to transition.

There has been a large amount of work undertaken in recent years to understand the changing role of DER in the NEM, and the impacts or potential benefits for distribution networks. A number of work programs are underway to help deliver the integration of DER into Australian electricity markets. Many DNSPs are involved in trials to develop solutions and build their capabilities to integrate DER in their networks.

As this work continues, and as market bodies, governments, DNSPs and other parties progress programs and policy reforms to address the changing market, it is useful to understand what these measures could actually achieve. This is where quantifying the potential benefits of DER integration is important. Once the ‘size of the prize’ of available benefits is assessed, it is possible to consider the role that various policy options and measures can play in realising this potential. Similarly, it provides a reference to assess the extent to which benefits aren’t likely to be realised without additional measures or stronger efforts being introduced.

1.2 OpEN cost-benefit assessment model

In June 2019, Baringa Partners (Baringa) was engaged by the Australian Energy Market Operator (AEMO) alongside the Energy Networks Association (ENA) to develop a cost benefit analysis (CBA) framework and undertake a CBA for a number of potential distribution system operator (DSO) frameworks – called the OpEN project. The CBA was developed with input from stakeholders across the industry.

As well as enabling decision makers to consider the relative merits of the different models, the study quantified the overall network efficiency benefits (and other benefits) that could be realised through more efficient DER integration over the next 20 years.

In order to assess the benefit potential of integrating DER more efficiently into the NEM, we assessed the potential benefits which might be possible under two of AEMO's 2019 Electricity Statement of Opportunities (ESOO) future scenarios – the central scenario (where DER uptake is moderate) and a step change scenario (where DER uptake is significantly higher), and the only scenario where warming is kept below 2 degrees Celsius. We then identified four high-level benefit categories of DER integration into the NEM:

- Avoided distribution investment / reduced curtailment costs
- Avoided transmission investment
- Reduced wholesale ancillary services costs
- Reduced wholesale energy costs

The figure below provides more detail around the drivers for each of the benefit categories and more detail on how the transmission and distribution benefits are calculated can be found in chapter 3 of this report.

Figure 1 DER integration benefit categories

Benefit category	Generation driven	Demand driven
1. Avoided distribution investment / reduced curtailment costs	Reduced curtailment of small-scale distribution connected generation: • Savings in marginal generation costs • Reduced losses	Reduced distribution investment to meet high local peaks: • Avoided local network augmentation to meet higher demand (e.g. from EV uptake)
2. Avoided transmission investment	Reduced curtailment of small-scale distribution connected generation avoids the need to build new transmission network to connect large scale renewables: • Savings in transmission connection costs	Reduced network augmentation to meet greater peak demand: • Savings in transmission augmentation costs
3. Reduced wholesale ancillary service costs	Greater competition provided by DER drives lower prices	
4. Reduced wholesale energy costs	Not applicable – this is about shifting demand away from peak to off-peak	Demand response at peak (e.g. shifting demand and storage import to off-peak times)

1.3 Scope of this report

As part of the Post-2025 Market Design Review, the Energy Security Board (ESB) is looking to build evidence to evaluate the case for different policy levers in supporting the efficient integration of DER into the National Electricity Market (NEM).

The ESB engaged Baringa to, among other tasks, quantify an updated benefits case for more efficient DER integration. This built on our existing study and incorporate updated DER forecasts from AEMO's 2020 ESOO. DER forecasts continue to be revised upwards each year, with significant increases in DER forecasts between the 2019 and 2020 ESOOs.

This report assesses the ability of tariff and non-tariff direct procurement measures to realise this 'size of the prize' of potential distribution and transmission benefits.

This report is structured as follows:

- In chapter 2, we set the context for how significant the increase in DER forecasts has been between the 2019 and 2020 ESOOs
- In chapter 3, we set out our updated 'size of the prize' assessment of the potential distribution and transmission network benefits from more efficient DER integration
- In chapter 4, we describe the range of potential policy levers for DER integration and summarise the current arrangements for network tariff reform and direct procurement of network support services
- In chapter 5, we perform a qualitative assessment of the scope of this 'size of the prize' benefits case that is achievable through current arrangements for network tariff reform and direct procurement.
- In chapter 6, we turn this qualitative assessment into a high-level quantitative assessment of the scope of this 'size of the prize' benefits case that is achievable through current arrangements for network tariff reform and direct procurement.
- In chapter 7, we set out further tariff and direct procurement reforms which could help unlock some of the unrealised network benefits from more efficient DER integration
- In appendix A, we set out in detail our methodology for calculating the 'size of the prize' available network benefits
- In appendix B, we set out a more detailed breakdown of some of our modelling results

It is important to note that this assessment is based on leveraging the opportunities of DER such as solar PV, storage and EVs, and does not include the broader spectrum of non-DER dependent demand management measures in the NEM. Further, this assessment is based on DER held primarily by residential customers, rather than extending to DER held by business or larger commercial and industrial (C&I) customers.

1.4 Criteria for qualitative assessment

In this report, we seek to understand, at a high level, the relative merits of different DER integration approaches and to assess their potential to contribute to unlocking the potential benefits of DER in the future.

To do this, we have developed a suite of evaluation criteria, shown in the table below. These criteria do not provide a fulsome evaluation of each of the mechanisms from a detailed and technical implementation perspective. Instead, they provide a high-level framework for considering the diverse range of both tariff and non-tariff mechanisms in parallel.

Table 1 Evaluation criteria for DER integration approaches

Criteria	Parameters
Ability to signal temporal network needs	Incentivises the time-shifting of load or export, to reduce or increase network use as needed to support stable network operations. In particular, to reduce load (or increase generation) during the evening peak and to increase load (or reduce generation) during the daytime minimum load period. Extent to which it provides real-time signals of network needs.
Ability to signal locational network needs	Incentivises network use (load or export) behaviours that meet the location-specific needs of the network, reflecting the different nature and magnitude of network requirements in different locations in the network. Extent to which it provides signals in line with dynamic changes in the nature and magnitude of locational needs.
Strength of response	Provides a clear and strong incentive, and is therefore likely to achieve the desired response and capable of being relied upon. Extent to which response is likely to be realised.
Reach	Reaches a wide range of customers with DER in a variety of circumstances (demographic, locational, consumption levels, active engagement levels). Emphasis is on reach to customers with DER, rather than reach across all customers, as the focus of this report is on benefits of better DER integration (and doesn't extend to all forms of demand response).
Ease of implementation and operation	Implemented without significant barriers or costs – considering the new systems, processes, infrastructure, and legislative or regulatory changes required. Extent to which ongoing operation requires limited administration or resourcing – considering operations, reporting, compliance and enforcement.
Access by providers	Limited barriers to aggregators or other new entrant participants providing the solution (level playing field for providers).

The key tariff and non-tariff approaches to integrating DER are assessed against these criteria in later chapters, to highlight their relative benefits and shortfalls. A five tier rating system is used for the evaluation, based on the ratings in Table 2, below. These qualitative ratings are then turned into a quantitative rating and used as an input into the quantitative assessment in chapter 6.

Table 2 Evaluation ratings

Qualitative rating	Quantitative rating	Description
●●●	100%	Option is very effective at satisfying the requirements of the criterion.
●●	75%	Option is reasonably effective at satisfying most of the requirements of the criterion.
●	50%	Option partly satisfies the requirements of the criterion.
●	25%	Option only satisfies some of the requirements of the criterion.
●	0%	Option goes a very limited way to satisfying the criterion, if at all.

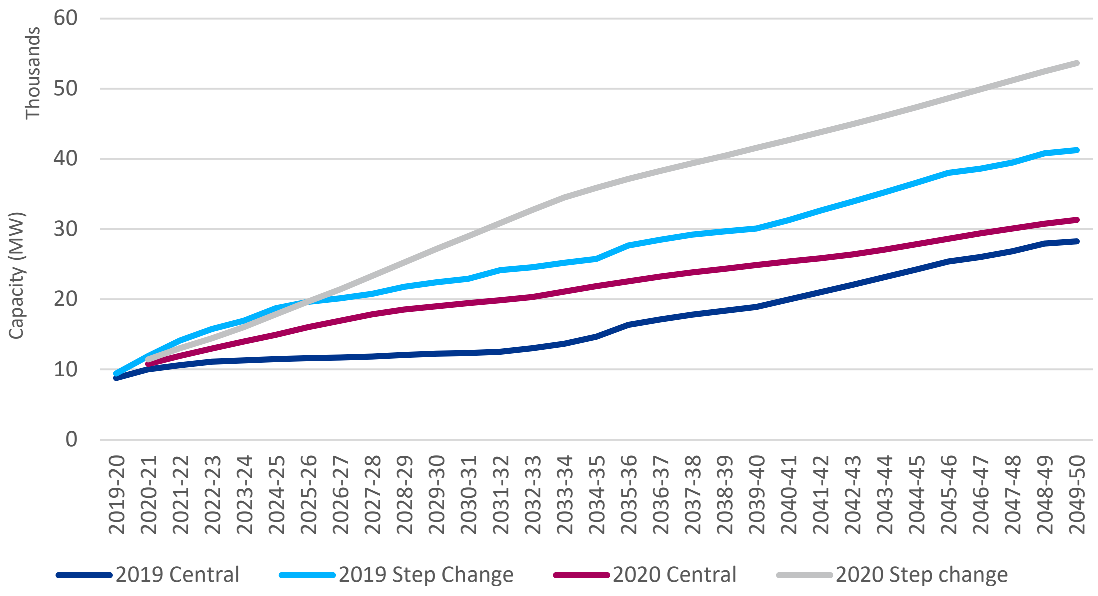
2 Increasing DER forecasts

The ESB 2020 Health of the NEM assessment published in January 2021 highlights the urgency of addressing the challenges associated with rapid change to the electricity system driven by high rates of DER including variable renewable energy installed on the distribution network, such as solar PV, and high peak demand growth in the advent of EV uptake, which is forecast to take-off significantly beyond 2030.

The Baringa-led OpEN CBA was modelled using two scenarios based from the AEMO ESOO 2019 forecasts. The two scenarios were a lower DER uptake scenario (2019 central) and a higher DER uptake scenario (2019 step-change). The central scenario is intended to represent the likely uptake of DER, and the step-change scenario is consistent with restricting global warming to two degrees Celsius. Since Baringa's original analysis was conducted, ESOO 2020 forecasts have been published by AEMO.

Australia already has a world-leading uptake of rooftop solar PV and further DER growth continues to 'surprise'. An observed trend is DER forecasts continue to be revised upwards each year. Between the 2019 and 2020 ESOO publications, AEMO significantly revised upwards its forecasts of DER penetration including rooftop solar PV and EVs updated across multiple scenarios as shown in Figures 2 and 3 below.

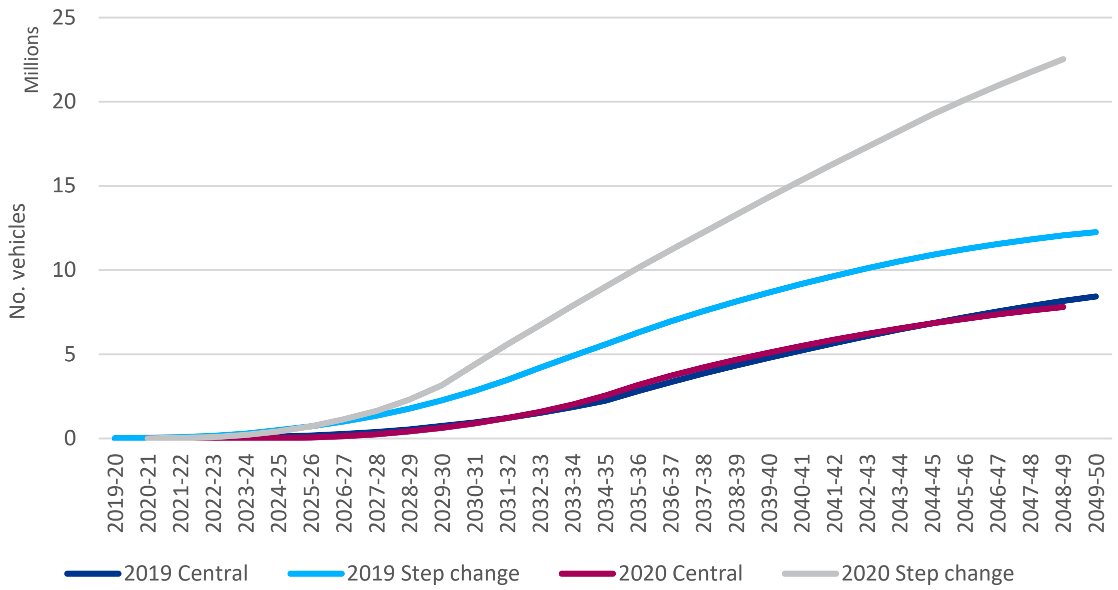
Figure 2 NEM rooftop solar forecasts (MW capacity)



We can see that rooftop solar PV forecasts have materially increased between the 2019 and 2020 forecasts under both the central and step change scenarios. What in the 2019 forecasts was considered a step change level of increase in rooftop solar PV was only one year later in the 2020 forecasts considered close to a central scenario projection.

EV forecasts have also had a significant uplift, in particular regarding the assumptions in the step change scenario, with few changes made to the central case forecasts. The 2020 step change scenario models a move towards a zero emission transport fleet by 2050, which would need to be driven by strong regulation and/or incentives such as bans on sales of new internal combustion engine vehicles.

Figure 3 NEM electric vehicle uptake forecast (number of vehicles)



Without a managed approach to the integration of DER and having effective policy settings in place, this significant increase in DER penetration is expected to result in a need for significant new network infrastructure to accommodate the increase in demand from EVs and significant wasted energy through curtailing solar PV at times when generation is excess to system needs.

The costs of an unmanaged approach to integrating DER can also be conceptualised as the benefits of a managed approach. These benefits ultimately flow through to consumers through lower energy bills and greater rooftop solar PV output.

3 Benefits case – available benefits of better DER integration

This chapter sets out our updated 'size of the prize' assessment of the potential distribution and transmission network benefits from more efficient DER integration. It is based on DER forecasts in the 2020 ESOO, whereas our original assessment for the OpEN project was based on 2019 ESOO forecasts. Each year, DER forecasts continue to be revised upwards.

3.1 Summary of benefits

Our assessment uses the latest ESOO and indicates that there are significant potential benefits from effective integration of DER compared with the counterfactual (as explained in the appendix A). This is the case for both the AEMO central scenario and step change scenario and is driven by forecasts in solar PV, EV adoption and embedded storage forecasts.

This report focusses on the network benefit categories of avoided investment in distribution and transmission networks and avoided curtailment costs, where we have identified the greatest change to potential benefits based on the updated ESOO 2020 forecasts highlighted below.

Our updated model indicates the potential benefits of avoided distribution investment in the central scenario have increased by 92% from $999m to $1.9bn out to 2040. In the step change scenario, the potential benefits of avoided distribution investment have increased by 112% from $3.9bn to $8.4bn. The potential benefits of avoided curtailment costs have increased 50% to $367m in the central scenario, and increased 132% to $1.5bn in the step change scenario.

Combined the distribution benefits have increased by 84% from $1.2bn to $2.3bn in the central scenario, and by 115% from $4.6bn to $9.9bn in the step change scenario. Likewise, transmission benefits have increased with respect to reduced curtailment by 3% in the central scenario and 122% in the step change scenario as well.

We have separately modelled these impacts over two 10 year stages. The first stage is 2020-30 and the second stage 2030-2040. In ESOO 2020, there is a significant increase in forecast solar PV in the central case across in stage 1 (2020-2030) but there is only a modest change to EV forecasts. Whereas in ESOO 2020 across stage 2 (2030-2040), the material increase in solar PV continues and is now joined by a significant increase in EV forecasts, particularly in the step change scenario, compared with ESOO 2019 forecasts. This results in an increase in the potential for avoided distribution and transmission investment as more flexible demand enters the system.

Consistent with our brief from the ESB, these figures focus on the benefits only and therefore do not include consideration of the costs for flexibility payments which was included in the reported figures of the published OpEN CBA.

Table 3 Distribution and transmission network benefits of better DER integration

Benefit category	Benefit sub-category	ESOO scenario	Stage 1 & 2 - NPV potential benefits (ESOO 2019) ($m)	Stage 1 & 2 - NPV potential benefits (ESOO 2020) ($m)	Difference stage 1 & 2 ($m)	% Change
Avoided distribution investment / reduced curtailment costs	**Avoided curtailment costs (generation driven)**	***Central***	244	367	123	50%
		Step Change	652	1,514	862	132%
	Avoided distribution investment (demand driven)	***Central***	999	1,918	919	92%
		Step Change	3,958	8,389	4,431	112%
Totals	**Total distribution benefits**	***Central***	**1,243**	**2,285**	**1,042**	**84%**
		Step Change	**4,610**	**9,902**	**5,293**	**115%**
Avoided Transmission investment / reduced curtailment costs	**Avoided curtailment costs (generation driven)**	***Central***	**17**	**18**	**1**	**3%**
		Step Change	**47**	**104**	**57**	**122%**
	Avoided transmission investment (demand driven)[2]	***Central***	**393**	**20**	**-373**	**-95%**
		Step Change	**1,358**	**1,315**	**-43**	**-3%**
Totals	**Total transmission benefits**	***Central***	**410**	**38**	**-372**	**-91%**
		Step Change	**1,404**	**1,419**	**15**	**1%**
Total Network Benefits		***Central***	**1,653**	**2,323**	**670**	**41%**
		Step Change	**6,014**	**11,321**	**5,307**	**88%**

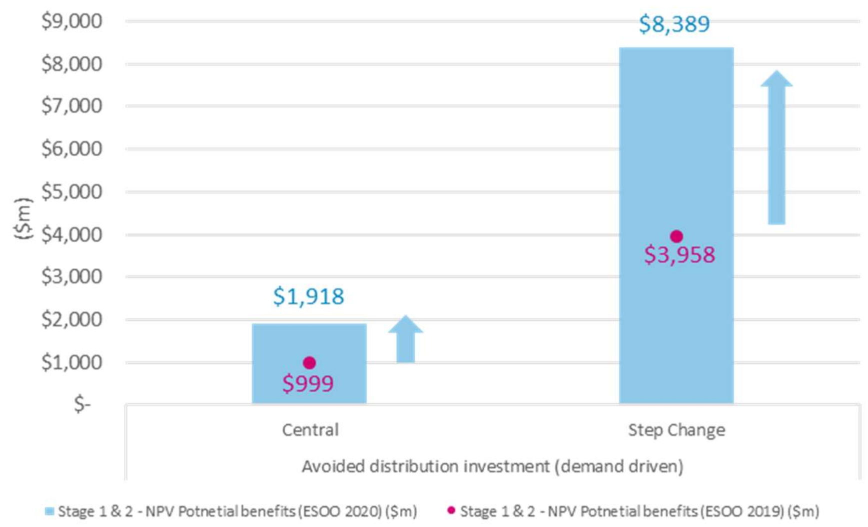
[2] What we would have expected to see in respect to the demand driven benefits for transmission would have also to increase in line with distribution networks due to increased forecasts for EVs, especially in the step change scenario. However, we completed a review of our assumptions used in the original OpEN CBA model and updated this to reflect more recent studies, which indicate a national diversified peak demand of approx. 0.4-0.5kW per EV at transmission level, when using ESOO 2020 data as the basis for the forecasts.

3.2 Demand-driven benefits

3.2.1 Avoided distribution investment

Overall, the projected benefits for avoided distribution investment increased by 92% in the ESOO 2020 central scenario to $1.9bn and by 112% in the ESOO 2020 step change scenario to $8.4bn as shown in the figure below.

Figure 4 Avoided distribution investment (demand driven)



The available benefit represents whether the required network augmentation calculated in the counterfactual can be reduced or avoided. The counterfactual assumes the main driver for peak demand growth is residential EV charging informed by AEMO's ESOO 2020 data. We also assume that EV peak load will have the largest impact on the low voltage network, as diversity of EV charging is lower even with a fewer numbers of EVs (e.g. smaller number of EVs on a single feeder needed to trigger LV augmentation).

The model uses data provided previously by networks to inform information around constraints and references UK EV trials in regards to the expected peak demand (kW) impact at feeder level on the LV and HV distribution network.

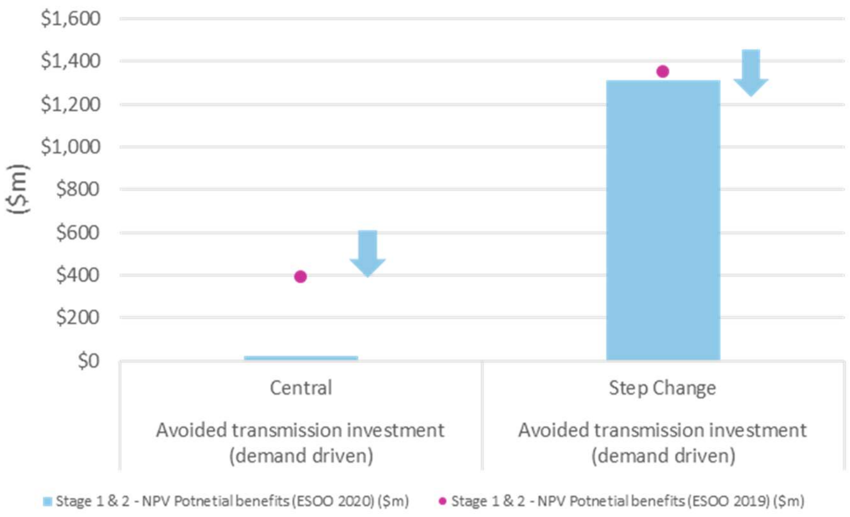
As a result of greater EV adoption and storage uptake in both the central and step change scenarios the available benefits (i.e. avoided distribution investment) has increased by 92% for the central scenario and 112% in the step change scenario (which assumes full electrification of the residential transport sector by 2050).

The purpose of the model is to consider the impact of EV uptake using assumptions informed by DNSPs around LV and HV headroom and the number of EVs per feeder that might trigger LV or HV augmentation. The model separately assesses the impact of EV uptake on network capacity in each NEM region (state/territory) at an average level across each region. In reality, EV uptake trends show that typical EV uptake would be clustered to more urban centers and will be highly localised so some areas would likely trigger benefits earlier or later given these variables that are unaccounted for in the modelling.

3.2.2 Avoided transmission investment

Similarly, for transmission the avoided transmission investment driven by increased demand through adoption of EVs in line with the ESOO 2020 forecasts would expect to have seen an increase in available benefits of EV integration. However, as stated earlier in this chapter, we have adjusted the assumptions down for diversified EV peak demand which has resulted in reducing the available benefits for the central scenario and a very modest reduction in available benefits for the step change scenario outlined by the chart below.

Figure 5 Avoided transmission investment (demand driven)

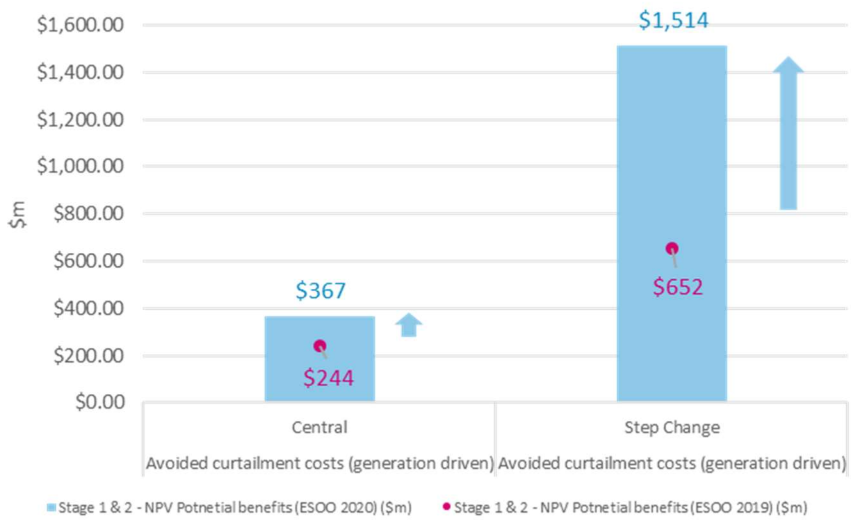


3.3 Generation-driven benefits

3.3.1 Avoided distribution curtailment costs

Overall, the projected benefits for avoided distribution curtailment costs increased by 50% in the ESOO 2020 central scenario to $367m and by 132% in the ESOO 2020 step change scenario to $1.5bn as shown in the figure below.

Figure 6 Avoided distribution curtailment costs (generation driven)



The available benefit represents the volume of excess generation (calculated in the counterfactual) that could be absorbed through demand response and by local coordination of demand (EVs and storage).

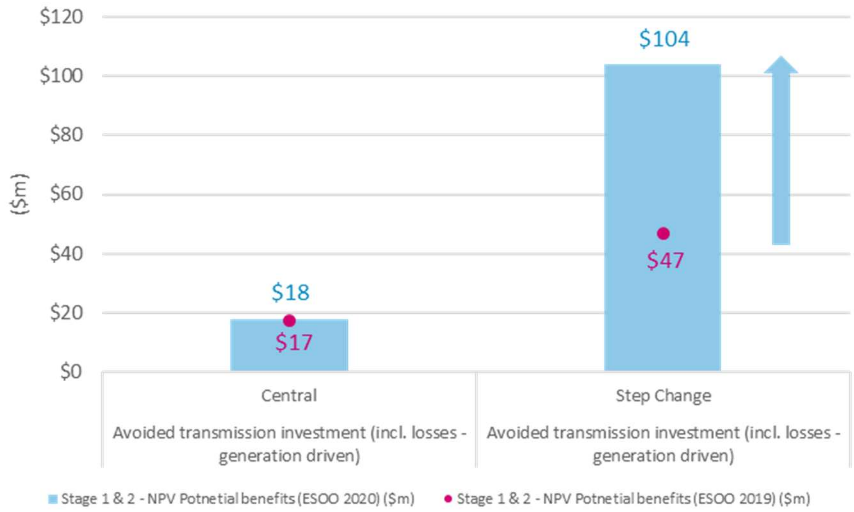
The model assumes that local flexible demand can better match with local peak solar, helping to reduce the volume of constraints from increased proliferation of residential solar PV on the network. It is assumed in the model that all of the excess solar generation is required to meet demand. By establishing how much excess solar PV curtailment (MWh) can be reduced by the increased projection of flexible demand in the NEM the model calculates the associated benefits through the marginal generation costs (i.e. the running of more expensive transmission connected generation).

3.3.2 Avoided transmission curtailment costs

The available benefit represents reduced curtailed energy through better integration of DER which affects the capacity of transmission augmentation required. In the optimal system operation, less generation build is required at transmission level, therefore corresponding transmission infrastructure build is also reduced.

In the central scenario there is broadly no change in the amount of curtailment reduction. In the step change scenario, the significant availability of flexible demand to reduce curtailment leads to a 122% increase in reduced transmission costs.

Figure 7 Avoided transmission curtailment costs



4 Policy levers for DER integration including current arrangements

In this chapter, we firstly describe the range of potential DER integration options and explain why our assessment has focused on two of these – network tariffs and direct procurement. Then, for network tariffs and direct procurement, respectively we:

- Outline the incentives or requirements on DNSPs to pursue reform
- Describe the current arrangements – this is used in our later qualitative and quantitative assessment, which assesses the ability of network tariffs and direct procurement to deliver the benefits case in chapter 3 if current arrangements continue but further substantive reform was not adopted.

4.1 Range of potential options

There is a range of tariff and non-tariff policy levers available to facilitate DER integration into distribution networks. With the emergence of new or enhanced technologies, including smart metering and inverter technologies, the range of policy levers and the potential opportunities they create is changing. Now, more than ever, tariff and non-tariff options can be used to drive changes in how, when and where customers use electricity and the distribution network.

Network tariff reform provide a traditional and relatively well understood lever to deliver price signals that encourage efficient DER operation across the market. There is increasingly a need for tariff structures that drive a shift in network usage – both imports and exports – to manage network conditions under changing demand patterns through the day.

Distribution network tariffs can be grouped into four broad categories:

- Upfront connection charges
- Ongoing distribution use of system (DUOS) charges for the import of electricity from the distribution network – this could potentially also include credits
- Ongoing export charges and/or credits
- Ongoing controlled load charges – where specific appliances are separately metered and can only operate during certain times in order to access a cheaper rate

Consistent with our brief from the ESB, in this report, we focus on the three categories of ongoing network charges and credits – which for simplicity we refer to collectively as network tariffs for the remainder of this report. We do not focus on upfront connection charges, though it is useful to remember that upfront connection charges could potentially also be used to send locational investment decisions for efficient integration of DER into the distribution network.

Tariff-based solutions alone are unlikely to unlock the full suite of potential benefits of DER integration. Complementary, non-tariff, mechanisms will also be important to supporting the efficient integration of DER and leveraging additional benefits for customers.

Non-tariff measures which are of particular relevance to DER integration include:

- Flexibility procurement – such as the direct procurement of network support services by DNSPs through bilateral contractual arrangements or through market platforms
- Access rights – such as dynamic export limits[3]
- Technology standards and controls – such as solar PV smart inverter standards and EV orchestration
- Community batteries

We describe each of these non-tariff options in turn.

Direct procurement of network support from DER is likely to play an important role alongside tariff reform. Direct procurement via DER aggregators has the potential to give DNSPs access to dynamic, locational, targeted, network support, which cannot as readily be achieved through tariffs.

Direct procurement in this context refers to DNSPs entering into contractual arrangements with customers with DER, typically via aggregators, for the provision of network support to help them to manage their network. This is achieved by calling on DER (via aggregators) to increase or reduce load or export volumes at particular times and locations in order to dynamically manage network conditions, such as voltage levels and constraints. The wide range of technical characteristics that DER can impact have been reported on in numerous other publications.[4] Alternatively, these arrangements may progress beyond bilateral contractual arrangements to instead be procured via a market platform. Either way, a DNSP may engage with an aggregator to procure network support from DER in a particular segment of its network. Depending on the particular contractual or market platform arrangements, the DNSP may call on the aggregator to dispatch generation from DER a number of times each week, with a few hours of advance notice. The DNSP could use this DER response to mitigate challenges of peak demand in that segment of its network. It would then pay the aggregator an agreed rate ($/kWh) for the network support, or as otherwise agreed. The aggregator would remunerate the DER owners for making their DER capacity available for the provision of this support.

The introduction of optional **dynamic export limits**, or dynamic operating envelopes, has significant potential to enable DNSPs as well as the wider energy market to maximise the benefits of DER and reduce DER curtailment when network conditions allow it. The technical capabilities to impose dynamic export limits, which would see time-variable limits on DER exports based on network conditions[5], are currently being developed and trialled by a number of DNSPs across the NEM. This

[3] Controlled load arrangements are listed above under network tariffs but also share characteristics of access rights in setting limits on how much electricity consumed can be consumed at particular times.
[4] For example, the Distributed Energy Integration Program, *Access and Pricing Reform Package – Outcomes Report*, 2020; and AEMC, *Distribution Market Model*, 2017.

[5] Most connection agreements in the distribution network define static export limits for the aggregate capacity of DER installed at the connection point. As DER penetration has increased and network capacity limits are reached, new DER connections are facing low or zero export limits. These static limits prevent DER access to the energy and ancillary service markets, and contribution to network services, even when network conditions are sufficient to allow it. Customers may have the option to fully fund network augmentation required to carry their additional export, however this is generally uneconomic for an individual connection point and small DER

measure has already been demonstrated as an enabler of greater benefits from virtual power plants (VPPs) and is expected to enhance the benefits from other DER integration measures.

Technical standards and controls have a major role to play in facilitating DER integration in the NEM. Recent policy reforms have progressed standards to improve visibility and control of DER[6]. It is likely that progress will continue to be made on this front. Of note, there are also some early signs that the potential of technical standards and controls may extend to supporting EV orchestration as EV uptake increases in Australia. These could be implemented alongside tariff measures, to optimise charging and minimise costs and technical impacts for the distribution network. Hardware and software approaches are being developed and trialled as levers to allow DNSPs to control or influence the timing and volume of charging in their networks. Many of these trials are still in their early stages and concerned with understanding customer behaviour, as well as the merits of different technical approaches. EV orchestration with hardware and software control has the potential to be a stronger and more dynamic and locational control option for DNSPs, complementary to tariff reforms. An example of this is the Jemena dynamic EV charging trial.[7]

Community batteries may or may not be considered as DER, depending on whether one defines DER as customer-owned behind-the-meter smart devices, or whether a broader definition is adopted. Community batteries could be owned by a DNSP (or a ring-fenced affiliate of the DNSP if also used to provide services other than network services), or alternatively owned by a non-related third party, and positioned on the low voltage network or in a substation rather than behind-the-meter.[8] However, by positioning a battery in a network area where DER export is high (particularly solar PV), community batteries can be used to time-shift some of the DER export to the wider network and thereby better manage network conditions. There are a number of community battery trials underway in the NEM, investigating the potential of this non-tariff option to address DER integration challenges in specific locations.

While we believe each of these non-tariff options have important roles to play in DER integration, consistent with our brief from the ESB, we focus on direct procurement as the main non-tariff measure of interest in this report.

4.2 Network tariffs

4.2.1 Regulatory requirements/incentives on DNSPs for reform

Each DNSP in the NEM is regulated under a revenue cap form of price control mechanism. A revenue cap places a cap on the total revenue a DNSP can earn each year, and includes an overs and unders

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capacity, and also doesn't guarantee the customer will receive the access they've paid for (i.e. access rights remain non-firm for export).

[6] For example: AEMC, *Technical Standards for DER*, 2021 https://www.aemc.gov.au/rule-changes/technical-standards-distributed-energy-resources, and SA Government, *Voltage ride through*, 2020 https://www.energymining.sa.gov.au/energy_and_technical_regulation/energy_resources_and_supply/regulatory_changes_for_smarter_homes/voltage_ride_through

[7] https://arena.gov.au/projects/jemena-dynamic-electric-vehicle-charging-trial/

[8] implementing-community-scale-batteries-bsgip.pdf (arena.gov.au)

account, which allows the DNSP to account for any differences in actual revenue from target revenue in the revenue cap of future years.

We consider a revenue cap has a broadly neutral incentive on a DNSP's incentives to pursue tariff reform, at least within the five year regulatory period. This is because regardless of how efficiently or inefficiently a DNSP sets its tariff structures, it will earn the same amount of revenue. If the regulated return is set above the DNSP's true cost of capital, then in the longer term, the DNSP may have an incentive not to pursue tariff reform in order to increase its regulated asset base and earn excess returns.

Around a decade ago in some NEM jurisdictions, such as Victoria, DNSPs were regulated under a weighted average price cap. Under this form of price control mechanism, the revenue earned by the DNSP depended on the prices that the DNSP sets for each of its services and the volume of sales of each of its services. A cap is placed on the weighted average of these movements.[9] A theoretical property of the weighted average is the DNSP is meant to have an incentive to set its tariff structures efficiently – that is, in such a way that the marginal tariffs reflect marginal costs as far as possible.[10] However, the AER found little evidence of this theoretical incentive to set efficient tariffs being borne out in practice when comparing the outcomes of DNSPs under different forms of regulation.[11]

Overall, we consider the best outcome that can be achieved through the choice of form of control mechanism is a neutral financial incentive on a DNSP's incentive to adopt tariff reform. Therefore other mechanisms are needed to drive reform. This is achieved in the NEM through regulatory process obligations on DNSPs by requiring them to submit a Tariff Structure Statement (TSS) proposal to the AER for review and approval.

In 2014, the AEMC amended the distribution network pricing arrangements in the NER in response to rule change proposals from the COAG Energy Council and IPART.[12] This introduced the TSS framework now in place. Since 2017, each DNSP's TSS is required to include:

- The tariff classes into which customers will be divided
- The policies and procedures the DNSP will apply for assigning or re-assigning customers to tariffs
- The structures and charging parameters for each tariff – such as whether the tariff is a flat rate tariff, time-of-use energy tariff, peak demand tariff or critical peak tariff; and the times for any peak, shoulder or off-peak charging windows and how peak demand or critical peak demand will be measured (if applicable)

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[9] For example, if a service has increasing volumes than the DNSP will be allowed to raise the price of this service less than if the service had decreasing or had a slower growth in volumes. There is no overs and unders account with this form of regulation.

[10] Where the tariffs are set so that the marginal prices approximate marginal cost, the DNSP is thought to have little incentive to increase or decrease sales at the margin, so it has no particular incentive to deter energy efficiency initiatives. At the same time, the risk arising from differences in forecast and out-turn cost drivers would be minimised.

[11] AER, *Discussion paper – Control mechanisms for standard control electricity distribution services in the ACT and NSW*, April 2012.

[12] AEMC, *Rule determination – Distribution network pricing arrangements*, November 2014.

- A description of the approach the DNSP will take in setting the level of each tariff during the annual pricing approval process
- An accompanying indicative price schedule of each tariff for each year during the regulatory period – these indicative prices do not bind the DNSP during the annual pricing approval process, however, the DNSP must explain any material departures from these indicative prices.[13]

DNSPs must engage with consumers in developing their proposal and explain how they have sought to address any concerns raised. The NER establish a network pricing objective and series of pricing principles that are to guide the development of the DNSP's proposal and the AER's assessment. If the AER does not accept a DNSP's TSS proposal, it may amend the TSS, however, the AER's discretion is limited to basing its amended TSS on the DNSP's proposal and varying it to the extent necessary to comply with the network pricing objective and principles.[14] This TSS assessment process runs parallel to the regulatory process to set the DNSP's revenue cap. Both TSS and revenue cap process repeats on a five year cycle.

This framework was designed to maintain a DNSP's "ownership" and control over the network tariffs that apply in its distribution area, while also providing greater regulatory oversight and stakeholder engagement than applied previously.[15] In principle, this enables a DNSP to tailor its network tariffs to the circumstances of its network and reflect the preferences of customers specifically within its distribution area. In practice, this occurs to a reasonable degree, however, this framework also results in complexity and differences between DNSPs' network tariff structures, including between DNSPs in the same state, which are unrelated to differences in network circumstances or customer preferences.

The pricing principles seek to establish a balance between economic efficiency and customer impact principles. The network pricing objective in the NER is that a DNSP's tariffs should reflect the DNSP's efficient costs of providing services to the customer. The pricing principles are that:[16]

- Expected revenue from each tariff class must lie on or between the standalone cost (upper bound) and avoidable cost (lower bound) of serving customers in that tariff class – this is a standard economic test for the presence of cross-subsidies
- Each tariff must be based on the long run marginal cost (LRMC) of providing the service having regard to the costs and benefits of calculating and implementing the method, as well as how the cost of servicing customers differs between locations and times
- Expected revenue from each tariff must reflect the DNSP's total efficient costs, when summed with the revenue from all other tariffs reflect the DNSP's revenue cap, and recover this revenue in a way that minimises distortions to efficient price signals
- A DNSP must consider the impact on customers of changes in tariffs from year to year and depart from the economic efficiency principles above to the extent necessary having

[13] *National Electricity Rules*, clause 6.18.1A.
[14] *National Electricity Rules*, clause 6.12.3.
[15] AEMC, *Rule determination – Distribution network pricing arrangements*, November 2014, p.86.
[16] The AEMC's recent draft rule determination on DER access, pricing and incentive arrangements proposes to amend several of these principles.

regard to the desirability of transitional periods to efficient prices, the extent to which customers can choose the tariff they are assigned to, and the extent to which customers can mitigate the impact of tariff changes through their usage decisions

- Tariff structures must be reasonably capable of being understood by customers having regard to the type and nature of those customers, and the information provided and consultation undertaken with those customers
- A tariff must comply with the NER and all applicable regulatory instruments – this includes jurisdictional regulatory instruments issued by state or territory governments[17]

This TSS framework provides a high degree of certainty on tariff structures and assignment arrangements for retailers and customers, until the next periodic five year review.

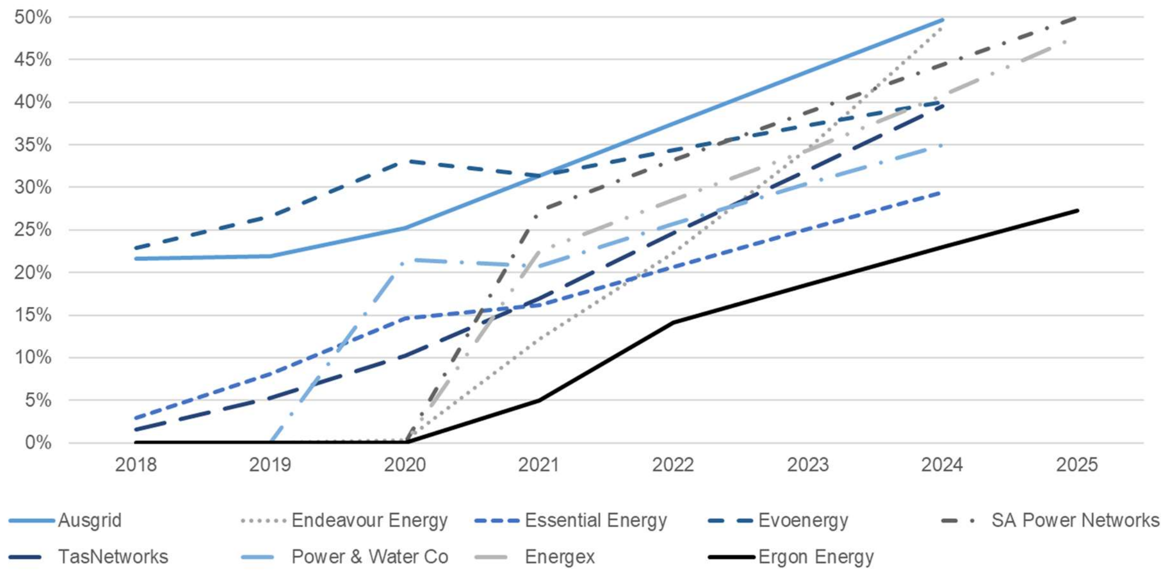
4.2.2 Current arrangements

The first round of TSS was introduced midway through DNSPs' five year regulatory periods as a transitional measure. The second round of TSS aligned with the five year regulatory period used for revenue cap setting. The TSS framework was initially slow to produce substantive change, however, material changes in the pace of network tariff reform are beginning to emerge in the second round of TSS's.

Figure 8 outlines the percentage of residential customers who are forecast to be assigned to a cost reflective network tariff (which refers here to either a time-of-use energy tariff or a demand tariff). These forecasts were made by the individual DNSPs and consolidated by the AER. As can be seen, under the pre-TSS framework only two DNSPs had any material proportion of residential customers assigned to cost reflective network tariffs, whereas from 2020 onwards, this proportion is expected to increase significantly across most DNSPs. This increase from around 2020 onwards is the result of reforms adopted in the second round of TSS's.

[17] *National Electricity Rules*, clause 6.18.5.

Figure 8 Percentage of residential customers assigned to a cost reflective network tariff



Source: AER

Metering technology is the main technical barrier to implementing cost reflective network tariffs, with the rollout of smart meters being a key enabler for network tariff reform. For residential customers with a smart meter, the DNSP's tariff assignment policy set out in its TSS is the next major enabler of tariff reform.

In the first round of TSS, the AER accepted DNSPs proposing either 'opt-in' or 'opt-out' cost reflective tariff assignment policies for residential network tariffs. It is important to remember that this refers to the structure of the network tariff that the DNSP charges the retailer. Specifically, whether DNSPs charge the retailer a cost reflective network tariff only if the retailer opts-in to being charged this way, or whether a cost reflective network tariff applies by default unless the retailer opts-out of being charged under these arrangements. Retailers are not required to reflect network tariff structures in retail tariff structures. Whether and how retailers respond to cost reflective network price signals in structuring their retail offers is largely a commercial decision of the retailer.[18]

For the second round of TSS, the AER has required all DNSPs to move at least to an opt-out arrangement, and has also considered tariff assignment policies where retailers cannot opt-out of being charged a cost reflective network tariff.

For most DNSPs, cost reflective network tariffs are being charged to retailers incrementally for customers in one or more of the following circumstances. The particular tariff assignment criteria applied differs between DNSPs but includes:

[18] This may also be influenced by retail price regulation, where this exists, particularly in regional Queensland where retail price regulation includes regulation of retail price structures for residential customers.

- New connections to the distribution network – this typically refers to new premises, rather than existing premises changing retailer or account holder
- The installation of new rooftop solar PV
- Upgrading from a single phase to three phase connection
- The ownership of an EV or installation of an EV charger – for example, the assignment of EV owners to a cost reflective network tariff is a new Victorian Government requirement for the 2021-2026 regulatory period. Implementing criteria such as this, however, requires DNSPs to be able to identify those customers with an EV which can be challenging due to a lack of visibility.
- The installation of a new smart meter for any reason including end-of-life replacements to the previous accumulation meter
- The installation of a smart meter in the past for any reason

Sometimes the retailer is charged the cost reflective network tariff for the relevant customers from the point the above tariff assignment criteria trigger occurs, and sometimes it is from 12 months after this trigger. In the latter case, this is to provide a 12 month data sampling period to provide the retailer and customer with 12 months' worth of smart meter data to better understand the customer's consumption profile before cost reflective network tariffs are charged to the retailer.

In some cases (e.g. TasNetworks), the above tariff assignment trigger means the retailer is charged a default cost reflective network tariff for that customer, but the retailer can opt-out to a non-cost reflective network tariff such as a flat rate or block rate network tariff. In other cases (e.g. Ausgrid), the retailer can choose from alternative cost reflective tariff designs but cannot opt-out to non-cost reflective legacy tariffs.[19] For some DNSPs the default residential cost reflective network tariff is a peak demand based tariff and for others it is a time-of-use energy network tariff. For all DNSPs, the AER requires the DNSP to have both demand and time-of-use energy tariffs within its portfolio of network tariffs, to enable retailers to have a choice over which cost reflective network tariff structure they are charged for particular residential customers.

Where opting-out to legacy non-cost reflective tariffs is adopted, the AER requires the cost reflective tariffs to be discounted relative to the legacy tariffs, to provide an incentive for customers to remain on the cost reflective tariffs.

SA Power Networks' has the most cost reflective tariff assignment policy for residential customers in the NEM. From 1 July 2021, retailers will be charged a cost reflective network tariff for all residential customers with a smart meter in South Australia. This will also apply to all residential customers who install a smart meter in the future for any reason. Overnight on 30 June 2021, this is expected to result in the number of residential households assigned to a cost reflective network tariff increasing from close to zero currently to over 20% of all households. Similar tariff assignment policies will also apply in Queensland from 1 July 2021.

In our assessment of the effectiveness of current arrangements in the next chapter, we have assumed these different levels of reform between DNSPs continues into the future. And we have

[19] Whether the forecasts in Figure 8 eventuate will depend on whether the DNSP's tariff assignment policy permits retailers to opt-out of cost reflective network tariffs and the degree that opt-out occurs in practice.

assumed cost reflectivity for residential network tariffs continues to be focused on temporally granular charges, rather than locational differences.

4.3 Direct procurement

As noted in section 4.1, there are a range of non-tariff mechanisms with the potential to support DER integration. This section will focus on the direct procurement of network support by DNSPs. Direct procurement of network support from DER has the potential to play an important complementary role alongside tariff reform. While tariff reform can provide network-wide incentives for more efficient network use, particularly reducing peak load, direct procurement provides an opportunity for more dynamic and locational control of network usage when needed. It is a particularly valuable complementary measure for tariff reform given, in practice, tariffs typically provide little or no locational signals while network constraints and technical issues are often very location specific and localised. See Box 1, below, on non-tariff mechanisms in lieu of location-reflective tariffs.

Box 1: Non-tariff mechanisms in lieu of location-reflective tariffs

Clause 6.18.5 of the NER outlines the pricing principles DNSPs must adhere to when setting tariffs. The principles include that tariffs should reflect the long run marginal costs of providing electricity to customers, with consideration of the location of retail customers and the extent to which costs vary between different locations in the distribution network. However, location differentiated tariffs are not typically observed in the NEM, with most DNSPs finding customers are generally not supportive of introducing this differentiation. In South Australia, the government has mandated that SAPN cannot provide locationally different tariffs for small users.

Non-tariff mechanisms, such as direct procurement of network support, offer an opportunity to address the intent of this pricing principle through another means.

Direct procurement is expected to deliver material benefits for all customers in the long run, by providing a lower cost means of meeting network needs than alternative options. In particular, it may enable deferral of network augmentation and other forms of network costs. Because direct procurement is a complementary approach to tariff reform, it can unlock benefits above and beyond those achievable with tariffs.

4.3.1 Regulatory requirements/incentives on DNSPs for reform

While a detailed assessment of the regulatory landscape is beyond the scope of this report, we note ongoing concerns by some in the sector that there are regulatory barriers to greater adoption of non-network solutions (such as direct procurement) by DNSPs.

For example, there remains a concern that there is unequal treatment of capital expenditure (capex) and operational expenditure (opex) in the regulatory investment test (RIT-D) and in the financial incentives for DNSPs[20] Various reviews by government and market bodies have formed different conclusions on the extent and direction of any capex or opex bias[21,22].

In terms of potential bias in the RIT-D, this concerns whether DNSPs are incentivised to seek approval for expenditure on capital (eg. poles and wires) projects rather than non-network alternatives. We note that the AEMC has a rule change request pending which is seeking to change the RIT-D rules to better incentivise non-network solutions, including by lowering the expenditure threshold for applying the RIT-D[23].

In terms of potential bias in the DNSP financial incentives, this concerns the post-allowance determination incentive mechanisms which drive actual DNSP expenditure, to reward efficiency and other outcomes. There have been a number of reforms over the last few years to adjust the financial incentives to reflect the potential benefits and costs savings from integrating demand-side participation, and balance out any capex bias. The AER's reform of demand management incentives was intended to balance capex and opex incentives by increasing the returns to non-network solutions, though we understand many DNSPs are yet to adopt this updated version of the demand management incentive scheme and allowance.

Regulatory process requirements to encourage reform include that DNSPs are now required to publish a demand-side engagement strategy. Though these strategies do not appear to go through the same level of stakeholder engagement and regulatory scrutiny as occurs for TSS proposals.

Notwithstanding these attempts to balance up capex and opex incentives, whether or not the capex and opex financial incentives are balanced or biased within the regulatory regime, in practice, is only part of the answer. The perception by DNSPs of any bias in the incentives is just as important, if not more important, than the reality because it is this perception that is likely to drive the actions of DNSPs.

4.3.2 Current arrangements

For the most part, direct procurement of network support from DER by DNSPs appears to us to remain in trial phase with deployment in small-scale projects and does not yet form part of standard business operations in the NEM.

These direct procurement trials are developing and demonstrating the software and hardware capabilities to exchange real-time and locational information with aggregators and to manage network needs with changes in DER export or load volumes[24]. A key aspect of these trials from a DNSP's perspective is to understand how coordinating a DER fleet can impact on network conditions. The real world and simulated trials seek to make efficient use of network capacity and the potential of DER while maintaining the network within its technical limits.

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[20] AEMC, *Rule change request ERC0314*, 2020, Lodged by the Australian Energy Council

[21] CEPA, *Expenditure incentives faced by network service providers*, 2018, Final Report for the AEMC

[22] AEMC, *Economic Regulatory Framework Review, Integrating Distributed Energy Resources for the Grid of the Future*, 2019.

[23] AEMC, *Rule change request ERC0314*, 2020, Lodged by the Australian Energy Council

[24] For example, see ARENA, *State of DER Technical Integration Project Summaries*, August 2020; AusGrid, Battery VPP Trial; SAPN, *Advanced VPP Grid Integration Trial*.

Trials appear to be limited primarily to procurement of network support via export from battery devices as part of broader virtual power plant trials, and have had limited deployment for the provision of network support from both import and export using a variety of DER including solar PV (without batteries) and EVs. Further, many of the trials are limited to a single make of battery, a single battery management software, or single aggregator and do not appear to demonstrate how a DNSP could concurrently draw on a range of technologies from a range of aggregators to meet a single network need[25].

As a result of the current focus on export from batteries, the benefits demonstrated from direct procurement to date are primarily generation driven. It is currently less clear that this measure is being, or will be, used to deliver demand driven benefits such as reduced EV charging demand at peak times.

Based on our review of some recent trials, the response is assumed to require 3-4 hours of advance notice under some arrangements, to allow for battery charging if needed, and assumed to be high at above 85% allowing for some non-response with technical communication and data issues[26].

Many of the trials of direct procurement that are underway are being conducted through broader VPP trials which are being run to leverage DER for multiple purposes, not just network service provision. VPPs are an aggregated pool of small generation and storage assets capable of being orchestrated to provide energy or ancillary services – operating in a similar manner to a power plant, in aggregate.

AEMO, SA Power Networks and others have published information on the status of VPP trials in the last few months and some of the successes and implementation challenges they've encountered.[27] Trials have revealed operational challenges which come with establishing systems for the first time (particularly developing and integrating APIs with AEMO) as well as ongoing challenges (e.g. internet continuity issues).

For our current arrangements assessment for this study, we have assumed this limited use of direct procurement continues into the future, with limited further growth in scope or scale. Direct procurement is assumed to be adopted by all DNSPs, with a small percentage of total DER-owning customers involved. It continues to be based around battery dispatch to manage the challenges of peak demand, rather than a demand and generation driven solution incorporating EVs, in particular.

Under this current arrangements assessment, DNSPs are assumed to bilaterally contract with aggregators in their network areas, rather than developing or using a more centralised or standardised market platform. This is retained partly due to some of the challenges faced by aggregators operating in the market, independently of retailers.

[25] For example, many of the trials are being run as partnerships between DNSPs, specific technology providers (such as Tesla, Reposit), and/or aggregators (such as Shinehub).

[26] AEMO VPP demonstration knowledge share reports indicate some challenges with data transfer. Discussion with industry has indicated a lead-time is sometimes required.

[27] AEMO, *Virtual Power Plant Demonstrations Knowledge Sharing Reports (#2, #3)*, 2020 and 2021.

5 Qualitative analysis – ability of current DER arrangements to deliver available benefits

This chapter sets out our qualitative assessment of the effectiveness of the current arrangements for network tariffs and direct procurement, as described in the previous chapter, to deliver the potential benefits of DER integration outlined in chapter 3.

5.1 Reduced network investment (demand-driven benefits)

The following table provides our qualitative assessment of the ability of network tariff reform and direct procurement – under the assumption that current arrangements continue – to deliver the available benefits from avoided network investment set out in chapter 3.

Table 4 Ability for current arrangements to deliver benefits case – demand driven benefits

Evaluation criteria	Network tariff rating	Direct procurement rating
Ability to signal temporal network needs	🟡	🟢🟢
Ability to signal locational network needs	🔴	🟢
Strength of response	🟡	🟢
Reach	🟢	🔴
Ease of implementation and operation	🟢	🟡
Access by providers	🟡	🟡

The network tariff reform ratings reflect that most residential tariff price signals are currently targeted towards temporal granularity (not locational signals) – and particularly static price signals based on hours of the day, with seasonal price signals occasionally adopted but not common.

The higher rating for reach reflects that even under current TSS reforms, the retailers for a sizeable portion of residential EV households could be expected to be charged a default cost reflective network tariffs given the tariff assignment criteria adopted by DNSPs including for new connections (across all DNSPs), for the ownership or installation of an EV charger (by some DNSPs), and for the installation of a new smart meter for any reason (by some DNSPs). Further, in South Australia, retailers will face a cost reflective network tariff for all customers with a smart meter from 1 July 2021, with similar arrangements applying in Queensland.

Direct procurement of network support is able to deliver demand-driven benefits by providing a mechanism for DNSPs to reduce peak demand. DNSPs can do this by directing DER to dispatch or reduce the volume of load at peak times. This can deliver benefits through helping to defer network augmentation that would otherwise be required to address network issues of peak demand.

Direct procurement is capable of signalling temporally-specific network needs to DER for the delivery of network support. This is assumed to be capable of providing intra-day response at a few hours' notice, but is not assumed to offer dynamic support in real-time.

Based on capabilities demonstrated in trials, direct procurement is assumed to be capable of signalling very location-specific network needs. This requires sufficient capacity of participating DER in a given location to achieve a meaningful response to a locational need and is therefore limited to the sites of small-scale deployment under current arrangements.

The strength of response from participants is assumed to be quite high, based on available information about trials to date. We assume issues with communications and data will continue to dampen the strength of response slightly, though this will decrease as systems improve with time.

Implementation is assumed to be challenging under a continuation of current arrangements, with each DNSP continuing to establish its own processes and engage with each aggregator individually. We have not assumed a more centralised or standardised market approach is implemented under a continuation of current arrangements.

Reach is assumed to be low in terms of the proportion of total DER-owners currently participating. It is important to note that we have assessed reach relative to the total DER engagement assumed to be achievable, which is less than 100% assuming there will never be full participation. Reach is assumed to be limited to small-scale projects in each DNSP's network, and focused on batteries rather than expanded to other DER.

Access by providers is assumed to be low, as some of the existing barriers to aggregators accessing a range of value streams and operating independently of retailers remain.

5.2 Reduced curtailment costs (generation-driven benefits)

The following table provides our qualitative assessment of the ability of network tariff reform and direct procurement – under a continuation of current arrangements – to deliver the available benefits from avoided curtailment set out in chapter 2.

Table 5 Ability for current arrangements to deliver benefits case – generation driven reforms

Evaluation criteria	Network tariff rating	Direct procurement rating
Ability to signal temporal network needs	●	●●

Evaluation criteria	Network tariff rating	Direct procurement rating
Ability to signal locational network needs	🔴	🟢
Strength of response	🟡	🟡
Reach	🟢🟢	🔴
Ease of implementation and operation	🟢	🟡
Access by providers	🟡	🟡

The moderate rating on signalling temporal needs under a continuation of current arrangements for tariff reform reflects the current focus on reforming static temporal price signals. We consider given the relatively predictable nature of solar PV output – i.e. unmanaged solar PV driven minimum demand is always likely to occur in the middle of the day – even static price signals can send moderately effective signals, though will send them at all times during the locked-in charging window rather than only when needed. The very low rating on signalling locational needs reflects the lack of locational price signals in current cost reflective residential network tariffs.

The reasonably high rating for reach for network tariffs reflects that the installation of new solar PV is a common tariff assignment policy criteria adopted by many DNSPs to trigger the reassignment of the customer to a cost reflective network tariff. Other commonly adopted assignment criteria, such as new connections, will also capture new premises with solar PV. Further, in South Australia and Queensland where solar PV penetration is currently highest, these DNSPs have tariff assignment policies where any customer with a smart meter installed for any reason will be assigned to some form of cost reflective network tariff from mid-2021.

Direct procurement of network support is able to deliver generation-driven benefits by providing a mechanism for DNSPs to reduce the curtailment of DER-derived generation. DNSPs can do this by directing DER to charge or otherwise increase the volume of load at times of high DER (solar PV) generation. This can deliver benefits by making more of the low cost, low carbon, generation available to the market and potentially displacing the need for additional large-scale generation build.

The potential of direct procurement to both signal temporally-specific and location-specific network needs to DER for the delivery of network support is the same for generation-driven benefits as for demand-driven benefits. The mechanism is technology neutral and capable of providing the same signals to direct DER (via aggregators) up or down.

The strength of response from participants is assumed to be lower than for achieving demand-driven benefits. This is based on the assumption that DER is less available to actively reduce curtailment in the distribution network, as batteries are already expected to be charging to capacity when solar PV is generating and are unlikely to have additional available capacity to absorb the excess generation.

Implementation, reach, and access by providers are assumed to be similar to their evaluation between generation-driven and demand-driven benefits.

6 Quantitative analysis – ability of current DER arrangements to deliver available benefits

This chapter builds on our qualitative assessment in the previous chapter, and sets out our quantitative assessment of the ability of network tariffs and direct procurement to achieve the benefits case outlined in chapter 3.

6.1 Our high level approach to quantify the scope of benefits delivered

The next aspect of our approach to updating the DER benefits modelling was to assess the overall 'size of the prize' for distribution and transmission networks from better system operation and evaluate the scope of benefit that could be achieved based upon the continuation of current arrangements for network tariff reform and the direct procurement of network support services

At a high level we have made a qualitative assessment of the likely performance of tariff and non-tariff options against the criteria described in the previous chapters. As in the qualitative assessment, we have assessed the tariff and non-tariff options as mutually exclusive solutions to improved integration of DER.

The following tables show the interpretation of the qualitative assessment scoring of criteria for the tariff and non-tariff direct procurement options below. These tables take the qualitative ratings from the previous chapter and translate these into a quantitative weighting for the quantitative assessment in this chapter. We have focused on the first four criteria as the fifth criteria (ease of implementation and operation) relates more to costs than benefits, and the sixth criteria (access by providers) is likely to have some overlap with the fourth criteria (reach).

Table 6 Ability to deliver benefits case – demand driven benefits

Evaluation criteria	Network tariffs	Direct procurement
Ability to signal temporal network needs	25%	75%
Ability to signal locational network needs	0%	50%
Strength of response	25%	50%
Reach	50%	0%

Table 7 Ability to deliver benefits case – generation driven benefits

	Network tariffs	Direct procurement
Evaluation criteria	**Low case**	**Low case**
Ability to signal temporal network needs	50%	75%
Ability to signal locational network needs	0%	50%
Strength of response	25%	25%
Reach	75%	0%

These scores are then factored by an appropriate weighting given to each criteria. These reflect:

- That signalling both temporal needs and locational needs are important (15% weighting each), as is the strength of the response (10% weighting). Collectively these criteria go to the cost reflectively of the design of the tariff or non-tariff option and these design criteria are afforded a 40% aggregate weight.
- That even the most cost reflective designed option will have little impact if it is applied to only a very small number of residential customers. Therefore, the extent that the tariff or non-tariff option is widely adopted, as reflected in the reach criteria, is given a 60% overall weight.

Table 8 Qualitative criteria weighting by benefit category

Benefit Category	Temporal need	Locational need	Strength of response	Reach
Distribution and transmission network deferral benefits (demand driven)	15%	15%	10%	60%
Distribution and transmission network deferral benefits generation driven)	15%	15%	10%	60%

Having established the available benefit for each factor by benefit category, we combined this with the qualitative scoring presented in the previous chapter to assess how tariffs (as defined in the current arrangements) and non-tariff direct procurement solutions (as defined in the current arrangements) could capture the available benefits from optimal integration of DER.

6.2 Network tariff and direct procurement results

The results show a quantitative representation of the performance of tariffs and non-tariff direct procurement solutions in capturing the available benefits defined in our updated ESOO 2020 DER benefit model. Figure 9 and 10 below show a similar trend between the ESOO 2020 central scenario and the ESOO 2020 step-change scenario, where our qualitative assessment leads tariff reform to outperform non-tariff (direct procurement) through greater capture of the potential demand and generation driven benefits. Neither tariff or non-tariff options are able to fully realise the DER benefits by themselves, which emphasises the need for both tariff and non-tariff direct procurement reforms to occur, building on progress made to date under current arrangements.

Figure 9 ESOO 2020 central scenario tariff and non-tariff performance

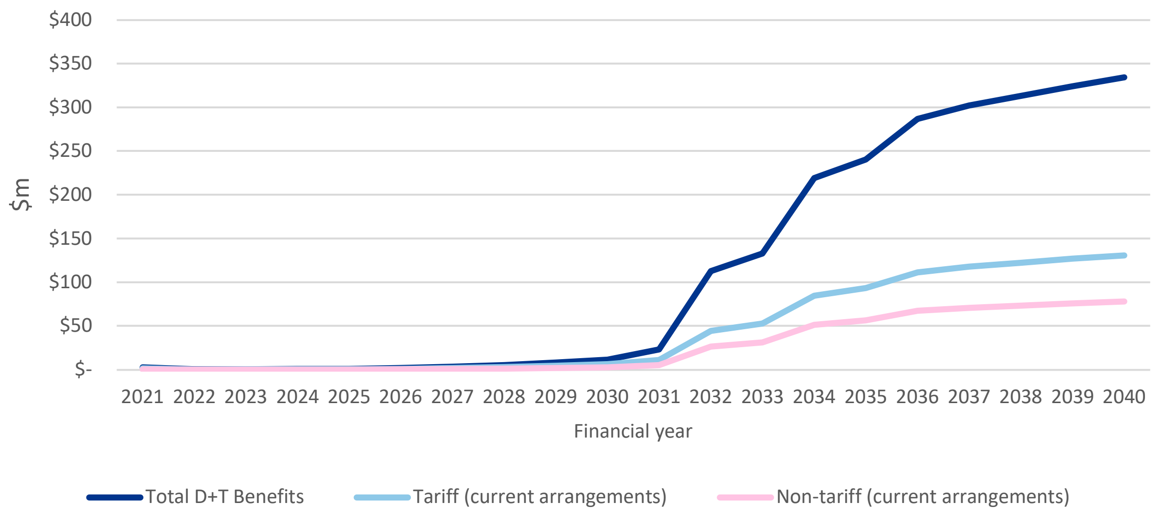
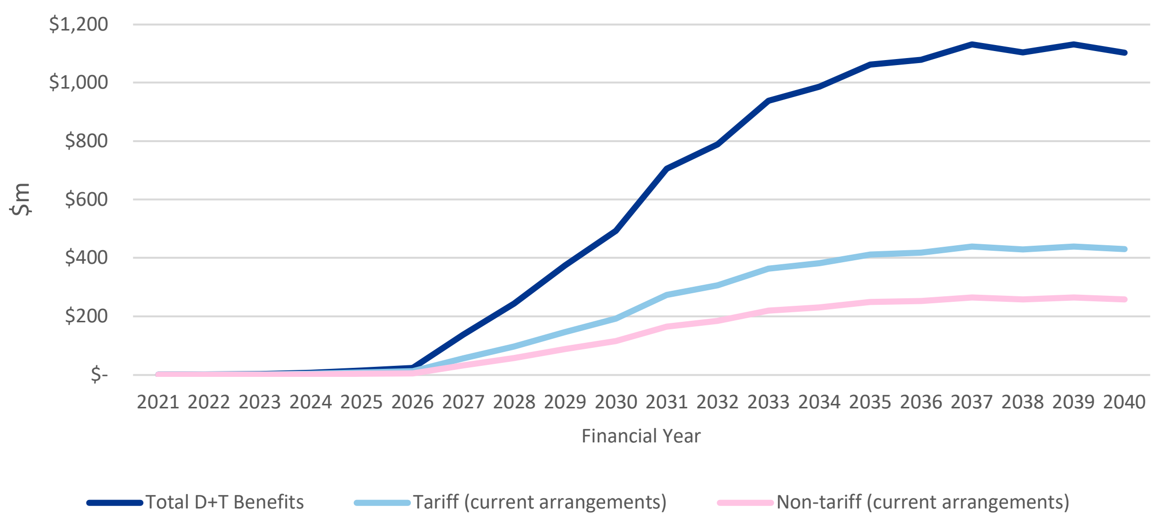


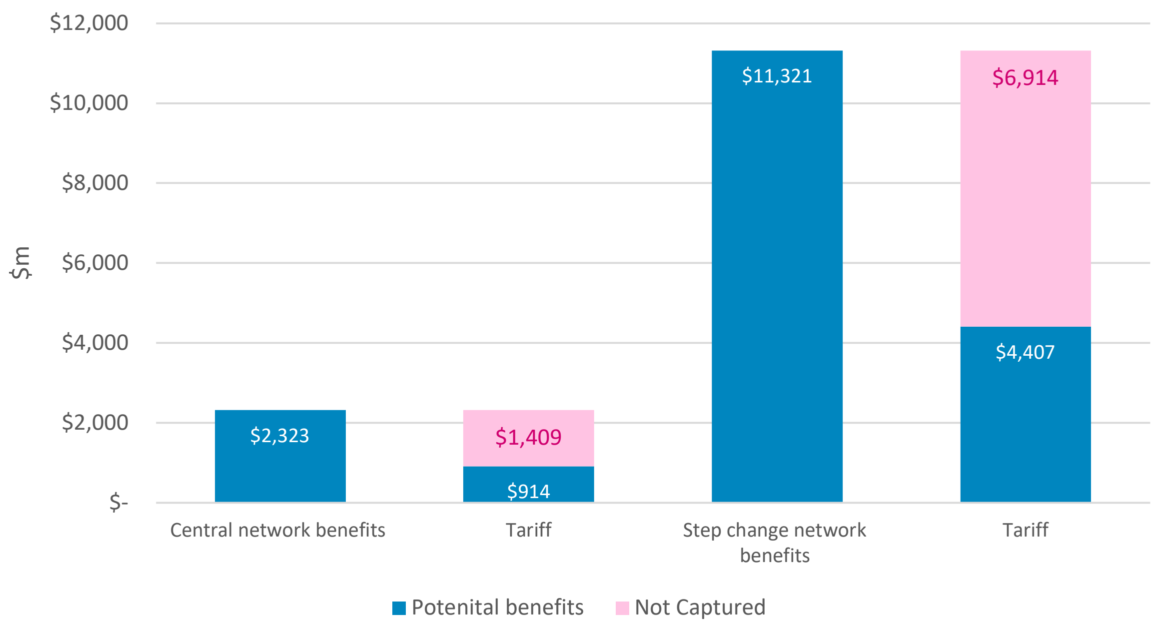
Figure 10 ESOO 2020 step change scenario tariff and non-tariff performance



Aligned with expectations, we find that in both the central and step change scenarios, the current arrangements for tariff and non-tariff direct procurement are not able to capture all of the available benefits (size of prize), signalling reform is needed in both areas to make greater progress towards optimal system operation in the efficient integration of DER.

Uncaptured benefits as a result of the qualitative assessment are largely driven by different factors for the tariff and non-tariff options. Figure 11 below shows that our assessment on tariffs (as described under the current arrangements) leave a $1.4bn gap in the central scenario and a $6.9bn gap in the step change scenario where there is greater scope of network benefits driven by higher DER forecasts.

Figure 11 Benefits captured by current arrangements on tariffs

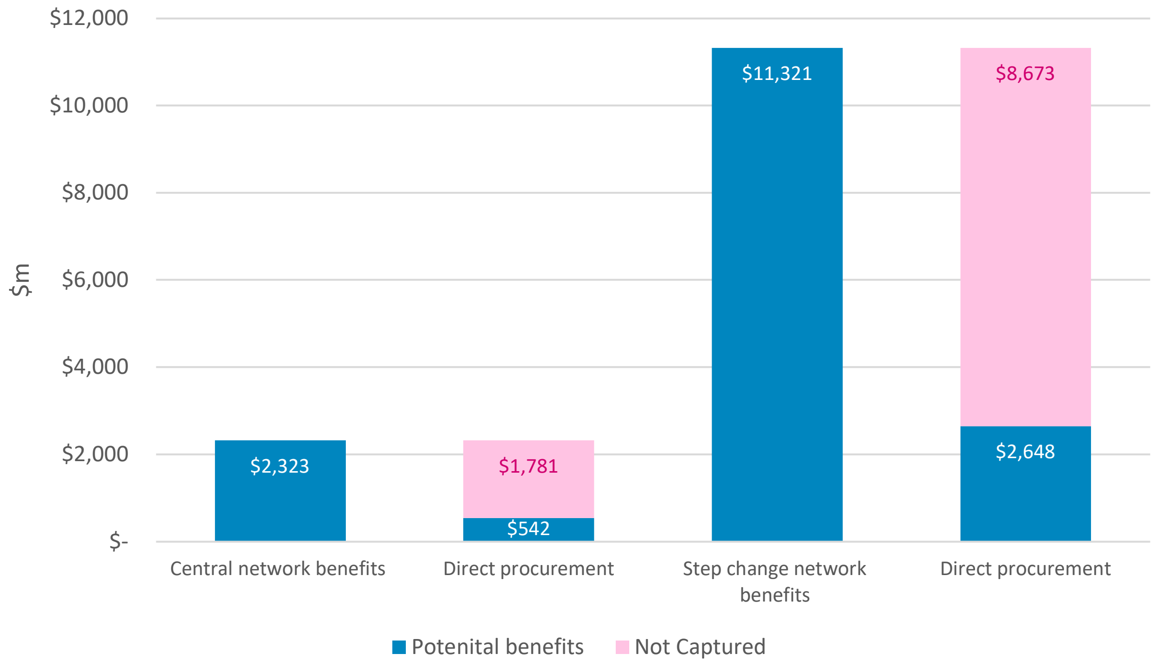


The performance of tariffs in our assessment is impeded by the ability to signal a dynamic temporal and locational price signal and consequently drives a moderate strength of response, though tariffs perform well in regard to their wider reach.

Figure 12 below shows that our non-tariff (direct procurement) assessment leaves a larger $1.7bn gap in the central scenario and a $8.7bn gap in the step change scenario where there is greater scope of network benefits driven by higher DER forecasts. Overall, non-tariff direct procurement under current arrangements performed less well compared with our assessment on tariffs.

Non-tariff direct procurement performance is unable to capture the full scope of benefits largely due to the level of reach, which is weighted as the most important factor, despite the potential for highly temporally and locationally granular signals. This is also reflective of the low maturity of direct procurement solutions in use under current arrangements.

Figure 12 Benefits captured by current arrangements on non-tariffs



7 Further reform to unlock available DER integration benefits

In the previous chapters, we outlined the current arrangements for network tariff reform and direct procurement, and our qualitative and quantitative assessment of a continuation of these current arrangements to deliver the potential benefits of efficient DER integration. In this chapter we outline further reforms that could assist in network tariff reform and direct procurement capturing a greater portion of the 'size of the prize' that is possible from efficient DER integration.

7.1 Network tariffs

7.1.1 Further reforms

We consider further network tariff reform can and should be pursued even under the existing TSS rules framework. In addition, the DER access, pricing and incentives rule change process currently before the AEMC would enable a greater set of innovative tariff reforms to develop.

The network pricing objective and distribution pricing principles guide the development of DNSPs' TSS proposals and the AER's assessment of those proposals. Even under the current rules framework, the AER expects DNSPs to propose additional and incremental sets of reforms in each new TSS period to maintain compliance with the pricing objective and principles.

We consider the following set of further tariff reforms could and should be considered even if there were no changes to the current rules framework. We have developed this set of recommendations in consultation with the AER. Specifically:

- We note tariff reform is an iterative process advancing every reset period both in terms of number of customers whose retailer is charged some form of cost reflective tariff and in terms of the cost reflectivity of tariffs
- We recommend consideration be given to all third round TSS's for each DNSP reaching the same tariff assignment policy standard set by SA Power Networks in its current TSS – that is, that retailers are charged a cost reflective network tariff for each residential customer with a smart meter, regardless of when the customer received the meter or the reason the customer received the meter. And we further recommend consideration be given to retailers not being able to opt-out to non-cost reflective legacy network tariffs for those customers. As the installation of new solar PV or an EV fast charger would ordinarily require a smart meter, if this approach is adopted, this means for all such residential households, the retailer will be charged some form of cost reflective network tariff sending a price signal to encourage the efficient integration of that DER device.
- We note tariff structures are becoming cost reflective over time – evolving from simply signalling peak demand constraints towards also pricing in the cost of minimum demand constraints and we expect this evolution to continue.

- We consider the temporal granularity of cost reflective network tariffs for residential tariffs should continue to improve (e.g. greater seasonal differences and potentially dynamic critical peak elements in some circumstances)
- We recommend retailer (and aggregator or other third party) products and services that help customers respond to these price signals, or develop smart products that automatically respond to price signals, continues to develop and become more widely available.

We assume the DER access, pricing and incentive arrangements rule change, currently at draft rule stage, continues to final rule stage in a similar form. This would mean for the third round TSS proposals, DNSPs could propose import charges or credits, as well as proposing export charges or credits, depending on network conditions at different times and possibly also different locations. It also improves the pricing principles to clarify that retailers are the target audience for network pricing signals, and opens up new potential options for cost reflective network tariff structures such as retailer aggregate tariff structures, where a retailer would be charged on the aggregate load profile of all its customers, or groups of customers, within an area. We consider a retailer aggregate model of network tariffs has significant potential to create stronger, easier and more innovative ways for retailers or aggregators to respond to network price signals.

We also assume the locational granularity for large user network tariffs continues to be improved from the current low base, however, that locational granularity for residential import network tariffs remains limited. On the other hand, we consider the locational granularity may be incorporated in the introduction of export charges or credits, given the likely locational cost differences. And that locational differences in export charges may be more acceptable than import charges as exports do not involve the same energy-as-an-essential-service characteristics that electricity imports have (e.g. for heating, cooling, lighting and cooking)

We consider this rule change process should be swiftly followed by trials on the new network tariff structure options that may be made possible by this rule change process, so that those trials can inform tariff structure design in the next round of TSS's.

As tariff structures are locked in for the 5 year TSS period, the earliest the above further reforms could be introduced would be at the start of the third round of TSS's. This means:

- In 2024-25 for DNSPs in NSW, the ACT and Tasmania
- In 2025-26 for DNSPs in South Australia and Queensland, and
- In 2026-27 for DNSPs in Victoria

Further, we consider the TSS framework in Australia has several advantages and disadvantages. Overall, we consider the main disadvantages of the TSS framework which are a potential barrier to achieving the target case are that:

- The individual DNSP's "ownership" of its tariff strategy creates significant and unnecessary differences between different DNSP's tariff structures, charging parameters, tariff assignment policies, and even terminology. This adds an administrative complexity barrier to retailers, and ultimately consumers, responding to cost reflective network price signals.

- The relatively short prescribed (45 business day) timeframe between the AER's draft decision and DNSP's revised TSS proposals creates a practical barrier to how many changes the AER can require the DNSP to make in that period – to overcome this, the AER has previously published "future direction" commentary to flag its expectations to DNSPs ahead of the submission of DNSPs' second round TSS proposals of the type and pace of reforms the AER expects to see in those proposals.
- Focus is placed on the TSS elements prescribed in the NER to the exclusion of other potential enablers of tariff reform (e.g. simplifying and unifying the practical procedural process for retailers to request tariff reassignments from DNSPs).

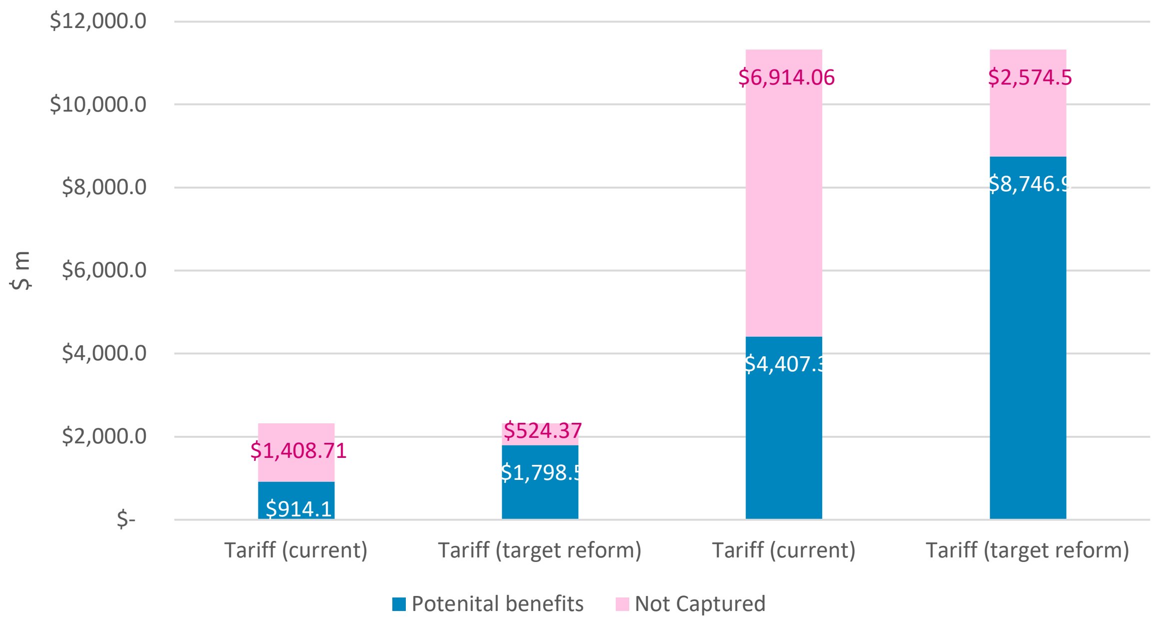
To help alleviate the first two barriers, the AER could consider establishing and publishing a similar "future direction" commentary for tariff reform ahead of DNSPs' third round TSS proposals. The requirement in the AEMC's recent draft rule change for the AER to publish an export charging guideline will also help early engagement with stakeholders and establishing advance notice to DNSPs of the AER's expectations on what it required for a compliant proposal.

7.1.2 Impact of further reforms

If these further reforms to network tariffs are undertaken, we estimate a further $884m of network benefits could be unlocked under the central scenario and $4.3bn could be unlocked in the step change scenario, over and above the benefits that could be delivered by current arrangements. This would increase the estimated portion of the 'size of the prize' of network benefits that could be realised to $1.8bn under the central scenario and $8.8bn under the step change scenario.

This is shown in Figure 13 below with the central scenario current and target reform benefits on the left of the chart and step change scenario benefits for current arrangements and target reform on the right of the chart.

Figure 13 Potential impact of tariff reform on benefit capture



The assumptions driving this increase in available benefit capture compared with our assessment of current arrangements are:

- 100% residential households with DER and a smart meter are assigned a more cost-reflective tariff from the third round of TSS onwards.
- We factor in that temporally granular network tariffs are expected to improve in cost reflectivity, though largely remain as static price signals
- We factor in some but very limited introduction of locational price signals in network tariffs.
- We assume there is some movement towards more innovative network tariff measures which are targeted towards the aggregated load profiles of retailers, rather than based solely on an individual customer's load.

7.2 Direct procurement

7.2.1 Further reforms

Direct procurement of network services (load and supply flexibility) from DER has the potential to deliver substantial benefits by enabling DNSPs to address technical challenges and network needs when and where it is required.

At present, the scale of direct procurement and the benefits delivered are limited. To the most part, this is because the technologies, business models, and implementation systems required to enable direct procurement are still being developed and finessed through trials and relatively small demonstration projects. DNSPs are dependent not only on development and trialling of their own systems and technologies, but also those of the aggregators, technology providers, and other intermediaries required to procure load and supply flexibility from consumers. Given DER is likely to be aggregated for the provision of a broader range of energy and ancillary services, rather than only network services, the uptake of direct procurement is also dependent on the development and trialling of VPPs facilitating access to these markets.

The scale of direct procurement at present is also limited by the rate of DER uptake by consumers. As DER uptake – particularly residential battery storage systems – increases in the future, with technology costs expected to continue to fall, the pool of potential providers of DER-based network services will naturally increase.

In addition to continuing to pursue trials, moving toward making direct procurement a standard business practice for DNSPs, and awaiting wider DER uptake, there are a number of other factors which could help to unlock more of the potential benefits in the future.

Potential regulatory barriers

As identified in Section 4.3.1, the continued debate on the existence of a potential bias between capex and opex in the RIT-D and/or in the post-allowance financial incentives on DNSPs is something which has attracted, and continues to attract, attention.

Addressing the potential capex bias in the financial incentives, in particular, has been the focus of numerous reviews and has led to reforms which seek to incentivise investment in demand-side solutions. Reforms such as changes to the demand management innovation allowance and the requirement to report demand-side engagement strategies are potentially valuable in progressing toward a more balanced approach to network solutions. However, we consider it will be important to continue to monitor the incentives framework and how it is applied to assess the effectiveness of these recent reforms after a period of time.

The potential capex bias in the regulatory investment test and related regulations is something which has come under scrutiny both at the distribution and the transmission levels in the past few years.[28] This includes whether DNSPs are incentivised to consider network and non-network solutions to address an identified need, and whether they are assessing these and their relative costs and benefits on a level playing field. It also involves whether the test itself and the criteria for applying it incentivise networks to seek approval of network and non-network solutions equally. As noted previously, there are divergent views on whether a capex bias exists.

A rule change request lodged by the Australian Energy Council in 2020 (currently pending with the AEMC[29]), proposed that a capex bias in the RIT-D persists, and that the test should be applied when the estimated capital cost for the most expensive credible option is over $1 million (down from the existing threshold of $6 million) to allow DNSPs to progress more non-network solutions through this mechanism. This request is still pending and the AEMC has not yet published any documents reviewing the proposal, however the request itself demonstrates that this is still an area of debate

[28] CEPA, *Expenditure incentives faced by network service providers*, 2018, Final Report for the AEMC; AEMC, *Economic Regulatory Framework Review, Integrating Distributed Energy Resources for the Grid of the Future*, 2019.

[29] AEMC, *Rule change request ERC0314, 2020*, Lodged by the Australian Energy Council

among the industry. Real and perceived regulatory barriers to non-network investment should be identified, addressed and monitored to promote industry confidence that direct procurement, and other solutions, are not overlooked for traditional network solutions when they provide opportunities to deliver greater benefits for consumers.

Technology and supplier diversity

Expansion of direct procurement trials and deployment projects to engage a wider range of DER technologies, technology providers and aggregators, will be important to working through the technical and commercial challenges of direct procurement, providing a trajectory to wider use of this mechanism in the future.

Trials are necessarily small in scale and scope, and primarily undertaken in a partnership arrangement between individual companies and technology types, to develop and test capabilities. To access a more fulsome suite of benefits in the future, it will be important that individual DNSPs are able to procure network services from a wide range of aggregators, to maximise the pool of DER customers they can access in their network area.

Further, the benefits leveraged from DER through direct procurement in the future will be enhanced if incorporating a diversity of technology types (for example, solar, storage, and EVs) from a range of technology providers.

Market access

From a regulatory perspective, there have been significant reforms over the last decade to enable aggregators, and aggregated DER, to contribute energy, FCAS, and demand response to wholesale markets. Enabling two-sided participation continues to be a focus of governments and energy market bodies, including through this Post-2025 Market Design work program and through AEMO's VPP demonstrations work.

These regulatory changes support the ongoing growth of the DER aggregation sector by removing barriers to entry and increasing the value streams aggregated DER can access. Growth of the aggregation sector broadly can be expected to aid DER orchestration and the pool of participating DER available for DNSPs to procure network services from. We do not assume many DER owners will sign up with aggregators solely to be available for network support services. More likely, aggregators will engage DER owners to be available for the provision of a range of services – energy, FCAS and network support services.

We have not undertaken a comprehensive regulatory assessment as part of this study, but note that other recent reviews and publications have identified a number of regulatory barriers which remain, and which could be addressed to support DER aggregation and network service procurement[30].

Currently, DER aggregators can provide and monetise both energy and FCAS services from DER if they register as, or engage in a commercial arrangement with, a retailer (this is required for the energy component, specifically). We understand this is the approach adopted for most VPPs to date. There are limitations to DER accessing value from both energy and FCAS without this retailer

[30] AEMO, *VPP Demonstrations Knowledge Sharing Report 3*, 2021; AEMC, *Rule Determination: Wholesale Demand Response Mechanism*, 2020; AEMO, *NEM VPP Demonstrations Program*, 2018.

relationship[31]. Removing this barrier to accessing multiple value streams is likely to further the growth of DER aggregation.

Network access arrangements

Increasingly, the potential for new entrant DER assets to access the distribution network for export purposes is likely to be hindered by low or zero export limits. This is a result of networks reaching their technical limits for secure network operation, and needing to limit the potential impacts of future connections.

There has been a lot of work in the last few years to investigate the role of dynamic export limits or dynamic operating envelopes to provide a more flexible control on DER export in line with the actual network conditions and capacity. At present, the application of dynamic export limits is something that is being trialled through a number of projects[32], but is generally not part of standard business operations for DNSPs.

Access arrangements are relevant to the potential benefits that can be unlocked with direct procurement because they will impact which assets are able to export and provide network services, and how firmly they can be relied upon. A more dynamic approach to export limits may allow more future connections of DER to provide network services through their export, which could include more batteries and other newer technologies as costs continue to reduce. However, on the flip side, this approach would also be expected to reduce the firmness of access and give aggregators less certainty that a particular DER asset will be able to export when needed.

Developing access arrangements that provide a range of customer choice on how they connect to the distribution network – including flexible or firmer access options for export of solar PV to vehicle-to-grid – is likely to help realise more of the benefits of DER integration through direct procurement.

7.2.2 Impact of further reforms

If these further reforms to direct procurement are undertaken, we estimate a further $602m of network benefits could be unlocked under the central scenario and $2.9bn could be unlocked in the step change scenario, over and above the benefits that could be delivered by current arrangements for direct procurement. This would increase the estimated portion of the 'size of the prize' of network benefits that could be realised to $1.1bn under the central scenario and $5.5bn under the step change scenario.

This is shown in Figure 14 below with the central scenario current and target reform benefits on the left of the chart and step change scenario benefits for current arrangements and target reform on the right of the chart.

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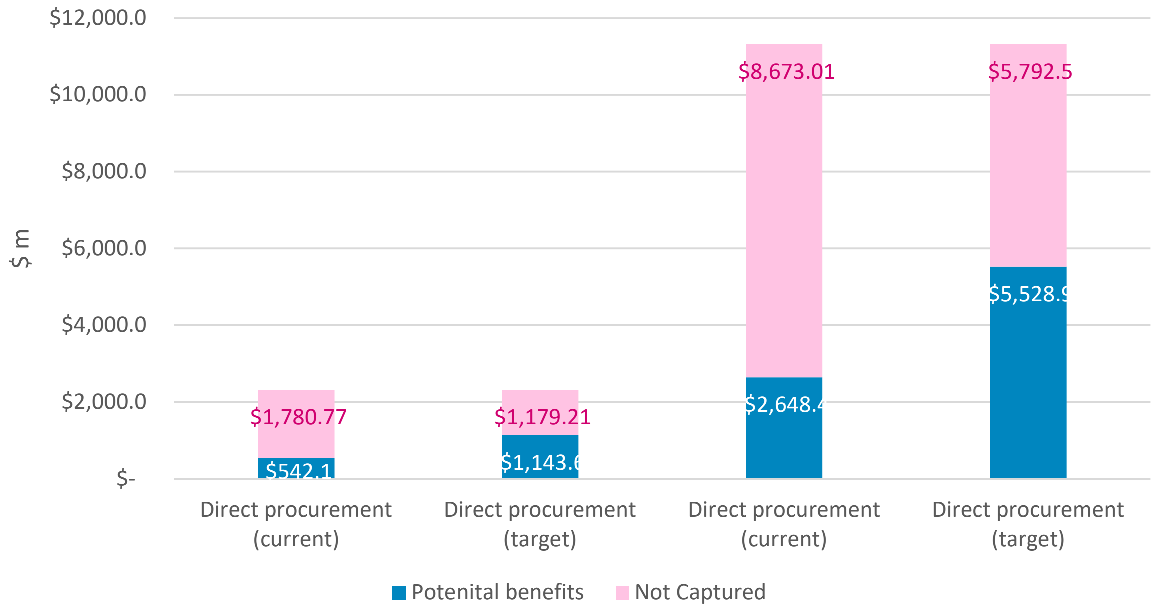
[31] Note that small generation aggregators (SGA) can participate in the energy market with aggregated DER however this must be independently metered. There has been some discussion around allowing SGAs to access the FCAS markets in the future however this has not been implemented. Market Ancillary Service Providers (MASP) are able to access the FCAS markets with aggregated DER, however the capacity must exceed 1MW. MASPs will be superseded by Demand Response Service Providers in October 2021.

[32] ARENA, *State of DER Technical Integration Project Summaries (for example, Advanced VPP Grid Integration, and Evolve DER projects*), 2021.

Figure 14 Potential impact of direct procurement reform on benefit capture



The assumptions driving this increase in available benefit capture compared with our assessment of current arrangements are:

- We assume direct procurement is capable of signalling temporally specific network needs to DER for the delivery of network support with intra-day to real-time response.
- We assume direct procurement is capable of signalling very location-specific network needs, with sufficient DER participation to provide meaningful locational responses.
- We assume a high strength of response from participants as system performance and communications improve with time.
- We assume reach is significantly higher, with widespread deployment of direct procurements by all DNSPs and reach extends to a variety of DER technologies.
- We assume growth in the aggregator sector, driven by easier access to value streams, and therefore more opportunities for DER owners to participate and access new revenue streams.
- Access by providers is assumed to be higher than under a continuation of current arrangements, as new entry aggregators are able to access a range of value streams and operating independently of retailers.

Appendix A Methodology to estimating available benefits

This appendix sets out the methodology underpinning the benefits case quantitation in chapter 2, as originally developed through the OpEN project.

A.1 Overview

A.1.1 Tailoring the methodology for Australia

The high-level approach for this benefits assessment was informed by our 2018 work on the UK Future Worlds Impact Assessment.[33] This methodology was tailored for Australia to take into account the different DER forecasts including higher PV adoption and slower uptake of electric vehicles. We also took into account relevant existing Australian studies such as:

- Arena projects (e.g. Oakley Greenwood);
- Victorian feed in tariff review;
- SA Power Networks' work with Houston Kemp on valuing DER;
- CSIRO's high level review of the benefits assessment and;
- The Electricity Network Transformation Roadmap from 2017.

However, in many ways this type of assessment is a first in Australia and consequently we brought some of our approach from the UK study (for example the approach to modelling EV impact) and worked with stakeholders to adapt it for the Australian context. The methodology section describes the approach and assumptions in more detail.

A.1.2 Stakeholder engagement

A sub-group of DNSPs (Essential Energy, SAPN, AusNet Services and Energy Queensland) and representatives from AEMO were involved in a series of working sessions to refine and iterate the methodology. Data requests (as detailed below) were shared with all DNSPs, AEMO and some TNSPs. The AER and AEMC were engaged upfront to feedback on the methodology.

A.1.3 Data requests

This modelling was informed by data inputs from both AEMO and the DNSPs. The majority of the DER forecasting and demand data was taken from AEMO's ESOO. The DNSPs provided data on the level of forecast constraints as a result of both PV and demand increases from EVs. Data from both the DNSPs and TNSPs was used to inform network augmentation costs.

[33] http://www.energynetworks.org/electricity/futures/open-networks-project/workstream-products/ws3-dso-transition/future-worlds/future-worlds-impact-assessment.html

A.1.4 Methodology

We assessed the potential benefits which might be possible under two of AEMO's future scenarios – the central scenario (where DER uptake is moderate, or at least was in the original 2019 ESOO adopted in the OpEN project) and a step change scenario (where DER uptake is significantly higher), and the only scenario where warming is kept below 2 degrees Celsius. We chose these two scenarios out of the five available to cover a range in DER uptake to tease out key differences in the frameworks and to understand how their suitability might change under different DER uptake scenarios. However, it should be noted that DER uptake was kept as an exogenous variable, and in reality barriers such as difficulty to access both networks and wider markets would impact DER uptake.

We identified four high-level benefit categories of DER integration into the Australian power system for the OpEN project, the first two categories being the focus for this current project with the ESB:

- Avoided distribution investment / reduced curtailment costs
- Avoided transmission investment
- Reduced wholesale ancillary services costs
- Reduced wholesale energy costs

This initial step was designed to understand the quantum of benefits which might be possible through integration of DER in each of the four categories we identified. We took a top down approach to modelling, rather than develop a bottom up, complex, whole system energy model.

Benefit Category	Generation driven	Demand driven
Avoided Distribution investment / reduced curtailment costs	Reduced curtailment of Distribution connected generation: • saved marginal generation costs • reduced losses	Reduced Distribution investment to meet higher local peaks • avoided local network augmentation to meet higher demand (e.g. from EVs)
Avoided Transmission investment	Reduced curtailment of Distribution connected generation avoids the need to build new Transmission network to connect large scale renewables • saved transmission connection costs	Reduced network augmentation to meet greater peak demand: • saved transmission augmentation costs
Reduced wholesale ancillary services costs	Greater competition provided by DER will drive lower prices	
Reduced wholesale energy costs	N/A – this is about shifting demand away from peak to off-peak	Demand response at peak (e.g. shifting demand and storage import to off – peak times)

A.2 Defining the counterfactual

In order to assess the potential benefits of better DER integration we needed to define a counterfactual. The counterfactual assumed that there would be limited distribution network access for a fixed DER uptake. As a result, a proportion of generation would be curtailed, DER would be managed in an uncoordinated way with limited access to wholesale markets and there would be unmanaged EV charging, driving network augmentation. We also assume there would be not access to flexible demand to reduce network or wholesale peaks.

A.2.1 Curtailment of distribution connected generation

In the counterfactual we assumed that a proportion of distribution connected generation will be curtailed as a result of network constraints. We used forecast data on network constraints from the DNSPs to inform the level of curtailment forecasted in the counterfactual. We assumed that rooftop solar and PV non-scheduled generation (PVNSG) were curtailed, we did not account for other non-scheduled generation (ONSG) as part of the curtailment analysis[34]. We assumed that in the counterfactual all curtailed solar energy is replaced with transmission connected solar generation. We assume that the curtailed energy is required to meet demand as a result of planned coal plant closures, hence why new generation build is required in the counterfactual.

To assess the volume of energy curtailed in the counterfactual:

- We calculated a customer adoption (%) of PV for each NEM region and each scenario (based on AEMO's PV uptake forecast and customer numbers per NEM region), as PV adoption most aligned with the data provided on DER uptake and corresponding network export constraints from the DNSPs.
- The DNSPs provided forecast data on the constraints which emerge for different types of networks as PV adoption increased
- In general PV was unconstrained to a threshold level of adoption, above which new generation capacity would be curtailed
- We have made assumptions based on DNSP data inputs that in the median case above 15% PV penetration, new generation capacity was curtailed by 80% (at all times of day). Above 37% PV adoption, all new capacity was fully curtailed. We acknowledge that these are averages and that individual regions will vary.

The volume of curtailed energy in the counterfactual was also increased to account for actual transmission and distribution losses, as we have assumed in the counterfactual that the curtailed energy is replaced with transmission connected generation.

To calculated the value of this curtailed energy, we use the solar levelised cost of energy (LCOE) $/MWh to value the curtailed generation. It was assumed that curtailed distribution connected PV would be replaced with transmission connected solar, maintaining the equivalent renewables penetration and export profile. The LCOE was used as generation would not be curtailed at the same time as peak demand. This is taken to be **$66/MWh**[35], It should be noted that there could be

[34] It was assumed that this type of generation would not be dispatched at solar peak, it is more likely to be dispatched to meet the demand peak.

[35] Based on Baringa's reference case modelling.

alternative approaches to assessing the value of this curtailed generation, for example, the methodology used to calculate the revised feed in tariff for Victoria included a broader range of DER benefits including a carbon price.

A.2.2 Transmission infrastructure investment: Generation driven

We assume that transmission network capacity needs to be built out to accommodate the equivalent volume of curtailed generation on the distribution networks. While demand is expected to increase primarily driven by EVs in the 2030s), AEMO's ISP sets out a number of coal plant closures in the near future. As a result, this means that additional generation capacity (equivalent to the curtailed generation) will be required in the counterfactual to meet demand. It is assumed that this capacity will be connected within Renewable Energy Zones which will require additional transmission infrastructure. As part of the modelling we also assume there is limited existing export capacity within the current transmission infrastructure.

The additional capacity of transmission infrastructure capacity required to meet the energy curtailed was calculated on an annual incremental basis using the load factor for renewable generation **(29%).** The cost of this incremental transmission capacity was calculated using a value of **$87,000/MW** based on AEMO's ESOO data. It should be noted that this augmentation value relates to building out transmission infrastructure for newly connected generation, if wider transmission infrastructure needed to be augmented the $/MW would likely be higher.

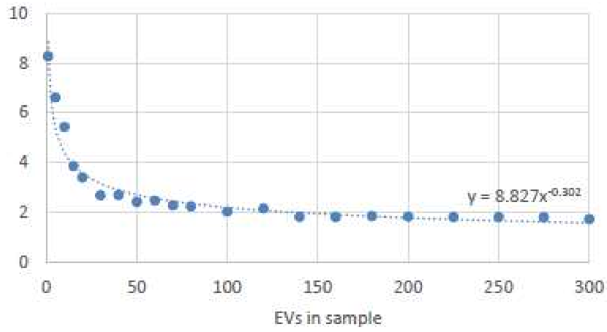
A.2.3 Distribution network investment: Demand driven

We assume that the main driver of peak demand growth is residential EV charging, as informed by AEMO's DER uptake scenarios and AEMO's maximum demand forecasting.

We assume that EV peak load will have the largest impact on the low voltage network, as diversity of EV charging is lowest with lower numbers of EVs (e.g. on a single feeder). This assumption has been validated in a number of large-scale EV trials in the UK, such as My Electric Avenue and Electric Nation[36] which appear equally applicable to Australian distribution networks. We calculate the average number of EVs per feeder over time based on AEMO's EV forecast, household numbers per NEM region and data on number of feeders per DNSP. We then assess the peak load at LV feeder level as a result of EVs, using unmanaged charging diversity assumptions based on peak load per EV data from the UK Electric Nation trail (trail of nearly 400 vehicles) – as per the figure below.

[36] http://myelectricavenue.info/sites/default/files/documents/Close%20down%20report.pdf

Electric Nation diversity curve, kW/EV vs. number of EVs



We assess the incremental annual LV and HV distribution network augmentation required (per region) as a result of EV peak load (incremental capacity required), based on the average load increase required to trigger LV reinforcement (based on augmentation volumes around EV scenarios provided by the DNSPs). This scalar value included DNSP data on the number of EVs at a point in time and the associated network augmentation.

We assess the distribution investment associated with this level of network augmentation, based on a $/MW input of augmentation. This is assumed to be **$85,000/MW** at LV and **$100,000/MW** at HV as part of our median model inputs, based on data provided by the DNSPs (based on the average equivalent capex cost of augmenting the network). We assumed that as a result of EV diversity EV peak demand would have only a third of the impact at HV when compared to LV (as informed by our UK Future Worlds Impact Assessment).

It should be noted that there will be significant locational variation in terms of EV uptake which has not been represented as part of this modelling. In reality, EV uptake tends to cluster in urban areas of higher income with charging infrastructure provision. Therefore, distribution network augmentation could be significantly earlier in some local areas of high EV uptake than shown as part of this modelling.

A.2.4 Transmission network investment – Demand driven

We have assessed how the EV peak load at transmission level differs from at LV to understand the volume of transmission capacity required in the counterfactual. We have assessed the demand impact of unmanaged EV charging on the transmission network, based on an estimated network headroom (as informed by TNSP data). We have used a value of **$150,000/MW** provided by a TNSP to calculate the augmentation cost in the counterfactual.

A.3 Optimal system operation

A.3.1 Reduced curtailment

We assessed the volume of curtailment reduction that might be possible through optimal distribution system operation. This involved assessing the volume of excess generation (the curtailment calculated in the counterfactual) which could be absorbed by local coordination of demand (e.g. storage and EVs). The premise is that through running local market mechanisms, local flexible demand can be better matched to local peak solar, helping to reduce the volume of constraints of that solar. The following assumptions are applied to the volume of flexible storage available:

- We use the storage uptake assumptions for each scenario from the ESSO data set
- Battery round-trip efficiency of **85%**
- Proportion of storage which is used to reduce curtailment assumed to be **100%**
- Co-location of storage and PV assumed to be **100%**

We then made assumptions about the volume of curtailed energy which can be reduced through aligning peak solar with EV charging demand:

- Based on the proportion of drivers who could incentivised to charge during the day time solar peak e.g. **20%**[37]
- Proportion of drivers taking part in flexibility propositions e.g. **80%** (modelled as part of UK smart charging studies, Project Shift[38])
- PV and EV co-location factor e.g.**75%**
- EVs which charge from storage during the evening peak were not included, as they were captured through the curtailed energy absorbed by storage

Combining these assumptions, we assess how much curtailment (MWh) is reduced by the above flexible demand and calculate the associated benefits through the marginal generation costs shown previously.

A.3.2 Reduced distribution network augmentation

We assessed the volume of demand that is flexible through EVs and storage (peak shifting), as a result of better integration of DER:

We assumed the volume of flexible peak demand associated with EVs (for each DER uptake scenario)

- Based on the proportion of EVs charging at peak times on a daily basis e.g. **20% -** this is based on 40% of drivers charging at peak times, and charging their vehicles 3.5 times per week, as informed by the UK's Electric Nation trial.[39]
- Peak charging demand reduction through smart charging e.g. **90%,** this assumption has been used in UK trials and assumes a significantly increased diversity factor[40]
- Proportion of customers taking part in flexibility propositions e.g. **80%**, modelled as part of UK smart charging studies

We then assessed the volume of demand flexibility through storage:

- We took account of the total volume of storage forecast for each DER uptake scenario
- We assumed the proportion of storage ready to discharge at peak times, **90%**

[37] Informed by the UK's Electric Nation trial, http://www.electricnation.org.uk/
[38] https://innovation.ukpowernetworks.co.uk/projects/shift/
[39] We note that commuting distances and therefore the charging frequency may be marginally higher in Australia but no concrete data was available.
[40] UKPN Shift trial - https://www.ukpowernetworks.co.uk/internet/en/news-and-press/press-releases/Launch-of-UKs-first-electric-vehicle-smart-charging-marketplace-trial.html

We assessed whether the augmented distribution network capacity calculated in the counterfactual can be reduced or avoided as a result of this reduced demand. We then assessed the value of delaying or avoiding this distribution network augmentation based on previous costs. We have also sense checked these benefits to ensure that we are not avoiding or deferring all distribution augmentation through demand flexibility as this would not be reflective of reality. Over the forecast time horizon the model assumes a maximum of 80% avoided/deferred augmentation, which is similar to the assumptions applied in our UK Future Worlds Impact Assessment and validated by UK distribution businesses.

A.3.3 Reduced transmission infrastructure investment

Reduced curtailment

The reduced curtailed energy through better integration of DER will also have an effect on the capacity of transmission augmentation required. In our optimal scenario, there is less generation build required at transmission, therefore the corresponding transmission infrastructure build can also be reduced, using the augmentation costs presented previously.

Reduced demand

Similarly, to the calculation for avoided distribution network augmentation, at transmission we assessed the volume of flexible demand through storage and EVs which could be used to reduce peak demand and therefore avoid the corresponding transmission network augmentation.

The storage capacity is equivalent to that at distribution level (as the use of storage is not influenced by a secondary use, such as driving), however, EV peak demand is less significant at transmission demand as a result of higher charging diversity.

We apply the same methodology as for distribution to understand the proportion of transmission augmentation which can be deferred or avoided, using the same transmission network augmentation value used in the counterfactual - **$150,000/MW**.

A.4 Suggested future data capture to inform further modelling

There were a number of aspects of the modelling which could have been improved with better data. There were certain inputs which were based on UK studies when no equivalent Australian data was available. There are also a number of input assumptions which are based on customer behaviour which could be validated through trials. The input assumptions which could be further refined in future are as follows:

- Unmanaged EV diversity in Australia and corresponding demand at different network levels
- Customer uptake of flexibility propositions (e.g. smart charging, using storage to reduce local curtailment of PV, Demand Side Participation (DSP))
- Further work could be undertaken to understand how the volume of flexible demand might increase in future, as this modelling focused on purely storage and EVs, for example we did not assess how the DSP volume could increase through future customer propositions

- Customer sensitivity to flexibility payments
- TNSP network headroom (the data in the model was informed by a single TNSP)
- The level of generation export capacity on the transmission network (this was assumed to be limited)
- Co-location of PV, storage and EVs
- The modelling was focussed at NEM region level, however, there would be benefits in carrying out the equivalent methodology at more granular locations to drive out differences in network augmentation costs, DER uptake and network constraints.
- Whilst the modelling looked at the benefits of peak vs. off-peak wholesale pricing, distribution network reflective pricing was out of scope for this work (and was not captured as a Future Framework or function within the SGAMs). Further work and trials should be carried out to understand customer response to network reflective pricing,
- This work did not look to apportion benefits to what could be delivered through "least regrets" network solutions vs. market solutions, or to breakdown market solutions into wholesale vs. local. Further work on this will help to inform appropriate timelines for investment in specific technology and capabilities to deliver the Future Frameworks.
- There are wider benefits to DER that have not been captured through this work, such as carbon benefits or benefits driven by retailers or aggregators.

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Appendix B – Distribution and transmission tariff and direct procurement results

This appendix provides further detailed figures showing how the tariff and non-tariff benefits are captured at the distribution and the transmission level, separately. The equivalent charts in the main body of the report reflect the combined distribution and transmission network benefits.

7.3 Distribution results

The following charts show the results of the qualitative assessment of tariff and non-tariff performance against distribution benefits only.

Figure 15 Central scenario distribution tariff and non-tariff benefits

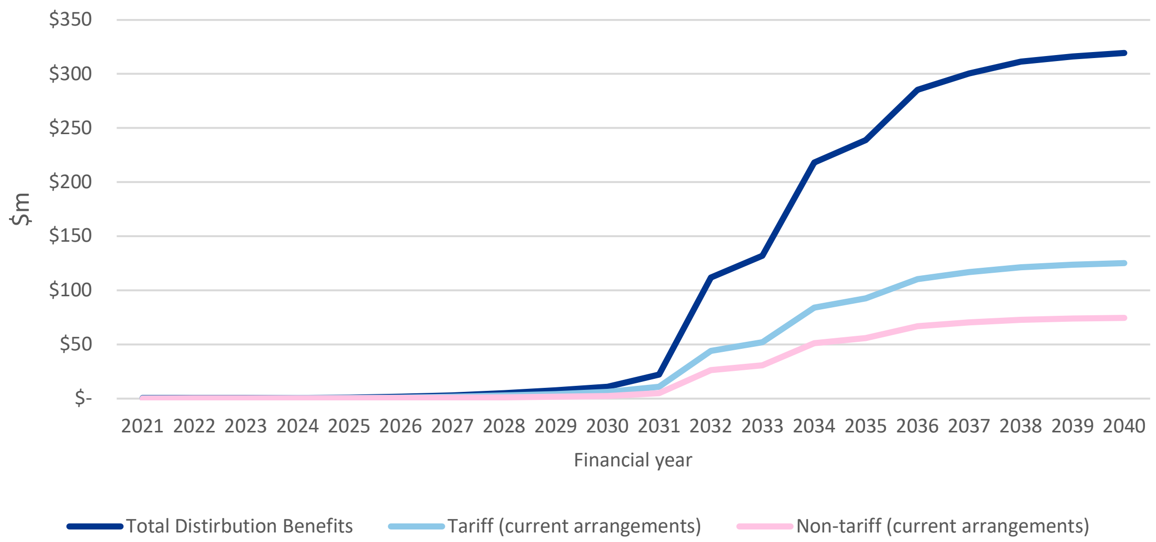


Figure 16 Step change scenario distribution tariff and non-tariff benefits

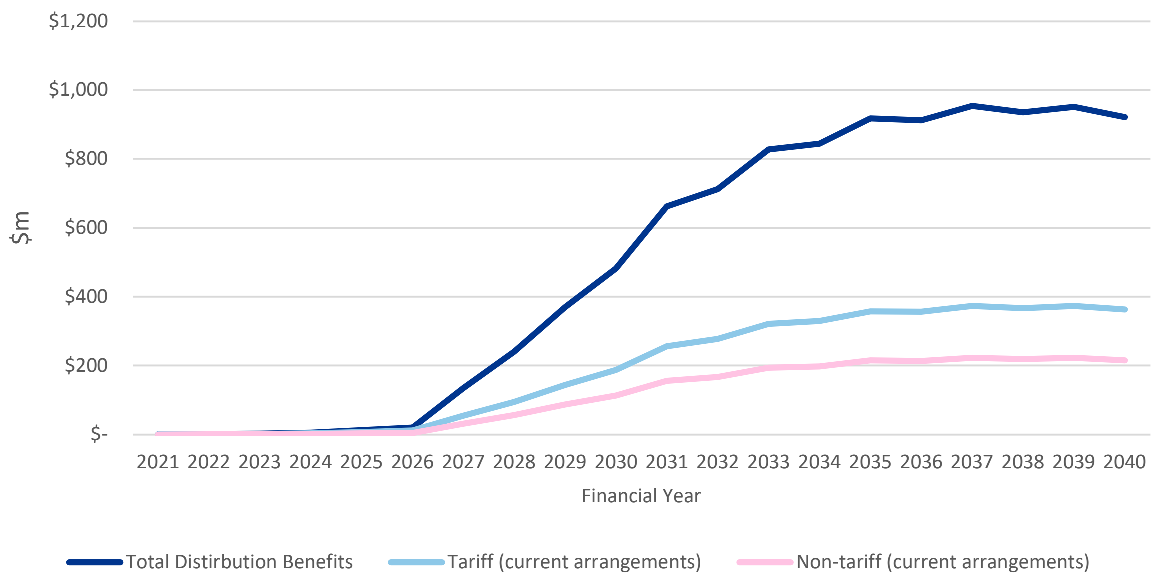


Figure 17 Distribution benefits captured by tariffs (under current arrangements)

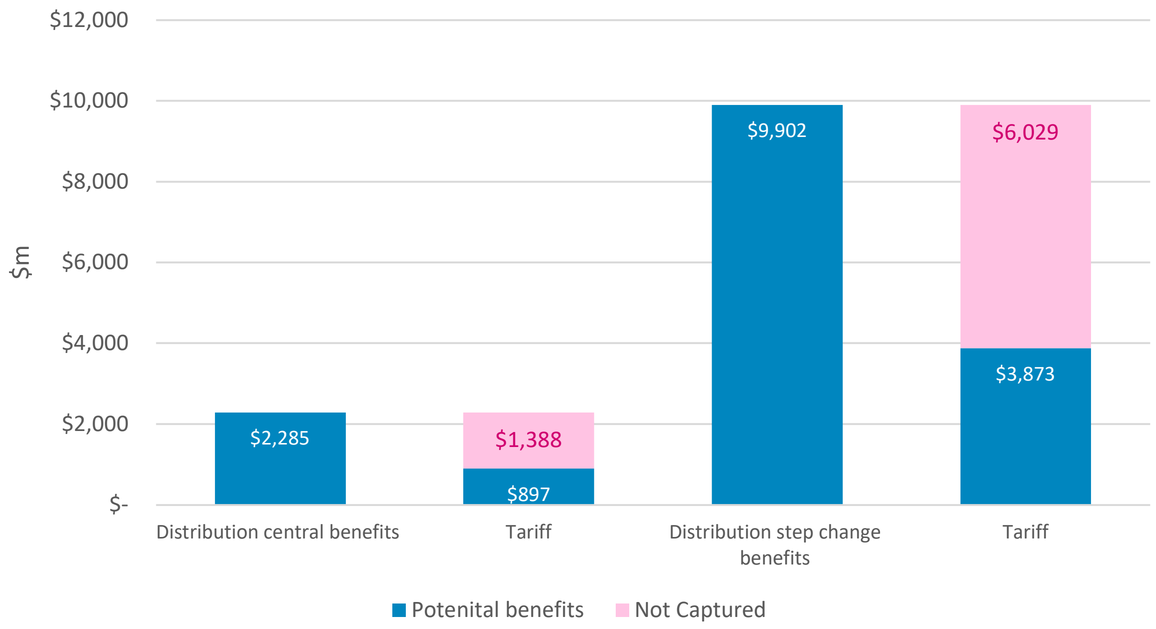
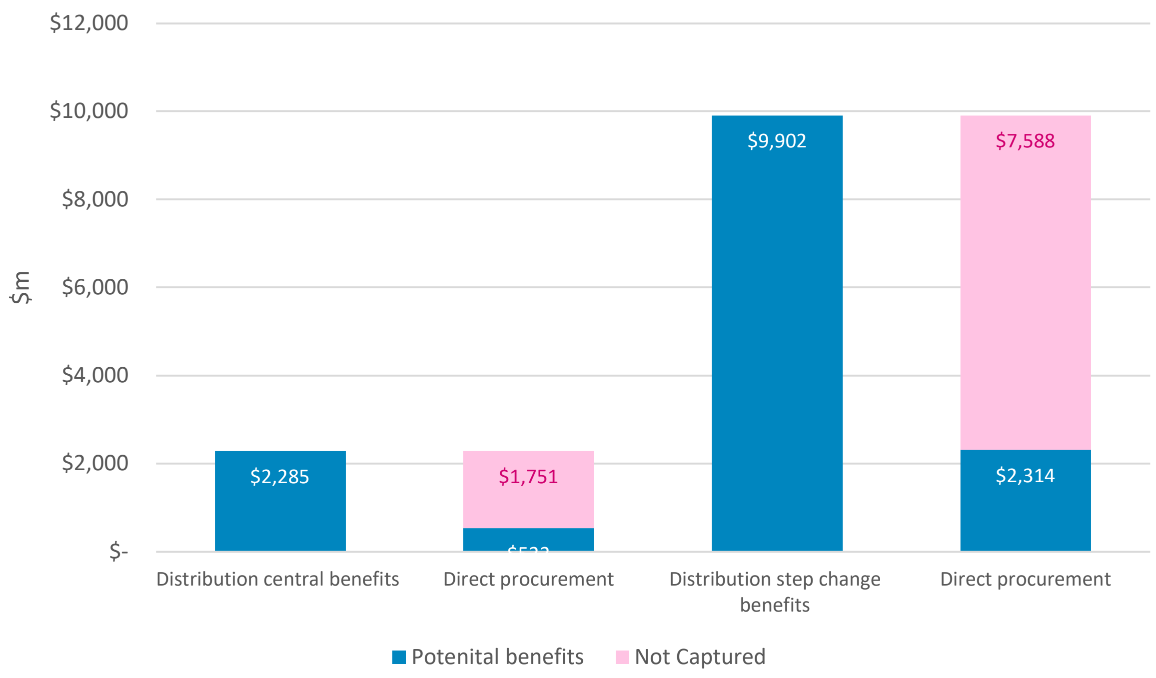


Figure 18 Distribution benefits captured by non-tariff options



7.4 Transmission results

The following charts show the results of the qualitative assessment of tariff and non-tariff performance against transmission benefits only.

Figure 19 Central scenario transmission tariff and non-tariff benefits

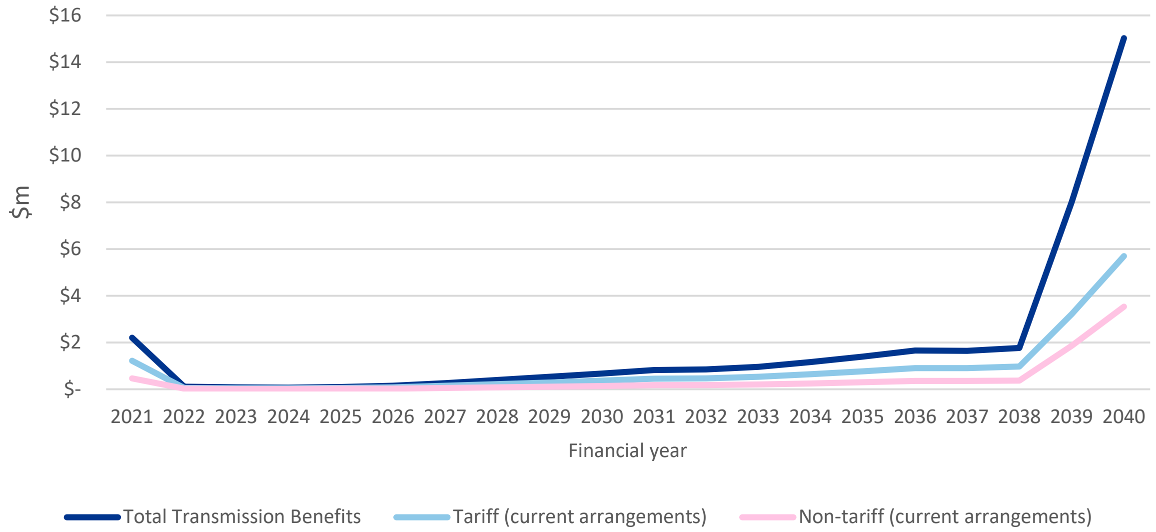


Figure 20 Step-change transmission tariff and non-tariff benefits

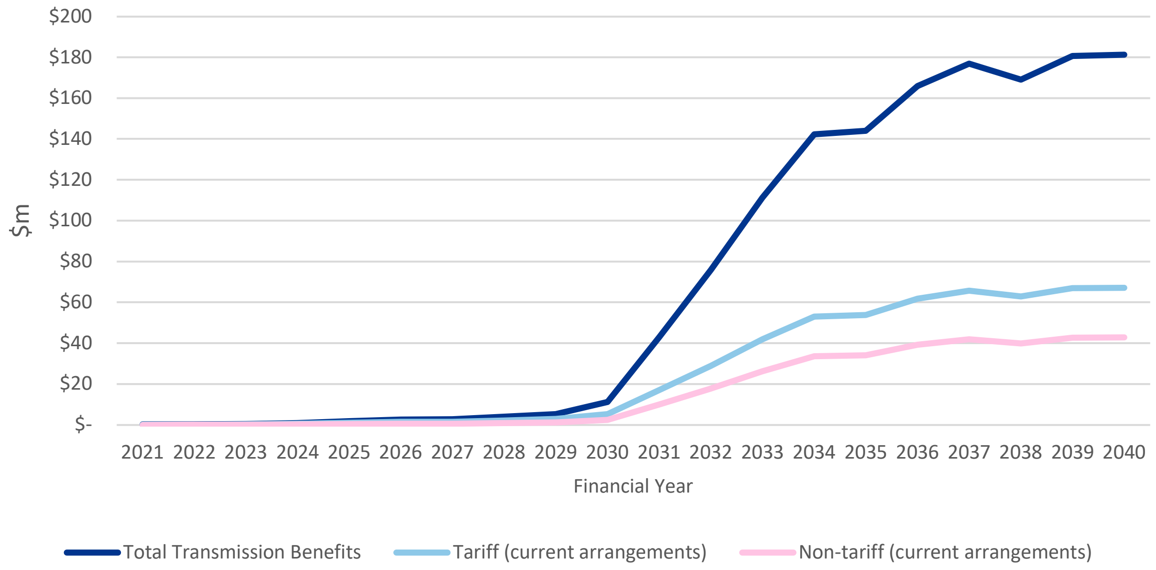


Figure 21 Transmission benefits captured by tariffs (under current arrangements)

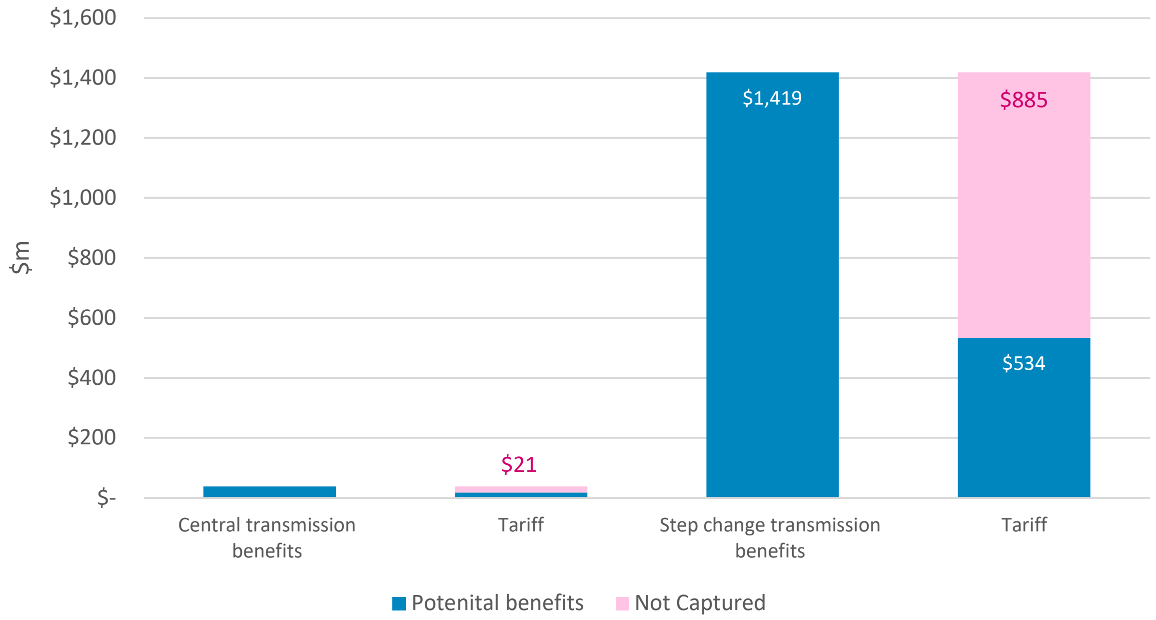


Figure 22 Transmission benefits captured by non-tariff options