AEMC

RULE

Australian Energy Market Commission

DRAFT RULE DETERMINATION

NATIONAL ELECTRICITY AMENDMENT (ACCESS, PRICING AND INCENTIVE ARRANGEMENTS FOR DISTRIBUTED ENERGY RESOURCES) RULE 2021

NATIONAL ENERGY RETAIL AMENDMENT (ACCESS, PRICING AND INCENTIVE ARRANGEMENTS FOR DISTRIBUTED ENERGY RESOURCES) RULE 2021

PROPONENTS

SA Power Networks
St Vincent de Paul Society Victoria
Total Environment Centre and Australian Council of Social Service

25 MARCH 2021

INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

EXECUTIVE SUMMARY

Our draft decision

1 The Australian Energy Market Commission (the Commission) has made more preferable draft electricity and retail rules (draft rules) in response to rule change requests from SA Power Networks (SAPN), the St Vincent de Paul Society Victoria (SVDP), and Total Environment Centre (TEC) together with the Australian Council of Social Service (ACOSS). These proponents requested that amendments be made to the National Electricity Rules (NER) to more efficiently integrate distributed energy resources, such as small-scale solar and batteries, into the electricity grid. The draft rules incorporate many of the proposed rule changes they put forward, as well as opportunities the Commission identified to improve the regulatory framework, and consequential rule changes.

2 This package of reforms is part of a program of work being undertaken by the energy market bodies and the Energy Security Board (ESB).[1] It follows a nine-month process of working with consumer representatives, industry associations and energy market bodies as part of ARENA's Distributed Energy Integration Program. And its aim is to support the consumer-driven transition that is currently underway.

3 The draft rules represent a package of reforms that:

- acknowledge the important role that distribution networks play in harnessing the benefits of distributed energy
- enable these benefits to accrue to all electricity system users
- support the decarbonisation of the electricity sector
- clarify networks' role includes providing two-way services
- realign distribution network service providers' incentives to efficiently provide export services
- enable more advanced pricing approaches so as to make the best use of the grid.

4 Key aspects of the draft rules to help achieve the above include:

1. **Updating the regulatory framework to clarify that distribution services are two-way and include export services** and that as such the current rules relating to distribution services apply to export services. This officially recognises energy export as a service to consumers.
2. **Promoting incentives to efficiently invest in, operate and use export services.** This will encourage distribution networks to deliver export services that customers value. Currently there are no financial penalties for poor network export service and no rewards for good service. A high-quality service would see more people exporting more of their energy more often in ways that use the network efficiently and incorporate innovative pricing structures.

1 The market bodies are the Australian Energy Market Commission (AEMC), the Australian Energy Market Operator (AEMO), and the Australian Energy Regulator (AER).

3. **Enabling distribution networks to offer two-way pricing for export services,** allowing them options to reward owners of distributed energy resources for sending power to the grid when it is needed and charging them for sending power when it is busy. This is designed to reward customers for actions that better use the network or improve its operations, and allocate costs equitably and efficiently.
4. **Allowing flexible pricing solutions at the network level,** enabling distribution networks to price options to suit their capability, customer preferences and jurisdictions.
5. **Giving consumers and jurisdiction governments a greater say.** New safeguards will ensure consumers and jurisdiction governments have a strong say in how distributed energy resources should be integrated into the energy system and priced.

5 The Commission considers that over time, this will allow more electricity consumers to access more distributed energy resources, while keeping the cost of supplying network services as low as possible. Without these changes, distribution networks may constrain the continued adoption of distributed energy resources.

6 This draft determination sets out the proposed rule change requests, the Commission's reasons for making its decision, and how stakeholders can continue to contribute to our rule change process.

The challenges posed by decentralisation

7 Australian consumers have led the decentralisation charge by enthusiastically embracing distributed energy resources.

8 A multitude of factors have driven this distributed energy resource transition. First, community concerns about the impact of fossil fuel generation on carbon emissions were a major catalyst for change, driving action by governments and businesses. Second, government incentives for lower emissions generation encouraged investment in wind, solar farms and small-scale solar PV systems. Third, a period of high energy prices gave further impetus to this transition, by driving customers to change their behaviour to use energy more efficiently and to generate their own power. Finally, as the uptake of distributed energy resources rose, technological advancement and economies of scale drove down equipment and installation costs.

9 Around 20 per cent of all customers in the National Electricity Market (NEM) now partly meet their electricity needs through rooftop solar PV generation, and sell excess electricity back into the grid – compared with less than 0.2 per cent of customers in 2007. In 2019, this production met over five per cent of the market's total electricity requirements.[2] In South Australia in October 2020, grid and distributed solar met 100 per cent of South Australia's demand for the first time.[3]

10 According to the Australian Enerngy Market Operator's (AEMO's) forecasts, rooftop-solar-installed capacity across the market is set to far exceed that of the market's largest remaining

2 AER, State of the Energy Market 2020, p. 39.

3 AEMO, Quarterly Energy Dynamics: Q4 2020, p. 8.

coal generator in the near-future and will double or even triple by 2040.[4]

A consumer-led transformation

11 Distributed energy resources are transforming the way consumers interact with the electricity system. They are enabling customers to make decisions about how and when they use and export electricity, and are providing a means for customers to participate in the broader electricity system through buying and selling energy services. For some, distributed energy resources are providing an additional source of revenue that, in many cases, more than offset electricity bills.

12 Consumers would benefit significantly if distributed energy resources become an integrated part of the electricity system. Why? Because successful integration will see more distributed renewable generation connecting to the grid – and it will do so in a way that not only makes the best use of the 'network platform', but also allocates costs in an efficient way.

13 For owners of distributed energy resources, efficient integration would provide the opportunity to maximise the return on their investment. This could range from using their exported electricity to reduce their bills, to accessing and participating in the growing number of new energy services markets – or a combination of both.

14 Efficient integration could also significantly benefit non-owners through lower total system costs. Generation assets (such as solar PV and batteries) could drive down energy costs by providing low- cost energy, as well as ancillary services in competition with traditional providers.

The limitations of networks built for one-way flows

15 While there is no doubt that distributed energy resources provide many benefits to consumers and the energy system, without a change to the regulatory framework, consumers will face growing limitations to the amount of energy they can export.

16 This is because distribution networks have a base level of hosting capacity for distributed energy resources. But most distribution networks were built when energy only flowed one way. Now, they are increasingly being used to export energy from customers and approaching the limit of their 'intrinsic hosting capacity'. As a result of these two-way flows, the ability of networks to transport and deliver electricity safely, securely and reliably is being challenged. These challenges raise medium- to long-term planning and investment issues.

The answer: a regulatory framework that incorporates the provision of export services to customers

17 The regulatory framework has an important role to play – it sets expectations on behaviour, it uses incentives to drive better outcomes, and very importantly, it provides safeguards to protect consumers against monopolistic behaviours.

18 In addition, the regulatory framework that supports the integration of distributed energy

4 AEMO, 2020 Integrated System Plan, July 2020, p. 12

resources must support the security of the power system, and support people who own renewable technology as well as people who do not. It must provide flexibility for changing customer and jurisdictional preferences, different network circumstances, and technology and market developments as they emerge.

19 This means re-thinking and updating the regulatory framework. It also means rethinking market incentives and how services are priced.

20 The Commission's draft determination creates a framework that does just this. If implemented, it will allow more consumers to continue to connect their distributed energy resources to the grid. It protects those who cannot, or choose not to, invest in distributed energy resources, from higher network costs, and helps the power system run securely.

21 The access and pricing reforms proposed in this draft determination are foundational to a future grid. The grid of the future will need to strike the right balance between hosting as many distributed energy resources as possible, while at the same time maintaining distribution security and minimising cost for all users.

22 Further, as more and more distribution energy resources connect, networks will play an even greater role in facilitating distributed energy resources (and their owners desire) to participate in the power system and markets.

The result: a package of reforms that maximises the benefits of distributed energy resources for all consumers

23 The Commission's draft determination represents a major set of reforms that recognises consumer expectations that the electricity grid now and into the future should be one that supports local energy options, and supports their ability to participate in the growing range of markets – regardless of whether they relate to consuming or exporting energy.

Clarifying that distribution services are two-way and include export services

24 The reforms crystallise distribution networks' obligation to connect distribution energy resources to their network in a way that benefits everyone – not just those who can afford them. The draft rules propose a framework for consumers, distribution networks, and the Australian Energy Regulator (AER) to decide the type and level of services – both consumption and export – that they desire and contributes to the transition to a lower-cost electricity system.

25 Distribution networks will be incentivised to deliver improved export services and the Commission expects they will offer a range of options so customers can choose what works best for them. For example, they might offer a free, but somewhat limited export service, and an alternative premium service that may include an export charge for greater access.

26 This is not an instant change being imposed on customers without their input. If adopted, implementation would require networks to consult with their customers about what they want, and the AER would consult further to assess any network proposals. New safeguards will ensure consumers and jurisdictions have a strong say in how distributed energy resources should be integrated into the energy system and priced.

Doing nothing is not a viable option

27 A 'do nothing' approach is likely to lead to a worse outcome for all consumers. Without positive action, distribution network constraints could become a bottleneck to more distributed energy resources connecting to the grid. There will be increasing instances where customers are limited in their level of exports or not be allowed to export at all.

28 Reforms under this package align with the Total Environment Centre's and the Australian Council of Social Service's rule change intent of 'more sun for everyone'. Changes under the draft rule aim to minimise the risk of networks under-investing in export services and incentivise them to provide export services to the extent that the overall benefits outweigh the costs. It also promotes incentives for efficient investment in, and operation and use of, export services. To create greater certainty, the AER will be required to provide additional guidance on network investment, planning and regulatory decisions for export services.

29 The draft determination clarifies that distribution networks should be considering improvements to enable them to provide the export hosting capacity that customers want and are willing to pay for. Financial incentives align their objectives with the long-term interests of consumers; they will look to maintain, or improve, their provision of export services – as the penetration of distribution energy resources continues to grow.

Providing for incentives to efficiently invest in, operate and use, export services

30 A key feature of the current regulatory framework is that it provides incentives for networks to meet their obligations and service requirements at least cost. The AER applies incentive-based regulation across the energy networks it regulates.

31 The Commission considers that the existing incentives framework may not provide balanced incentives to networks for providing export services. The current expenditure-based incentive schemes apply to export services, but the current service-level incentive scheme does not include metrics for export services and is therefore not suitable for incentivising export performance.

32 Under the current arrangements, networks face no financial penalties for providing poor quality export services or rewards for providing higher quality of service. The Commission has made a draft rule requiring the AER to undertake a review of the service target performance incentive scheme with the view to extending it to export services. Providing an appropriate incentive scheme will lead to the networks being incentivised to provide a level of service that matches the customers' needs, with the networks facing rewards and penalties for providing better or worse services.

33 Effective incentive arrangements, coupled with a clear planning and investment framework for providing export services, will mean customers will have better access to these services. The networks will be incentivised to provide more customers with a better-quality service, instead of using measures such as static export limits to manage their network's export limitations.

34 The Commission has also made a draft rule requiring the AER to develop a method to regularly calculate the customer export curtailment values (CECV). These values will serve as

an important input for guiding efficient network planning and investment decisions for export services.

Enabling distribution networks to offer two-way pricing for export services

35 Enabling two-way export pricing will potentially result in significant consumer benefits. There are good economic reasons to implement export pricing, both in the short-term to manage new investment related to distribution energy resources, and in the longer- term to take advantage of future market and technology developments.

36 Pricing is a common tool used in regulated industries to send efficient signals for future expenditure and incentivise customers to best use existing infrastructure. It is about getting the most from the network we have and investing in the network over time to meet consumers' needs. Where significant new expenditure is required to maintain or improve export services, price signals can help to ensure it will be the result of customers making informed decisions about the costs that they impose on the network.

37 By enabling export charges for distributed energy resources, pricing structures can be developed that allocate investment costs between users, and over time, in proportion to the benefits that customers are expected to receive from these services. But that decision should be made on a jurisdictional and network basis, where consumer preference, government policies and network circumstances are all taken into account. Our more preferable draft rules do not mandate a specific pricing approach, but rather, pave the way for innovative options and solutions at the jurisdictional and network level.

38 Non rooftop solar owners may benefit overall if increased exports lead to lower wholesale energy and/or essential system services costs. But the benefits resulting from the network investment may be highly unevenly distributed. A system that only serves those on a 'first come, best dressed' basis is inequitable and will ultimately cost everyone more.

39 The Commission has consulted widely through the rule change process, and acknowledges that some stakeholders are opposed to the changes proposed under this draft rule. However, the reality is that rooftop solar owners are already paying a financial penalty from being constrained off the network at times, and this problem will become worse. Everyone can benefit – regardless of whether they have solar or not – by incorporating the provision of export services into the regulatory framework.

Impact on customer bills

40 The Commission modelled the potential impact on customer bills if networks introduced export charges. Most retail customers could receive a small discount to their bill. This reflects that those customers who have not had the opportunity to invest in rooftop technology may no longer be asked to pay an equal share of the costs for distribution networks to maintain or improve export services. Customers with battery storage could see more benefits. They could gain especially through export rebates (negative prices). The bigger the battery, the more substantial the benefit.

41 For the customers with solar, there was a range of impacts, depending on the size of the system.

42 Households with large solar PV systems (above 6–8 kW) are currently earning over $1,200 a year on average. This includes reduced energy costs from the grid, as they supply their own load. Depending on how distribution networks design the pricing structure and the extent to which grandfathering arrangements are put in place by networks, these customers could see their benefits reduced by around $100 per year. This still leaves a significant ongoing benefit and allows new consumers to access those savings over time as networks are upgraded to provide more export hosting capacity. The Commission considers that this approach provides benefits to all electricity consumers.

43 Those with typical systems of say 2–4kW, who are currently earning an average of $645 a year, could earn about $30 a year on average less from their exports, while some network areas would not be materially affected.

44 Under a 'do nothing' approach, customers with solar systems would be worse off as they could see increasing instances of restrictions on export. For example, a restriction on export for only 10% of the time for customers with a 2-4kW system could see a reduction in annual export revenue of around $30. There benefits would decrease by $80 if the exports are restricted for 25% of the time. For customers with 4-6kW systems, they would see an average reduction in annual export earnings of $152.

45 To be clear, the draft rule does not mandate export pricing. Implementation is optional. The Commission's decision to enable export pricing options under the regulatory framework is not a decision to mandate the implementation of export pricing. We do not propose all customers with rooftop solar should start paying ongoing export charges. The AER, as the economic regulator, oversees revenue determinations and pricing proposals for each distribution network. Any decision to implement export pricing would be part of the AER's regulatory process and would be subject to consumer safeguards.

Allowing flexible pricing solutions at the network level

46 Where customers have flexibility with their electricity demand and exports, this can provide valuable services to the grid. The draft rules create flexibility for innovation around new pricing and service options. They do this by removing the current prohibition on charges for energy exported into the grid and clarifying that networks may create tariffs that reward customers for exporting energy to the grid at times of high demand and charging them when the grid is congested.

47 In the coming years distribution networks are expected to invest significantly to improve and expand their export services. Pricing structures can be designed to benefit customers by rewarding those who either change their behaviour – like using their own supply when there is excess demand for network export services – or by shifting their energy export to periods of high demand for network consumption services.

48 Further, customers who seek a higher level of export service than is typically offered now, may have the option to choose higher service levels. This could include higher average export limits, if the customer agrees to face pricing structures that reflect network costs and encourage 'demand response'. This in turn may incentivise customers to make efficient, complementary investments in behind-the-meter appliances, such as batteries, EVs or

demand management devices, to maximise the value of their solar PV system investments.

Customer safeguards

49 The Commission considers additional safeguards will help assure customers and other stakeholders that any concerns they have about the way services are priced are addressed before the networks and the regulator make any decision about implementing two-way pricing.

50 The draft rules require networks to consult when they develop their tariff structure proposals and help consumers engage in the regulatory process. These requirements build on existing arrangements that allow distribution networks to phase-in new pricing structures over five years or more.

51 To address any stakeholder concerns about how export charges may be implemented, the Commission has decided to strengthen these consultation requirements – while balancing the need for regulatory flexibility. Networks will be required to develop and consult on a transition strategy to phase-in any proposed export pricing over time. This strategy must be approved by the AER. Networks must also explain the interrelationships between different aspects of their regulatory and tariff structure proposals in a plain language overview. Finally, to promote greater certainty and transparency of the decision-making process, the AER is required to consult on and publish an export pricing guideline.

BOX 1: A HIGH-LEVEL OVERVIEW OF THE PROPOSED REFORM INITIATIVES

1. **Update the regulatory framework to reflect community expectations for distribution networks to efficiently provide export services to support distribution energy resources.** The draft determination clarifies that distribution services are two-way, and include export services, across the electricity and retail rules (including in the standard conditions for connection contracts).
2. **Promote incentives for efficient investment in, and operation and use of, export services.** The AER must update incentive mechanisms to better align the networks' incentives to provide efficient levels of export services. Export service levels will be guided by performance targets that the networks will be incentivised to maintain and improve on
3. **Support informed network planning and investment decisions.** The AER will be required to regularly calculate the customer export curtailment values (CECV), which will be used to guide the network investment, planning and regulatory decisions for export services.
4. **Promote greater transparency of network export service performance.** Networks will be required to report on metrics relating to export service performance as part of their annual planning reports.

5. **Create regulatory flexibility for new pricing options.** The current prohibition on networks to charge for energy exported into the grid is removed, and distribution tariffs may include payments or credits to customers.
6. **Strengthen stakeholder engagement in the transition process.** Networks will be required to develop and consult on a 'transition strategy' to phase-in any proposed export pricing over time, and explain the interrelationships between different aspects of their regulatory and TSS proposals in a plain language overview.
7. **Promote greater certainty and transparency of the decision-making process.** The AER is required to consult on and publish an export pricing guideline and a method for calculating the CECV to inform regulatory proposals.
8. **Support innovation and future market developments.** The 'individual' and 'cumulative' thresholds for tariff trials is increased over networks' next two regulatory periods. A pricing principle that is a barrier to their designing more advanced network tariffs targeting retailers and intermediaries for end customers has been clarified.
9. **Improves the adaptability of the pricing framework to emerging network issues.** The reference to cost drivers in the pricing principles is broadened to capture contemporary network issues such as minimum demand.

Source: AEMC

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1 INTRODUCTION

1.1 Another step forward in this reform process

The Australian Energy Market Commission (the Commission) has made more preferable draft electricity and retail rules (draft rules) in response to rule change requests from SA Power Networks (SAPN), the St Vincent de Paul Society Victoria (SVDP), and Total Environment Centre (TEC) together with the Australian Council of Social Service (ACOSS).

The three proposals draw on a previous nine-month consultation process that was conducted as part of ARENA's Distributed Energy Integration Program (DEIP).[5] This consultation was led by a steering group of consumer representatives, industry association and market bodies, and saw a wide range of stakeholders collaborating to develop and test access and pricing reform options, and to identify consensus on needed reforms and principles.[6]

Implementation of distribution access and pricing reforms that impact the provision of DER services is a major change management exercise – especially given renewable generation is a big part of Australia's commitment to reduce emissions. Building trust is key to long-term success. This requires openness and transparency, and ongoing consultation to understand and address stakeholder concerns.

The Commission has worked extensively with a range of stakeholders through this process and the prior DEIP consultation. The Commission is very grateful for the high level of commitment demonstrated by key stakeholders, and the informative submissions received to date. This includes attendance at public forums, six technical working group (TWG) meetings and submissions received by the Commission. The TWG was established with representatives from key stakeholder groups to support the development of the draft determination.

The knowledge and expertise of our stakeholders is invaluable to us and has significantly influenced our draft determination. Through the many discussions, we have considered different perspectives, underlying concerns and a range of possible solutions that promote the long term interests of consumers.

The next steps of our rule change consultation process include submissions on the draft determination, a virtual public forum and ongoing consultation with the TWG. The final determination is due to be made by mid-2021.

Following our final determination, the AER, DNSPs, retailers, consumer groups, governments and other key stakeholders will be responsible for then implementing the reforms. There will be continued consultation, led by the AER, and the expectation is for the sector to work with retail customers in each jurisdiction to develop network service options that meet customer needs and preferences.

5 DEIP is a collaboration of government agencies, market authorities, industry and consumer associations aimed at maximising the value of DER for all energy users.

6 This consultation gave stakeholders an opportunity to participate in three large workshops and six more technical 'Reference Group' meetings, and provide written submissions. Over 120 stakeholders participated in this consultation process – informing five reports.

1.2 Structure of this document

This draft determination sets out what is proposed by the rule change requests, the Commission's reasons for making its decision, and how stakeholders can continue to contribute to our rule change process:

- **Chapter 2** provides an overview of the rule change proposals
- **Chapter 3** sets out the assessment framework, and assessment of the draft rules against the assessment framework
- **Chapter 4** outlines the Commission's draft determination with regard to updating the regulatory framework so that the range of services, including export services, provided by DNSPs to their customers are recognised in the regulatory framework. It sets out the Commission's draft decision to recognise export services within the existing regulatory framework. It also explains the Commission's draft decision in respect of enabling DNSPs to efficiently provide the services that customers require, for example, through clarifying the treatment of export services in the existing planning and investment frameworks.
- **Chapter 5** outlines the Commission's draft determination with regard to the export service levels that DNSPs are expected to provide customers and the incentive arrangements for efficient delivery of export services.
- **Chapter 6** sets out SAPN and SVDP's proposals to enable export pricing, the reasons the Commission has accepted these proposals and further changes to the rules to support these reforms – including additional customer safeguards to promote confidence in the DNSP and AER consultation processes in deciding whether to implement export pricing. Some broader reforms identified through our consultation are also noted.
- **Appendices A–F** include legal requirements of this draft determination under the NEL and supporting material. This includes a summary of the changes to the NER and NERR, and the Commission's customer bill impact analysis (as discussed above).

The amendments to the NER and NERR as a result of this draft rule are separately published on the rule change project's web page.

1.3 Key project milestones

On 30 July 2020, the Commission published a notice advising of its commencement of the rule making process and consultation in respect of the rule change request.[7] A consultation paper identifying specific issues for consultation was also published. Submissions closed on 10 September 2020.

The Commission received 52 submissions as part of the first round of consultation. The Commission considered all issues raised by stakeholders in submissions. Issues raised in submissions are discussed and responded to throughout this draft rule determination.

On 12 November 2020 the Commission published a consolidation notice related to the consolidation of ERC0311, ERC0310 and ERC0309 and extended the timeline for publishing a draft determination to 25 March 2021.

7 This notice was published under s.95 of the National Electricity Law (NEL) and 251 of the National Energy Retail Law (NERL).

Any person or body may request that the Commission hold a hearing in relation to the draft rule determination. Any request for a hearing must be made in writing and must be received by the Commission no later than **1 April 2021**. Submissions and requests for a hearing should quote project number ERC0311 or RRC0039 and may be lodged online at www.aemc.gov.au.

The Commission invites submissions on this draft rule determination, including the more preferable draft rule, by **13 May 2021**.

The Commission will hold a virtual public forum in mid-April 2021 as part of our consultation. Interested stakeholders will be able to register for the forum via the project webpage.

Following consideration of submissions, the Commission intends to publish its final determination by **24 June 2021**.

2 SUMMARY OF RULE CHANGE REQUESTS

This chapter summarises the issues raised by rule change proponents, and the proposed solutions to address the issues and associated benefits.

2.1 SA Power Networks

2.1.1 Issues raised

SA Power Networks (SAPN) stated that although there is a clear regulatory framework for consumption services, no such framework exists in relation to export services and, consequently:[8]

- DER customers are beginning to experience poorer performance of their systems, as the technical limits of the network are reached
- the renewables industry is concerned that DNSPs will increasingly impose 'zero export' requirements on new solar customers connecting in areas that are already congested
- DNSPs do not have a clear basis upon which to make DER-related investment decisions
- vulnerable customers are concerned about increasing cross-subsidies from customers who do not have DER, and may never be able to, to those who do
- the AEMC and ESB are concerned that the current regulatory framework may not support efficient investment in the long term.

2.1.2 Proposed changes

SAPN's proposal sought to update the regulatory framework to directly recognise and consider export services. The objectives are:[9]

1. Ensuring recognition of all services that customers value – including use of the network by customers to consume energy, and use of the network to export energy they generate
2. Encourage efficient investment, and prevent potential over-investment, by DNSPs to support the service levels that customers desire
3. Enable customers to make informed choices with regard to their energy consumption and export decisions – including the DER they invest in and how these are operated and used.

With the intention of mirroring existing regulatory controls and incentives to an extent to minimise change and any uncertainty, SAPN proposed to create:[10]

- Clear rights for all customers to request and be provided with an offer to access the distribution network to export energy, on a fair and non-discriminatory basis – that is, customers should be able to receive a service offer that does not explicitly deny their ability to export, such as via the setting of a static export limit of zero

8 SAPN rule change request, p. 5.
9 ibid, p. 10.
10 ibid, p. 22.

- For small customers, a defined standard capacity level that customers can request and receive a connection offer for
- A clear regulatory mandate for DNSPs to plan for and invest in providing export services commensurate with customer demand and their desired service levels, and incentive schemes that motivate distributors to maintain service levels at averages that customers value and improve these over time if supported.

SAPN considered the question of access can be addressed by definitional changes in the NER that would then enable export services to be recognised as a fundamental part of the services provided by DNSPs to customers:[11]

> This change would mean that network businesses would have a new requirement to meet or manage customer demand for export services.
>
> Once this change is made, the existing regulatory requirements, incentive schemes and controls that apply to distribution networks' provision of consumption services would apply and could be adapted to their provision of export services. While most incentive schemes can apply simply, work is needed to adapt the Service Target Performance Incentive Scheme (STPIS) to export services.

SAPN proposed to remove the current rule that prevents DNSPs from proposing tariffs that include an export component, to allow such tariffs to be considered through the TSS process in future.[12] SAPN states any future tariffs applied to exports would principally seek to recover incremental costs associated specifically with the provision of export capacity.[13]

An objective of SAPN's proposal is to enable customers to make informed choices with regard to their energy consumption and export decisions – including the DER they invest in and how these are operated and used.[14]

SAPN considered customers should have choices that enable them to avoid some or all of the export component of the tariff if they choose to maintain their exports below a level that would, on average, require additional capacity investment – such as through a set export limit reflective of the inherent network capacity, or by using a smart inverter capable of responding to a 'flexible' or dynamic export limit.[15] For example, SAPN envisaged customers could choose from the following menu of options:[16]

1. a 'basic' service at low or zero cost, perhaps reflective of a fixed, low export capacity, aligned to the intrinsic hosting capacity of the network
2. a 'base' level of capacity and reliability – that is, the average reliability across customers as set by an adapted STPIS

11 ibid, p. 6.
12 ibid, p. 8.
13 ibid, p. 7.
14 ibid, p. 10.
15 ibid, p. 7.
16 ibid, p. 25.

3. a 'premium' service, such as higher than average export capacity – without the associated costs being apportioned to customers that don't want them.

Further, SAPN proposed to enable options for customers to be better rewarded for providing export services at a time that is most valued by the energy system. SAPN stated a new rule should make it explicit that any cost reflective distribution charges can also include negative prices.[17]

SAPN said it does not observe any other required rule changes to enable its vision of customer service choices that could be made available, but requests the Commission to review "if there are any other regulatory barriers to customising export service offers should distribution networks seek to do so, or any regulatory barriers to customers being able to move between offers over time."[18]

2.1.3 Benefits of proposed changes

SAPN considered its proposal will lead to improved outcomes for all customers in the long term, as the energy system continues its community-led transition to distributed renewable energy. SAPN stated that its proposal will:[19]

- Provide greater confidence to customers and their agents in respect of service levels for DER
- Provide enhanced market benefits for all customers through increased DER exported energy
- Encourage efficient investment by DNSPs to support services levels desired by customers by providing DNSPs a clearly defined regulatory framework
- Provide DNSPs a means of enabling and customising service choices to their customers
- Substantively preserve competitive neutrality between upstream and downstream sources of generation in the NEM
- Enable efficient price signals and rewards to be provided to customers which in turn will:
    - enable customers to make more informed investment and operational decision
    - improve equity in allocating the costs and benefits of DER.

2.2 The St Vincent de Paul Society Victoria

2.2.1 Issues raised

St Vincent de Paul Society Victoria (SVDP) considered that DER participants (the direct beneficiaries of DER integration) should pay their fair share of the costs associated with the measures implemented to integrate DER.[20] SVDP stated clause 6.1.4 of the NER impedes DNSPs from recovering export service costs from these customers – potentially leading to inequitable and inefficient allocation of costs and benefits.[21] SVDP considered:[22]

17 ibid, p. 24
18 ibid, p. 25.
19 ibid, p. 5; 27.
20 SVDP rule change request, p. 4.
21 ibid, p. 9.

> As the cost of DER technologies such as rooftop solar are likely to decrease we can expect to see an increase in uptake, both in terms of the number of installations and the size of the systems installed. We therefore need to create a framework that can address these issues in the long run.
>
> An increased uptake in DER technologies should be a positive development, however as some consumers will be unable to participate a sustainable framework must ensure that not everyone pays the same when the greatest benefits are returned to some.

Further, SVDP said prohibiting export charges under the NER precludes DNSPs from rewarding customers who choose to store energy and export it later.[23]

2.2.2 Proposed changes

SVDP proposed to remove impediments in the NER to DNSPs recovering their costs in supporting the export of electricity from the users who export energy.[24] SVDP stated it is not necessarily advocating for an approach where DER participants have to pay for using the networks. SVDP is proposing to explore a solution that allows exporters to choose between paying or being constrained. This, SVDP said, is an important distinction as some DER participants may prefer being constrained, rather than paying a distribution use of system charge for export.[25]

2.2.3 Benefits of proposed changes

SVDP expected the benefits of its proposal include enhanced opportunities for distributed energy providers and other participants in the market, greater options and choices for energy consumers and communities, and increased participation of DER in the wholesale and other markets. SVDP stated that its rule change enables options rather than proposed solutions, so the costs will be minimal.[26]

2.3 Total Environment Centre / Australian Council of Social Service

2.3.1 Issues raised

Total Environment Centre / Australian Council of Social Service (TEC/ACOSS) submitted that the NER are 'stuck in the outdated one-way system', with several consequences:[27]

- Current pricing arrangements result in investment in and deployment of DER that is not economically efficient.
- Technical issues will increasingly act as a handbrake on the decarbonisation of the energy system due to the increasing practice of limiting rooftop solar exports.

22 ibid, p. 3.
23 ibid, p. 2.
24 ibid, p. 1.
25 ibid, p. 7.
26 ibid, p. 9.
27 TEC/ACOSS rule change request, p. 2.

- Equity issues are arising, especially because people without DER are paying a higher proportion of the costs of the grid that everyone depends upon.

2.3.2 Proposed changes

The objective of TEC/ACOSS's request was to create a regulatory framework that efficiently and equitably optimises the expanding role of DER exports to support a rapid, fair and affordable transition to a zero net carbon energy system.[28] TEC/ACOSS aimed to prevent 'prosumers' (defined as consumers who also produce energy) from facing export limits or being shut off (preventing even self-consumption),[29] and to optimise existing and incentivise additional DER hosting capacity.[30]

TEC/ACOSS proposed incremental reforms focused on two aspects of DER exports:[31]

- Planning and investment – to make the best use of existing network capacity to integrate DER and encourage efficient network investment in new DER hosting capacity.
- Access – to allow choices for 'prosumers' to increase their export capacity in return for a guaranteed level of service (but not 'firm access rights'), and ensure the equitable distribution of hosting capacity between prosumers.

The TEC/ACOSS request applied only to small customers.[32]

2.3.3 Benefits of proposed changes

TEC/ACOSS said that the proposed rule changes are intended as a first step to creating a fit-for-purpose regulatory framework that will "support greater investment in and better operation of DER to facilitate faster decarbonisation of the energy system and deliver more equitable and efficient outcomes for all energy users."[33] TEC/ACOSS' proposal aimed to:[34]

- improve the utilisation of existing DER and encourage investment in new DER
- distribute costs, benefits and risks associated with DER integration transparently
- allow for greater utilisation of existing low carbon generation and greater uptake of new low carbon generation, assisting the shift to a zero net emissions energy system by 2030.

28 ibid, p. 2.
29 ibid, p. 3.
30 ibid, p. 10.
31 ibid, p. 3.
32 ibid, p. 10.
33 ibid, p. 2.
34 ibid, p. 10.

3 DRAFT RULE DETERMINATION

3.1 The Commission's draft rule determination

The Commission's draft rule determination is to make a more preferable draft electricity rule and a more preferable draft retail rule.[35] Key aspects of the more preferable draft rules include:

1. Updating the regulatory framework to clarify that distribution services are two-way and include export services, and that as such the current rules relating to distribution services (including standard terms for distribution contracts under the NERR) apply to export services.
2. Providing for incentives for efficient investment in, and operation and use of, export services, including by requiring the AER to regularly calculate the values of DER curtailment to guide investment and regulatory decisions
3. Removing the prohibition on DNSPs pricing for export services, allowing for both positive and negative charges

The Commission's reasons for making this draft rule determination are summarised below. Further details on the draft rules are set out in chapters 4–6 and appendix B.

In relation to the electricity rule's application in the Northern Territory, the Commission has determined to make a uniform rule.[36]

This chapter outlines:

- the rule making test for changes to the NER and NERR, including the more preferable rule test (section 3.2)
- the assessment framework for considering the rule change request (section 3.3)
- the Commission's consideration of the more preferable draft rules against the national electricity objective and national energy retail objective and other relevant criteria (section 3.4)
- proposed commencement dates and transitional provisions for draft more preferable rules (section 3.5)

Further information on the legal requirements for making this draft rule determination is set out in Appendix A.

3.2 Rule making test and process

3.2.1 Achieving the NEO

Under the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO).[37] This is the decision-making framework that the Commission must apply.

35 In accordance with sections 99 of the NEL and 256 of the NERL.

36 See sections 3.2.5 and 3.4 of this determination for the definitions of a uniform and differential rule and the reasons for the Commission’s decision.

37 Section 88 of the NEL.

The NEO is:[38]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

Under the Northern Territory legislation adopting the NEL, the Commission must regard the reference in the NEO to the "national electricity system" as a reference to whichever of the following the Commission considers appropriate in the circumstances having regard to the nature, scope or operation of the proposed rule:[39]

(a) the national electricity system

(b) one or more, or all, of the local electricity systems[40]

(c) all of the electricity systems referred to above.

For the draft electricity rule, the Commission has determined that the reference to the national electricity system in the NEO is a reference to (c) (noting that the draft rule, if made as a final rule, would have effect in relation to all of the electricity systems referred to above).

3.2.2 Achieving the NERO

Under the NERL, the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national energy retail objective (NERO).[41] This is the decision-making framework that the Commission must apply.

The NERO is:[42]

> to promote efficient investment in, and efficient operation and use of, energy services for the long term interests of consumers of energy with respect to price, quality, safety, reliability and security of supply of energy.

The Commission must also, where relevant, satisfy itself that the rule is 'compatible with the development and application of consumer protections for small customers, including (but not limited to) protections relating to hardship customers' (the 'consumer protections test').[43]

Where the consumer protections test is relevant in the making of a rule, the Commission must be satisfied that both the NERO test and the consumer protections test have been

38 Section 7 of thence.

39 Clause 14A of Schedule 1 to the NT Act, inserting section 88(2a) into the NEL as it applies in the Northern Territory.

40 These are specified Northern Territory systems, listed in schedule 2 of the NT Act.

41 Section 236(1) of the NERL.

42 Section 13 of the NERL.

43 Section 236(2)(b) of the NERL.

met.[44] If the Commission is satisfied that one test, but not the other, has been met, the rule cannot be made.

There may be some overlap in the application of the two tests. For example, a rule that provides a new protection for small customers may also, but will not necessarily, promote the NERO.

3.2.3 Making a more preferable rule

Under section 91A of the NEL and section 244 of the NERL, the Commission may make a rule that is different (including materially different) to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule will or is likely to better contribute to the achievement of the NEO or the NERO (as applicable).

In this instance, the Commission has made more preferable draft electricity and retail rules. The reasons are summarised below in section 3.4.

3.2.4 Revenue and pricing principles – electricity rule

In addition to the NEO, the Commission must take into account certain other principles and factors when it makes rules on particular topics.

Under section 88B of the NEL, the Commission must take into account the revenue and pricing principles when making a rule for or with respect to distribution system revenue and pricing.[45]

The Commission must therefore take into account the revenue and pricing principles in this rule change project. The revenue and pricing principles are set out in section 7A of the NEL. The Commission considers the following revenue and pricing principles are the most relevant to the draft electricity rule:

- A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes:
  - efficient investment in a distribution system or transmission system with which the operator provides direct control network services
  - the efficient provision of electricity network services
  - the efficient use of the distribution system or transmission system with which the operator provides direct control network services
- Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.

44 That is, the legal tests set out in s. 236(1) and (2)(b) of the NERL.

45 Section 88B of the NEL refers to items 25 to 26J of Schedule 1 to the NEL, which cover distribution system revenue and pricing and regulatory economic methodologies.

- Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

In making the more preferable draft electricity rule, the Commission has taken the revenue and pricing principles into account by reflecting them in the assessment framework (section 3.3) and using that framework to assess the rule (section 3.4).

Under section 88A of the NEL, the Commission must take into account the form of regulation factors[46] when making a rule that confers a function or power on the AER to specify under a network revenue or pricing determination an electricity network service (to which the relevant determination applies) as a direct control service or a negotiated network service. In the draft electricity rule, the Commission clarifies that distribution services include export services. The AER is able to classify distribution services, including export services, under its existing functions and powers in Part B of NER chapter 6. As the Commission has not conferred a new function or power on the AER in this regard, and given the AER must itself have regard to the form of regulation factors in classifying distribution services,[47]the Commission is not required to take the form of regulation factors into account in making the draft electricity rule.

3.2.5 Rule making in the Northern Territory – electricity rule

The NER, as amended from time to time, apply in the Northern Territory, subject to modifications set out in regulations made under the Northern Territory legislation adopting the NEL.[48] Under those regulations, only certain parts of the NER have been adopted in the Northern Territory.[49]

As the draft electricity rule relates to the parts of the NER that apply in the Northern Territory, the Commission has assessed whether to make a uniform or differential rule (defined below) under Northern Territory legislation.

Under the NT Act, the Commission may make a differential rule if it is satisfied that, having regard to any relevant MCE statement of policy principles, a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.[50] A differential rule is a rule that:

- varies in its terms as between:
  - the national electricity system; and
  - one or more, or all, of the local electricity systems; or
- does not have effect with respect to one or more of those systems,

46 These factors are set our in NEL section 2F.

47 NER cl 6.2.1(c).

48 The regulations under the NT Act are the National Electricity (Northern Territory) (National Uniform Legislation) (Modification) Regulations 2016.

49 The version of the NER that applies in the Northern Territory is available on the AEMC website at www.aemc.gov.au/regulation/energy-rules/northern-territory-electricity-market-rules/current.

50 Clause 14B of Schedule 1 to the NT Act, inserting section 88AA into the NEL as it applies in the Northern Territory.

but is not a jurisdictional derogation, participant derogation or rule that has effect with respect to an adoptive jurisdiction for the purpose of s. 91(8) of the NEL.

A uniform rule is a rule that does not vary in its terms between the national electricity system and one or more, or all, of the local electricity systems, and has effect with respect to all of those systems.[51]

The Commission has determined to make a uniform rule as it does not consider that a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule. The reasons for this decision are summarised in section 3.4.

3.3 Assessment framework

3.3.1 Assessment criteria applied for this draft rule determination

Investing in and operating the networks in the long term interests of consumers means that reliability, safety, security and quality requirements for network services are met at efficient long term cost. Consistent with the NEO and NERO, this outcome will be achieved if a number of conditions are met:

1. **Efficient provision of electricity services** – The regulatory framework should facilitate the efficient provision of electricity services. A key consideration in the Commission's assessment of the rule change requests and the more preferable draft rules is how likely they are to contribute to the lowest possible total system cost, taking into account the revenue and pricing principles.[52]
2. **Efficient pricing** – Prices should signal to consumers the costs of providing network services. Price signals can provide opportunities for consumers to adjust their usage patterns in ways that can reduce their own costs of using the network as well as contribute to reducing future network costs more broadly. Price signals can include negative prices (eg, payments or credits to customers) to reward customers for actions that better utilise the network or improve network operations. The Commission has considered whether the more preferable draft rules will provide for efficient pricing outcomes.
3. **A regulated network service provider should be provided with effective incentives to promote economic efficiency** – Efficient outcomes can be best promoted by aligning the commercial incentives on businesses with the interests of consumers – consistent with the revenue and pricing principles. Financial incentives provide an understandable and transparent approach to influence behaviour. Businesses that face financial incentives therefore have the best ability to respond to the regulation. Financial incentives are likely to lead to more efficient outcomes.
4. **Risks should be allocated to those best placed to manage them** – The party holding the risk should have: incentives to manage the risk, because it stands to gain or lose from doing so, and there is a clear link between its actions and the outcomes of the

51 Clause 14 of Schedule 1 to the NT Act, inserting the definitions of "differential Rule" and "uniform Rule" into section 87 of the NEL as it applies in the Northern Territory.

52 See section 3.2.5 above. These principles are set out in NEL section 7A.

risk; more information than other parties to manage risk since it can use this information to better mitigate the impact of the associated loss; the ability to better manage risk than other parties, so it can take actions to avoid or reduce the impact of the associated loss; and the ability to improve risk management over time through experience. Risks should be borne by, or allocated to, parties who are in the best position to manage them and have the incentives to do so. This ultimately leads to lower costs for consumers.

5. **Robustness to climate change mitigation and adaptation risks** – In order to make decisions that promote the NEO and NERO, the Commission considers whether its decisions are robust to impacts of climate change, or climate change mitigation or adaptation measures, on the price, quality, safety, reliability and security of supply of energy or energy services.
6. **Regulatory clarity and certainty** – A lack of clarity and certainty in regulatory arrangements can affect the confidence of stakeholders to invest and participate in the markets. Similarly, the framework needs to provide clear rights for customers to allow them to make optimal consumption choices and investment decisions in behind the meter devices.
7. **Regulatory burden** – The Commission has considered whether the implementation and administrative costs arising from the more preferable draft rules are proportionate to the benefits. Where possible, rules should minimise additional regulatory burden or the increase in administrative costs.
8. **Promote consumer choice** – Market-based outcomes, which broadly promote the NEO, are best achieved when consumers are put at the centre of things. Consumer empowerment is a key driver of the transformation of the energy sector currently underway – whereby consumers can both buy and sell energy services, and participate in different markets under a variety of new business models. The regulatory framework should provide for flexibility for energy sector participants to respond effectively to changes in technology and market developments over time. Consumers should have the opportunity to make informed decisions or choices about which electricity services they use and the way they use them, based on the benefits that the services provide to them. Transparent and understandable information on prices and other terms and conditions of access are important, so consumers can weigh up different options available to them, adjust consumption and dispatch accordingly, and make informed decisions about their use of the network and DER-related investments. Ultimately, consumers will be in the best position to decide what works for them and how they engage in energy markets, which promotes allocative and dynamic efficiency.

Most submissions that commented on the assessment criteria proposed in the July 2020 Consultation paper (the above criteria, with the exception of criteria 3, 4 and 8) broadly supported them – including: AGL, Ausgrid, AusNet Services, Ecojoule Energy, Endeavour Energy, EnergyAustralia, EUAA, Evoenergy, Firm Power, Jemena and Renew.

Criteria 3, 4 and 8 have been added to the assessment framework since the consultation paper – largely in response to submissions, as discussed below.

3.3.2 Commission response to submissions on assessment criteria

The NEO and NERO include a specific set of variables – price, quality, safety, reliability and security of supply – which must be objectively considered when assessing a rule change or a review. We must base our decision on how the outcome of a particular decision would impact on these variables, where relevant, and these variables alone. That said, other variables may be relevant to the extent they affect the price, quality, safety, reliability and security of supply. The impacts of climate change, and climate change mitigation and adaptation risk, on the price and reliability of electricity is an example of this.

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The Commission agrees with criteria proposed in the following submissions:

- Risks should be allocated to those best placed to manage them’ (criterion 4 above), has been added in response to AGL’s submission proposing the assessment framework should also include the principle of efficient allocation of risk.[53] Allocation of risk to a party who can, relative to others, better assess and manage the consequences of that risk, should lead to incentives to improve risk management over time and minimising overall costs to society.
- ‘Consumers should have options in the way they use energy’ (criterion 8 above), has been added in response to the AGL and Renew submissions proposing the assessment framework should also reflect the values of customer choice, optionality and transparency.[54] Customer options are central to SAPN and SVDP’s proposals to enable export charges, and transparency is fundamental for customers to understand the available options.

The Commission considers some additional assessment criteria proposed in submissions are already captured in our assessment framework, namely:

- The Jemena, Firm Power and Renew submissions generally propose criteria covering investment certainty, risk of stranded assets and ‘sovereign risk’.[55] The Commission considers these issues are covered in criteria 1 above, ‘Regulatory clarity and certainty’. The Commission agrees regulatory frameworks and market design should provide a clear, understandable set of rules. This promotes confidence in regulation and markets, and allows participants to invest and develop and adapt business strategies to best meet the changing needs of consumers.

53 AGL submission to the consultation paper, p. 3.

54 Submissions to the consultation paper: AGL, p. 3; Renew pp. 4 -5.

55 Submissions to the consultation paper: Jemena, p. 3; Firm Power, p. 2; Renew, p. 5.

- Renew proposes criteria covering 'value' – whereby solutions should deliver the greatest net outcome for all customers, not just those with DER.[56] The Commission considers this is encompassed by the 'Efficient provision of electricity services'. The Commission considers reforms to better integrate DER into the energy system should benefit the broader community – not just those with DER.
- Renew proposes criteria covering cost-reflectivity – including where customers' use of their DER creates net costs to the network, or where DER use reduces costs in the network.[57] The Commission considers this issue is part of 'Efficient pricing'. Nevertheless, the Commission has clarified that price signals can include negative prices to reward customers for actions that better utilise the network or improve network operations.
- The Jemena and Customer Advocate submissions propose additional detail under 'Regulatory burden'. The Commission notes these views and considers these issues are already broadly incorporated under this criterion.[58]
- Ausgrid's submission proposes that the assessment framework should promote the NERO by ensuring that the rule is compatible with the development and application of consumer protection for small customers.[59] As discussed in section 3.2.2 above, the Commission may only make a Rule if it is satisfied that the Rule will or is likely to contribute to the achievement of the NERO – including, where relevant, that the Rule is compatible with the development and application of consumer protections for small customers.[60]

The Commission is limited in its ability to consider notions of equity and fairness – as generally proposed by Jemena, Planet Ark Power, Firm Power, AGL, Ausgrid and Renew – otherwise than with reference to efficiency.[61] Efficiency is the fundamental objective of the energy market objectives. Although the notion of the 'long term interests of consumers' is somewhat ambiguous, the second reading speech for the Bill containing the NEO clarifies:[62]

> The market objective is an economic concept and should be interpreted as such. For example, investment in and use of electricity services will be efficient when services are supplied in the long run at least cost, resources including infrastructure are used to deliver the greatest possible benefit and there is innovation and investment in response to changes in consumer needs and productive opportunities. The long term interest of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised. If the National Electricity Market is efficient in an economic sense the long term economic interests of consumers in respect of price,

56 Renew submission to the consultation paper, p. 5.

57 Renew submission to the consultation paper, pp. 4-5

58 Jemena states in its submission, NER changes should be minimised and any NER changes should allow for overlapping operation of jurisdiction instruments (p. 3).; The Customer Advocate states in its submission, "under the banner of regulatory burden, the cost-benefit of these proposed changes to consumers through additional charges, new market entities, communication and infrastructure costs and cybersecurity must be considered in a transparent and effective way." (p. 3)

59 Ausgrid submission to the consultation paper, p. 4.

60 NERL clause. 236(1); 236(2)(b).

61 Submissions to the consultation paper: Jemena, p. 3; Planet Ark Power, p. 4; Firm Power, p. 2; AGL, p. 3; Ausgrid, p. 4; Renew, p. 4.

62 Second reading speech, *National Electricity (South Australia) (New National Electricity Law) Amendment Bill 2005*, 9 February 2005.

quality, reliability, safety and security of electricity services will be maximised.

Energetic Communities argues the Commission should also consider affordability of essential energy and access to zero carbon supply.[63] The Commission acknowledges governments and the community are concerned about affordability and environmental issues. Achievement of such policy objectives is typically associated with a subjective value judgement that typically differs, depending on a particular view, and may potentially have broad societal impacts. For example, lowering emissions requires governments to make value judgements using information on the economy as a whole and the welfare of the population.

However, when making rules, the Commission takes wider policy objectives into account to the extent they impact on NEO and NERO matters such as safety, security, reliability, quality and price. For example, under 'Efficient pricing', the Commission will consider the promotion of market outcomes where prices reflect the efficient costs of providing energy services. In loose terms, this means that energy consumers should pay no more than necessary for the safe and reliable delivery of electricity services. Further, under 'Robustness to climate change mitigation and adaptation risks', the Commission will consider whether the draft rule is robust to the impacts of climate change, and climate change mitigation and adaptation risks, on the NEO and NERO matters.

The Commission agrees with CSR and Endeavour Energy that it will be important that this rule change fits within the broader suite of industry reforms that are occurring.[64] The Commission considers the rule change requests are foundational to future market design considerations – especially two-sided markets, which is being considered by the ESB as part of the Post 2025 Market Design review. The Commission takes a holistic view in making decisions. The above assessment framework criteria broadly cover off on the need for a consistent approach.

Although noteworthy and important, the Commission considers the following proposals are less relevant to the NEO and NERO:

- The Customer Advocate proposes that the risk assessment must include the immediate impacts of the pandemic[65]
- Energetic Communities proposes to invite suggestions or comments on alternative considerations for cost recovery[66]
- Evoenergy proposes that the assessment framework should also acknowledge the role of jurisdictional government and customer preferences in determining appropriate changes[67]
- Renew proposes the assessment framework should consider how the new regulatory arrangements will enable principles of materiality of costs or benefits passed on the consumers, 'additionality' and simplicity[68]

63 Energetic Communities submissions to the consultation paper, p. 3.

64 Submissions to the consultation paper: CSR, p. 2; Endeavour Energy - Appendix A, p. 1.

65 The Customer Advocate submission to the consultation paper, p. 3.

66 Energetic Communities submission to the consultation paper, p. 3.

67 Evoenergy submission to the consultation paper, p. 9.

68 Renew submission to the consultation paper, p. 5.

Energetic Communities also proposes to include customer impact analysis as part of the assessment framework, including 'willingness to pay'.[69] Further, the Customer Advocate states the framework must include clear consideration of how consumers are likely to react to the change, embrace the advantages and consider their own responses.[70] The Commission considers these types of analysis and analytical tools can be used to identify the benefits and costs of the proposed rule changes, which can inform our decision – as distinct from assessment criteria.

Planet Ark Power identified many relevant considerations in its submission.[71] The Commission considers the above assessment framework criteria broadly cover off on these issues.

3.4 Summary of reasons

The more preferable draft rules made by the Commission are published with this draft rule determination. The key features of the more preferable draft rules are outlined in section 3.1 above.

Further detail on the more preferable draft rules can be found in chapters 4–6 and appendix B.

The Commission is satisfied that, having regard to the issues raised in the rule change requests and during consultation, the more preferable draft rules will, or are likely to, better contribute to the achievement of the NEO and NERO for the reasons set out below.

3.4.1 Updating the regulatory framework to recognise the provision of export services to customers

The proponents' rule changes proposed the need to update key terms in the NER to clearly recognise export services in the regulatory framework. In addition, SAPN suggested that the existing planning and investment framework could be adapted to apply to export services. TEC/ACOSS proposed the need for additional planning and investment obligations to be set in the NER to support DNSPs in the provision of export services.

Accordingly, the Commission has considered the merits of expanding the definition of distribution service to include export services. This has been considered in the context of the development of the national regulatory framework, which was established at a time when energy flows were not bidirectional, and the need for this framework to be flexible to accommodate change and continue to evolve with customer demand for emerging DER technologies. As a result, it has concluded that it is appropriate to clarify that export services form part of a distribution service. The Commission considers that this is likely to advance the NEO as it would provide regulatory clarity and certainty for customers in relation to access to export services and to DNSPs regarding expectations to provide export services.

Under an approach where export services are recognised as forming part of a distribution service, the draft rule is intended to enable existing planning and investment arrangements

69 Energetic Communities submission to the consultation paper, pp. 2–3.

70 The Customer Advocate submission to the consultation paper, p. 3.

71 Planet Ark Power submission to the consultation paper, pp. 4–7.

to be adapted for export services. Consequential changes to enable the application of existing regulatory mechanisms, such as incentive schemes, are also required. These changes support the application of the existing framework by broadening the application of relevant rules in the NER and NERR to export services. As such, the Commission considers that these changes to support the application of the existing regulatory framework to export services are consistent with the key intent of the proponents' proposed approaches. In addition, the Commission considers the draft rules are consistent with achieving the NEO and the NERO as they clearly establish the application of the existing regulatory framework to export services. This supports the effective application of existing processes to export services and should therefore minimise any associated regulatory burden and administrative cost that may result.

Given the emerging nature of export services, and the fact that they are not essential services in the same way as consumption services, the Commission also considers there should be some further guidance in the NER to support transparency and efficiency with regard to planning and investment decisions around export services. On this basis, the more preferable draft rule supplements the existing framework with a number of new reporting requirements to increase transparency around planning and investment opportunities for export services. As such, the draft electricity rule takes into account the assessment criteria relating to regulatory clarity and certainty by providing clear guidance as to the regulatory arrangements that are to apply to export services.

To support additional requirements around the type of information that DNSPs would be required to provide in relation to planning and investment for export services, the Commission's draft electricity rule requires that the AER, through its Expenditure Forecast Assessment Guidelines, develop guidance to assist DNSPs in their expenditure proposals (e.g. by outlining the type of information and analysis that should be included) and provide clarity with regard to the assessment of export related expenditure so as to provide support to DNSPs in the efficient provision of export services. In this regard the draft electricity rule takes into account the assessment criteria relating to the efficient provision of electricity services.

The more preferable draft rules are likely to better achieve the NEO and NERO than the rule changes sought by the proponents because they not only utilise the existing regulatory framework, which enables existing regulatory mechanisms to be adapted for export services, but also take into account the need to integrate export services in the context of the future development of the rules, particularly in light of the move to two-sided market arrangements. This will likely result in a more cost-effective solution that creates consistency with future market developments and is administratively efficient.

The more preferable draft retail rule is compatible with the development and application of consumer protections for small customers because it clarifies the extent to which the consumer protections under the NERR apply to export services. In particular, it makes provisions to allow retail customers to access metering data about exports in the same way that they are given access to consumption data. This is likely to result in improved protection and certainty for retail customers of export services.

3.4.2 Incentive arrangements and service levels of export services

The Commission's more preferable draft rule:

- Supports the application of incentive arrangements for efficient delivery of export services by introducing requirements under NER clause 11.[xxx].3 for the AER to undertake a review to consider arrangements, which may include the STPIS, for providing performance incentives for export services (see section 5.1.4). This is consistent with assessment criteria on providing DNSPs with effective incentives to promote economic efficiency, as discussed further below.
- Provides greater flexibility to the AER in providing export service performance incentives by:
  - amending the factors that need to be considered by the AER in developing the STPIS, including in extending the STPIS to exports under NER clauses 6.6.2 (v)(3)(i), 6.6.3 (b) (3) (vi) and 6.6.3 (b) (5) (see section 5.1.4).
  - amending other relevant parts of incentives framework to provide more scope for the AER to consider the application of the DMIS, DMIA and the small-scale incentive scheme to export services under NER clauses 6.6.3(b) and (c)(3), NER clauses 6.6.3A(b), (c) and (d) and NER clause 6.6.4(b)(3) respectively (see section 5.1.4). This is consistent with assessment criteria on providing DNSPs with effective incentives to promote economic efficiency, as discussed further below.
- Promotes greater transparency of export service performance delivered to customers by introducing requirements on DNSPs under NER schedule 5.8 clauses (l)(3) and (4) to report annually on a range of metrics related to their export service performance in their Distribution Annual Planning Reports (DAPR) (see section 5.2.4). This is consistent with assessment criteria on the regulatory burden for the parties involved, as discussed further below.
- Introduces a new requirement on the AER under NER rule 8.13 to develop a methodology for and to regularly calculate customer export curtailment values (CECV). The Commission considers these values are more likely to contribute to achieving the NEO than a measure for the value customers place on export service reliability because customer export curtailment values would better reflect the benefits to customers from exporting customers being able to access greater levels of export capacity. (see section 5.3.4) This is consistent with assessment criteria on the efficient provision of electricity services and regulatory burden for the parties involved, as discussed further below.

The Commission's more preferable draft electricity rule is likely to better contribute to the achievement of the NEO than the rules proposed by the proponents because the Commission's more preferable draft electricity rule:

- Includes provisions for DNSPs to report on their export service performance on an annual basis. Enhanced transparency of export service performance will provide for more informed regulatory, policy decisions and DER investment decisions by customers.
- Amends the factors that need to be considered by the AER in developing the STPIS to provide greater flexibility to the AER in providing incentive arrangements for export services and improves regulatory consistency.

- Does not include requirements for DNSPs to offer minimum levels of export capacity to customers. The Commission considers that, in this respect, the draft rule is more likely to promote the NEO than the rule proposed by SAPN and TEC/ACOSS as it would provide greater ability for DNSPs to meet differing network circumstances and reduce the likelihood of inefficient network expenditure.

The elements of the Commission's draft electricity rule summarised above, and in more detail in chapter 5, contribute to the achievement of the NEO in the following ways:

1. **Efficient provision of electricity services** – The impact of defining export service levels, the proposal for requirements on DNSPs to provide minimum export capacity to customers and the development of customer export curtailment values on efficient provision of electricity services was considered. The Commission considers that development of customer export curtailment values would support efficient provision of electricity services and contribute to the lowest possible system costs by enabling the assessment of whether increasing hosting capacity leads to lowest overall system costs. Similarly, defining export service level requirements through the STPIS is considered to support efficient provision of export services.
2. **A regulated network service provider should be provided with effective incentives to promote economic efficiency** –In assessing the incentive arrangements for export service the Commission has considered the need to provide effective incentives to promote economic efficiency. The Commission considers that the amendments under the draft electricity rule to support export service performance incentives for DNSPs would lead to a better alignment of commercial incentives of DNSPs with the interest of consumers. The DNSPs will be incentivised to reduce the cost of delivery of export services, share the efficiency benefits with customers and deliver a superior export service that is better able to meet their customers' export needs.
3. **Regulatory clarity and certainty** – The implications of the proposal for outlining service level requirements and requirements on DNSPs to provide minimum export capacity to customers for regulatory clarity and certainty were considered by Commission. The Commission considers that defining service level requirements through the STPIS would improve regulatory clarity while the minimum export capacity requirements would not.
4. **Regulatory burden** – In considering the arrangement for customer export curtailment values, the export service performance reporting and the proposal for supplementary connection arrangements for additional hosting capacity, the Commission has been cognisant of minimising regulatory burden on the stakeholders involved. The regulatory burden of the CECV framework and the performance reporting requirements is likely to be proportionate to the benefits to the market.

3.4.3 Distribution network pricing arrangements for export services

The Commission's more preferable draft electricity rule:

- Removes the current prohibition on DNSPs to charge for energy exported into the grid by deleting NER clause 6.1.4, as proposed by SAPN and SVDP (see section 6.4.2). This creates regulatory flexibility to enable pricing options of DER that send efficient signals for future expenditure and incentivise customers to best utilise existing infrastructure. This is a way to integrate DER more effectively into the electricity system and lower costs for all distribution network users – helping to achieve assessment criteria 2, 4, 5, and 8, as discussed further below.

- Makes clear that distribution tariffs may reflect efficient negative costs for both export and consumption services by amending NER cl. 6.18.5(a) – consistent with SAPN's proposal (see section 6.4.2). This creates regulatory flexibility for DNSPs to better reward customers for actions that better utilise infrastructure or improve network operations – helping to achieve assessment criteria 2, 4, 5, and 8, as discussed further below.
- Strengthens stakeholder engagement in the transition process above that proposed by SAPN and SVDP, which the Commission considers is necessary to mitigate customer risks and therefore preferable, by requiring DNSPs to:
  - develop and consult on an export tariff transition strategy as part of its TSS process to phase-in any proposed export pricing over time, by amending NER cl. 6.8.2(c1) and cl. 6.18.1A (see section 6.4.3)
  - explain the interrelationships between different aspects of its regulatory and TSS proposals, including how the proposed pricing structures relate to connection policies and expenditure plans, in a plain language overview, by amending NER cl. 6.8.2(c1) (see section 6.4.3).
  - These changes help to achieve assessment criteria 2, 4, 5, 6 and 8, as discussed further below.
- Promotes greater certainty and transparency of the decision-making process, above that proposed by SAPN and SVDP, by requiring the AER to consult on and publish Export Tariff Guidelines under NER cl. 6.8.1B – helping to achieve assessment criteria 2, 4, 5, 6 and 8, as discussed further below (see section 6.4.3).
  - The Commission considers this is preferable to find a balance of providing regulatory flexibility while giving stakeholders more confidence in the TSS process, and to promote consumer engagement in the AER's decision making.
  - Under NER cl. 11.XXX.4, by 1 July 2022, the AER must develop and publish the initial Export Tariff Guidelines. The AER must comply with the distribution consultation procedures when preparing the initial Export Tariff Guidelines.
- Supports innovation and future market developments, above that proposed by SAPN and SVDP, by:
  - increasing the 'individual' and 'cumulative' thresholds for tariff trials as a transitional arrangement over the next two regulatory periods under NER cl. 11.XX.7 – which is preferable to facilitate more informed TSS proposals of potential customer impacts (see section 6.4.2)
  - amending a pricing principle so that DNSPs are able to design more advanced network tariffs targeting retailers and intermediaries for end customers under NER cl. 6.18.5(i) (see section 6.4.2).

  - These changes help to achieve assessment criteria 2, 4, 5, 6 and 8, as discussed further below.
- Improves the adaptability of the pricing framework to emerging network issues relating to the increased use of DER – especially minimum demand periods – by broadening the reference to cost drivers under NER clause 6.18.5(f)(2), as proposed by the AER in its submission – helping to achieve assessment criteria 2, 4, 5, 6 and 8, as discussed further below (see section 6.4.2).
  - This clause currently require DNSPs to base tariffs on the long run marginal cost of providing services with regard to meeting demand 'at times of greatest utilisation of the relevant part of the distribution network'. It is preferable to say, 'times of greatest utilisation of the relevant service', which covers minimum demand-related network constraints.
- Makes consequential rule changes required to support the above amendments, above that proposed by SAPN and SVDP, which is preferable for regulatory clarity in-line with assessment criterion 6, including to:
  - the NER clause 6.18.4 principles governing assignment or re-assignment of retail customers to tariff classes and assessment and review of the basis of charging (see section 6.4.2)
  - the billing and credit risk pass through arrangements under chapter 6B of the NER to support the implementation of export tariffs (see section 6.4.2).
  - These changes help to achieve assessment criteria 2 and 6, as discussed further below.

The Commission's more preferable draft electricity rule, summarised above and in more detail in chapter 6, better contributes to the achievement of the NEO in the following ways:

- **Efficient pricing** – The Commission considers enabling export pricing promotes efficient investment in both network electricity services and behind-the-meter investments made by retail customers. These price signals can provide opportunities for consumers to adjust their usage patterns in ways that can reduce their own cost of using the network, as well as contribute to reducing future network costs more broadly.
- **Risks should be allocated to those best placed to manage them** – implementation of price signals allocates the risk to retail customers of excessive demand of network services at a given point in time, which could lead to inefficient network expenditure. This is especially so for export pricing, given non-DER-households (who currently contribute to DER-related costs) do not have the ability to take actions to manage the risk of excessive demand of network export services. Retail customers will have an incentive to manage the risk because they will seek to minimise bill impacts. Increasingly, it is expected retail customers will have the ability to adjust their usage or exports during times when there are network constraints. Customers should be rewarded for this flexibility. When new expenditure is required to meet demand for network services, price signals can help to ensure it will be the result of customers making informed decisions about the costs that they impose on the network.

- **Robustness to climate change risk and climate change mitigation and adaptation risks** – Enabling export pricing, as well as addressing incentives for providing export services (discussed above) creates greater regulatory flexibility and opens up a range of potential service options to efficiently manage the integration of DER into the energy system. This flexibility is robust to jurisdictional measures to promote DER and complementary investments in behind-the-meter appliances – including batteries, EVs and demand management devices – as part of climate change mitigation programs. Without these regulatory changes, measures to increase DER may affect the price and reliability of the supply of electricity. Efficiently integrating DER into the energy system, so that greater exports from DER can be accommodated, is also robust to climate change risks affecting reliability, such as severe weather events which may interrupt supply from large centralised generators.
- **Regulatory clarity and certainty** – The Commission considers the requirements on the AER to publish a TSS guideline, and DNSPs to develop a transition strategy, promote understanding and confidence in regulatory arrangements, and strengthen the forum for customers and other stakeholders to express their concerns and preferences.
- **Regulatory burden** – The Commission has considered whether the implementation and administrative costs arising from the more preferable draft rule are proportionate to the benefits. In particular, the Commission considers the new consultation and reporting requirements on DNSPs and the AER are the minimum necessary steps to manage stakeholder concerns in implementing export pricing reforms. Further, the existing pricing framework, which is well understood by the sector, will largely apply to export pricing – minimising additional regulatory complexity.
- **Promote consumer choice** – In the context of the major transformation underway, the Commission considers enabling export pricing creates regulatory flexibility for the sector to respond to changing customer and jurisdictional preferences, network circumstances, and technology and market developments as they emerge. Further, it is increasingly important for consumer views, preferences and priorities to be reflected in network proposals and regulatory outcomes. The Commission's decision to strengthen consultation requirements promotes consumer engagement and stakeholder management.

3.4.4 Uniform rule

As noted in section 3.2.5 above, the Commission has determined to make a uniform rule for the more preferable draft electricity rule, as it does not consider that a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule. The Commission considers that there are no relevant differences between the NEM and the local NT systems that would necessitate a differential rule. While the systems have different physical characteristics, these should not impact the implementation of the rule.

3.5 Proposed commencement dates and transitional provisions for draft more preferable rules

The following tables outline the implementation timelines and key transitional provisions for amendments under the draft more preferable rules.

Table 3.1: **Amendments to the NER**

SCHEDULE OF AMENDING RULE	INCLUDES AMENDMENTS TO THESE PROVISIONS OF THE NER	COMMENCEMENT DATE
1	All NER changes other than those below	1 July 2021
2	Provisions relating to the export tariff guidelines and customer export curtailment values	1 July 2022
3	Transitional rules in chapter 11, including: • Requirements on the AER in relation to updating guidelines (by 1 July 2022 or 1 July 2023), develop export tariff guidelines (by 1 July 2022), conduct a review of incentive arrangements for export services (by 31 December 2022), consult on changes to the annual benchmarking reports (by 1 July 2022), and develop an initial CECV methodology and value (by 1 July 2022) • Increases to the thresholds for trial tariffs for the current and next regulatory control period Provisions allowing DNSPs at least 12 months before they need to report new information in their Distribution Annual Planning Reports.	1 July 2021

Table 3.2: **Amendments to the NERR**

SCHEDULE OF AMENDING RULE	INCLUDES AMENDMENTS TO THESE PROVISIONS OF THE NERR	COMMENCEMENT DATE
1	• Body of NERR (rules 56A, 56B, 86A, 86B, relating to providing information to customers on their exports) • Schedule 1 (model terms and conditions for standard retail contracts) • Schedule 2 (model terms and conditions for deemed standard connection contracts)	1 July 2021
2	Transitional rules (Schedule 3 Part 17), requiring retailers	1 July 2021

SCHEDULE OF AMENDING RULE	INCLUDES AMENDMENTS TO THESE PROVISIONS OF THE NERR	COMMENCE-MENT DATE
	and distributors to update their contract terms and conditions by 30 September 2021	

4 UPDATING THE REGULATORY FRAMEWORK TO RECOGNISE THE PROVISION OF EXPORT SERVICES TO CUSTOMERS

This chapter outlines the Commission's draft determination with regard to updating the regulatory framework so that the range of services, including export services, provided by DNSPs to their customers are recognised in the regulatory framework. It sets out the Commission's draft decision to recognise export services within the existing regulatory framework. It also explains the Commission's draft decision in respect of enabling DNSPs to efficiently provide the services that customers require, for example, through clarifying the treatment of export services in the existing planning and investment frameworks.

BOX 2: OVERVIEW

- The evolving nature of DER technologies (e.g. storage, EVs, communications, PV) and the rapid pace of change in these technologies means that the regulatory framework will need to be flexible to accommodate change and continue to evolve with customer demand for emerging technologies.
- While there is a well-established regulatory framework for the provision of services that involve the connection and supply of energy to customers, growth in DER has increasingly required DNSPs to manage the emergence of customers seeking to export energy to the market.
- How these 'export services' are treated within the existing regulatory framework is not clear.
- To clarify the regulatory treatment of export services and to support DNSPs to achieve efficient planning and investment outcomes in respect of export services, the Commission's draft rule introduces a number of changes to existing definitions in the NER and existing planning and investment arrangements to increase clarity and transparency around both the opportunities for, and decisions made in respect of, export services.

Changes to definitions

- To clarify that export services form part of a distribution service, the Commission's draft rule changes the definition of "network" in the NER. This change is also intended to enable existing regulatory mechanisms to be adapted for export services.
- To support the application of existing incentive schemes to export services, the Commission's draft rule replaces, where relevant:
    - references to electricity consumers with references to "network service end users" (a new defined term covering end-users of electricity and embedded generators who are not registered participants), and

- references to the demand for electricity with references to the demand for distribution services (which would include consumption and export services).
- For greater clarity and flexibility, recognising that retail customers increasingly have generation facilities as well as load, the draft rule applies the definition of "retail customer" currently used in chapter 5A throughout the NER (with a few exceptions). This definition clarifies that "retail customer" includes embedded generators who are not registered participants.

Changes to existing planning and investment frameworks

- The Commission's draft rule introduces new requirements for a DNSP to provide information related to (i) how it intends to manage the integration of DER through the different elements of its regulatory proposal (i.e. connection services, pricing, expenditure); and (ii) an explanation of the DNSP's proposed approach to DER integration against alternative options.
- To support additional requirements around the type of information that DNSPs would be required to provide in relation to planning and investment for export, the Commission's draft rule also requires the AER, through its Expenditure Forecast Assessment Guidelines, to develop guidance to assist DNSPs in their expenditure proposals (eg by outlining the type of information and analysis that should be included) and provide clarity with regard to the assessment of export related expenditure, with particular consideration to how the benefits arising from expenditure to provide for export services are to be valued.

4.1 Background: the treatment of "export services" under current arrangements

The proponents' rule changes proposed the need to update key terms to clearly recognise export services in the regulatory framework. To varying degrees, SAPN and TEC/ACOSS proposed changes to the existing definition of 'distribution service' to provide clear recognition of export services in regulation. In addition, SAPN suggested, with a view to aligning the treatment of export services with that of consumption services under the regulatory framework, that the definition of 'retail customer' may present a barrier to the application of the existing framework to export services. TEC/ACOSS proposed the need for specific planning and investment obligations to be set in the NER to support DNSPs in the provision of export services. In this context, this section provides an overview of existing arrangements under the regulatory framework in relation to how the services distributors provide, and to whom, are defined, classified and treated under the existing framework.

4.1.1 Existing definitions in the regulatory framework

The regulatory framework contains a number of definitions that govern, amongst other things, a service that a DNSP provides, its ability to recover the cost of providing such services, and its relationship with customers in relation to access and connections arrangements. Importantly, the approach taken to the classification of the activities and services is determined, in part, by whether the service is defined as a distribution service.

The current regulatory framework defines 'distribution service' and related terms as follows:

BOX 3: DISTRIBUTION SERVICE AND DISTRIBUTION SYSTEM

- NER (Chapter 10) defines a 'distribution service' as 'a service provided by means of, or in connection with, a distribution system'
- NEL section 2 contains a parallel definition: '***electricity network service*** means a service provided by means of, or in connection with, a transmission system or distribution system'
- NEL section 2: '***distribution system*** means the apparatus, electric lines, equipment, plant and buildings used to convey or control the conveyance of electricity that the Rules specify as, or as forming part of, a distribution system'
- NER (Chapter 10) definitions relating to 'distribution service':
  - a 'distribution system' is defined as 'a distribution network, together with the connection assets associated with the distribution network, which is connected to another transmission or distribution system…'
  - a 'distribution network' is defined as 'a network which is not a transmission network'
  - a 'network' (used in the definitions of both transmission network and distribution network) is defined as the apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail) excluding any connection assets…'

Given that definition as a 'distribution service' forms the basis of the services that customers receives from distributors, this definition will affect distributors' ability to provide the services required by customers.

Definitions such as 'distribution system' and 'retail customer' affect how services are classified and subsequently form the basis for which regulatory mechanisms apply to services. In terms of the definition of 'retail customer', the application of incentive schemes, in some instances, is linked to the provision of services to a 'retail customer'.[72] Considered in the context of the provision of export services, there are potential implications for the effective application of the existing framework to export services.

The current regulatory framework defines 'retail customer' and related terms as follows:

72 The NER provides guidance as to the specific incentive schemes that can be applied and how distribution pricing should be designed and applied. Some of the guidance in the NER on these matters refers to the provision of services to 'retail customers'. For example, NER clause 6.6.3 or NER clause 6.18.

BOX 4: RETAIL CUSTOMER

- National Electricity Law (NEL) section 2 defines a 'retail customer' as a person who purchases energy without specific reference to exporting energy: "means a person to whom electricity is sold by a retailer and supplied in respect of connection points, for the premises of the person, and includes a person (or a person who is a class of persons) prescribed by the Rules for the purposes of this definition".
- The NER and National Energy Retail Law (NERL) define 'retail customer' in the following ways:
    - NER (Chapter 5A) explicitly includes in the definition of 'retail customer', for the purposes of rules relating to connection agreements for these customers, a person who in addition to consuming also generates electricity (subject to certain thresholds): "…includes a non-registered embedded generator and micro-embedded generator". (A non-registered embedded generator may or may not also consume energy; a micro-embedded generator is a sub-type of retail customer with very small generating equipment, such as a rooftop PV system.)
    - NER (Chapter 10) defines a 'retail customer' as "a small customer or a large customer" and these customers are defined according to the NERL or jurisdictional electricity legislation
    - NERL (section 5) defines a 'small customer' as a "customer who is a residential customer; or who is a business customer who consumes energy at business premises below the upper consumption threshold"
    - NERL (section 2) defines a 'residential customer' is "…a customer who purchases energy principally for personal, household or domestic use at premises".

4.1.2 Service classification

Service classification defines the type of economic regulation, if any, that will apply to services provided by DNSPs. This includes whether or not a service is subject to economic regulation (and the level and type of regulation), the approach to cost recovery, and whether or not a service will need to be ring-fenced from other services offered by a DNSP. Service classifications are first proposed by DNSPs and the decisions are made by the AER and form the regulatory foundation of its distribution determinations for each DNSP. The classification process also signals the potential for network services to be provided in competitive markets. For example, services that have the potential to be provided competitively in future have typically been classified as 'alternative control services' by the AER.[73]

Distribution services may be classified by the AER or in accordance with the NER if the NER contains a requirement to assign a service to a specific classification.[74] Typically the NER have not classified distribution services and, therefore, the AER has had to consider which

73 AER, Electricity distribution service classification guideline: Explanatory statement, September 2018, p. 1.
74 NER clause 6.2.1(e).

distribution services provided by DNSPs should be classified. The AER undertakes distribution service classification during the 'framework and approach' stage of each DNSP's regulatory determination.[75]

Distribution services can be classified as direct control services, negotiated distribution services, or left unclassified. The NER do not set out the specific characteristics of services that should fall within each classification category.[76] Instead, the NER define classifications in terms of the regulation that will apply to the services in each classification:

- a direct control service is regulated under a distribution determination, which sets out the control mechanism that applies to the relevant service (i.e. the price to be paid or revenue to be earned from the services)
- a negotiated service is a service that is subject to the DNSP's negotiating framework, which is approved by the AER in its distribution determination
- a distribution service falling outside the classifications of a direct control service or a negotiated distribution service is left unclassified and not subject to economic regulation.

Services classified as direct control services are then split into two sub-classes: standard control services (SCS) and alternative control services (ACS). The NER defines these services by reference to how they are regulated once classified:

- standard control services are services subject to a control mechanism based on a DNSP's total revenue requirement
- all other direct control services are alternative control services, which are subject to a control mechanism to be specified in the DNSP's distribution determination.[77]

In general, the service classification framework has important implications for determining the potential treatment of export services within the regulatory framework.

4.1.3 Obligations for distributors to provide export services

The NER do not provide any specific guidance – either in the form of obligations or incentives – as to how DNSPs should incorporate the provision of export capacity in their general planning and investment decisions. Rule 5.13 of the NER, which regulates the distribution annual planning process, requires DNSPs to identify network limitations based only on forecast maximum demand. DNSPs are required to have regard to embedded generation only to extent that this might have an impact on maximum demand (noting that maximum demand could encompass export demand).

DNSPs are required to offer a connection to retail customers, including for 'micro embedded generators',[78] but have discretion to set export limits. Where there is high penetration of solar PV, some DNSPs have started to restrict the level of electricity that customers can export to

75 NER clause 6.8.1(b)(2)(i).

76 The NER sets out the factors the AER needs to have regard to in classifying distribution services, as well as standard control services or alternative control services. See NER clauses 6.2.1(c) and 6.2.2(c).

77 NER clauses 6.2.5 and 6.2.6.

78 NER chapter 5A.

the grid to manage technical issues caused by DER exports.[79] Some customers face very low or even zero export limits in areas of the network with high levels of solar penetration.

Nevertheless, the NEO requires DNSPs to consider wider system benefits and costs in their investment and operational decisions. This requirement is made explicit in the RIT-D requirements set out in the NER.[80] The AER states that it is consistent with the capital expenditure criteria for DNSPs to consider benefits in this way when assessing DER-related capital expenditure proposals.[81]

4.1.4 Network planning and investment framework

The national framework establishes a nationally consistent annual planning and reporting cycle and project assessment process for distribution networks. It consists of:

(i) Distribution annual planning and reporting process:

- Distribution annual planning review
- Distribution annual planning report (DAPR)

(ii) Demand side engagement obligations

(iii) Distribution investment project assessment process:

- Regulatory investment test for distribution (RIT-D)
- Dispute resolution process

Distribution annual planning review and report

Each DNSP is required to undertake an annual planning process covering a minimum forward planning period of five years for its distribution assets (and 10 years for its dual function assets).[82] The forward period commences on a date deemed appropriate by each DNSP.

The planning process applies to distribution network assets and activities undertaken by DNSPs that would be expected to have a material impact on the distribution network in the forward planning period.

In carrying out the planning process, DNSPs are, at a minimum, required to:

- prepare forecasts of maximum demands for the relevant network assets
- identify (based on those forecasts) system limitations; and
- take into account non-network options when considering network options

DNSPs must publish a DAPR setting out the results of the distribution annual planning review for the forward planning period. DAPRs are to be published by the date specified in jurisdictional electricity legislation or, if no date is specified, by 31 December. The DAPR must include the information specified in the NER (schedule 5.8).

Demand side engagement obligations

79 AEMO, Renewable Integration study Stage 1 Appendix A High Penetration of Distributed Solar PV, April 2020, p. 27.
80 NER clause 5.17.
81 AER, Assessing DER integration expenditure: Consultation paper, November 2019, p. 12.
82 NER clause 5.13.

DNSPs are required to develop a demand side engagement strategy which sets out the strategy for engaging with non-network providers and considering non-network options for addressing system limitations.[83] This strategy must be documented in a report (demand side engagement document) which includes certain information specified in the NER, and which must be reviewed and published every three years. DNSPs are also required to establish and maintain a register of parties interested in being notified of developments related to DNSP planning and expansion activities.

Regulatory investment test for distribution (RIT-D)

The RIT-D establishes the processes and criteria to be applied by DNSPs in order to identify investment options which best address the needs of the network. It has two key components:

(i) A cost benefit test

(ii) Procedures (project assessment process) which includes

- Project specification
    - exempt projects
    - cost threshold assessment (+$6 million)[84]
- screening for non-network options which involves
    - draft project assessment report consultation
    - final project assessment report.

Certain types of projects and expenditure are exempt from the RIT-D, including projects initiated to address urgent and unforeseen network issues.

In applying the test, DNSPs must consider all credible options (which may include both network and non-network options) when choosing how to address an identified need for investment in the network. The preferred option is the one which maximises the economic benefit to all those who produce, consume and transport energy in the NEM.

Under the RIT-D, the quantification of market benefits is optional.[85] DNSPs *may* quantify each class of market benefit where it considers that the quantification of market benefits may alter the selection of the preferred option. A DNSP would need to quantify both the applicable costs and market benefits in order for the preferred option to have positive net market benefit.

Consistent with the requirements of NER clause 5.17.2(a), the AER sets out guidance for the operation and application of the RIT-D via the RIT-D application guidelines.

83 NER clause 5.13.1.

84 Clause 5.17.3(a)(2) of the NER. The RIT–D cost threshold was $5million but became $6 million from 1 January 2019 to end-2021. See AER, Final determination: Cost thresholds review, November 2018, p. 12.

85 However, the Commission previously recommended that the NER provisions on the RIT-D should be amended to mandate the quantification of applicable classes of market benefit specified in the rules (and any additional classes of market benefit specified by the AER) where these may be material or where the quantification of market benefits may alter the selection of the preferred option, rather than leaving quantification optional in these circumstances. (AEMC, Updating the regulatory framework for distributor-led stand-alone power system review, May 2020, p. 88.)

4.2 Proponents' views

4.2.1 What problems do the rule change request seek to address?

In its rule change request, SAPN proposed that current definitions in the NER create ambiguity as to customers' rights to export services, and the status that regulation affords these services in the planning that DNSPs need to undertake. In its rule change request, SAPN stated:[86]

- there is ambiguity in the NER as to whether 'distribution services' only relate to the *consumption* of energy and the conveyance of electricity *to* customers.
- guidance provided in the NER as to the provision of services to 'retail customers' is unclear. This is on the basis that there is some ambiguity in the meaning of the term stemming from different definitions in the NEL, NER and NERL.[87]

SAPN highlighted that the definition of 'distribution services' is foundational to the AER classifying export services, deciding the form of regulatory oversight and, where revenues/prices are to be directly controlled by the AER, the control mechanism to apply. SAPN noted this is also foundational to applying the NER capital expenditure and operating expenditure objectives, factors and criteria – which are used by the AER to assess network expenditures proposed for services that are classified as 'standard control services'.[88]

SAPN also noted that the AER must follow guidance provided in the NER as to the specific incentive schemes that can be applied, and how distribution pricing should be designed and applied to services.[89] In the context of considering which regulatory mechanisms should apply to export services, SAPN indicated that the existing guidance in the NER refers to the provision of services to 'retail customers', a term which SAPN considered is inconsistent across the NEL, NER and NERL. SAPN considered this may have implications as to the specific incentive schemes that can be applied and how distribution pricing may be designed and applied.

In SAPN's view, if customer demand for export services continues to increase and DNSPs approach their intrinsic hosting capacities,[90] decisions will need to be made on whether and how much investment there should be to support provision of export services. SAPN said the effect of maintaining the status quo of an unclear mandate for DNSPs is that there is a risk that DNSPs may under-invest in network capacity to accommodate customers' desires for export services – that is, invest in a lower level than customers want and are willing to pay for. SAPN considered this would mean that:

86 SAPN, rule change request, p. 11.

87 SAPN notes that this is the case for rules relating to the Demand Management Incentive Scheme, the Value of Customer Reliability (VCR), and the distribution pricing rules. The Service Target Performance Incentive Scheme (STPIS) rules refer more generally to 'customers' and the Efficiency Benefit Sharing Scheme (EBSS) to 'network users'.

88 SAPN rule change request, p. 11.

89 SAPN rule change request, p. 11.

90 Note that there is a base level of DER export capacity that all networks already provide, because network assets constructed to supply load have an inherent capacity to support reverse power flow without any additional investment.

- customers' ability to export energy to the network may progressively degrade over time, reducing the return (both for individual customers and the community) on their investment in DER
- customers will increasingly face barriers to exercising choice and participating in energy markets, such as by exporting energy to networks when this helps avoid network costs, or exporting energy into the NEM spot market or ancillary services markets
- competition barriers may arise for DER to participate in the NEM, potentially limiting market access to a cheaper source of generation, reducing the flow-on benefits of DER to other customers.[91]

TEC/ACOSS proposed amendments to the NER in order to optimise existing DER hosting capacity and incentivise additional hosting capacity. TEC/ACOSS consider:[92]

- DNSPs are increasingly constraining DER exports using static export limits– noting DNSPs appear to be managing their constraints in different ways, and there is no clearly established set of principles for them to follow
- the existing regulatory framework remains inflexible, as existing access and pricing arrangements create barriers to efficient and equitable cost recovery.

4.2.2 What are the proponents' proposed solutions?

SAPN and TEC/ACOSS presented different approaches to clarifying the treatment of export services in the regulatory framework. SAPN suggested making definitional changes to allow for the adaptation of the existing mechanisms to export services, while TEC/ACOSS proposed a number of new obligations in the framework to guide network planning and investment around export capacity.

This section outlines these proposed solutions and identifies points of overlap or divergence.

Proposed definition changes

TEC/ACOSS state definitions should be updated to recognise "prosumers" as the export equivalent of retail customers via amendments to chapter 5A (Part A) and Chapter 10 of the NER.[93]

SAPN proposed that expanding the definition of distribution service to include export services would allow the existing regulatory arrangements to be adapted to export services. This definitional change is considered by SAPN as central to ensuring that export services are recognised under the NER as a distinct service provided by DNSPs. The implication of this is that export services could then be considered as an 'identified need'. This means that DNSPs would be able to incur expenditure on the network guided by the need to meet or manage expected demand for export services. SAPN suggested that this would provide a mandate for DNSPs to invest in and provide export services guided by the capital and operating expenditure objectives in the NER.[94]

91 SAPN rule change request, p. 13.
92 TEC/ACOSS rule change request, p. 7.
93 TEC/ACOSS rule change request, p. 14.
94 SAPN rule change request, pp. 11–12.

As discussed previously, a central outcome SAPN seeks through the proposed definitional changes is the application of existing regulatory obligations and requirements to export services, such as existing regulatory controls on network expenditure.

At a high level, SAPN proposed for the Commission to:[95]

- amend the definition of terms applicable to 'distribution service', so that these terms explicitly recognise that the distribution network now not only conveys electricity to customers but also conveys electricity from customers
- make any such changes to the NER as required so that the regulatory framework explicitly recognises that customers who purchase electricity from retailers now not only consume energy but also export energy to the distribution network, so that the regulatory framework (including existing incentive schemes, distribution pricing rules and other guidance the NER provides to the AER) can apply to export services
- consider any other terms present in the NEM regulatory framework that may intersect with terms as to what comprises a customer and the services that a DNSP can provide.

Proposed changes to service classifications

TEC/ACOSS stated that service classifications should be amended to recognise the export of DER as a distribution service via amendments to Chapter 10 (glossary) of the NER.[96]

SAPN considered with export services being linked to 'distribution services', the AER would be able to classify these services through the framework and approach and distribution determination processes.[97] In SAPN's view, as export services involve the use of the grid to export energy, these are natural monopoly services that should be regulated and provided for in DNSPs' regulated revenue allowances as 'standard control services', in accordance with the AER's current approach to service classification. SAPN stated that the costs of all network augmentations used to provide export services best reside in a single 'regulatory asset base' – given the commonality of assets used to provide export and consumption services, which renders an 'alternative control services' pricing approach impractical. Further, SAPN considered that network augmentations driven by small customers will most practically be planned and funded on an ex-ante basis via standard control service. This is intended to mirror the approach taken to the treatment of augmentations driven by small customers' consumption demand.[98]

Proposed obligations on DNSPs to guide network planning and investment in export services

An important difference between SAPN and TEC/ACOSS's proposals relates to the necessary obligations on DNSPs to provide export services and the treatment of expenditure assessment.

95 SAPN rule change request, p. 17.
96 TEC/ACOSS rule change request, p. 15.
97 SAPN noted it does not seek to mandate the classification decision in the NER (SAPN, rule change request, p.18).
98 SAPN rule change request, p. 18.

Application of existing planning and investment frameworks for export services

SAPN considered the mandate for DNSPs to provide export services can be made by updating the definitions of a 'distribution service' in the NER, which would clarify the need for the AER to classify and regulate (if required) export services.[99] SAPN suggested that if export services are classified as a standard control service, DNSPs will be required to meet or manage demand for export services, comply with any regulatory obligations or requirements (if they exist for export services), and if there are no obligations or requirements, maintain the quality, reliability, safety and security of the distribution system, which would include export services. It is suggested that the target baseline of service performance to maintain would be guided by an adapted STPIS for exports.[100]

On expenditure proposals and assessment, SAPN proposesed that these should not be limited to market benefit assessments, and should consider the extent to which customers' views support particular levels of network investment.[101] Here, SAPN highlighted that the requirement would be for distribution networks to consider the least-cost way of meeting customer demand for export services and invest to meet that demand. As such, DNSPs' cases to the AER for investment would not be limited to meeting this goal based solely on market benefits analysis.

Reflecting another approach, TEC/ACOSS proposesed that obligations should be introduced in the NER to guide DNSPs' planning for investment in export capacity and that augmentations carried out to provide capacity for export services should be assessed via a net market benefit test.[102] These points are discussed further below.[103]

Establishing a planning and investment strategy for DER integration

TEC/ACOSS considered that a new obligation on DNSPs is appropriate to encourage them to think strategically about the role of DER exports in their future planning. To this end, TEC/ACOSS suggested the introduction of a requirement for DNSPs to prepare a comprehensive DER integration strategy (DERIS).[104]

TEC/ACOSS proposed that the DERIS could work on a five yearly basis and alongside other regulatory obligations, such as the DAPR. The proposed content of the DERIS may include an outline of the current and projected DER uptake, network challenges and opportunities, and proposed investments and other actions over the coming five years and beyond.[105] A DNSP's proposed DERIS would then be considered by the AER and incorporated into its assessment of the individual elements of the regulatory proposal (connections, pricing, and expenditure).

99 SAPN rule change request, p. 18.

100 SAPN rule change request, p. 18. SAPN's proposed approach to STIPIS is dealt with in further detail in chapter 4 of this draft determination.

101 SAPN rule change request, p. 19.

102 The DEIP consultation process also considered the appropriateness of establishing an obligation to provide export services. DEIP Access and Pricing Reform Package: Outcomes report, June 2020.

103 TEC/ACOSS also proposed a number of obligations related to access, optimisation and the allocation of export capacity that are dealt with in the following chapters.

104 TEC/ACOSS rule change request, p. 11.

105 TEC/ACOSS rule change request, p. 11.

To supplement this information, the DERIS would also require an outline of how the network has consulted customers and incorporated feedback into the regulatory proposal.

Investment in hosting capacity to benefit all customers

TEC/ACOSS suggested imposing a further obligation on DNSPs to invest in additional DER hosting capacity, when it benefits all consumers, by introducing a net market benefit test to guide network planning and investment for DER.[106]

According to TEC/ACOSS, this could be achieved by extending the principles set out in the RIT-D to all network planning decisions.[107]To this end, TEC/ACOSS proposed amending NER clause 5.13.1 to expand the scope of the distribution annual planning review such that 'The distribution annual planning review must explain how the DNSP will optimise additional DER export capacity for system-wide net market benefits'.[108]

4.3 Stakeholder views

4.3.1 Definitions

Including export services in the definition of distribution service

Overall, the majority of stakeholders expressed support for changes to the regulatory framework to recognise export services. In nearly all cases, this support extended to SAPN's proposal to make required changes to include export services within the definition of distribution service.[109]

AGL and EnergyAustralia, while supportive of this definition change to recognise export services, noted that any changes should complement the development of a market-based framework for the provision of DER services.[110] To this end, EnergyAustralia encouraged the Commission to give consideration as to the implications of the proposed definition change on the future ability of retailers or third-party aggregators to provide different forms of access rights and pricing arrangements at the retail level.[111]

The Victorian Department of Environment, Land, Water and Planning (DELWP) also suggested that any changes to the regulatory framework currently being contemplated need to consider the full range of DER technologies and services that may be available to networks and markets in future. Similarly, Ausgrid considered that in making any changes to the definition of distribution services it would be important to provide flexibility in the definition

106 TEC/ACOSS rule change request, pp. 11–12.

107 TEC/ACOSS developed this position based on the findings developed in CEPA's report: Distributed Energy Resources Integration Program – Access and pricing: Reform options, 9 April 2020.

108 TEC/ACOSS rule change request, pp. 11–12.

109 AGL submission to the consultation paper, p. 2 and 4; AER submission to the consultation paper, p. 4; CEC submission to the consultation paper, p. 2; Energy Queensland submission to consultation the paper, p. 1; Jemena submission to the consultation paper, p. 5; EUAA submission to the consultation paper, p.1; AER submission to the consultation paper, p. 3; Energetic Communities submission to the consultation paper, p. 1; University of Wollongong submission to the consultation paper, p. 1; DELWP, submission to the consultation paper, p. 3.

110 AGL submission to the consultation paper, p. 2 and 4.

111 EnergyAustralia submission to the consultation paper, p. 7.

to allow for new services to be included in the future. For example, voltage control or reactive power.[112]

The AER, while supportive of the proposed update to the definition of distribution service, noted that the current definition is sufficiently broad to include export services.[113]

Jemena was of the view that new definitions for 'grid-imports' or 'grid-exports' would not be required in the NER. Instead, these services could be catered for in the explanation of distribution services, and in the AER's service classification guideline.[114]

In contrast to these views, Firm Power suggested that the implications for the proposed definition change, to enable the application of the existing regulatory controls (eg application of capital and operating expenditure objectives and incentive mechanisms), overlooks the existing inefficiencies in network planning and investment frameworks. On this basis, Firm Power proposed that instead of requiring DNSPs to provide export services, an alternative category of services should be considered in the form of 'balancing' services. These balancing services would help to balance the import and export of power flows within distribution networks.[115]

Definitions of retail customer and prosumers

Stakeholders who addressed the considerations around the definition of retail customer raised by SAPN[116] and those related to the introduction of the term 'prosumers' by TEC/ACOSS[117] held different views with regard to the appropriateness of the proposed changes.

The Customer Advocate expressed support for definition changes to ensure prosumers are recognised as the export equivalent of retail customers through Chapter 5A and Chapter 10 of the NER.[118]

In further comments supporting this approach, Energetic Communities noted that while there is an existing definition for retail customer, there is no definition of prosumer or a similar term. Energetic Communities suggested that one implication of this is that the definition of retail customer may present a barrier to the application of the existing framework to export customers.[119]

Conversely, AGL considered that the introduction of the concept of prosumers may introduce unnecessary additional complexity in the context of consumer protections, as provided for under the National Energy Customer Framework (NECF), and that SAPN's approach, in

112 Ausgrid submission to the consultation paper, p. 5.
113 AER submission to the consultation paper, p. 4.
114 Jemena submission to the consultation paper, p. 6.
115 Firm Power submission to the consultation paper, p. 3.
116 SAPN, rule change request, p. 11.
117 TEC/ACOSS rule change request, p. 14.
118 The Customer Advocate submission to the consultation paper, p. 3.
119 Energetic Communities submission to the consultation paper, p. 4.

amending the definition of terms applicable to 'distribution service', may provide a more holistic solution.[120]

In its submission Jemena raised that under Victorian arrangements the definition of 'small customer' needs to be considered, given that Victoria does not—in effect—participate in the NERL. In Jemena's view, this would present the same issues as that in the national instruments—that is, the definition of small customer references electricity consumption as a part of its meaning. Subsequently, in Victoria's case, jurisdictional instruments would need updating.[121]

4.3.2 Regulatory treatment of export services

Service classification

Views with regard to the classification of export services were strongly supportive of SAPN's proposal to follow the current process in the NER, whereby a service classification decision is arrived at during a framework and approach stage of a DNSP's regulatory determination, and that the export services should be treated as a SCS.[122]

Endeavour Energy, while supportive of classification of export services as an SCS through the framework and approach, noted the possibility for some aspects of export services to be treated as an ACS (such as particular connection services). However, Ausgrid suggested that, in line with the current treatment of consumption services, network augmentation driven by small customers export hosting demand will most practically be planned for and funded through SCS.[123]

A number of stakeholders expressed views with regard to need for the classification process to be flexible and accommodate future changes in DER services. TasNetwork considered it vital that variations in the cost-recovery arrangements applied by individual networks are also possible under any rule change.[124] EnergyAustralia proposed the Commission should consider how the classification of export services could be restrictive in an evolving DER landscape (e.g. will the classification of export services impact a move to voltage instead of energy export).[125] The Energy Users Association Australia (EUAA) considered that under an SCS classification locational pricing is difficult, with postage stamp pricing the norm. To the extent that the current rules allow or can be amended to allow locational pricing, the EUAA supported export services being classified as a SCS.[126]

Application of mechanisms under existing framework

120 AGL submission to the consultation paper, p. 4.

121 Jemena submission to the consultation paper, p. 5.

122 Jemena submission to the consultation paper, p. 6; The Customer Advocate submission to the consultation paper, p. 4; Energy Queensland submission to the consultation paper, p. 2; Ausgrid submission to the consultation paper, p. 6; Ausnet Services submission to the consultation paper, p. 3; AGL submission to the consultation paper, p. 6.

123 Endeavour Energy submission to the consultation paper, p. 2. This point was also raised in ENA's submission to the consultation paper, p. 11.

124 TasNetworks submission to the consultation paper, p. 2.

125 EnergyAustralia submission to the consultation paper, p. 8.

126 EUAA submission to the consultation paper, p. 8.

The majority of stakeholders were also supportive of the proposed application of existing regulatory mechanisms to export services.[127]

Ausgrid considered that the symmetrical treatment of consumption and exports would allow the application of the existing regulatory framework to both consumption and export services with minimal amendments. Ausgrid considered that this approach is the least burdensome and the most appropriate way to create a mandate for distributors to undertake expenditure on export services in line with what their customers demand and are willing to pay for.[128]

Energy Networks Australia (ENA) considered that the application of the existing capital and operating expenditure objectives in the NER will mean that DNSPs will have an obligation to meet or manage customer demand for export services classified as SCS; matching the current treatment of consumption services classified as SCS. ENA also considered that mirroring the current well-established regulatory framework for consumption services is highly efficient and reduces the risks of material regulatory change to all stakeholders.[129]

The AER, in its submission supported SAPN's view that if export services are recognised as a distribution service, they can be explicitly considered in service classification, benefit from the direct application of the capital and operating expenditure objectives and criteria, and be subject to regulatory mechanisms such as incentive mechanisms.[130]

South Australia Council of Social Services (SACOSS) noted that changing the definition of distribution service in the NER to allow for the inclusion of export services in network planning and investment frameworks has the potential to involve cost recovery from all customers. While recognising that that export tariffs can be used to direct those costs to users of DER, SACOSS proposed that the Commission considers the potential inequities of the proposal.[131]

Energy Queensland suggested consideration also be given to the treatment of export service within different frameworks. In particular, how export service would be treated in relation to embedded networks (if at all) and in relation to stand-alone power systems.[132]

Existing planning arrangements

Views among stakeholders were mixed on whether the inclusion of a DER integration strategy was necessary. Views ranged from the DERIS being important to support coordinated and transparent planning, the existing framework being adequate, through to the DERIS being a regulatory burden.

Stakeholders that supported the DERIS considered it may improve transparency of possible future network investment needs for export capacity, giving consumers and other parties

127 AER submission to the consultation paper, p. 4; Essential Energy submission to the consultation paper, p. 2; Ausgrid submission to the consultation paper, p. 4.

128 Ausgrid submission to the consultation paper, p.4.

129 ENA submission to the consultation paper, p.11.

130 AER submission to the consultation paper, p. 4.

131 SACOSS submission to the consultation paper, p. 2.

132 Energy Queensland submission to the consultation paper, p. 2.

more information to inform their investment decisions.[133] DELWP considered that the DERIS may play a role in supporting DNSPs to explicitly define the outcomes they will achieve for proposed investments.[134] Energetic communities noted the potential for the information required as part of the DERIS to provide transparency and feed into the AER reset process.[135]

The AER expressed general support the DERIS and noted it would be valuable to consider any consequential amendments to the distribution annual planning process under Rule 5.13 of the NER to assess whether the planning arrangements require updating to better support DNSPs in making the required information publicly available.[136]

The ENA and some submissions from individual DNSPs expressed views that the DERIS is not necessary as the existing framework has similar requirements. ENA and Essential Energy noted that the AER already considers the extent to which DNSPs have engaged with their stakeholders in preparing both tariff proposals and expenditure forecasts.[137] In ENA's view, the regulatory determination process requires DNSPs to engage with their customers and stakeholders in an integrated way with regard to key inputs such as their network and non-network solutions, connections policies and proposed tariffs. In its view, DER strategies and expenditure will be incorporated into this engagement process, and engagement with stakeholders is best facilitated through this process rather than a standalone strategy document.[138] AusNet Services considered that formalising information provision on export services as proposed in the DERIS goes beyond requirements that are required for consumption services.[139]

EnergyAustralia considered existing planning arrangements are suitable to be applied to export service. However, they suggested that the Commission should consider establishing requirements on DNSPS to provide information regarding the nature and the volume of spend undertaken to increase hosting capacity and historical and forecast spend on hosting capacity.[140]

A number of DNSP submissions expressed the view that the proposed DERIS would add to the regulatory burden and was unnecessary.[141]

Assessment process for DER related expenditure

Broadly, stakeholders who responded to the consultation paper expressed either a preference or in-principle support for the application of a net market benefit test to DER related expenditure. Stakeholders also raised a number of considerations with regard to how net market benefits are measured and quantified.

133 SA Department of Energy and Mining submission to the consultation paper, p.2; ERM power submission to the consultation paper, p. 3; AEC submission to the consultation paper, p. 13; Tesla submission to the consultation paper, p. 3.

134 DELWP submission to the consultation paper, p. 3.

135 Energetic Communities submission to the consultation paper, p. 5.

136 AER submission to the consultation paper, p. 4 and 7.

137 ENA submission to the consultation paper, p. 11; Essential Energy submission to the consultation paper, p. 3.

138 ENA submission to the consultation paper, p. 11.

139 Ausnet services submission to the consultation paper, p. 4.

140 Energy Australia submission to the consultation paper, p. 4.

141 EVO Energy submission to the consultation paper, p. 5; Ausgrid submission to the consultation paper, p. 7.

AusNet Services, Ausgrid, EnergyAustralia, the Australian Energy Council (AEC), Endeavour Energy and EUAA supported the use of a net market benefit test but were opposed to prescribing this as a specific obligation in the NER.[142]

Ausgrid noted that a net market benefit test can be applied too widely and may result in accepting investment projects not maximising the value to customers. This may lead to a situation where market benefits accrue to parties other than the network and its customers. Ausgrid noted that the distribution of benefits is a matter of public policy.[143] Endeavour Energy also considered that it would not be appropriate to mandate that DER export capacity investment below the RIT-D threshold be justified solely by reference to a mandated net market benefit test. Endeavour Energy noted that it is a useful guide but not the only guide of network investment needs.[144] Similarly, EVO Energy considered that the decision-making framework for investment in DER hosting capacity should allow for different approaches that are appropriate for the scale of the investment.[145]

The South Australia Department for Energy and Mining and the Customer Advocate, while supportive of a net market benefit test as a measured approach for expenditure assessment, noted that undertaking this assessment when the potential DER benefits and impacts are yet to accurately quantified may be difficult.[146]

The Clean Energy Council (CEC) considered that the investment framework should not be limited to costs and benefits for DNSPs, but should also consider broader societal benefits. To this end, any net market benefit test should place an avoided value on greenhouse gas emissions.[147] Similarly, CitiPower, Powercor and United Energy strongly support extending the market benefits test to recognise wider DER benefits, such as wholesale or behind-the-meter benefits, including societal and environmental benefits from DER such as decarbonisation.[148] Jemena considered, to determine market benefits, the Essential Service Commission of Victoria (ESCV) feed-in tariff as the best proxy of market benefits. In Jemena's view, valuing grid export services should take into account market benefits rather than network impacts. Network impacts—which may be a net increase in costs where available hosting capacity is depleted or a net decrease where augmentation can be avoided—are inherently captured in the price reset process and/or through mechanisms within a regulatory control period, for example, through the cost pass-through arrangements in NER clause 6.6.1.[149]

142 Ausnet Services submission to the consultation paper, p. 4; Ausgrid submission to the consultation paper, p. 7; Energy Australia submission to the consultation paper, p. 8; AEC submission to the consultation paper, p. 14; Endeavour Energy submission to the consultation paper, p. 3; EUAA submission to the consultation paper, p. 3.

143 Ausgrid submission to the consultation paper, p. 7.

144 Endeavour Energy submission to the consultation paper, p. 3.

145 Evoenergy submission to the consultation paper, p. 5.

146 SA Department of Energy and Mining submission to the consultation paper, pp. 2-3; The Customer Advocate submission to the consultation paper, p. 4.

147 CEC submission to the consultation paper, p. 1 and 4.

148 CitiPower, Powercor and United Energy submission to the consultation paper, p. 2.

149 Jemena submission to the consultation paper, p. 8.

4.4 Analysis and draft rule determination

4.4.1 Recognising export services in the regulatory framework

The Commission's draft rule has been guided by its view that it is necessary to clearly recognise exports services as distribution services in order to provide clarity for (i) customers around their rights to access export services and (ii) DNSPs regarding expectations to provide export services.

A central outcome of the treatment of export services as a distribution service is that the regulatory mechanisms under the existing arrangements – the service classification process, application of capital and operating expenditure objectives, and existing controls on network expenditure (assessment against capital and operating expenditure objectives, incentive schemes, ex post review and reporting etc) – would then shape the regulatory treatment of export services. In respect of minimising the regulatory burden and costs arising from the proposed changes, the Commission concludes that an approach which continues to utilise the existing frameworks and mechanisms to support the provision of export services is appropriate and consistent with its broader approach to recognise the evolving role of DNSPs as a platform to connect, manage and enable DER integration.

To enable the effective application of the existing framework to export services, the Commission's draft rule includes changes to the definition of "network" and a number of consequential changes to other terms related to what comprises a customer used in the regulatory framework. These changes are discussed below.

Encompassing export services in the definition of distribution service

As a first step to recognising export services in the regulatory framework, the Commission's draft rule makes changes to clarify that distribution services include export services. The Commission considers that this change is required to make clear how export services fit into the existing regulatory framework. This change is intended to provide clarity for customers around their rights to access export services and to DNSPs regarding expectations in relation to providing export services.

To achieve this outcome, the draft rule removes "to customers" in the definition of "network" in the NER in order to remove the only direction-specific reference within the definitions related to "distribution service".[150] This change is intended to remove any ambiguity as to whether "distribution services" only relate to the <u>consumption</u> of energy and the conveyance of electricity <u>to</u> customers.

It is the Commission's expectation that this change (to support a clear interpretation that an export service constitutes a distribution service) in the NER is also reflected in the AER's Distribution Service Classification Guidelines and associated Explanatory Statement, which should be updated, as necessary, to reflect any changes. As such, the Commission's draft rule includes in chapter 11 of the NER a transitional rule that the AER must review and where

150 Amending NER definition Chapter 10.

necessary amend that guideline to take into account the Amending Rule, within twelve months of the relevant schedule of the Amending Rule taking effect in July 2021.[151]

Overall, the Commission considers that these changes will provide regulatory clarity around whether an export service is considered a distribution service.

Regulatory implications of clarifying exports as a distribution service

As previously noted, an important aspect of the treatment of export services as a distribution service is that the existing regulatory arrangements would then shape the regulatory treatment of export services. Taking into account stakeholder feedback, the Commission considers that the existing regulatory requirements, incentive schemes and controls that currently apply to distribution services are appropriate to be adapted to a DNSP's provision of export services. It considers that utilising existing regulatory mechanisms will minimise the regulatory change and cost on industry. The approach also maintains, for the most part, a consistency in approach to the provision of distribution services by DNSPs.

In this case, the Commission is of the view that including export services within the scope of distribution services will therefore enable export services to be:

- explicitly considered by the AER in service classification;
- subject to the capital and operating expenditure objective in the NER, forming a mandate to invest to provide export services; and
- subject to existing regulatory controls on network expenditure – including assessment against capex and opex objectives, RIT-D, incentive schemes, ex-post review, benchmarking and reporting.

Service classification

On the basis that export services will be treated in a similar way to consumption services, the Commission considers that it remains appropriate that the AER should follow the process outlined in the NER[152] to arrive at a service classification decision during the Framework and Approach stage of a DNSP's regulatory determination. Acknowledging stakeholder feedback, the Commission does not consider there is a need to specify in the rules how export services should be classified by the AER. This flexibility remains important because different aspects of export services may require a combination of SCS and ACS classification (the current treatment of connection services differs between DNSPs). In addition, as the nature of export-based service offerings delivered by DNSPs continue to develop, the flexibility of the existing classification arrangements will provide the AER and DNSPs the ability to manage changes in the provision of export related services.

Capital and operating expenditure objectives

The Commission considers that for components of export services classified as SCS by the AER, the capital and operating expenditure objectives in the NER will apply.[153] This will mean that network businesses will have a new requirement to meet or manage customer demand

151 Amending NER clause 11.[xxx].2.

152 NER clause 6.2.1 and 6.2.2.

153 NER clauses 6.5.6 and 6.5.7.

for export services guided by the operating and capital expenditure objectives outlined in Box 5. The application of the operating and capital expenditure objectives will provide DNSPs with an 'identified need' – the objective the DNSP seeks to achieve by investing in the network – to meet and manage expected demand for export services. In proposing expenditure that is needed to meet target service levels based on forecast demand, DNSPs will be required to have regard to whether the expenditure associated with export services reasonably reflects the pre-determined capital and operating expenditure criteria in the NER.[154] The Commission is satisfied that the application of the capital and operating expenditure objectives and criteria to expenditure relating to export services will help define a prudent and efficient level of investment in export services and support the efficient provision of export services while minimising any additional regulatory burden associated with developing regulatory mechanism specific to export services.

BOX 5: OPERATING AND CAPITAL EXPENDITURE OBJECTIVES (NER CLAUSES 6.5.6 AND 6.5.7)

(a) A building block proposal must include the total forecast operating/capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the operating/capital expenditure objectives):

(1) meet or manage the expected demand for standard control services over that period

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) the quality, reliability or security of supply of standard control services; or

(ii) the reliability or security of the distribution system through the supply of standard control services, to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control services; and

(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services.

Application of Amending rule to stand-alone power systems and embedded networks

154 NER clauses 6.5.6 and 6.5.7.

The Commission notes Energy Queensland's suggestion to clarify the treatment of export services in relation to embedded networks and stand-alone power systems (SAPS).[155] In the final report for the review on *Updating the regulatory frameworks for distributor-led stand-alone power systems*, published in May 2020, the proposed drafting closely followed existing arrangements to support efficient planning and investment outcomes and extend settlement systems and the full suite of energy specific consumer protections to accommodate DNSP-led SAPS. The purpose of this package of changes is to ensure that customers transitioned to DNSP-led SAPS are not disadvantaged in terms of price and reliability, and retain access to existing consumer protections such as access to retail market offers. The Commission continues to consider that the arrangements proposed under its review are appropriate for SAPS.

The Commission has also considered the application of this draft rule to embedded networks and instances where embedded generation in an embedded network may want to export to the DNSP's network. Under current arrangements in embedded networks, electricity is purchased from the NEM at the parent connection point and on-sold to customers at child connection points within the embedded network. On-selling entities must hold a retailer authorisation from the AER or be exempted by the AER from having to hold a retailer authorisation (and in that case the on-seller will be on-selling electricity it has bought from a retailer).[156] In an embedded network, the total consumption for the entire embedded network is metered by the parent meter at the parent connection point and individual consumption within the embedded network may be metered at the customer's connection point. The Commission's draft rule enables an exempt retailer buying at the parent connection point to be captured by the definition of retail customer.[157] Services provided by the DNSP would include supply services to support export to the DNPS's network through the parent connection point of the embedded network.

Changes to support the application of incentive schemes to export services

The Commission has considered a number of terms used in the regulatory framework that present potential barriers to the application of incentive schemes to export services. Some of the rules on these matters refer to the provision of services to "retail customers" (for example, NER clause 6.6.3). There are also some references to "electricity consumers" (but not defined) in NER Chapter 6 (for example, clause 6.5.6(e)). The Commission's draft rule proposes to make the following changes to these terms.

The definition of 'retail customer' in chapter 10 of the NER would be amended to give it an extended meaning based on the meaning it currently has in NER chapter 5A, [158] which includes micro embedded generators and non-registered embedded generators.[159] While in many cases these will also be retail customers, that may not always be the case and extending the definitions will allow for new business models to emerge. The extended

155 Energy Queensland submission to the consultation paper, p.2.

156 AER, Electricity Network Service Provider - Registration Exemption Guideline (Network Exemption Guideline).

157 Amending definition NER Chapter 10.

158 Amending definition NER Chapter 10.

159 The new definition would exclude non-registered embedded generator who elect to connect under Chapter 5.

meaning would apply throughout the NER with some limited exceptions. In chapter 6, this would enable the application of incentive schemes to export services. The Commission notes it is at the discretion of the AER as to which regulatory mechanisms should apply to export services.

A new definition of 'network service end user' would replace 'electricity consumer' and would cover all retail customers and electricity consumers buying directly from the NEM ('Customers' under the NER) who are not retailers and have a connection to a distribution network, and electricity consumers in embedded networks.[160]

The definition of 'micro embedded generator' (used in the definition of 'retail customer') would be amended so that it extends to customers of MSGAs with micro EG connections. The result will be to bring these customers within the scope of the basic connection service arrangements in Chapter 5A.

Consequential changes to support the application of the existing framework to export services

Other consequential changes to the NER will support the application of the existing framework to export services.

- A change to the definition of 'supply service' will clarify that it covers services provided for both export and import of electricity.[161] This change is intended to clarify the meaning for users of the NER and not change the existing meaning, since as a matter of interpretation, a 'supply service' already covers delivery of electricty to or by customers.
- In the distribution service classification provisions and in provisions dealing with distribution determinations, changes clarify that references to 'users' means users of the relevant service, not users of electricity.[162]
- In the provisions related to demand management incentive schemes, innovation allowances and billing, changes will clarify that 'demand' refers to demand for distribution services, not demand for electricity.[163]
- In the principles governing assignment or reassignment of retail customers to tariff classes, and the pricing principles that apply when tariffs structures are determined, references to 'usage' and 'usage profile' will be amended to clarify that these refer to use of distribution services (covering import and export) and not to use of electricity.[164]
- The tariff reassignment obligations of retailers will be amended to clarify that they apply where the customer notifies changes in use of export or import distribution services.[165]

Amendments to the NERR to make clear that they apply supply services bi-directionally

160 Amending definition NER Chapter 10.

161 Amending NER clause 5A.A.1. Refer also to draft NER, Schedule 5A.1, Part B, paragraph (b)(1).

162 For example, Amending NER clauses 6.2.2(c)(2) and 6.2.5(c)(2).

163 Amending NER clauses 6.6.3(b) and (c)(3); clauses 6.6.3A(b), (c)(2) and (d); clause 6.20.1(a).

164 Amending NER clauses 6.18.4(a) and (b), 6.18.5(f)(2) and 6.18.5(h).

165 Amending NER clause 6B.A3.2(a)(1).

The draft rule proposes changes to the NERR to clarify that retail customers should be given access to metering data about exports in the same way they are given access to consumption data and to recognise the provision of export services by distributors.

The NERR requires distributors and retailers to give a retail customer or a customer's authorised representative information about the customer's energy consumption, if requested.[166] The draft rule extends these requirements to information about exports, and makes similar changes to the corresponding provisions in the model contracts in the NERR.[167]

The draft rule proposes amendments to the 'Model terms and conditions for deemed standard connection contracts' in the NERR to recognise the provision of export services by distributors. Most of the amendments replace references to supply with references to supply services, supported by a new defined term to explain that the supply service covers both imports and exports.[168] A new clause confirms that a distributor may interrupt or curtail supply services for exports from small generators.[169]

For the draft rule, the Commission also considered the following matters relating to the NERR and has concluded that changes should not be made or that changes cannot be made as they fall outside the scope of the NERR framework.

The NERR apply to retailers in relation to the sale of electricity and gas to retail customers, and to distributors in relation to the provision of customer connection services (including supply services) to retail customers. For the NERR, the term 'retail customer' is defined in the NERL and does not cover Market Small Generation Aggregators or the customers of exempt retailers. The wider extended meaning proposed for the NER will not apply under the NERR.

The NERL and NERR provide important customer protections relating to the supply of energy to customers as an essential service. These include rules about interruptions to supply and disconnections. The Commission's draft rule does not extend these consumer protections to export services as export services are not regarded as essential services.

The NERR provides for the classification of retail customers according to their use of energy (domestic or business) and how much energy they consume (small or large customers). Distributors classify business customers as small or large customers and in doing so have regard to annual consumption of energy at the customer's premises over the previous 12-month period.[170] During consultation for this draft determination, the Commission has not been made aware of issues about the application of the NERR when classifying customers who also export; for example, issues about whether consumption for classification purposes is the net or gross figure. On that basis, the draft rule does not propose any change to the classification provisions.

166 The provisions require the data to be provided in accordance with the metering data provision procedures made under the NER.

167 Amending NERR rules 56A (retailers), 86A and 86B (distributors); Schedule 1 clause 9.4A in the 'Model terms and conditions for standard retail contracts'; Schedule 2 clause 15.2A of the 'Model terms and conditions for deemed standard connection contracts'.

168 Amending NERR, Schedule 2, Preamble and throughout.

169 Amending NERR, Schedule 2, clause 10.5.

170 NERR rule 6(b) and NERR rule 11.

4.4.2 Enabling the efficient provision of export services

Having regard to the views of stakeholders and its own analysis, the Commission considers that the existing distribution planning and investment framework – which includes the DAPR, demand side engagement obligations and the RIT-D – is largely appropriate and fit-for-purpose to encourage DNSPs to make efficient planning and investment decisions with regard to export services.

However, the Commission's draft rule supplements the existing framework with a number of new reporting requirements to increase transparency around planning and investment opportunities for export services. Specifically, the draft rule introduces requirements for a DNSP to provide, as part of the overview paper accompanying the DNSP's regulatory proposal:

- information on how it intends to manage the integration of DER through the different elements of its regulatory proposal (i.e. connection services, pricing, expenditure); and
- an explanation for the DNSP's proposed approach against alternative options.

In addition, the Commission proposes that the AER, through its Expenditure Forecast Assessment Guidelines, develop guidance to assist DNSPs in their expenditure proposals (e.g. by outlining the type of information and analysis that should be included) and provide clarity with regard to the assessment of export related expenditure.

The Commission's draft rule and the reasons for its decision are explained below.

Suitability of existing planning framework for export services

As previously mentioned, TEC/ACOSS proposed the introduction of a DER integration strategy (DERIS) which sets out requirements around the type of information that DNSPs would be required to provide in relation to planning and investment for export services (see section 4.3.2).

While supportive of the intention of the DERIS, stakeholders generally considered and the Commission agreed that applying the existing framework with minor additions would achieve similar outcomes. Therefore, in addition to existing DAPR reporting requirements set out in schedule 5.8 of the NER, the Commission's draft rule includes two changes to existing arrangements to further support DNSPs to achieve efficient planning and investment outcomes and increase transparency for stakeholders around DSNPs planning and investment decisions for export capacity.

First, the draft rule includes a new obligation on DNSPs to provide information, as part of the overview paper accompanying the DNSP's regulatory proposal, on how they intend to manage the integration of DER. The draft rule requires a DNSP to present information specifically relating to how DER integration is managed through the different elements of its regulatory proposal (i.e. connection services, pricing, expenditure) and discuss how its proposal is appropriate to meet expected consumer outcomes.[171] This obligation would support DNSPs in communicating with customers and DER providers as part of planning for

171 Amending NER clause 6.8.2(c1).

and undertaking investments in export services and would improve transparency for stakeholders.

Second, the draft rule establishes a requirement in the overview paper for DNSPs to explain their proposed approach to export related planning and investment against alternative options.[172] The draft rule requires DNSPs to report on the degree with which connection services, pricing and expenditure solutions are substitute or complementary options; the trade-offs between different options the network considered; and why the network has proposed the particular approach around DER integration and management. This obligation is intended to ensure that relevant information is made accessible to network users with regard to current and future opportunities around export services.

As such, the Commission considers that the draft rule is likely to contribute to regulatory clarity and certainty for DNSPs, as well as increasing transparency for consumers and other stakeholders around DNSPs' planning and investment decisions. Accordingly, it considers this approach is consistent with achieving the NEO.

Establishing a clearer assessment process for DER related expenditure

Having considered stakeholder views and undertaking its own analysis, the Commission's view is that the existing investment assessment framework in the NER is, in general, appropriate and fit-for-purpose to support the AER in assessing DER integration expenditure.

Currently, the RIT-D establishes the processes and criteria that DNSPs are to meet as part of making an investment decision. The RIT- D requires DNSPs to consider all credible options (network and non-network) when seeking to address identified network needs.[173] The preferred option is one that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM.[174] The RIT-D must also consider applicable classes of market benefit specified in the rules (and any additional classes of market benefit specified by the AER).[175] Guidance on the methodology for valuing these market benefits is set out in the AER's RIT-D Application Guidelines.[176]

Consistent with existing arrangements, the Commission considers that DNSPs should be required to use the RIT-D and associated consultation process to test the efficiency of credible options for export related investment projects which meet the RIT-D cost threshold and are not otherwise exempt projects.

However, it is important to recognise that the general characteristics of distribution investments have evolved over time. For example, the rise in DER and the increased sophistication of demand management capabilities have shown that distribution investments are increasingly delivering benefits that have traditionally been seen at the transmission

172 Amending NER clause (c1)(3).
173 NER clause 5.15.2(a).
174 NER clause 5.17.1(b).
175 NER clause 5.17.1(b).
176 AER, Application guidelines regulatory investment test for distribution, 2018,pp. 35-36.

level.[177] Consistent with previous recommendations, the Commission considers that the quantification of market benefits is becoming increasingly important as the characteristics of traditional distribution investments have evolved.[178]

Determining a consistent value (or methodology) against which DNSPs' business cases for investment in DER integration can be justified and assessed is a critical part of developing a pathway for future DER expenditures. DNSPs are already preparing or considering how to prepare business cases to justify expenditure on DER integration projects. This presents the risk of a lack of consistency in approaches but also raises considerations about how the benefits of the expenditure are likely to accrue. As such, the Commission considers there should be some further guidance provided by the AER around the type of information it would like to see from DNSPs and how this would feed into the expenditure assessment process, particularly in relation to how the benefits arising from expenditure to provide network hosting capacity are valued.

On this basis, the Commission proposes that the AER update Expenditure Forecast Assessment Guidelines to provide guidance on its approach to the assessment of DER driven investment.[179] The Commission acknowledges the ongoing work in this area by the AER, particularly through its consultation on its approach in assessing DER integration expenditure and its study on Value of DER (VaDER). This work provides a strong basis for the development of guidance on DER integration expenditure as part of updating the Expenditure Forecast Assessment Guidelines.

This draft rule is intended to support better outcomes for DNSPs through improved transparency, consistency and predictability in the regulatory process. The draft rule should also improve customer outcomes by promoting efficient and prudent investment in capacity for export services and in assisting the AER in its assessment of proposed expenditures.

177 This point is discussed by the AER in its decision on the application guidelines for the regulatory investment tests for transmission and distribution. In that report, the AER acknowledges stakeholder views that DER can increasingly affect wholesale markets. See: AER 2018, Final decision, Application guidelines for the regulatory investment tests, pp. 37-38.

178 AEMC, Review of stand-alone power systems, 30 May 2019. p. 33.

179 Amending NER clause 6.4.5.

5 INCENTIVE ARRANGEMENTS AND SERVICE LEVELS FOR EXPORT SERVICES

This chapter outlines the issues raised in the rule change requests, relevant background information, stakeholder views and the Commission's draft determination with regard to:

- the incentive arrangements for efficient delivery of export services
- the export service levels that DNSPs are expected to provide to customers and connection arrangements for DER
- the development of customer export curtailment values (CECV) to guide efficient export planning, investment, and incentives decisions.

BOX 6: OVERVIEW

Incentive arrangements

- The Commission considers that export services should be able to benefit from the application of incentive arrangements that provide for their efficient delivery to customers. Providing DNSPs rewards or penalties based on their export service performance would facilitate greater levels of DER exports in a least cost way and the delivery of a better quality export service customers that use the network to export.
- The current incentive arrangements need amendment to extend the Service Target Performance Incentive Scheme (STPIS) to exports in order to provide incentives for DNSPs to maintain and improve export service performance, otherwise DNSPs may be incentivised to reduce costs at the expense of export service performance.
- To support balanced incentives for efficient delivery of export services, the Commission's draft rule introduces a requirement for the AER to undertake a review within 18 months to consider arrangements, which may include the STPIS, for providing performance incentives for export services.
- To provide greater flexibility to the AER in implementing export service performance incentives, the draft rule amends the factors that need to be considered by the AER in developing the STPIS and adjusts other parts of incentives framework to allow the AER to consider a broader range of incentive tools if necessary.

Service levels and connection arrangements

- In line with the current arrangements for service reliability, the extended STPIS would be the appropriate mechanism for guiding export service levels that DNSPs are expected to provide to customers. Some jurisdictional authorities may also seek to set service standards covering the performance of export service that better meet the jurisdictional circumstances.

- To promote greater transparency of DNSPs' export service performance, the Commission's draft rule requires DNSPs to report on a range of metrics related to their export service performance in their distribution annual planning reports (DAPR).
- The Commission's draft rule doesn't include requirements for DNSPs to offer a minimum level of export capacity to all customers as proposed by SAPN and TEC/ACOSS. Effective incentive arrangements provided by the extended STPIS along with a clear planning and investment framework for exports will provide for better customer access to export service.
- The current connection arrangements provide sufficient flexibility and options for customers to negotiate additional export capacity.

Customer export curtailment values

- To support efficient investment in export services and enable customers to receive export service that better their needs, the Commission has also made a draft requiring the AER to develop a methodology for and to regularly calculate the customer export curtailment values (CECV).

5.1 Incentive arrangements for export services

5.1.1 Rule change requests

SAPN proposal

In its rule change request, SAPN considered that export services should be subject to financial incentive schemes that promote efficiency in their delivery and outcomes that customers support – consistent with the revenue and pricing principles and NEO.[180] SAPN considered that there is no apparent barrier to applying the majority of existing incentive schemes (providing it is clear that 'distribution services' include export services) and that the STPIS is the principal incentive scheme requiring work to adapt it to apply to export services. It did not propose for the NER to mandate the approach that the AER should take.[181]

SAPN said that the key considerations for extending the STPIS were likely to include:

- the need to derive service performance measures that, mirroring the approach to consumption, apply as averages across all customers, or across broad classes of customers, or regions, rather than in respect of any individual customer's service level.
- how to measure and express service performance, such as referring to average annual hours of availability of a certain level of export capacity for a given customer group.
- determining exactly what distribution networks should be incentivised to do for customers. For example, consideration would need to be given as to whether incentives

180 SAPN rule change request, pp. 19–20.

181 SAPN rule change request, pp. 19–20.

should be applied to improve export capacity on average for applicable customers, in aggregate across all customers, or both.

The rule change request from SAPN also suggested that an adapted STPIS for export services would ideally be established progressively over a period of time, to build confidence in requisite measurement processes, systems and datasets, as occurred when the STPIS was first applied to consumption services. SAPN proposed that in that interim period, until the STPIS is operational, a reporting regime could be applied to encourage effective management of performance. SAPN also noted that there is also an intrinsic incentive for networks to manage performance so as to minimise customer complaints.[182]

TEC/ACOSS proposal

The TEC/ACOSS proposal seeks to encourage networks to make the best use of existing infrastructure to maximise DER exports. It suggests that the current STPIS in clause 6.6.2 of the NER should be amended to include a component related to exports.[183]

5.1.2 Incentive arrangements under the current framework

A key feature of economic regulation in the NEM is that it is based on incentivising DNSPs to provide regulated services as efficiently as possible. It does so by locking in DNSPs' total revenue requirement prior to the start of each regulatory control period. With revenue locked in, DNSPs' profits are determined by their actual costs of providing services. DNSPs are provided with discretion to choose how they provide the regulated services – such as operating solutions or capital investments.

This high-level incentive regulatory framework is then enhanced through specific incentive schemes for operating expenditure, capital expenditure, service performance and demand management. These schemes are administered by the AER. The NER provides high-level guidance on the development and implementation of the different incentives schemes by the AER. The AER designs the schemes in consultation with stakeholders and decide on their application to DNSPs.

Efficiency Benefit Sharing Scheme

The efficiency benefit sharing scheme (EBSS) seeks to provide DNSPs a continuous incentive to achieve efficiency gains. The NER require the AER to develop an EBSS that fairly shares the efficiency gains (losses) derived from the operating expenditure of a DNSP for a regulatory control period being lower (higher) than that set by the AER's revenue determination process.

Capital Expenditure Sharing Scheme

The capital expenditure sharing scheme (CESS) seeks to provide DNSPs with an incentive to undertake efficient capex during a regulatory control period. It achieves this by rewarding NSPs that outperform their capex allowance and penalising NSPs that spend more than their

182 SAPN rule change request, p. 20.

183 TEC/ACOSS rule change request, p. 11.

capex allowance. [184] The CESS sets out a mechanism to share capex efficiency gains and losses between NSPs and network users.[185]

Service Target Performance Incentive Scheme

The Service Target Performance Incentive Scheme (STPIS), which rewards or penalises DNSPs based on their service performance, is designed to discourage DNSPs from cutting costs by inefficiently reducing service levels. The STPIS aims to maintain service performance to customers and incentivise improvements over time when these can be undertaken efficiently – and if valued by customers, accounting for their willingness-to-pay.[186] The STPIS provides rewards to a DNSP where its service performance on average across customers is better than the past average performance level (performance target) and penalties where performance is below this performance target.[187] The current version of the STPIS developed by the AER has four components, including:

- the 'reliability of supply' component (s-factor)
- the 'quality of supply' component (currently undefined)
- the 'customer service' component
- the 'guaranteed service level' (GSL) component.

The defined components of the scheme include several performance measures (called parameters) for different attributes of the services provided by DNSPs. e.g. reliability of supply component includes the performance measures of unplanned SAIFI and unplanned SAIDI.[188]

Demand Management Incentive Scheme and Demand Management Innovation Allowance

To promote the use of non-network options, the AER also applies the demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIA).[189] The DMIS provides for incentive payments to undertake efficient expenditure on non-network options. The DMIA provides funding for research and development on demand management projects that have the potential to reduce long term network costs.

Regulatory Investment Test for distribution

DNSPs must also satisfy the regulatory investment test for distribution (RIT-D) prior to making significant network investments. The purpose of the RIT-D is to identify the distribution investment option that maximises NEM-wide net economic benefits and, where applicable, meets the relevant jurisdictional or rule-based reliability standards.

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184 AER, Capital Expenditure Incentive Guideline for Electricity Network Service Providers, November 2013, p. 5.

185 AER, Capital Expenditure Incentive Guideline for Electricity Network Service Providers, November 2013, p. 6.

186 AER, SA Power Networks distribution determination 2020 to 2025: attachment 10 service target performance incentive scheme, June 2020, p. 4.

187 AER, SA Power Networks distribution determination 2020 to 2025: attachment 10 service target performance incentive scheme, June 2020, p. 8.

188 The performance targets are set in terms of these performance measures.

189 AER, Fact sheet: Demand management incentive scheme and innovation allowance, December 2017, p. 1.

5.1.3 Stakeholder views

The need for incentive arrangements for export services

Stakeholders generally consider that there is a need to provide balanced incentives for DNSPs to efficiently deliver export services.[190] Several stakeholders expressly support regulatory arrangements aimed at supporting efficient delivery of export service by DNSPs.[191] The Clean Energy Council (CEC), AGL and EcoJoule Energy say that they support the focus on aligning network incentives. [192] While the Victorian Government says that, "it supports the development of regulatory instruments to facilitate efficient delivery of DER integration investments and maintain service quality".[193]

The Customer Advocate considers that "should the definition of distribution services expand as proposed, it is logical that the customer service incentive schemes and value of reliability be reviewed as well".[194]

Some stakeholders provided suggestions for the objective of such regulatory arrangements.

Endeavour Energy considers that "incentive schemes could be used to incentivise networks to meet a benchmark level of service or improve their historical performance (where valued by customers)".[195]

Essential Energy suggests that "Optimally, any new export investment incentive should encourage DNSPs to enlarge the hosting capacity of their local network, when the value of additional DER exports facilitated through the new capacity, outweighs the incremental costs of delivering that hosting capacity."[196]

According to Origin "the scheme should provide both an incentive for DNSPs to invest in export services" and also "could be incorporated to discourage over-investment in export capacity or only allow such investment where the value to customers is clearly demonstrated and approved".[197]

Can the existing arrangements provide the right incentives?

Some stakeholders commented on the suitability of existing regulatory arrangements, including the incentives schemes in their current form, for providing suitable incentive arrangements for export services.[198] Most of these stakeholders consider that the existing incentive schemes would be effective for an export service, except for the STPIS. They note that the STPIS would need to be adapted to suit exports.[199]

190 Submissions to the consultation paper: ENA, p.13; EUAA, p.4 ; CEC, p.1 ; AGL, p.8; EcoJoule Energy, p.1, Endeavour Energy, p. 2, Essential Energy, p. 4 ; Renew p. 10.

191 Submissions to the consultation paper: CEC, p. 1; AGL, p. 8; EcoJoule Energy, p. 1; Endeavour Energy, p. 2; ENA, p. 13; Essential Energy, p. 4 ; Renew p. 10.

192 Submissions to the consultation paper: CEC, p. 1 ; AGL, p. 8; EcoJoule Energy, p. 1.

193 Victorian Government submission to the consultation paper, p. 4.

194 The Customer Advocate submission to the consultation paper, p. 5.

195 Endeavour Energy submission to the consultation paper, p. 2.

196 Essential Energy submission to the consultation paper, p. 4.

197 Origin submission to the consultation paper, pp. 3-4.

198 Submissions to the consultation paper: Origin, p.3.; AER. P. 5; AusNet Services p. 5.

199 Submissions to the consultation paper: AER, p. 5; AusNet Services p. 5; ENA p. 13; EnergyAustralia, p. 9; Planet Ark Power, p.

The AER says that, while incentives to minimise costs apply to DER-related expenditure (under EBSS and CESS), performance incentives and standards (under the STPIS) around export services do not. The AER considers that "Given this, it is worthwhile considering how to balance cost-minimisation incentives around export services".[200]

AusNet Services agrees "with SAPN that all existing incentive schemes can apply (including the EBSS, CESS, DMIS, CSIS) other than the STPIS, for which an additional parameter will need to be developed".[201]

Similarly, Energy Networks Australia (ENA) considers the STPIS "requires work to adapt it to apply to export services" and EnergyAustralia states that STPIS was the only scheme that couldn't be effective for exports in its current form.[202]

According to Planet Ark Power, the existing regulatory arrangements such as the VCR, SAIDI, SAIFI, and power quality standards and incentive arrangements including the DMIA will need to be adjusted to cater for export service.[203]

Meanwhile, Jemena considers that the current incentive arrangements were sufficiently structured to include export services. Jemena states that there is "no need to change to STPIS for export services; the use of one connection for both import and export services—and using the measures SAIDI, SAIFI, and MAFI (which are flow direction agnostic)—already captures the performance of export services".[204]

Several stakeholders raise concerns that if the STPIS doesn't effectively cover the provision of export services, it could mean that the DNSPs face little incentive to invest in measures to improve export service quality as there would be no associated penalty for constraining DER exports. As an example, the CEC states that:[205]

> There is currently no targeted incentive for DNSPs to invest to improve hosting capacity and no penalty for not doing so. A more clearly structured and targeted incentive/penalty framework would drive more efficient investment in hosting capacity.

Similarly, Origin states that "in the absence of appropriate incentives, it is likely that investment in export services will be sub-optimal and economic efficiency will not be maximised" and that "incentivising efficient investment and operation of DER (including export services) is fundamental to the achievement of the National Electricity Objective".[206]

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200 AER Submission to the consultation paper, p. 5.

201 AusNet Services Submission to the consultation paper, p. 5; The Customer Service Incentive Scheme (CSIS) is developed by the AER to encourage DNSPs to engage with their customers and provide customer service in accordance with their preferences. It was developed in accordance with the small scale incentive scheme framework

202 Submissions to the consultation paper: ENA, p. 13; EnergyAustralia, p. 9.

203 Planet Ark Power submission to the consultation paper, p. 11.

204 Jemena submission to the consultation paper, p. 11.

205 CEC Submission to the consultation paper, p. 1.

206 Origin submission to the consultation paper, p. 3.

AGL also submits that "Currently there is little incentive for networks to invest in measures to reduce export constraints as the regulations do not currently impose a penalty for constraining DER exports."[207]

The AEC/Oakley Greenwood submit that:[208]

> Clearly, it will be important to ensure that if businesses are provided with capital expenditure ex-ante to increase hosting capacity - as SAPN proposes - customers have some assurance that the additional hosting capacity funded by that expenditure will actually be built, if it is efficient to do so at the time when the expenditure is being contemplated (i.e., within the regulatory period).

Approach to providing balanced incentives for exports

There is widespread stakeholder support for the proposal to extend STPIS to cover export service in order to align incentives for DNSPs to efficiently deliver export services. [209] These stakeholders also support the AER adapting the STPIS for exports in consultation with stakeholders.[210]

The AER submits that it "sees benefits in expanding the STPIS to incentivise performance associated with export services".[211]

Several DNSPs also highlighted their support for extending the STPIS to exports. More specifically, Ausgrid states that "extending the STPIS to export services provides a minimum cost regulatory change, and an alternative scheme for export services is not required".[212] Similarly, AusNet Services submits that "the STPIS should be extended to export services, which would be appropriate as the STPIS sets service targets. This would be preferred over introducing an additional incentive scheme into the framework."[213] Evoenergy considers that adaption of STPIS would be preferable because it "reduces complexity across incentive schemes, provided that baseline performance targets are appropriately set".[214] Jemena notes that STPIS "is the most likely candidate for service level performance if changes are to be made".[215] Essential Energy submits that the STPIS appears set to play a key role in incentivising efficient export services investment and that it will provide an incentive to maintain and improve service performance metrics for export services.[216]

207 AGL submission to the consultation paper, p. 8.

208 AEC/Oakley Greenwood submission to the consultation paper, p. 6.; The AEC's submission attaches an independent report by consultants Oakley Greenwood.

209 Submissions to the consultation paper: AusNet Services, p. 5; Ausgrid, p. 9; EcoJoule Energy, p. 9; Endeavour Energy p. 2; ENA, p. 13; Essential Energy, p. 4; Jemena p. 10; Vector, p. 1; Evoenergy p. 13; Momentum p. 2; Renew p. 10; Planet Ark Power, p. 11.

210 Submissions to the consultation paper: Ausgrid, p. 5; ENA, p 13; AER, p. 5.

211 AER submission to the consultation paper, p. 5.

212 Ausgrid submission to the consultation paper, p. 9.

213 AusNet Services submission to the consultation paper, p. 5.

214 Evoenergy submission to the consultation paper, p. 13.

215 Jemena submission to the consultation paper, p. 9.

216 Essential Energy submission to the consultation paper, p. 4.

In supporting the extension of the STPIS to exports, EcoJoule Energy states that the STPIS is a proven successful mechanism for delivering sustainable reliability benefits to customers.[217]

Planet Ark Power supports the extension of STPIS to exports but recommends that:[218]

> ...regular (5-year) reviews should be undertaken to consider challenges from increasing adoption of EV charging and batteries on future grid requirements, along with the acceleration of DER on the STPIS. Regular reviews of the STPIS should ensure ongoing flexibility and relevance in a changing energy market.

Endeavour Energy supports the approach of extending STPIS to exports and highlights that as an alternative, networks could propose small scale incentive schemes (like AusNet Services proposed Customer Service Incentive Scheme) to address DER hosting and service quality.[219] Vector considers that DNSPs should also be provided incentives to assess the least cost option for meeting demand for export services i.e. no network options.[220]

Stakeholders also expressed preference for the adaptation of the STPIS to exports over the development of a new incentive scheme for exports.[221] Ausgrid considers that "an alternative scheme was not needed".[222] Similarly, Renew submits that a "new scheme was not required as STPIS approach would be sufficient".[223] The Customer Advocate also states "that no new scheme is needed".[224]

Meanwhile, Origin considers that the STPIS shouldn't be extended to export services and instead a separate incentive scheme for exports should be considered because adapting the STPIS to exports is likely to be very difficult.[225]

Challenges associated with extending the STPIS to exports

Although stakeholders overwhelmingly support the extension of STPIS exports to support efficient delivery of exports, some DNSPs foresee that there could be practical challenges associated with it. The key challenges identified include defining robust export service performance measures, the availability of reliable data, limited Low Voltage (LV) network visibility, and estimating performance baselines.[226]

Essential Energy considers that the design of any incentive scheme to apply to export services will need to overcome a range of practical challenges, including network visibility which currently varies significantly across networks.[227] Essential Energy explains that:[228]

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217 EcoJoule Energy submission to the consultation paper, p. 2.
218 Planet Ark Power submission to the consultation paper, p. 11.
219 Endeavour Energy submission to the consultation paper, p. 2.
220 Vector submission to the consultation paper, p. 1.
221 Submissions to the consultation paper: Ausgrid p. 9; Renew, p. 10; The Customer Advocate, p. 2.
222 Ausgrid submission to the consultation paper, p. 9.
223 Renew submission to the consultation paper, p. 10.
224 The Customer Advocate submission to the consultation paper, p. 2.
225 Origin submission to the consultation paper, p. 3.
226 Submissions to the consultation paper: Ausgrid p. 9; Essential Energy, p.1, Evoenergy, p. 13; Jemena, p. 10.
227 Essential Energy submission to the consultation paper, p. 1.
228 ibid, p. 4.

> ...it is worth noting that many DNSPs do not currently have clear visibility on the extent to which their individual networks currently constrain DER exports. Consequently, it will be challenging to estimate STPIS baseline targets, address issues of unequal network access and measuring DER outcomes.

Ausgrid submits that "the major challenge would be to develop metrics of export performance for setting the service targets or standards" and that "currently we either do not collect, or do not have access to, the data on the curtailment or cut-off of customer's generation equipment".[229] Ausgrid adds that:[230]

> To distinguish between distributor-caused curtailment versus other causes of reduced exports would require visibility of a variety of factors. The visibility of both the low voltage network and customer's installations would need to improve significantly.

Evoenergy considers that regulatory review allowances need to include the cost of DNSPs obtaining this the required data.[231]

Similarly, Jemena considers that there are several challenges associated with establishing a new incentive scheme or STPIS. Jemena states that these include:[232]

- Data collection: data to set performance baseline would need to be collected. Jemena notes that in Victoria, the data can be collected from AMI meters but in other jurisdictions where metering competition exists:
  - the data will have to be acquired by the DNSP from the meter data provider
  - an obligation will need to be placed on the meter data provider to provide the data mandatorily, or new devices will need to be installed in the field
- Setting a baseline: it was first necessary to collect the data to set baseline on which to determine performance
- Rate of change: Jemena states that "when the rate of change in circumstances is above normal levels, a trend factor arises, which means that if the trend is not accounted for, then the performance—based on historical averages—is misleading and could result in an incorrect performance reward or penalty".

AGL and Red Energy and Lumo Energy consider that due to practical challenges associated with extending the STPIS to exports, it would be preferable to consider it at a later stage, after a period of information gathering.[233] Meanwhile, AusNet Services and EcoJoule Energy state that these challenges could be overcome.

AGL anticipates that a range of operational challenges would impede the STPIS from driving improved customer outcomes in the immediate term, including:[234]

229 Ausgrid submission to the consultation paper, p. 9.
230 ibid.
231 Evoenergy submission to the consultation paper, p. 13.
232 Jemena submission to the consultation paper, p. 10.
233 Submissions to the consultation paper: AGL, pp. 8-9; Red Energy and Lumo Energy, p. 3
234 AGL submission to the consultation paper, p. 8.

- The current lack of robust data to benchmark DNSPs' export performance
- The need to define performance measures and a performance standard for exports
- The difference between hosting capacity and other service attributes currently reflected in the STPIS (e.g. reliability), as its value is derived from indicators that vary irregularly (wholesale market prices)

Accordingly, AGL suggests that in the short-term other options such reputational incentives underpinned by informational disclosure should be considered. AGL considers that once adequate reporting and data had been collected, development of appropriate performance standard could take place.[235]

Similarly, Red Energy and Lumo Energy suggest the Commission should "consider placing an obligation requiring regular transparent reporting by networks on their performance with regard to export capacity, either directly into the National Electricity Rules or indirectly via inclusion in an existing guideline managed by the Australian Energy Regulator". It suggests that the information disclosure would "provide a consistent evidence base for the networks to propose a change to incentive schemes in the future."[236]

Meanwhile, AusNet Services says that "the practical challenges in designing an incentive scheme are outweighed by the benefit, and not disproportionally greater than those that have arisen historically with other incentive schemes that successfully operate today". AusNet Services considers that "In terms of data provision, the Victorian DNSPs have smart meters which provides, for individual customers, data on voltage and energy exported. These could be key inputs when designing a scheme which could apply in Victoria." AusNet Services considers that setting an appropriate baseline was an issue that could be overcome over time but "in the near term, flexibility will be required when designing and applying the scheme".[237]

Several other stakeholders consider export service performance measures could be developed using voltage data, which can currently be accessed by DNSPs. [238]

In relation to the availability of suitable data, EcoJoule Energy says that:

> If the metric is based on voltage magnitude there are no major challenges. Accuracy of smart meters is already sufficient. In areas with low penetration of smart meters a statistical approach may be required.

EcoJoule adds that "additional low-cost voltage measurement devices could be strategically deployed if smart meter penetration levels were not statistically robust".[239]

On the issue of data availability, Vector says that "Incentive schemes for DER integration should incentivise DNSPs to use data already available from existing metering investments, for example, from Metering Data Providers". Vector adds that "Smart technologies, enabled

235 AGL submission to the consultation paper, p. 9.

236 Red Energy and Lumo Energy submission to the consultation paper, p. 3.

237 AusNet Services submission to the consultation paper, p. 5.

238 Submissions on consultation paper: The Australian Power Quality and Reliability Centre at the University of Wollongong, p. 2; Endeavour Energy, p. 7.

239 EcoJoule Energy submission to the consultation paper, pp. 3-4.

by advanced metering data, can help make networks become 'asset light' and avoid costly new network investment or expansion".[240]

Alternative incentive arrangements

AEC/Oakley Greenwood also foresee several challenges associated with extending the STPIS to exports and suggest the Commission consider an alternative approach involving the customers facing cost reflective export prices and the DNSPs self-funding network investment for exports prior to committing to the STPIS approach.[241]

More specifically, AEC/Oakley Greenwood state that "hosting capacity is quite different to the other service attributes reflected in the STPIS (e.g., reliability)", in particular because its "primary value is already revealed 'in the market' (via wholesale market prices, contract prices, FiTs and FCAS)" and "these values can change materially and irregularly."[242] AEC/Oakley Greenwood say that for the existing attributes captured in the STPIS, there was no revealed market value, which is why they were usually derived from customer willingness to pay (WTP) studies and they change marginally in the short to medium term. According to AEC/Oakley Greenwood, these differences raise several questions including:[243]

- How often would the incentive rate for export service be adjusted under a STPIS type arrangement if the customer WTP for hosting capacity is subject to greater volatility than their WTP for reliability improvements?
- If the incentive rate for exports were adjusted more frequently (e.g. every second year), would this lead to other consequential issues such as:
  - Who bears the financial risk of any downside adjustment to this parameter?
  - Would allocating this risk to DNSPs affect their willingness to invest otherwise economic investments in hosting capacity?
  - Would the administrative costs of adjusting the incentive rates to reflect new information exceed its benefits?
- If network expenditure for exports is predominately underpinned by the outturn workings of the STPIS mechanism, then
  - Who bears the financial consequences if forecast take-up of hosting capacity doesn't transpire as forecast (e.g. due to a change in government policy)?
  - If the STPIS incentive is for hosting capacity availability rather the than the DER exports supported by hosting capacity, then how could the arrangements be operationalised in a manner that doesn't lead to DNSPs expanding network capacity to increase availability rather than support throughput?

AEC/Oakley Greenwood question whether a STPIS type mechanism was even required if DNSPs provided customers cost reflective export prices. They query whether "the market, faced with a cost-reflective export price, would 'reveal' the efficient level of network hosting

240 Vector submission to the consultation paper, p. 2.

241 AEC/Oakley Greenwood submission to the consultation paper, pp. 2 - 4.

242 ibid, pp. 2.

243 ibid, pp. 2-3.

capacity via demand for those services". They suggest that DNSPs investments could either be:[244]

- Self-funded over the long-run, where DNSPs would invest in the export service if their expectation of the revenue generated from an export tariff exceeded the incremental cost – analogous to an alternative control service.
- Self-funded as above but with some adjustment mechanism to share downside volume risk.

Other existing incentive schemes

Some stakeholders consider that the DMIS and DMIA should also be reviewed for application to exports.[245]

Planet Ark Power says that a "utility that leverages the DMIA incentive for a demand management initiative should also be able to leverage that for an export service".[246] Firm Power states that, "incentive schemes, such as demand side engagement and the DMIS should be adapted to reward DNSPs for contracting balancing services and increasing DER hosting capacity via non-network solutions. This creates an efficient marketplace for balancing service providers that delivers services at the lowest cost and improves the utilisation of network assets".[247]

Whether details of the scheme be outlined in the NER or be developed by the AER

There is a strong preference amongst stakeholders for the adaptation of the STPIS to exports to be carried out by the AER instead of the NER prescribing the detailed design of the adapted scheme.[248] Several stakeholders suggest that the AER could adapt the STPIS in consultation with the industry and other stakeholders. They also consider that prescribing the scheme in the NER would limit flexibility. Some stakeholders note that this approach would be consistent with the AER's current role in designing incentive schemes.[249]

For example, Ausgrid states that it was "appropriate for the AER to extend the existing STPIS scheme in collaboration with industry and customers". Ausgrid further said that "defining the scheme in the NER would be overly prescriptive and not flexible enough to respond to the market developments and technological change".[250] EcoJoule Energy and Essential Energy say they supported the responsibility for the design of the incentive scheme to be assigned to the AER.[251]

244 AEC/Oakley Greenwood submission to the consultation paper, p. 4.

245 Submissions to the consultation paper: The Customer Advocate, p. 5; Firm Power, p. 4; Planet Ark Power, p. 11.

246 Planet Ark Power submission to the consultation paper, p. 11.

247 Firm Power submission to the consultation paper, p. 4.

248 Submissions to the consultation paper: AusNet Services p.5; Ausgrid, p. 10; EcoJoule Energy, p. 4; Endeavour Energy, p. 7; ENA, p. 13; Energy Queensland, p. 2; EnergyAustralia, p. 6; Essential Energy, p. 4; Origin, p.4; Jemena, p. 11; Evoenergy p. 13, Momentum, p. 2; Renew, p. 10.

249 Evoenergy submission to the consultation paper, p. 13.

250 Ausgrid submission to the consultation paper, p. 10.

251 Submissions to the consultation paper: EcoJoule Energy p. 4; Essential Energy, p. 4.

ENA consider that allowing the AER to adapt the STPIS was preferred to prescribing the details of the scheme in the NER, which "would limit the responsiveness and adaptability of the scheme". ENA further add that the introduction of the STPIS will need to consider the different customer preferences and data capabilities of each DNSP, and allow for transition paths as necessary."[252]

EnergyAustralia states that:[253]

> It is appropriate for the AER to design the scheme, as they will be responsible for approving the STPIS and for assessing the impacts (overlap/over-incentivisation) on other incentive schemes. The AER can also determine if STPIS scheme should exist if all the practical issues cannot be overcome.

Similarly, Energy Queensland says that it "would not support any prescriptive incentives in the rules without further clarification as to how enablement of export services can be effectively measured".[254]

Some stakeholders commented that the NER should only outline the principles that guide the development of STPIS to exports.[255] For example, Origin states that "given the dynamic nature of export services, we consider that the NER should establish the core principles associated with the proposed incentive scheme, with details of the scheme to be determined by the Australian Energy Regulator (AER) through stakeholder consultation".[256]

Regulatory barriers to extending the STPIS to exports

Several stakeholders consider that there would not be any regulatory barriers to adapting the existing incentive schemes to exports if export services were defined to be part of distribution services.[257] For example, Endeavour Energy states that "if export services are included within 'distribution services' there are no barriers to the AER amending existing incentive schemes to cover DER export hosting or introducing new incentive schemes via a rule change".[258] Similarly, Origin considers that "to the extent that export services are incorporated in the definition of a distribution service, we are unaware of any regulatory impediments to adapting existing National Electricity Rules (NER) incentive schemes to export services".[259]

Although Jemena did not outline regulatory barriers, it suggests that the NER could be amended to require the AER to amend the STPIS to reflect the intended incentives for grid exports.[260]

Meanwhile, the AER states that:[261]

252 ENA submission to the consultation paper, p. 13.
253 EnergyAustralia submission to the consultation paper, p. 10.
254 Energy Queensland submission to the consultation paper, p. 2.
255 Submissions to the consultation paper: Endeavour Energy p. 7; Origin p. 4.
256 Origin submission to the consultation paper, p. 3.
257 Submissions to the consultation paper: Ausgrid, p. 8; EcoJoule Energy, p. 4; Endeavour Energy p. 7; Renew, p. 10.
258 Endeavour Energy submission to the consultation paper, p. 7.
259 Origin submission to the consultation paper, p. 3.
260 Jemena submission to the consultation paper, p. 11.
261 AER submission to the consultation paper, p. 5.

> The NER currently provide the AER with flexibility in how it constructs the STPIS — for example, the provisions do not reference consumption services. We consider this flexibility is appropriate as it allows the AER to explore amending the STPIS as an element of the broader incentive framework. This would also provide us with the time and flexibility to address the challenges of expanding the STPIS to apply to export services.

Factors to be considered by the AER when extending the STPIS

To support the extension of STPIS to exports, some stakeholders suggest amendments to the current factors listed in NER clause 6.6.2(b)(3), that the AER must take into account when developing the STPIS.

AusNet Services says that as well as considering the past performance of the distribution network (NER clause 6.6.2(b)(3)(iii)) the AER should also take into account forecasts in the uptake of DER. AusNet Services consider that this was appropriate as "export services have not yet reached the same 'steady state' as consumption services". Furthermore, AusNet Services says that "If forecast DER uptake and penetration levels are materially different to those seen historically, the AER should have the flexibility to set the scheme's targets and parameters, and apply these in ways that are fit for purpose, and will not materially disadvantage either the DNSP or customers".[262]

Ausgrid submits there needs to be flexibility in the scheme to "account for additional system services to support broader DER hosting capacity (for example distributor provided system strength services)". Ausgrid further adds that "any changes to the scheme should also consider any additional appropriate exclusion mechanisms to ensure that DNSPs are not unfairly penalised for factors outside their control".[263]

Endeavour Energy submits that "clause 6.6.2(i) may require modification to more explicitly recognise exporters of electricity".[264] Endeavour Energy states that:[265]

> Currently, it makes reference to the need to ensure that benefits to electricity *consumers* likely to result from the scheme are sufficient to warrant any reward of penalty under the scheme for the network. The reference to 'consumers' may need to be replaced or expanded to also recognise 'producers' or 'exporters'.

Endeavour Energy further states that:[266]

> It is also worth noting that the value of curtailed energy is currently relatively low for the average DER customer based on recent studies. In accordance with 6.6.2(i), as modified by this rule change, the reward or penalty for curtailed energy would be low.

262 AusNet Services submission to the consultation paper, p. 5.

263 Ausgrid submission to the consultation paper, p. 10.

264 Endeavour Energy submission to the consultation paper, p. 8.; The Commission understands the Endeavour Energy submission may be referring to NER 6.6.2 (b)(3) (i) in this instance.

265 Endeavour Energy submission to the consultation paper, p. 8.

266 ibid, p. 5. The Commission understands the Endeavour Energy submission may be referring to NER 6.6.2(b)(3)(i) and NER 6.6.2 (b)(3)(vi) in this instance.

> A more holistic view of the benefits of voltage optimisation (beyond export capacity) would likely result in a stronger case for implementing an incentive scheme.

Interim incentive arrangements

Several stakeholders consider that the extension of STPIS to exports may need to occur progressively over time. For example, the AER says that while it supports reviewing incentive schemes to support the efficient provision of export services it, we would likely adopt a staged approach. The AER adds that:[267]

> expanding the STPIS might entail the AER:
>
> 1. Identifying and testing a range of reporting metrics through paper trials, benchmarking and/or annual reporting.
> 2. Assessing whether the proposed metrics and reporting frameworks are of sufficient quality and incentive value to provide an overall benefit to consumers

ENA submits that "as occurred when the STPIS was first applied to consumption services, an adapted STPIS for export services would ideally be established progressively over a period of time, to build confidence in requisite measurement processes, systems and datasets".[268]

Similarly, Renew states that it agreed with "SAPN that the STPIS for exports may need to be introduced progressively so that the right metrics, data collection and reporting can be determined and implemented".[269]

Ausgrid recommends that a "paper" scheme is established first, to collect data and establish the appropriate metrics. Ausgrid explained that "starting from the current lower levels of monitoring, it will be important to distinguish between genuine changes in performance versus changes in the performance measure purely due to the improved measurement".[270]

In light of the potential need to progressively extend the STPIS to export, some stakeholders suggest that while the STPIS is being adapted to exports by the AER, interim incentive arrangements based on a reporting regime should be introduced as a transitional measure.

The AER says that reputational incentives from AER reporting or benchmarking DNSPs on export service performance could be a transitional measure before expanding the STPIS.[271]

Similarly, ENA considers that in "that interim period, until the STPIS is operational, a reporting regime could be applied to encourage effective management of performance". ENA also claims that "as with any other service, there is also an intrinsic incentive for networks to manage performance so as to minimise customer complaints".[272]

267 AER submission to the consultation paper, p. 6.
268 ENA submission to the consultation paper, p. 13.
269 Renew submission to the consultation paper, p. 10.
270 Ausgrid submission to the consultation paper, p. 11.
271 AER submission to the consultation paper, p. 5.
272 ENA submission to the consultation paper, p. 14.

According to Renew "During this implementation period the question of whether and how a performance baseline and service standards might be set can be explored.[273]

Essential Energy states that "It may be the case that transitional options, that require limited information, may be more feasible to implement in the short term". Essential Energy considered that in the long term, visibility and other challenges could be overcome with improved data systems and investment.[274]

Export service performance metrics

Some stakeholders highlighted the importance of carefully considering the export service measures to be included in the STPIS in order to avoid perverse incentives for DNSPs.[275]

The Victorian Government considers that "it is critical that robust measures be developed and tested over time to ensure baselines can be set accurately and avoid perverse incentives".[276]

On this issue, the AER highlights that:[277]

> DER export curtailment can be measured in different ways— e.g. hard export limits (including bans), curtailment in response to overvoltage, enacting dynamic export limits. If the incentive overlooks a relevant metric, it could incentivise DNSPs to shift the method used to curtail exports, rather than to minimise curtailment. While it would be possible to create a reporting and measurement framework that captures all the relevant metrics, this will require a degree of judgement (including how to weight the different metrics).

Several other stakeholders provide suggestions on export service performance measures to be included in the extended STPIS for exports. Most of these stakeholders suggest that export service performance measures should be based on the magnitude of the supply voltage as DER exports were generally constrained due to elevated voltage levels and information on voltage levels was more readily accessible.

For example, Endeavour Energy states that:[278]

> Our preference is an extension of the STPIS to include voltage quality. This is the best proxy for export capability and most DER curtailment is due to voltage rather than thermal capacity.

Endeavour Energy states that it recommends the use of voltage as a performance metric because "it is measurable and there are good techniques available to extrapolate population performance based on statistical samples of customer measurements".[279] According to Endeavour Energy, this means that a reliable dataset can be developed even in jurisdictions

273 Renew submission to the consultation paper, p. 10.
274 Essential Energy submission to the consultation paper, p. 4.
275 Submissions to the consultation paper: Momentum, p. 2; Victorian Government, p. 4.
276 Victorian Government submission to the consultation paper, p. 4.
277 AER submission to the consultation paper, p. 6.
278 Endeavour Energy submission to the consultation paper, p. 7.
279 ibid.

with lower penetration of smart metering. Endeavour Energy further adds that voltage was also "less sensitive to year by year performance fluctuations so a shorter data gathering period, than the five years used for reliability, could be used to establish performance targets".[280] Endeavour Energy also adds that the existing reliability components of the STPIS may also require a review to consider the value of lost opportunity for export in the incentive rates.[281]

Similarly, the Australian Power Quality and Reliability Centre (APQRC) at the University of Wollongong submits that supply voltage should be considered as a key performance metric because:[282]

- Voltage magnitude can be measured accurately by relatively low-cost devices and there are power quality monitoring and/or revenue meter measurement standards in place that define measurement requirements and accuracy.
- Chapter 4 of the STPIS already allows for provision of management of Quality of Supply component within the incentive mechanism.
- There exists a significant quantum of data that could be used to establish a performance baseline for supply voltage magnitude performance.
- Voltage magnitude obligations in the NER are not supported or complemented by incentive mechanisms. The proposal presented here may assist in incentivising enhanced management of supply voltage levels.

According to the APQRC, the primary objective of any extension of STPIS to voltage magnitude should be to ensure that they are within the allowable range for the majority of sites for the majority of the time. It adds that further consideration should be given to "a preferred voltage range somewhat below the upper boundary to allow headroom for energy export".[283]

Ausgrid says that "currently we either do not collect, or do not have access to, the data on the curtailment or cut-off of customer's generation equipment" but suggested it would be useful metric of export service performance.[284] It says that an alternative performance measure of voltage could be used as a proxy for inverter performance and applied to an incentive scheme for export services and notes that "the practical challenge of using voltage measurement is that voltage varies continuously, including at different points along a feeder or distributor. Ausgrid further notes that "If the number of customer complaints related to DER constraints is used as a performance measure, changes to our customer management system would be required to collect this data".[285] EcoJoule Energy also support the use of voltage as a measure for export service performance and suggests that:[286]

280 Endeavour Energy submission to the consultation paper, p. 7.
281 ibid.
282 APQRC submission to the consultation paper, p. 2.
283 ibid.
284 Ausgrid submission to the consultation paper, p. 9.
285 ibid, p. 10.
286 EcoJoule Energy submission to the consultation paper, p. 3.

> the specific voltage metrics and incentives be determined by the AEMC and AER through analysis and consultation with various stakeholders and experts. We propose that the metric be developed to maximise total consumer benefit including solar PV/DER integration, energy/bill reduction and consumer appliance longevity. We suggest that this metric could be quite simple.

Origin doesn't suggest a specific measure for export performance but says that it expected the AER's current review assessing the integration of DER to assist in "determining appropriate export services performance measures against which to measure achievement of network strategies. Origin further adds that the review meant that "the AER is likely to be well placed to understand the key issues associated with the development of an appropriate incentive scheme".[287]

Potential benefits of including voltage levels under the STPIS

According to some stakeholders, the supply voltage levels in distribution networks have been higher than desirable.[288] Some of these stakeholders suggest that the inclusion of voltage levels in the STPIS as a performance attribute would lead to a range of benefits for consumers beyond enabling DER exports.[289]

For example, the APQRC says that a number of studies that have identified that voltage magnitudes within distribution networks are generally at the upper end of the allowable range and that this leaves little headroom for connection of DER into distribution networks. It considers there is currently "little incentive (or penalty) for DNSPs to invest in programs designed to reduce voltage magnitudes to bring voltage levels within the allowable range let alone reduce operating voltage levels to magnitudes that allow headroom for energy export". The APQRC further considers that "in addition to allowance for energy export, incentive schemes that will allow mechanisms for improvement of management of voltage magnitude will manifest in a range of consumer benefits".[290]These were said to include: [291]

- Increased lifespan of consumer equipment
- The concept of Conservation Voltage Reduction (CVR) indicates that reduction of supply voltage will reduce energy consumption and in turn provide reductions in consumer bills
- Consumer equipment will operate more efficiently

Similarly, EcoJoule Energy considers that "surveys by UNSW and the University of Wollongong over many years show that the average voltages across the NEM are well in excess of the nominal 230V level, often in the region of 245V or more". According to EcoJoule Energy, this decreases the voltage margin available for the connection of consumer owned solar PV. EcoJoule Energy proposes that quality of supply measure for voltage be included within the existing STPIS framework, and shares its finding that a reduction in system voltage to

287 Origin submission to the consultation paper, p. 4.

288 Submissions to the consultation paper: APQRC, p. 2; EcoJoule Energy p. 4; CEC, p. 3.

289 Submissions to the consultation paper: APQRC, p. 2; EcoJoule Energy p. 4; Endeavour Energy p. 7.

290 The APQRC submission to the consultation paper, pp. 2-3.

291 ibid, pp. 2-3.

nominal (230V) levels, would conservatively save every NEM consumer an average of $210 per annum with a project payback of a few months.[292]

Endeavour Energy also considers it is worth noting that there are more benefits from voltage optimisation than DER export capability, including appliance lifetime improvement and avoided appliance energy wastage for all customers. Endeavour energy submits than an incentive scheme that incentivises the service quality received by both DER and non-DER customers would be preferable.[293]

Need for better governance of voltage management

Some stakeholders raise concerns that the supply voltage levels in distribution networks have been higher than desirable and it is leading to a reduced ability for the DER to export.[294] The CEC, AGL and Solar Citizens said that a report commissioned by the Energy Security Board (ESB) and undertaken by the University of New South Wales observed high voltages across the networks regardless of whether customers were exporting. AGL suggests that this was due to historic circumstances of distribution network operation.[295]

The CEC, AGL and Solar Citizens say that further consideration needed to be given to how voltage management on low voltage (LV) networks could be better governed. AGL and CEC suggest that voltage management may need to be regulated through the NER.[296]

For example, AGL submits that "the proposed definitional changes to incorporate export services may also necessitate broader consideration of the regulatory framework governing voltage management on low voltage (LV) networks". AGL adds that "while voltage management is substantially a matter for state jurisdictional regulation, the network expenditure regulatory framework informs distribution networks' ability to fulfil their regulatory obligations and ensure that voltage levels remain within the permitted statutory range". AGL further adds that it "also observed an increasing desire for distribution networks to utilise technical standards to obtain network support services in the invocation of power quality response modes to ensure voltage level remains remain within the permitted statutory range".

AGL recommends that given that DER is typically not the sole cause of voltage issues, the Commission should consider "how the proposed reforms would interact with the existing regulatory arrangements for voltage management to promote equitable customer outcomes enabling access to the network on fair terms". AGL further adds that:[297]

> In particular, the Commission should consider:
>
> - Whether the proposed reforms require that voltage management be regulated through the NER

292 EcoJoule Energy submission to the consultation paper, p. 2.

293 Endeavour Energy submission to the consultation paper, p. 4.

294 Submissions to the consultation paper: APQRC. pp. 2-3; EcoJoule Energy, p. 2; AGL, p. 5.

295 AGL submission to the consultation paper, p. 5.

296 Submissions to the consultation paper: CEC, p. 3; AGL, p. 5; Solar Citizens, p. 3.

297 AGL submission to the consultation paper, pp. 5-6.

- Approaches to support more comprehensive solutions to voltage management, including articulating additional service standards, providing more explicit incentives and/or performance benchmarking.

The CEC submits that "voltage management on low voltage (LV) networks was a key component of the provision of 'export services' and 'hosting capacity'". The CEC considers that the rule change requests were "essentially proposing a national, pricing-based approach to voltage management" which would be overlaid on a state and territory regulatory approach to voltage management.[298]

The CEC suggests that the governance of voltage management and hosting capacity should be clarified before obligations to provide export services are placed on DNSPs and a pricing-based approach for voltage management is introduced. According to the CEC, the "governance of voltage management is currently highly fragmented and is the responsibility of state and territory regulators".[299] The CEC states that given that "voltage management is an important component of enabling export services, it seems less than optimal to regulate export services through the NER while leaving the regulation of voltage management in the hands of state and territory regulators" and suggests that the Commission "should consider bringing regulation of voltage on the low voltage network into the NER".[300]

The CEC further states that networks should first be required to meet their regulatory obligations regarding voltage management and once that has been achieved, a net market benefit test would be a useful approach to guiding investment.[301] Similarly, submissions from Solar Citizens supporters said that "Research conducted by UNSW for the Energy Security Board shows that the impact of solar on the networks has been overestimated, and that there are cheap and simple ways of enabling more solar.[302]

Solar Citizens submits that "we support the comments of the Clean Energy Council that responsibility for the regulation of voltage should be clarified before the imposition of obligations for managing export capacity are imposed on networks, 'and a pricing based approach for voltage management is introduced".[303]

5.1.4 Analysis and draft rule determination

Following the recognition of export services in the regulatory framework (as discussed in chapter 4), there is a need to consider the applicable incentive arrangements.

The Commission considers that like other distribution services, export services should also be able to benefit from the application of arrangements that incentivise their efficient delivery. The incentive approach to regulation used in the NEM is the foundation of the regulatory framework and provides network businesses an incentive to become more efficient over time.

298 CEC submission to the consultation paper, p. 3.
299 ibid p. 4.
300 ibid, p. 4.
301 CEC submission to the consultation paper, pp. 3-5.
302 Solar Citizens supporters submission to the consultation paper, pp. 2 - 1725.
303 Solar Citizens submission to the consultation paper, p. 3.

The extension of the incentive-based approach to regulation to export services is likely to deliver long term benefits to customers in the form of reduced costs and better quality of service.

The following sections outline the Commission's proposed approach to extending the incentives framework to export services.

Can the existing arrangements incentivise efficient delivery of export services?

The Commission considers that current incentive framework, if left unchanged, could incentivise DNSPs to reduce expenditure through the application of CESS and EBSS without providing effective incentives for DNSPs to maintain and improve export service performance.

This is because currently the STPIS does not include performance measures reflecting the relevant attributes of the export services.[304] For example, one of the potentially desirable attributes of the export service could be the capacity that is available to customers to export, however the current STPIS does not include performance parameters for export capacity. This means there could be an incentive for DNSPs to reduce costs at the expense of export service quality.

As discussed in Section 5.1.2, under the ex-ante incentive regulation framework, DNSPs would be provided with an efficient level of revenue (as determined by the AER) and DNSPs are provided with discretion on how the revenue is spent to deliver the services. Where the incentives are not balanced – in this case a STPIS that does not include performance parameters for export services, there is a risk that DNSPs may decide to not incur or to defer the expenditure needed to deliver efficient levels of export service. The provision of lower than desirable levels of export service performance would not be in the long term of interests of consumers.

How to realign the incentives for DNSPs

To provide balanced incentives to DNSPs, the existing incentive arrangements could be adjusted to extend the STPIS to include export service performance parameters, or alternative arrangements such as a new incentive scheme targeting export services could be developed and introduced.

The Commission considers extending the STPIS to export services to be preferable given it is likely to require less regulatory change, and the approach aligns with the existing regulatory arrangements. The STPIS can also be used to guide the service levels that DNSPs are expected to provide to customers. There is also strong stakeholder support for the extension of STPIS of exports.

The Commission considers that the extension of STPIS to exports is likely to be in the long term interest of consumers because it will lead to a better alignment of commercial incentives of DNSPs with the interest of consumers and promote efficient delivery of export services. DNSPs will be incentivised to reduce the cost of delivery of export services, share the

304 Other than the incentives to reduce unplanned network outages affecting both consumption and export services provided through the reliability component of the STPIS.

efficiency benefits with customers and deliver a level of export service that better meets their customers' expectations.

Whether details of the scheme should be outlined in the NER or be developed by the AER

The Commission considers that the extension of the STPIS to exports should be carried out by the AER instead of prescribing the detailed design of the scheme in the NER. It would be appropriate for the Rules to continue to provide high-level guidance that may be needed for export service incentives and for the details of operation of any schemes to be determined by the AER in consultation with stakeholders. Prescribing the detailed design of the scheme in the NER would be inconsistent with the approach to other incentive schemes under the current framework.

Factors to be considered in extending the STPIS

The rules framework outlines the factors that the AER must take into consideration in developing and implementing the STPIS.[305] The Commission considers that the current factors listed in the NER could limit the approach that the AER could take in extending the STPIS to exports.

The draft rule amends these factors so that they could be applied to a STPIS covering export services as well as consumption services. The Commission considers that a common set of factors are appropriate given that the STPIS is intended to cover the service performance of DNSPs in a broad manner instead of only applying to certain performance characteristics of the services e.g. service reliability.

The Commission's draft rule makes amendments to recognise that the extended STPIS would need to apply to small exporters as well as consumers of electricity, by referring to network service end users instead of electricity consumers.[306]

The draft rule also amends the factor that currently requires the AER to consider customer willingness to pay for improved performance in the delivery of the services.[307] The draft rule makes this factor broader, requiring the AER to consider the value to network service end users of enhanced service performance. The Commission considers that this amendment is appropriate to provide the AER greater flexibility in measuring the value to customers (and other small exporters) from enhanced service performance. More specifically, the Commission considers that amendment is necessary to encompass the value to customers of enhanced levels of export service as captured under the Customer Export Curtailment Values (CECV) framework (see section 5.3). The amendment should also address stakeholder concerns regarding the current factors not being broad enough to capture the wider range of benefits associated with DER exports.

For the reliability element of the STPIS, this factor guides the AER to considering the value to customers of enhanced service reliability as established using the Values of Customer Reliability (VCR) framework. The Commission notes that there may be several different

305 NER clause 6.6.2(b)(3).

306 Amending NER clause 6.6.2(b)(3)(i). The new defined term 'network service end user' is discussed in chapter 4.

307 NER clause 6.6.2(b)(3)(vi).

approaches to measuring the value that customers place on service reliability. While using a willingness to pay survey (as implied by the current wording of clause 6.6.2(b)(3)(vi)) is one way to measure VCR, it is not the only way. The rules on developing the VCR (rule 8.12) do not prescribe a methodology that the AER must use for calculating VCRs, apart from requiring that the AER engage directly with customers and have a mechanism for annual adjustment. The Commission considers that it could be inconsistent to provide flexibility to the AER to decide the appropriate methodology under the VCR rule while limiting the AER to a particular type of methodology under the STPIS framework. It could potentially limit the AER from choosing a preferable methodology for VCR in the future. The amendments to clause 6.6.2(b)(3)(vi) in the draft rule address this issue.

The Commission notes concerns raised by some stakeholders that the AER may need to take into consideration other factors such as forecasts in the uptake of DER. To address such concerns, the Commission has amended the factors to explicitly allow the AER to take into consideration other factors that it considers relevant.[308]

Minimal regulatory barriers to extending the STPIS

The Commission notes that apart from the factors to be considered by the AER needing adjustment, there are minimal regulatory barriers for the extension of STPIS to exports by the AER.

Currently under the NER, the AER is required to develop and publish a STPIS to provide incentives for DNSPs to maintain and improve performance.[309] This could also include performance of export services. The current rules also provide flexibility for the AER to amend or replace the STPIS in accordance with the distribution consultation procedures.[310] Flexibility for the AER to provide the DNSPs with incentives that promote economic efficiency is also provided under the NEL.[311]

Practical challenges in extending the STPIS

Although there are minimal regulatory barriers to extending the STPIS, there could be practical challenges and complexities to be overcome in extending it to exports, as highlighted by several stakeholders. The challenges could include defining robust performance metrics for exports, the availability of reliable and consistent performance data and the need to ensure DNSPs are only rewarded and penalised for factors within their control. However, it is not clear that these practical challenges would prevent the AER from being able to extend STPIS to export altogether. While there could be complexities involved in extending the STPIS, other approaches such as a new incentive scheme are also likely to have associated challenges. Other approaches are not as well developed and may lead to a departure from the current approach to incentive-based regulation in the NEM.

308 Amending NER clause 6.6.2(b)(5).

309 NER clause 6.6.2(a).

310 NER clause 6.6.2(c).

311 NEL section 16(2), referring to the Revenue and Pricing Principles in section 7A.

The Commission has also considered whether regulatory barriers could limit the AER from considering other approaches to providing incentives, in case STPIS can't feasibly be extended in a timely manner due to practical challenges. The draft rule adjusts the rules framework to provide greater flexibility to the AER to consider the use of a broader range of tools for providing incentives for efficient delivery of export services. Amendments made under the draft rule provide more scope for the AER to consider the application of the DMIS, DMIA and the small-scale incentive scheme to export services.[312]

Draft rule to provide for a timely extension of STPIS to exports

Given the potential practical challenges to extending the STPIS to exports discussed above, the Commission considers that it is appropriate for the AER to conduct a review to determine whether it is practically feasible for the STPIS to be adapted for exports. The draft rule requires the AER to undertake a review to consider arrangements, which may include STPIS, to provide performance incentives for export services. The report on this review is to be published within 18 months of the rule being made. The review should consider the practical feasibility of extending the STPIS to exports and outline an approach to providing balanced incentives for exports services. The Commission considers that given the potential practical challenges highlighted by some stakeholders, it may be appropriate for the review to first consider whether and how STPIS could be practically extended to exports. To undertake this review, the AER may need to collect relevant information from DNSPs and test the feasibility of certain metrics through paper trials. After this is complete, another process may need to follow to consult, design and publish the extended Scheme.

The Commission expects this rule to provide stakeholders greater certainty on the timeliness and approach for the provision of incentive arrangements for exports. It is expected that the 18 month timeline to undertake the review would balance the need to have effective incentive arrangements for export services in place in a timely manner with the need to allow for sufficient time to be able to undertake a thorough review.

The draft rule does not require the AER to conduct this review as a standalone project. This review could be conducted as part of a broader review of incentive arrangements should the AER consider that it is desirable to conduct a more holistic review of incentive arrangements for DNSPs under the NER.

Interim incentive arrangements

In the previous sections, the Commission has set out its view that the existing incentive arrangements together with an extended STPIS scheme are likely to provide the appropriate longer-term mechanism to ensure DNSPs provide the level of export services required by customers. Nevertheless, as the AER and some stakeholders noted in submissions, it may take some time before an effective STPIS could be put in place to provide DNSPs with financial incentives to maintain and improve their export service performance.

312 See amending NER clauses 6.6.3(b) and (c)(3) in relation to the DMIS, amending NER clauses 6.6.3A(b) (c) and (d) in relation to the DMIA and amending NER clause 6.6.4(b)(3) in relation to the small scale incentive scheme.

The Commission considers interim incentive arrangements are likely to be required if the time to extend STPIS to exports takes longer than other parts of the reform under this rule such as investment and pricing arrangements.

While interim arrangements are desirable, it is not necessary to introduce additional requirements under the Rules for them to be implemented. The AER has the ability under the current framework to use tools such as reputational incentives and benchmarking to provide performance incentives to DNSPs while it undertakes the process to extend the STPIS to exports. The AER also has extensive information gathering powers under the NEL to collect the available information on DNSPs' export performance.[313]

As mentioned in its submission, the AER may make use of its annual benchmarking report to provide a public comparison on DNSPs' export service performance to provide reputational incentives. The AER could also make use of the electricity network performance report outlining the networks' financial and operational performance.

The Commission considers that this approach will allow the AER to take into account the relevant factors such as the timeline for the extension of STPIS to exports, the timeline for implementation of other elements of the reform, the administrative burden of implementing reputational arrangements, and put in place interim incentive arrangements as necessary.

Metrics for export service performance

Metrics to measure the network performance of export services are not currently defined under the framework. It would be appropriate for the metrics to be used to measure the network performance of export services to be considered by the AER as part of its process to extend STPIS to exports. The AER may seek to gather the relevant information from DNSPs to undertake paper trials to test the robustness of potential metrics before deciding on how export service performance should be measured.

The Commission notes that there is a need to carefully consider how to measure a network's performance in enabling exports before financial incentives are provided to DNSPs to improve their performance against those metrics. To enable better performance of export services, the AER would need to consider whether an export service performance metric is:[314]

- Measurable i.e. the required information is available, the metrics capture the right information, and the results are accurate and consistent over time, and methodology is transparent and replicable
- Not significantly influenced by exogenous factors i.e. factors outside the DNSPs' control
- Not gameable i.e. it doesn't provide DNSPs perverse incentives

The Commission notes that information on magnitude of the supply voltage to customers could serve as an important input into measuring the network performance of export services. However, the metric may also need to consider the impact of other variables in DNSPs' control such as thermal constraints or export curtailment by DNSPs using dynamic or

313 Part 3, Division 4 of the NEL.

314 Cambridge Economic Policy Associates (CEPA), Feasibility of export capacity obligations and incentives, 20 July 2020, p. 29.

static export limits on the export service performance. Relying solely on voltage information could potentially create perverse incentives for DNSPs, whereby DNSP could be incentivised to provide most customers seeking to connect their DER a static zero export limit in order to limit voltages on their networks.

Governance of voltage levels supplied to customers

The DNSPs are required to supply power to their customers in accordance with the voltage supply standards set by jurisdictional authorities. NEM states and territories specify a nominal supply voltage level of 230V with an acceptable range of +10% to -6%.[315]

Some stakeholders raised concerns about customers being supplied higher than desirable voltage levels and this leading to a reduced ability for DER to export. To address these concerns, it was suggested that supply voltage levels should be regulated through the national framework.

The Commission notes that higher levels of voltage supply to customers can reduce customers' ability to export. All else being equal, a DER installation supplied with a lower average voltage level will be able to export more energy before encountering the upper allowable voltage thresholds than a DER site that has higher average supply voltage levels.[316] DER exports could also be limited by network thermal limitations under some circumstances. In managing their networks, the DNSPs not only have to consider compliance with the upper allowable voltage limit but also the lower allowable limits. The voltage levels can drop along feeders during high load and low export conditions. With higher levels of DER, the networks generally need to operate over a greater range of power flows.

The Commission considers that the overall objective for the framework should be to enable the provision of export services in the most efficient manner possible. An effective framework will drive the DNSPs to choose the best course of action for an efficient outcome. For the delivery of export services, it may be that reducing voltage levels is the cheapest approach to enabling more exports under some circumstances. The Commission considers that the investment, planning and incentive arrangements for export services provided under the draft rule will provide for the efficient enablement of greater levels of exports.

The Commission notes the findings from the ESB's report that maximum voltages recorded are generally towards the upper bound of acceptable range and stakeholders have concerns regarding potential non-compliance with the voltage standards.[317] The Commission considers that compliance with the jurisdictional voltage standards is a matter for the relevant jurisdictional authorities. The Commission also notes that under the Australian Energy Market Agreement, the responsibility for distributor technical and safety authorisations rests with the jurisdictional authorities.[318]

315 UNSW, Voltage Analysis of the LV Distribution Network in the Australian National Electricity Market, May 2020, p.4.

316 Dynamic Limits, the role of decentralised control for managing network constraints for DER on Regional, Rural and Remote networks, August 2020, p.29.

317 ESB, ESB Cover note on UNSW Voltage reports, May 2020, p. 2.

318 Australian Energy Market Agreement, 30 June 2004 (as amended on 2 June 2006 and 9 December 2013), Annexure 2 item 16.

5.2 Export service levels and connection arrangements

5.2.1 Rule change requests

Proposal for defining export service level requirements

SAPN's rule change request raised concerns that for customers who use the distribution network to receive export services, the actual performance of the service they receive is unclear. SAPN said that for export services, regulation does not provide means for distribution networks to directly consider the service performance that customers desire, and there are no standards nor service targets and incentives in regulation. According to SAPN this impedes customers from making informed service choices.[319]

The rule change request from SAPN suggested that the export service performance levels that customers can expect from their DNSP should be set by the STPIS performance targets (in line with the current arrangements for consumption).[320]

SAPN said that the STPIS should "incentivise distribution networks to maintain the performance of export services at a level that customers value". According to SAPN, the STPIS would need to establish a baseline level of service performance that networks are incentivised to maintain and improve upon.[321]

SAPN explained that the:[322]

> STPIS should motivate networks to improve service performance for customers of export services on average across some (to be determined) group(s) of customers consistent with customer expectations and willingness to pay as per the current NER principles for the STPIS.

SAPN added that a key consideration for establishing the baseline level of performance would include establishing appropriate performance measures that apply as averages across all customers rather than in respect of any individual customer's service level.[323]

SAPN's rule change request considered that there was a need to determine exactly what the distribution networks should be incentivised to do for customers e.g. whether incentives provided to improve capacity on average for applicable customers or all customers. According to SAPN, the approach taken could affect the level of confidence customers could have in their service levels.[324]

SAPN said that a "Guaranteed Service Level (GSL) inconvenience payment should apply to customers of export services who experience service performance well outside of average levels. We consider this to be a payment for inconvenience, mirroring the payments made on the consumption side. We do not propose or consider it justified to use a GSL to compensate

319 SAPN rule change request, p. 14.
320 ibid, pp. 20-21.
321 ibid, p. 20.
322 ibid, p. 20.
323 SAPN rule change request, p. 20.
324 ibid.

for lost income due to service interruptions (e.g. lost Feed-In-Tariff revenue), or any other form of financially firm access to the distribution network".[325]

Export service standards

SAPN said that:

> the STPIS would work together with any defined service standards if these are developed by jurisdictions. As is the case for consumption services, any such defined jurisdictional service standards may act as a backstop to the STPIS to avoid the risk of regional service performance deterioration

Nevertheless, SAPN considered that it might not be necessary to apply explicit service standards to export services, noting that:[326]

> There may be merit in defining service standards to set the baseline level of service that customers want distributors to provide and maintain for export services. However, an adapted STPIS may serve the same purpose.

DER export limits and minimum export capacity requirements

SAPN raised concerns that "In the absence of a clear framework enabling investment to support export services, some networks have had to actively consider (as we did in our Regulatory Proposal for the 2020-25 period) and in some cases enact, static limits of zero exports for some customers as networks have approached constraints".[327]

SAPN said that a measured approach was required for providing customers with clear access rights to export, in order to not drive excessive cost nor create inequities between customers depending on the date on which they request an export service. SAPN said that it was also impractical to assign a small customer an exclusive right to use assets that comprise a shared distribution network.

SAPN's rule change request proposed that there should be clear rights to all customers to request and be granted an offer to access the distribution network to export energy on a fair and non-discriminatory basis. SAPN explained that, "customers should be able to receive a service offer that does not explicitly deny their ability to export, such as via the setting a static export limit of zero".[328]

SAPN also proposed that for small customers, there should be a defined standard capacity level that customers can request and receive a connection offer for. SAPN clarified that it could be expressed as a 'base service' and customers could either request this service or a service in excess of this service. SAPN suggested that this approach could be implemented by Government, the NER or the AER's connection guidelines.[329]

325 ibid.

326 ibid, p. 21.

327 ibid, p. 14.

328 SAPN rule change request, p. 22.

329 ibid.

SAPN's rule change request emphasised that it did not support firm access as the costs and issues it could create between customers would be problematic.

Similarly, the rule change request from TEC and ACOSS also raised concerns that DNSPs were increasingly constraining DER exports using static limits to manage emerging technical issues. The rule change request proposed that all prosumers should have some ability to export surplus energy to the grid. ACOSS and TEC suggested that there should be a requirement for networks to offer prosumers a 'base level of service' for DER exports. ACOSS and TEC clarified this to mean that where augmentation to add hosting capacity passes the net market benefit test, it should be mandated that networks must offer some level of export (e.g. 3Kw) – i.e., they can no longer impose zero exports. ACOSS and TEC suggested that the implementation approach could include amendments to NER 5A.B.2 (Proposed model standing offer for basic connection services) to include base export services.[330]

Supplementary connection arrangements for customers seeking additional export capacity

In its rule change request, ACOSS/TEC proposed rule amendments to allow for a 'supplementary' connection agreement for a DNSP and its customer to negotiate additional capacity, if that investment is not otherwise justified under a 'net market benefits' test.[331] This, TEC/ACOSS said, will allow more equitable allocation of DER-related costs by allowing DNSPs to recover the costs associated with augmenting local hosting capacity upfront from prosumers.

5.2.2 Current arrangements

Current approach to setting service reliability levels

Under the current arrangements, the service levels provided to customers by DNSPs are guided by both national and jurisdictional regulatory arrangements. The role of jurisdictional standards and the national STPIS arrangements in guiding the distribution reliability was foreshadowed by the COAG energy council's endorsement in 2014 of the principles for distribution reliability outlined the Commission's *Review of the National Framework for Distribution Reliability*.[332]

Under the national arrangements, the performance targets set under the STPIS scheme guide the reliability performance of DNSPs. As mentioned earlier, the AER's STPIS provides a financial incentive to distributors to maintain and improve service performance. The NER requires the AER to take into consideration the past performance of the DNSPs in developing and implementing the STPIS.[333] Hence, the AER uses a network's average performance over the past five years to set a baseline for the performance target that the DNSP is expected to meet for the different network segmentations. The STPIS provides rewards to a DNSP where

330 ibid, p. 14.

331 Alternatively, TEC/ACOSS proposed to amend or remove NER clause 6.1.4 if it involves cost recovery via ongoing tariffs for exported energy (see pp. 12–14 of their rule change request). However, TEC/ACOSS consider this option is less preferable because it would create uncertainty, risk and potential ongoing costs for prosumers.

332 COAG EC, Response to the Australian Energy Market Commission's Review of the National Framework for Distribution Reliability and Review of the National Framework for Transmission Reliability, December 2014, p. 4.

333 NER clause 6.6.3 (b)(3)(iii).

its service delivered performance is greater than the performance target and penalties where performance is below this performance target. These arrangements provide incentives for DNSPs to maintain and improve on service levels linked to the value customers place on service reliability (VCR).

The STPIS operates concurrently with any service standards and Guaranteed service levels (GSL) schemes that apply to DNSPs under jurisdictional legislation.[334] The reliability service standards, where applicable, set a regulatory requirement on DNSPs to meet a minimum levels of service reliability. The reliability standards, like the STPIS targets are generally not specific to any individual small customer but rather they reflect a standard to be met at an aggregate level. Under some circumstances, they can represent a binding regulatory obligation on DNSPs allowing them to seek regulated revenue allowance to meet the obligation. Meanwhile the STPIS, does not include any binding obligations to meet performance targets, and the costs of reliability improvements undertaken to outperform STPIS targets cannot be funded through ex ante expenditure allowances. Under the national framework, the DNSPs generally seek prudent and efficient costs to maintain reliability, rather than improve reliability.[335] Jurisdictional standards generally also represent additional requirements on DNSPs to address performance of worst performing feeders.

Jurisdictional service standards applicable to DNSPs can also encompass requirements other than those for service reliability such as quality of supply, safety, technical and design requirements. The NERR require DNSPs to comply with the applicable distributor service standards and GSL scheme.[336] Although the current framework provides for guidance on service level for consumption services, there are no clear provisions for how exports service levels should be set.

Guaranteed service levels

Guaranteed Service Level (GSL) payments schemes are currently defined through national and jurisdictional arrangements.

As mentioned earlier, the current STPIS also includes a GSL scheme that provides payments directly to the worst served customers (in the case of reliability) or where certain levels of service are not met. The s-factor and the GSL payments scheme both provide an incentive for the electricity distributors to maintain or improve reliability. The s-factor component encourages distributors to improve the average level of reliability over their entire networks where it is cost effective to do so. However, reliability improvements for the worst served customers may not be prioritised under the s-factor part of the STPIS because the performance is measured in terms of network average outcomes, and there would be some consumers at remote ends of the network who experience supply reliability that is substantially below the average for the network.[337] To address these concerns, the GSL payments scheme provides an additional incentive for electricity distributors to improve the

334 NER clause 6.6.6 (b).

335 Clauses 6.5.6(a)(3) and 6.5.7(a)(3) of the NER.

336 NERR rule 84(1).

337 AER, Final decision - Amendment to the Service Target Performance Incentive Scheme (STPIS), November 2018, p. 26.

reliability for the worst served customers, but more importantly provides compensation to these customers.

The current design of the STPIS provides for jurisdictional GSL schemes to be applicable where they are defined instead of the scheme defined under the STPIS.[338] All jurisdictions currently have their own GSL payment schemes meaning jurisdictionally defined GSL schemes are currently applicable in the NEM.

Current connection framework

Under the current arrangement, a DNSP must first submit a proposal as to how the AER should classify its distribution services and the AER must either accept that classification or substitute its own classification of the DNSP's distribution services (see section 5.2.2 - service classification).[339] This classification determines how DNSP services, including connection services for micro embedded generation (such as solar PV) are regulated.[340]

DNSPs have the ability to offer three broad categories of connection services to customers– basic, standard and negotiated. Chapter 5A of the NER requires DNSPs to develop a 'model standing offer' to provide 'basic connection services' to retail customers. The model standing offer must contain minimum terms and conditions and must be approved by the AER. DNSPs may also develop model standing offers for standard connection services – they too must be approved for the AER if a DNSP would like to offer that service. Lastly, customers may also elect to negotiate specific terms and connections with DNSP (negotiated connection) (see section 5.2.2 - customer connections).

DNSPs must also have model terms and conditions for 'deemed standard connection contracts' (see section 5.2.2 - Deemed standard connections contract). These provisions cover the ongoing relationship between the retail customer and DNSP.

Service classification

The Framework and Approach (F&A) is the first step in the regulatory process to determine efficient prices. The F&A determines how the AER will set prices for electricity distribution services, the application of any incentive schemes, and considers service classification (among other things). The F&A also facilitates early consultation with consumers and other stakeholders and assists DNSPs to prepare their regulatory proposals.

Before a service offered by a DNSP can be classified, it needs to be identified, in terms of the name and description of the service. The AER, in its *Distribution Service Classification Guidelines* indicates the 'baseline' distribution services – which DNSPs may adopt.[341] But as the services offered by DNSPs vary, no single list of baseline services will adequately reflect

338 AER, Service target performance Incentive Scheme – version 2, November 2018, p.19.

339 NER clause 6.8.2(c) and NER clause 6.12.1(1)

340 A micro embedded generator is defined in cl 5A.A.1 as a retail customer who operates, or proposes to operate, an embedded generating unit for which a micro embedded generator connection (of the kind contemplated by AS 4777: Grid connection of energy systems via inverters) is appropriate. In essence, a micro embedded generator is a retail customer who has small, inverter-based generating equipment, such as a rooftop PV system.

341 See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/distribution-service-classification-guidelines-and-asset-exemption-guidelines

all the services provided by a single DNSP. Consequently, each DNSP needs to identify the services it offers to consumers in order to enable service classification. That is, if the DNSP does not propose to provide a particular service, the AER will not classify it.

The AER may classify the service as a direct control service or a negotiated distribution service or, if the AER decides against classifying a distribution service, the service is not regulated under NER Chapter 6 (but may be regulated by Chapter 5A).[342]

If a distribution service is classified as either a direct control service or a negotiated distribution service, then the DNSP must, on request, provide those distribution services to a customer within its distribution region, subject to the relevant terms and conditions.[343]

Where the service is classified as a direct control service, the DNSP must provide that service at the prices determined under the DNSP's distribution determination.[344] A service is regulated as a direct control service if it is a 'monopoly service' – that is, where DNSPs regularly offer services to customers where only one distribution provider is licensed to operate or where ownership and control of its infrastructure prevents or restricts alternative suppliers.[345]

The AER's service classification guideline says connection services, including for micro embedded generators, are generally treated as a direct control service.[346]

A direct control service may be further sub-classified as an alternative control service if it is only used or requested by certain customers.[347]

For 'enhanced connection services', that is, activities to provide customers with a higher standard of electricity supply that exceeds the minimum technically feasible standard (including activities where customers request higher levels of reliability or three-phase electricity), the AER states it classifies these services as alternative control because:[348]

- the services are provided to individual customers upon request, rather than to all customers
- the classification is administratively efficient, and consistent with previous regulatory approaches for many DNSPs' services
- the classification promotes a consistent regulatory approach to similar services within and across jurisdictions.

Customer connections

Chapter 5A is concerned with the provision of connection services by DNSPs to retail customers (among others). Connection services in this context include services relating to the

342 Direct control services are further classified by the AER as either standard control services or alternative control services; NER clause 6.2.1

343 NER clause 6.1.3.

344 NER clause 6.1.3.

345 AER, Electricity Distribution Service Classification Guideline, September 2018, pp. 11–13.

346 NER clause 6.2.2; AER, Electricity Distribution Service Classification Guideline, September 2018, p. 12.

347 NER cl 6.2.2; AER, Electricity Distribution Service Classification Guideline, September 2018, p. 12.

348 AER, Electricity Distribution Service Classification Guideline, September 2018, p. 21.

initial connection to the grid and alterations to that physical connection (not services for ongoing supply) and may be:

- basic connection services, for retail customers generally (including retail customers who are, or propose to become, micro embedded generators (DER)) and for which a DNSP must have one or more model standing offers approved by the AER
- standard connection services, being other connection services (which may be offered to non-registered embedded generators) for which a DNSP may have other model standing offers approved by the AER[349]
- negotiated connections, which are individually negotiated between the DNSP and the customer, including where the connection service required is more extensive than the basic connection service or any offered standard connection services.

The terms and conditions of the DNSPs' proposed model standing offer must cover specified criteria including:[350]

- a statement of maximum capacity of the connection[351]
- jurisdictional or other legislation and statutory instruments that impose specific requirements (such as qualifications of the service provider, and safety and technical requirements)[352]
- details of the connection charges (or the basis on which they will be calculated), together with the cost of any necessary *extension* to the distribution system[353]
- if the service is a basic micro embedded generator connection service, the particular requirements with regard to the export of electricity into the distribution system including:
  - the special requirements for metering and other equipment for the export of electricity
  - the DER generation information that the DNSP requires.[354]

The connection charge principles prohibit retail customers who are seeking a basic connection service from being required to make a capital contribution towards the cost of augmenting the shared network.[355] The connection charges paid by these retail customers are often referred to as 'shallow' connection charges, as discussed in more detail below.

Chapter 5A goes on to address the formation and performance of connection contracts (Part F), principles for the determination of connection charges (Part E) and dispute resolution arising out of connection contracts or relating to connection charges (Part G).

More on how connection policies and model standing offers are approved

349 A non-registered embedded generator is an embedded generator who is neither a micro-embedded generator or a Registered Participant.

350 NER clause 5A.B.2.

351 NER clause 5A.B.2(b)(1).

352 NER clause 5A.B.2(b)(3); 5A.B.2(b)(4).

353 NER clause 5A.B.2(b)(5).

354 NER clause 5A.B.2(b)(7).

355 NER clause 5A.E.1(b).

The AER has guidelines for how DNSPs can charge customers for standard and basic connection services. The AER describes its guideline as 'flexible' to allow for different jurisdictional and operational requirements of DNSPs.[356]

The NER require a DNSP to prepare and obtain AER approval of a connection policy setting out the circumstances in which the DNSP may require a retail customer or real estate developer to pay a connection charge for the provision of a connection service under Chapter 5A.[357] The proposed connection policy must be consistent with the 'connection charge principles' and the 'connection charge guidelines', and must specify:

- categories of persons that may be required to pay a connection charge
- circumstances in which such a requirement may be imposed
- aspects of a connection service for which a connection charge may be made.

The AER may approve the proposed model standing offer by a distribution network service provider for basic connection services if satisfied that it meets specified criteria[358], including that the:

- connection charges are consistent with the DNSP's distribution determination including the connection policy[359]
- terms and conditions are fair and reasonable[360]
- terms and conditions comply with applicable requirements of the energy laws.[361]

In deciding whether to approve a proposed model standing offer to provide basic connection services on specified terms and conditions, the AER must have regard to:[362]

- the NEO
- the basis on which the DNSP has provided the relevant services in the past
- the geographical characteristics of the area served by the relevant distribution network.

If the AER does not approve a proposed model standing offer, the DNSP must re-submit it with appropriate amendments as soon as reasonably practicable.[363]

This decision-making process does not require the DNSPs to consult with their customers. The DNSPs have discretion to change their model standing offers at any time, subject to AER approval.[364]

More on the difference between basic, standard and negotiated connections

356 See: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/national-electricity-connection-charge-guideline-2012
357 NER clause 6.7A.1.
358 NER clause 5A.B.3.
359 NER clause 5A.B.3(a)(2).
360 NER clause 5A.B.3(a)(3).
361 NER clause 5A.B.3(a)(4).
362 NER clause 5A.B.3(b).
363 NER clause 5A.B.3(c).
364 NER clause 5A.B.6.

The Chapter 5A framework has the effect of obliging DNSPs to enter into and perform connection contracts if a valid connection application is made by a connection applicant:

- If an application is made for a basic connection service or a standard connection service, the DNSP must make a connection offer to the connection applicant within 10 business days after receiving a properly completed application.[365]
- If an application is made for another kind of connection service, then the DNSP must advise the connection applicant of the negotiated connection process (NER cl 5A.D.3(f)(2)), must negotiate in good faith with the connection applicant under the NER clause 5A.C.3 negotiation framework, and must use its best endeavours to make a negotiated connection offer within 65 business days after receiving a properly completed application.[366]

Under NER clause 5A.A.1, a basic connection service means a connection service related to a connection (or a proposed connection) between a distribution system and a retail customer's premises in the following circumstances:

- either:
    - the retail customer is typical of a significant class of retail customers who have sought, or are likely to seek, the service; or
    - the retail customer is, or proposes to become, a micro embedded generator; and
- the provision of the service involves minimal or no augmentation of the distribution network; and
- a model standing offer has been approved by the AER for providing that service as a basic connection service.

For a basic connection, augmentation costs are shared across other customers regardless of the additional costs. That is, retail customers may only be charged for works related to the connection between their property and the distribution network. The connection charge principles set out in Chapter 5A of the NER prohibit retail customers who are seeking a basic connection service from being required to make a capital contribution towards the cost of augmenting the shared network.[367]

If a retail customer requires greater capacity/service levels than provided by the basic connection or standard connection (if any), the DNSP can offer them a 'negotiated connection'. This provides flexibility for a DER owner who wants a larger export capacity connection from a DNSP than what the DNSP offered as part of the basic or standard connection services. The terms and conditions of a negotiated connection must also cover the cost of any necessary *augmentation* of the distribution system for which provision has not already been made through existing DUOS charges or a tariff applicable to the connection.[368] This is often referred to as a 'deep' connection charge. It is noted a standard connection service, which may be provided for a particular class or sub-class of connection

365 NER clause 5A.F.1(a)(1).

366 NER clause 5A.F.4(a)

367 NER clause 5A.E.1(b).

368 NER clause 5A.B.4(5)(ii); clause 5A.C.3(5)(ii).

applicant, may involve extension and/or augmentation but the customer contribution is more limited.[369]

Setting of export connection capacity

As mentioned earlier, if an applicant including one with micro-embedded generation (DER), seeks a basic or standard connection service from their DNSP, then the DNSP is required to make an offer to connect the applicant in accordance with its model standing offer.[370]

A DNSP's connection offer to a DER customer is required to include among other information, the maximum capacity of the connection to import and export electricity. Some of the terms and conditions in the connection offer remain relevant after connection has been established (such as the size of the connection). This means that the maximum export allowed at a customer's connection point is established during the connection process.

Deemed standard connection contracts for ongoing supply services

Section 67 of the NERL outlines the three different kinds of customer connection contracts that may be entered into between a distributor and a customer. One of these are 'deemed standard connection contracts' (DSCCs) for the ongoing provision of electricity supply services to a customer (as distinct from upfront connection services, discussed above), which are to be entered into with small customers unless the customer negotiates and enters into a negotiated connection contract.

Model terms and conditions specific to DSCCs are set out in the NERR, and must be adopted by a DNSP (with permitted or required alterations) for acceptance by customers.[371]

A DSCC for electricity is deemed to take effect between a DNSP and a customer:

1. where the customer has a new connection or seeks to make a connection alteration: on the customer's acceptance of the distributor's connection offer in accordance with NER Ch 5A[372]
2. where the customer has an existing connection (which is not being altered):
    a. if the existing connection is not energised: when the customer's premises are re-energised; or
    b. if the existing connection is energised: when the customer commences to take supply of electricity at those premises.[373]

Where a DSCC is in place, the NERL provides that except in relation to a new connection or a connection alteration (ie, the connection services discussed above), a DNSP must not bill a small customer on a DSCC, but must render a statement of charges to the customer's retailer in accordance with the energy laws.[374]

369 See: NER clause 5A.E.1(c)(3).
370 NER clause 5A.F.1.
371 NER clause 5A.F.1.
372 NERL section 70(2)(a).
373 NERL section 70(3).
374 NERL section 71(2).

5.2.3 Stakeholder views

Defining export service level requirements

Some stakeholders consider that there is need to clarify the export service levels that DNSPs are expected to provide to customers. Stakeholder submissions generally support SAPN's proposal for export service performance levels that customers can expect from their DNSPs to be defined by the STPIS performance targets, mirroring the current approach for consumption services.[375]

For example, Endeavour Energy submits that it will be critical for networks to provide a level of export hosting that customers value and that this could be achieved through standards, incentives or both. Endeavour Energy added that "incentive schemes could be used to incentivise networks to meet a benchmark level of service or improve their historical performance (where valued by customers)".[376]

Similarly, ENA states that "the STPIS would need to establish a baseline level of service performance that networks are incentivised to maintain and improve upon".[377] AusNet Services adds that "to mirror the approach to the reliability of consumption services in Victoria, the use of historical performance levels should be considered".[378] Evoenergy considers that "minimum or baseline standards must be set but they should reflect performance and customer expectations specific to the jurisdiction" and that "DNSPs should determine the service levels appropriate for their jurisdiction and network topology".[379]

CitiPower, Powercor and United Energy say that while they support the concept of base levels of performance "these are best negotiated by individual distributors with the customers/AER in the context of that network and what customers are able, and willing, to afford".[380]

AEC/Oakley Greenwood submit that if there were to be an incentive scheme, a baseline would be needed, regardless of the metric used to drive the incentive.[381]

Some stakeholders also support SAPN's proposal for export service performance measures to be defined as averages across all customers rather than in respect of any individual customer's service level.

Evoenergy states that "service standards should apply to an average level of performance rather than to every customer". Evoenergy further adds that the "application of DNSP incentives should only apply once DNSPs have developed experience in the supply of the new export service and it is well established service".[382]

CitiPower, Powercor and United Energy express strong support for an "incentive scheme with base level performance measures that can be aggregated". They add that base levels of

375 Submissions to the consultation paper: Endeavour Energy, p. 2; EcoJoule Energy, p. 5; Jemena, p. 13.

376 Endeavour Energy submission to the consultation paper, p. 2.

377 ENA submission to the consultation paper, p. 13.

378 AusNet Services submission to the consultation paper, p. 6.

379 Evoenergy submission to the consultation paper, p. 14.

380 CitiPower, Powercor and United Energy submission to the consultation paper, p. 3.

381 AEC/Oakley Greenwood submission to the consultation paper, p. 9.

382 Evoenergy submission to the consultation paper, p. 14.

performance should not go down to the customer level but rather it should be an aggregated measure per network. According CitiPower, Powercor and United Energy "consideration should also be given to the impact of performance against service standards with the emergence of aggregator models".[383]

ENA says that "The STPIS should motivate networks to maintain or improve service performance for customers of export services on average across some (to be determined) group(s) of customers consistent with customer expectations and willingness to pay as per the current NER principles for the STPIS".[384]

Service standards

Most stakeholders support SAPN's view that separately defined service standards were not necessary.[385] Stakeholders generally agree that jurisdictional flexibility in setting service standards that currently exists for consumption services should be extended to exports. An approach involving the setting of explicit service standards via the national regulatory framework was considered unnecessary.

For example, Endeavour Energy submits that:[386]

> Many jurisdictions currently set minimum reliability standards as a safety net for customers. The same could be done for export services but may not be necessary if the incentive scheme provides adequate incentive to address worst served customers.

According to Endeavour Energy, the jurisdictional regulators were best placed to develop and administer minimum DER standards if required.[387] Endeavour Energy considers that "A standard would only be required if a benchmark level of service was being incentivised via the scheme, which would be out-of-step with how the reliability and customer service components of the STPIS operate".[388] AGL also submits that it was not necessary to set service standards for export services in the NER.[389]

According to ENA, the jurisdictions should have flexibility to develop and apply service standards for export services, consistent with the current treatment for consumption services, which would then work alongside the amended STPIS designed by the AER. Explicit service standards for export services in the NER were said to not be required.[390] Essential Energy also considers that the proposal to allow jurisdictional flexibility appeared appropriate. [391] TasNetworks states it is "imperative that any rule change eventuating from the proposals received by the AEMC does not prevent jurisdictional variations in the service standards that DNSPs are expected to provide to customers with DER".[392]

383 CitiPower, Powercor and United Energy submission to the consultation paper, p. 3.
384 ENA submission to the consultation paper, p. 13.
385 Submissions to the consultation paper: Essential Energy, p.4; Endeavour Energy, p. 5; AGL, p. 9.
386 Endeavour Energy submission to the consultation paper, p. 5.
387 ibid, p. 2.
388 ibid, p. 5.
389 AGL submission to the consultation paper, p. 9.
390 ENA submission to the consultation paper, p. 4.
391 Essential Energy submission to the consultation paper, p. 4.

EnergyAustralia submits it was "unclear how the AER would establish the export service standard, and how this would be appropriate for all DER customers across the NEM". EnergyAustralia says that for this reason it did not support the AER establishing export service standards, as DNSPs will have a greater understanding of their (location specific) customer's expectations.[393]

CitiPower, Powercor and United Energy submit that:[394]

> Consideration should also be given to the impact of performance against service standards with the emergence of aggregator models. The co-ordinated use of DER, without regard to network limitations, can increase the instances of DER constraint and result in the deterioration of reliability and higher costs.

Meanwhile, Ausgrid considers that interactions between the AER and jurisdictional incentive schemes need to be considered (for example, average performance and worst served customers).[395]

Inclusion of GSL

Some stakeholders expressed support for SAPNs proposal for Guaranteed Service Level (GSL) inconvenience payments. They agree that GSL payments should apply to customers of export services who experience service performance well outside of average levels and not for compensating lost income export income (e.g. lost Feed-In-Tariff revenue).

For example, Ausgrid submits that, "should the export service standard be established and supported by the Guaranteed Service Level (GSL) payment to the customer, we agree with SAPN's view that the GSL should only be an inconvenience payment for service levels well outside the reasonable range for this type of customer". Further supporting SAPN's proposal, Ausgrid says that it did not "support the GSL payment for export to include any deeper costs such as the loss of feed-in-tariff revenue or of the wholesale market benefit". Ausgrid explains that such arrangements would lead to the GSL for exports not being commensurate with the standard for consumption.[396]

ENA considers that a GSL inconvenience payment, developed under the STPIS, should apply to customers of export services who experience service performance well outside of average levels.[397] Evoenergy states that "Jurisdictional governments may also set export guaranteed service levels".[398]

392 TasNetworks submission to the consultation paper, p. 2.
393 EnergyAustralia submission to the consultation paper, p. 10.
394 CitiPower, Powercor and United Energy submission to the consultation paper, p. 3.
395 Ausgrid submission to the consultation paper, 10.
396 ibid, p. 11.
397 ENA submission to the consultation paper, p. 14.
398 ibid, p. 15.

Essential Energy mentions that visibility of LV network would be required for guaranteed service levels or "inconvenience payments" in order to independently identify and verify breaches of the guaranteed service levels.[399]

Firm access rights for exports

Stakeholders do not support firm rights for customers to export under the export service.

For example, CitiPower, Powercor and United Energy say that "applying firm access to residential customers for solar export is inconsistent with open access for consumption and raises serious competitive neutrality concerns". CitiPower, Powercor and United Energy explain that "Firm access also raises implementation issues in terms of grandfathering existing capacity and the ability of distributors to manage it in the context of a set of rules designed for open access". They add that if firm access was to be considered it "must be considered across the entire supply chain, including transmission generators, large generators connected to the distribution network and residential households with solar PV".[400]

ENA also supports SAPN's proposal that access to export service should not be provided on a firm basis.[401] Similarly, Evoenergy says that capacity would not be made available as a firm right for every residential and small business customer or for exporting electricity at any point in time.[402]

The Customer Advocate submits that "most generation connection agreements between consumers and the network operator preclude claims for costs of loss in income should local generation be unavailable". It suggests that "This should continue in the medium term at least until the role of non-commercial exports are better understood".[403]

Rights to a minimum level of export capacity

Some stakeholders consider that DNSPs should be prevented from offering customers static export limits of zero KWs, which deny DER customers the ability to export.

For example, the CEC submits that it strongly supports "the proposal to prevent the imposition of static zero export limitation by DNSPs".[404] Similarly, PIAC says that it "opposes setting a default level of export at 0 kW outside of limited specific locations that are identified to have materially constrained network capacity".[405] Energetic Communities says it supported the principle that "everyone should be able to export some of their excess regardless of their location and timing of installation". It explains that "where this comes at a cost to the distribution network, prosumers should be given an opt-in payment option".[406]

399 Essential Energy submission to the consultation paper, p. 4.
400 CitiPower, Powercor and United Energy submission to the consultation paper, p. 3.
401 ENA submission to the consultation paper, p. 13.
402 Evoenergy submission to the consultation paper, p. 15
403 The Customer Advocate submission to the consultation paper, p. 5.
404 CEC submission to the consultation paper, p. 2.
405 PIAC submission to the consultation paper, p. 2.
406 Energetic communities submission to the consultation paper, p. 8.

Meanwhile Evoenergy says that "export capacity services will be available to prosumers where it is cost effective to supply".[407]

PIAC, Rheem and AGL supported the proposal for DNSPs to be required to offer customers a defined 'base level' of export service (e.g. 5 KW), that doesn't deny their right to export.[408]

PIAC considers that "Any DER connection must come with a default level of export capacity – for instance 5 kW – above which consumers could pay for greater access to the grid". PIAC adds that "permitting a basic level of export for all DER connections allows more households to benefit from sharing solar generation, especially as peer-to-peer trading, virtual power plants and community batteries become more common". PIAC further adds that:[409]

> households must be given the option to receive higher export capacity in return for a one-off charge. The level of basic export allowance and the charge for higher allowances must be regulated and transparently determined

Similarly, Rheem submits that "DNSPs should be required to offer access to the distribution network to export energy, on a fair and non-discriminatory basis".[410] AGL also supports the proposal to "offer base level of service at no additional cost based on 'net market benefit' test". AGL considers "that this should be aligned to networks regulatory reset 5-yearly cycle to provide a base level of investment certainty for customers".[411]

Nonetheless, AGL raises concerns that it anticipates some complexity "in how this service and allocation will interact with dynamic export envelopes (which could fluctuate day to day)".[412] AGL further adds that there "may also be some complexity in how site specific the service is i.e. how it reflects network topology".[413] The Victorian Government requests that the "AEMC explicitly considers how the implementation of operating envelopes and dynamic connection agreements by distribution network operators will interact with the proposed reforms".[414]

Meanwhile, CitiPower, Powercor and United Energy say that introducing base levels of DER export capacity requires careful consideration. CitiPower, Powercor and United Energy explain that while they agreed that their customers are entitled to a minimum level of expectations, "the setting of base levels must necessarily differ across and within networks".[415] They say that:

> A common national minimum standard is unlikely to result in an efficient outcome given the different starting points of networks in terms of DER penetration, levels of existing network utilisation and network structure e.g. single wire earth return (SWER) networks. CitiPower, Powercor and United Energy suggested that the "costs should be

407 Evoenergy submission to the consultation paper, p. 6

408 Submissions to the consultation paper: PIAC, p. 3; AGL, p. 7; Rheem, p. 1.

409 PIAC submission to the consultation paper, p. 2.

410 Rheem submission to the consultation paper, p. 1.

411 AGL submission to the consultation paper, p. 7.

412 ibid, p. 8.

413 ibid, p. 7.

414 The Victorian Government submission to the consultation paper, p. 3.

415 CitiPower, Powercor and United Energy submission to the consultation paper, p. 3.

> weighed against the benefits of this element of the proposal.

Evoenergy's submission does not support the proposal for a base level of export capacity to all connecting customers. It states that "The obligation should not be 'firm' because it is not an efficient use of resources for DNSPs to be obliged to provide export capacity to every residential and small business DER owning customer". Evoenergy adds that "The requirements for eligibility to receive export service capacity will need to be defined as capacity would not be made available as a firm right for every residential and small business customer" or for exporting electricity at any point in time".[416] Evoenergy suggests that an average service standard level applicable across customer groups would be more appropriate.[417]

In relation to the implementation approach, Endeavour Energy states "Irrespective of whether a standard export hosting capacity is set we consider the connection process should mirror import connection arrangements and existing connection processes in Chapter 5 and 5A of the NER (which directly address embedded generation connection offers)".[418]

Export service performance reporting requirements

Some stakeholders raise concerns regarding the lack transparency of network performance in enabling exports and the imposition of static export limits by DNSPs. They suggest that reporting by DNSPs on their export service performance would be useful for informing regulatory processes and arrangements, such as, revenue determinations and incentive schemes.

For example, Solar Citizens submits they are "concerned about the imposition of export limits and a lack of transparency as to when and how these are imposed by networks". Solar Citizens suggests that "greater transparency and oversight on export limits is needed".[419]

SA Government says that the low visibility of the LV networks "hinders stakeholder understanding of the existing network hosting capacity and the quantification of the potential network impacts and benefits of DER". SA Government states that the suggestion of reputational incentives for DNSPs to "publish statistics on their performance related to export capacity could increase transparency and potentially inform any future DNSP expenditure assessments or incentive schemes".[420]

Red Energy and Lumo Energy submit that:[421]

> The Commission should consider placing an obligation requiring regular transparent reporting by networks on their performance with regard to export capacity, either directly into the Rules or indirectly via inclusion in an existing guideline managed by

416 Evoenergy submission to the consultation paper, p. 13.
417 ibid, p. 11.
418 Endeavour Energy submission to the consultation paper, p. 2
419 Solar Citizens submission to the consultation paper, p. 1.
420 SA Government submission to the consultation paper, p. 3.
421 Red Energy and Lumo Energy submission to the consultation paper, p. 3.

> the AER.

According to the AER "it would be valuable to consider whether the planning arrangements require updating" so that DNSPs can be better supported in making more information publicly available, including "Information on export limits and impending constraints on exporting connections (including the value of such constraints)".[422]

Similarly, AGL says that options may need to be need to be considered in the short term to improve DNSPs' disclosure of export service levels.[423]

While ERM Power also states that "there is a strong case to require DNSPs to publish information about DER hosting capacity in different areas of the network". According to ERM Power this would, "along with other proposed reforms discussed in the rule change, give consumers and other parties more information to inform their investment decisions".[424]

Supplementary connection arrangements for customers seeking additional export capacity

Submissions for and against TEC/ACOSS' proposal to allow for a 'supplementary' connection agreement for a DNSP and its customer to negotiate additional capacity, if that investment is not otherwise justified under a 'net market benefits' test, are highlighted below.

Those for

Several submissions support TEC/ACOSS' proposal. For example, Energetic Communities states:[425]

> we support the ACOSS/TEC position of charging for additional exports over a base amount if and only when there are no broader market benefits. As these are network charges, and may not be visible to the account holder through their retail tariffs, the process must be transparent. It should be made clear that prosumers have the option to go with the status quo and not pay for exports (over and above the base level), but this would likely mean that the DNSP will manage this with zero or limited exports (over the base level).

PIAC considers:[426]

> An up-front connection charge for export is preferable if any change were to be made to allow charging for DER export to the grid, PIAC prefers an up-front connection charge.
>
> This better aligns with a household's one-off decision to choose and invest in a DER system, signals to the household the full impact (both positive and negative) of the decision to invest, and reflects the nature of network changes and upgrades required.

422 AER submission to the consultation paper, p. 8.
423 AGL submission to the consultation paper, p. 9
424 ERM Power submission to the consultation paper, p. 3.
425 Energetic Communities submission to the consultation paper, p. 7.
426 PIAC submission to the consultation paper, p. 2.

> It may prompt a better optimised DER installation that, for example, has less need for export capacity by including battery storage and/or westerly orientation of solar panels. These decisions are more easily and economically made as part of the initial installation than as a retrofit partway through a DER system's life.

Renew submits:[427]

> There is some potential for complexity in the option to purchase additional export capacity – this would need to be done simply to be effective and accessible. We expect that if done right, it will almost always be worth it for DER owners to pay an appropriate additional fee to substantially increase their export capacity – so consumers need to be able to understand this value proposition.

The Customer Advocate states:[428]

> Simplicity is critical. Consumers and networks are familiar with connection processes, simple energy tariffs and demand response concepts, including the widespread application of off-peak energy tariffs. Extrapolation of these simple concepts to the 'flip side' of energy feed-in in concept, application and economic return is essential for the proposal to be widely adopted. In this sense, many of the connection concepts proposed by SAPN in their proposal are endorsed.
>
> ...
>
> The concept of customers being able to negotiate deeper connection agreements is supported, in a manner that would operate in a similar fashion to negotiating increased demand capability.
>
> An enhanced form of the Basic Connection Agreement – MEG or Standard Connection Agreement under Chapter 5A may be considered, as they are already used in the industry with a degree of familiarity.

Those against

Others were less convinced of the need for TEC/ACOSS' proposal for supplementary connection arrangements. For example, EnergyAustralia submits the ability to negotiate additional hosting capacity is already available under connection agreements.[429]

Jemena considers there are sufficient obligations and requirements in place, as well as an ability to charge for a 'non-economic generation', to connect embedded generation and therefore, there is no need to create an additional supplementary agreement:[430]

> In its service classification guideline, the AER has identified a service "Enhanced connection services", which can be used to charge for export services where it is not

427 Renew submission to the consultation paper, p. 3.

428 The Customer Advocate submission to the consultation paper, p. 2; 5.

429 EnergyAustralia submission to the consultation paper, p. 11.

430 Jemena submission to the consultation paper, pp. 11–12.

> economic or technically feasible to provide (depending on jurisdictional requirements). The guideline sufficiently accounts for these circumstances.
>
> Similarly, DNSPs already have model standing offers and other embedded generator connection agreements available to facilitate the connection of micro-embedded generation and other large-scale generation.
>
> Finally, section seven of the AER's connection guideline outlines the requirements for connecting large embedded generators.
>
> ...
>
> If the Rule Change proponents identify a deficiency in these existing arrangements, then those guidelines and other arrangements should be addressed rather than making changes through the NER; the AER has the powers to consult on and make the necessary arrangements, and the proponents should engage the AER on this approach.

Ausgrid states:[431]

> TEC/ACOSS's proposal envisages recovery of hosting capacity via charges similar to connection charges, applied to DER customers on an opt-in basis. The proposal would also require creating new rules to allocate hosting capacity between new and existing customers. We consider that connection charges are a blunt instrument not capable of sending a time varying price signal that influences behaviour at the margin.
>
> The alternative proposal for symmetrical treatment of consumption and exports services and appropriate pricing can place a charge on behaviours that cause network costs, reward behaviours that help avoid network costs and result in more efficient use of DER. We do not consider that a supplementary connection agreement is required.

Endeavour Energy submits:[432]

> We consider the existing connection arrangements under Chapter 5 and 5A of the NER are appropriate as complemented by the determination process which classifies services (including connection services) and establishes a networks connection policy.
>
> For the most part, we expect most DER customers will connect via the basic connection offer process, under an AER approved model standing offer. It is unlikely that small customers will need to go through the standard connection offer process and even more unlikely that small customers will trigger a negotiated connection application under rule 5.3A of the NER.
>
> In which case, small customers will not be required to make a capital contribution towards the cost of associated network augmentations and these costs will instead be funded via standard control service revenue. We note that if any connection charges are required under a standard or negotiated connection process the NER provides

431 Ausgrid submission to the consultation paper, p. 13.

432 Endeavour Energy submission to the consultation paper, p. 5.

> guidance on how these charges are to be developed as well as the AER connection charge guidelines. We also note that schedule 5A.1, Part B of the NER provides for a separate and distinct set of requirements to be contained in a connection offer made to customer connecting embedded generation. We do not consider changes are required to this framework.

AGL anticipates a range of operational challenges to implementing TEC/ACOSS proposals to allow for supplementary connection agreements for a DNSP and its customer to negotiate additional capacity, where that investment is not otherwise justified under a 'net market benefits' test.[433] AGL states:[434]

> We also note the proposal brought forward by TEC and ACOSS to allow for supplementary connection agreements for a network and its customer to negotiate additional capacity, where that investment is not otherwise justified under a 'net market benefits' test. We support the concept as a means to overcome the tension between the open access regime and networks' ability to constrain access based on local network conditions. Nevertheless, we anticipate a range of operational challenges to implementing this option including the following:
>
> - Negotiating individual supplementary connection agreements could entail substantial cost, given that networks may need to undertake network augmentation works to facilitate access. These costs may not be economically efficient to support only a small customer cohort, particularly in circumstances where the 'net market benefits' test has not been satisfied.
> - Individual customers may still encounter an unequal bargaining position in negotiating supplementary agreements. Accordingly, additional safeguards may be required to encourage more balanced negotiations between the parties, for example requiring that networks negotiate on reasonable terms.

Further, AGL submits: [435]

> While we support this concept in principle, we consider it may be difficult in practice for DER customers to negotiate appropriate outcomes, given the disparity in bargaining power with distribution networks. We also note that while DER customers can negotiate additional access now, there is no incentive for networks and the cost to customers may be a substantial impediment. Accordingly, additional safeguards may be required to enable this to work in practice, including that distribution networks negotiate in good faith and that any appropriate regulatory oversight be provided with respect to the pricing for additional access.

433 AGL submission to the consultation paper, p. 2.

434 ibid, pp. 10–11.

435 AGL submission to the consultation paper, p. 7.

Alternative perspective

AusNet Services submits:[436]

> Designing a coordination mechanism that enables all DER customers who will directly benefit to share the upfront costs of required upgrades to relieve a constraint (where it fails the market benefit test) will facilitate more DER export while avoiding price increases for non-DER customers. This change in the framework would increase the number of DER customers able to benefit from export services while maintaining prices for other customers.
>
> ...where investment is not justified by the net market benefit test, under the current framework, at the time of connection, the customer can pay the full costs of addressing the specific network constraint to enable them to export. In many cases this cost is prohibitively high. Designing a mechanism to enable all customers who benefit from this investment to share any upfront costs levied at the time of connection will enable greater levels of export for DER customers while maintaining prices for remaining customers.

ERM Power states:[437]

> TEC and ACOSS's proposal of giving consumers the option to negotiation for supplementary connections, but for both import and export size may be preference to SVDP and SAPN's proposals for simple export tariffs. However, the latter can provide a more dynamic signal that would reward the right investments in the right locations. As such, we do not support one model over another but rather, wish to advise the AEMC of the kinds of issues it should consider in addressing these rule changes.
>
> One potential model can be observed in France where households pay an effective maximum demand tariff for consumption as part of their daily charge. Such a model could be employed for DER exports (as well as consumption).

5.2.4 Analysis and draft rule determination

Defining export service levels

Under the current arrangements, there are no clear obligations or incentive arrangements directing the DNSPs to deliver efficient levels of export service that meet their customers' needs. Without clearer guidance on service levels that DNSPs are expected to provide to customers, there is risk that customers may not receive efficient levels of export services.

The Commission considers the current framework for setting service reliability for consumption services provides a useful framework to determine the export service levels provided by DNSPs and that the extended STPIS is the appropriate mechanism for this purpose. Separately defined service standards under the national framework are not likely to be necessary, especially once STPIS has been extended to exports. It could lead to

436 AusNet Services submission to the consultation paper, p. 2; 6.

437 ERM Power submission to the consultation paper, pp. 3–4.

duplication with the STPIS and any jurisdictionally defined service standards. The export service performance targets under the extended STPIS could be regularly adjusted by the AER taking into account network specific factors and changing conditions e.g. additional investment in hosting capacity or increased usage of export service. In relation to the approach to defining the STPIS performance targets, including whether they should be set in terms of average across a group of customers, the Commission considers that this is best considered through the AER's review process.

In line with the current service reliability arrangements, some jurisdictional authorities may also seek to set service standards covering the performance of export service that better meet the jurisdictional circumstances. Similar to the reliability arrangements for consumption services, the extended STPIS would need to be able to operate concurrently with any such service standards and GSL schemes defined through jurisdictional instruments. The extended STPIS may also support the relevant jurisdictional authorities to define appropriate export service standards once a suitable export service performance metric has been defined through the AER's review process.

Guaranteed service levels for exports

The Commission considers that it would be appropriate for the AER's extension of STPIS to export services to consider the need for GSL payments to export customers.

Similar to the current reliability arrangements, some jurisdictional authorities may also seek to set up their own GSL payment schemes for exports. As mentioned earlier, the STPIS including any GSL schemes for exports defined under the STPIS would need to be able to operate concurrently with any jurisdictionally defined GSL schemes.

To the extent to which a national GSL scheme for exports is deemed to be necessary by the AER, the Commission considers that it should not seek to fully compensate the customer for lost income due to lower levels of export service provided to a customer. That would constitute fully firm access rights for customers to export and lead a level of access for export service that is higher than the level of access that customers receive for the essential consumption service. Firm access rights would also be inconsistent with the open access framework at the transmission level.

Minimum export capacity rights

The Commission's *2019 Economic regulatory framework review* highlighted that DNSPs were experiencing different levels of DER penetration, with the South Australian and Queensland DNSPs experiencing greater levels of uptake. The review also found that the DNSPs were affected by greater levels of DER uptake in different ways as the impact of DER on the networks varied (sometimes with a DNSP's operating areas) due to differing network characteristics and circumstances. The Commission considers that the regulatory framework needs to provide flexibility to address these different circumstances being faced by the DNSPs.

The review also highlighted that some DNSPs were managing network export constraints arising from greater DER uptake using static export limits. The review further noted that the broad-based use of static export limits as the approach for addressing export constraints could lead to inefficiencies and that in some circumstances, investment to enhance the network capability to support exports could lead to greater overall system efficiencies and better outcomes for customers. The rule change requests from TEC/ACOSS and SAPN seek to address concerns stemming from the use of static export limits by DNSPs by proposing requirements on DNSPs to offer minimum level of export capacity to all customers seeking to connect their DER to the DNSP's network.[438]

The Commission considers that requirements for DNSPs to offer a minimum level of export capacity to DER customers could lead to several issues and therefore shouldn't be introduced. Instead, a more flexible approach with clear investment, planning and incentive arrangements for the provision of export services would better enable greater access to export services for DER customers and reduce the use of inefficient static export limits by DNSPs.

Potential issues associated with minimum export capacity requirements

The Commission considers that introducing regulatory requirements for DNSPs to offer a minimum level of export capacity to all DER customers could limit DNSPs' ability to cater for their differing network characteristics and circumstances. Some parts of the networks may be able to easily support higher levels of export than a minimum national requirement, in which case it may not lead to a meaningful outcome for those customers, while other parts of the network could need significant expenditure to meet these minimum requirements. Prohibiting them from being able to set static export limits under any circumstance would limit the tools available to DNSPs to manage their networks. Under some specific circumstances, it may be efficient for DNSPs to be able to use static export limits.

Minimum export capacity requirements could also drive inefficient network investment under some circumstances. Under these requirements, the DNSPs could be obliged to invest in the network to enable additional exports, even when it's not economically justified.[439] For example, the cost of upgrading some parts of the network (e.g. areas with SWER lines) to meet minimum export capacity could be significant if the DNSP is to maintain the safety, reliability and quality of supply parameters.[440] Requiring DNSPs to invest in areas where it may not be economically justified could lead to all export customers facing higher than efficient charges for exports, especially if these costs are spread across the export customer base.

Not having minimum export capacity requirements could provider for simpler export service level arrangements and a simpler approach to extending the STPIS to exports. A specific minimum export capacity requirement on DNSPs would be defined in terms of connection capacity (e.g. 5 KW) to be offered to all customers. Such requirements being in place could

438 Although the proposals don't provide a specific implementation approach, the Commission expects such minimum export capacity requirements will need to be given effect through connection offer arrangements. That is, it will be required that the maximum capacity offered by DNSPs under the connection offers to all DER customers must meet a minimum threshold e.g. export capacity offered must be greater than 5 KW.

439 The Commission notes that with greater compliance with inverter volt-watt and volt-var settings and the use of dynamic operating envelopes by DNSPs in the future, the risk of DNSPs being required to invest inefficiently may be reduced.

440 Single Wire Earth Return (SWER) systems can be used to supply power to remote and rural areas.

lead to an overlap with STPIS export performance targets that could also be similarly defined e.g. a target for urban export customers to be able to access 5KW capacity 99% of the time in a year. A DNSP's performance against its STPIS performance targets could be impacted by requirements on the DNSP to also offer minimum export connection capacity to customers. Hence, the STPIS may need to be designed to account for any impacts of minimum export capacity requirements on STPIS performance. Having dual export service performance requirements could lead to complexity of arrangements and a lack of clarity surrounding service level requirements and confusion for customers and DNSPs.

The Commission also considered that, a best endeavours type approach, such as requiring the DNSPs to offer export limits that are greater than zero KW when business cases for additional export capacity meet the net market benefit tests, may not provide meaningful outcome for customers. It is also likely to be challenging for the AER to enforce.

Approach to providing better access to export services

The Commission considers that a more flexible approach including a clear planning, investment and incentive framework for exports could better provide for improved customer access to export services and limit the inefficient use of export limits by DNSPs. Effective planning, investment and incentive arrangements for export services as outlined in Chapter 4 and Section 5.1, should enable the DNSPs to deliver the highest amount of export capacity feasible – in the most efficient way.

The Commission notes that, as observed by one of the rule change proponents, a key driver for the use of static export limits may have been the lack of a clear framework for enabling investment to support delivery of export services. The changes proposed by the Commission to recognise the evolving role of the DNSPs, as explained in Chapter 4, seek to provide a clearer planning and investment framework for the provision of export services by the DNSPs. These changes support DNSPs in proposing efficient and prudent network investment to enable customers to receive greater access to export services. Therefore, the proposed framework enables DNSPs to plan their network for the provision of export services and consider investing the network to support greater levels of exports where constraints arise instead of relying on static export limits.

As mentioned in section 5.1, the Commission's draft rule supports the extension of the current incentive arrangements, including the service performance incentive arrangements to export services. The application of STPIS to exports would mean that the DNSPs face a financial incentive to enhance the export service performance levels and reduce the use of static export limits. It is envisaged that when customers are denied export capacity using static export limits, it would be factored into the DNSP's measured performance under the STPIS. This means that where customers are provided inefficient export limits, the DNSPs would face financial penalties under the STPIS.

As outlined in the next section, the Commission has also introduced measures to promote greater transparency of export service level provided by the DNSPs, including on the use of static export limits by DNSPs. This could provide further insight into the need to consider any additional measures in the future aimed at reducing the likelihood of export limits being imposed on customers.

Export service performance reporting requirements

The Commission notes stakeholders concerns around the potential lack of transparency of export service performance raised in submissions. As DNSPs role in providing export services are being recognised under the regulatory framework, and they are provided with the option to charge customers for the provision of export services, it appropriate that the transparency of export service performance by DNSPs is enhanced.

The Commission considers that enhanced transparency of export service performance will support more informed regulatory policy decisions and investment and operating decisions by customers. The draft rule therefore introduces requirements on DNSPs to report annually on a range of metrics related to their export service performance including:[441]

- average of the maximum export capacity provided to customers by type of feeder
- average of export capacity requested by customers by different feeder type
- number of enquiries related to connection of DER
- number of applications for DER connection
- the number of *retail customers* provided zero export limits or provided export capacity lower than requested
- the estimated volume of electricity that could not be exported due to system limitations

These requirements are not intended to serve as interim incentive arrangements but to provide for general purpose reporting by the DNSPs on their export service performance. The Commission considers this requirement is not likely to create additional reporting burden on DNSPs as most of the data required to meet these requirements should be currently available, and that a number of jurisdictional governments and jurisdictional regulators are collecting this information (or in the process of requiring DNSPs to provide them).

Supplementary connection arrangements for customers seeking additional export capacity

The Commission's draft determination is to not make amendments to the NER as proposed by TEC/ACOSS in relation to supplementary connection arrangements. A 'supplementary connection agreement' would duplicate existing arrangements. The Commission considers the implementation and administrative costs that would arise from the proposal would likely outweigh the benefits, as identified by some stakeholder submissions.

As discussed above, DNSPs are obliged to enter into and perform connection contracts if a valid connection application is made by a connection applicant under NER chapter 5A. The DNSP must advise the connection applicant of the negotiated connection process.[442] Where the connection applicant elects to negotiate the terms and conditions of the connection service, or is seeking a service that is not a basic connection service or a standard connection service, the DNSP must:

441 Amending electricity rule S5.8 on the DAPR, introducing new clauses (l)(3) and (4).

442 NER clause 5A.D.2(b)(4).

- negotiate in good faith with the connection applicant[443]
- use its best endeavours to make a negotiated connection offer within 65 business days after receiving a properly completed application.[444]

To date, the Commission is not aware of any retail customer disputes that have been raised with the AER about customers' ability to negotiate additional capacity.

More broadly, the Commission considers the regulatory framework is not a barrier to allowing retail customers to purchase additional access or capacity. In addition to the option for customers to negotiate additional export capacity, NER Chapter 5A allows DNSPs to offer standard connection services above service levels provided for in basic connections. Improved service offers could be provided through dynamic export limits when introduced (including possibly operating envelopes), new service/pricing options enabled by the Commission's draft decision to allow export pricing (see chapter 6), and the service classification process to enable a group of customers to have a higher level of export capacity.[445] DNSPs are free to design and propose to the AER a coordination mechanism for retail customers to apply for additional export capacity, if this is a network service valued by customers.

A key principle of this draft determination is to promote regulatory flexibility to efficiently manage the integration of DER. The Commission seeks to accommodate different network circumstances, customer preferences and government policies. We are careful to not be too prescriptive at a national framework level. The expectation is for the AER, DNSPs, retailers, consumer groups and governments to work together with retail customers in each jurisdiction to develop service and pricing options that meet customer needs. DNSPs should be responsive to community preferences and clearly communicate service options, but how this is achieved is a matter for individual regulatory processes. Our reform package provides more flexibility for this level of engagement.

5.3 VCR equivalent for export service: customer export curtailment values

5.3.1 Rule change request

SAPN's rule change request said that DNSPs' planning decisions should be based on the value customers place on particular service levels. SAPN considered that "network planning for the provision of export services, particularly augmentations for small customers, needs to be planned and funded on an ex-ante basis which is the case for SCS". SAPN says that this "means that the value customers place in particular service levels needs to be understood upfront and, and for consumption services this is informed by applying a VCR". SAPN said that:[446]

443 NER clause 5A.C.3(a)(1).

444 NER clause 5A.F.4(a).

445 During its F&A for the 2021–26 regulatory determination, AusNet Services proposed a new service called community network upgrades to allow community groups to negotiate collectively for exportable PV connection to the network. The AER decided to classify this new service as an alternative control service and considers that it will include activities that relate to the collective customer upstream augmentation.

446 SAPN rule change request, p. 21.

Mirroring the approach used for consumption, we see merit in the AER being tasked to develop a VCR equivalent for export services (VCR-E). This would then serve as an input to:

- adapting the STPIS to export services, and helping to inform the setting of the service performance baseline that DNSPs should maintain
- the setting of any service standards if and where these are implemented
- DNSPs' evaluation of the benefits of network expenditure that they may seek to propose in order to increase service performance above that reflected in the STPIS baseline.

5.3.2 Current arrangements

What are VCRs?

Values of customer reliability (VCRs), now calculated by the AER under rule 8.12, indicate the value different types of customers place on having reliable electricity supply (in other words, the value customers place on avoid an outage) under different conditions, measured in dollars per kilowatt hour ($/KWh).[447] VCR estimates play an important role in balancing the need to deliver secure and reliable electricity supplies and the need to maintain reasonable costs for electricity consumers. The VCRs are currently used in the regulatory framework for a range of purposes, including:[448]

- by the AER and network service providers:
  - in regulatory resets as a key factor in assessing major capital projects
  - to assess a network's capital forecast as part of revenue proposals
  - in service target performance incentive schemes (STPIS) as the key measure for linking performance with the STPIS incentive
  - as an input in most regulatory investment test assessments
- by jurisdictional network regulators in the setting of transmission and distribution reliability standards and targets
- by the Reliability panel:
  - to inform wholesale market settings such as market price caps
  - in reviews to quantify the value of unserved energy

In the context of network regulation, VCRs can help identify the efficient levels of network expenditure. Using VCR to estimate the value of unserved energy resulting from outages, it can be assessed whether proposed steps to prevent outages (such as increasing network capacity) are economically justified.[449]

447 AER, Values of Customer Reliability: Consultation paper, October 2018, p. 8.

448 AER, Values of Customer Reliability: Draft Decision, September 2019 2018, p. 20.

449 AER, Values of customer reliability: Final decision, November 2019, p. 11.

The AER's role in the VCR framework

In July 2018, the Commission made a rule to make the AER responsible for determining the VCR methodology and calculating VCRs. (Previously, AEMO calculated a form of VCR.) The NER establish a VCR objective, which requires the AER's VCR methodology and set of VCR values to be fit for purpose for any current or potential uses of values of customer reliability that the AER considers relevant. Rule 8.12 requires the AER to:

- develop a national methodology for estimating VCRs in accordance with the Rules consultation procedures, that includes a mechanism for engaging with customers and a mechanism for adjusting VCRs on an annual basis
- review the VCR methodology and update the VCRs at least once every five years, and publish updated numbers[450]
- adjust the VCRs using the adjustment mechanism.

In November 2019 the AER published its final decision on the methodology for the VCR followed by the publication of the VCR estimates in December 2019.

In developing its methodology, the AER considered a range of possible approaches for estimating VCR. The current methodology adopted by the AER includes the use of contingent valuation (willingness to pay surveys) and choice experiment techniques to derive standard outage VCRs for residential and business customers with peak demand of less 10 MVA. For customers with peak demand of more than 10 MVA, the AER uses a direct cost survey approach.[451]

5.3.3 Stakeholder views

Some stakeholders express support for the proposal to task the AER to develop 'value of customer reliability' (VCR) equivalent for export services, which would provide insight into how much customers value the export service.[452] The stakeholders agree that such a measure would support regulatory processing including the operation of the STPIS.

Essential Energy submits that "we do see value in the proposal for the AER to develop a Value of Customer Reliability equivalent for export services (VCRE), as a direct way to ascertain how much customers value particular service levels, as well as a potential method of setting any future STPIS performance baselines". Essential Energy adds that "The construction of a VCRE would be familiar to participants and complementary to the AER's existing VCR survey functions, likely making it straightforward to implement".[453] Similarly Ausgrid says it agrees that the AER "would need to develop values of customer reliability for exports to support application of STIPS or any standard for exports".[454] Evoenergy submits that the "VCR-E should be considered in the incentive structure". [455]

450 The reviews must also follow the rules consultation procedures.

451 AER, Values of customer reliability: Final decision, November 2019, p. 3.

452 Submissions to the consultation paper: The Customer Advocate, p. 5; Essential Energy, p. 4; Ausgrid, p. 9; Evoenergy, p. 14; Renew, p. 9.

453 Essential Energy submission to the consultation paper, p. 4.

454 Ausgrid submission to the consultation paper, p. 9.

455 Evoenergy submission to the consultation paper, p. 14.

Renew states that "an approach to valuing DER enabled must be developed and used consistently across networks – the values may differ jurisdictionally or even sub-jurisdictionally, but the approach should be the same". Renew added that it looked "to the AER's Assessing DER Integration Expenditure work as an opportunity to develop an approach that can be used consistently across the NEM."[456]

5.3.4 Commission analysis

The Commission's more preferable draft electricity rule requires the AER to develop customer export curtailment values (CECV). These values will help guide the efficient levels of network expenditure for the provision of export services and serve as an input into network planning, investment and incentive arrangements for export services. These values will be different from VCRs, as they are not intended to measure the value to customers of having a more reliable export service or consumption service but rather the detriment to customers and the market from the curtailment of exports.

Why are the CECVs needed?

The CECVs are expected to play a similar role to the VCRs under the current framework. The Commission considers that measures providing for the valuation of different levels of export service may be needed to support the relevant planning, investment, and incentive arrangements for export services.

Under the proposed investment framework for exports, DNSPs can be allocated revenue for export services on-ex ante basis. This means that in proposing expenditure relating to export services, DNSPs would likely need to know ahead of time the value to customers and the market of relieving network export constraints. Therefore, such values are likely to be needed for the revenue determination processes. Similarly, these values may also be needed for the extension of STPIS to exports to link the outcome performance with the STPIS incentive. They could also potentially inform any export service standards defined by jurisdictional authorities. The need for such common values across DNSPs was also foreshadowed in the Commission's ENERF 2019 review.

Why can't the VCR be used?

For clarity, the Commission notes that the current VCR would not be the appropriate measure to help identify the efficient levels of network investment for exports. The VCR measures the value to customers of having a more reliable service i.e. the value customers place on avoiding a complete loss of their energy services, including for consumption. However, to guide efficient network investment, there is a need to consider the detriment to the customers and the market, of export curtailment due to network limitations (in $ per KWh of exports curtailment). The CECVs could be used to assess whether proposed steps to reduce export curtailment (such as increasing DER hosting capacity) can be economically justified.

456 Renew submission to the consultation paper, p. 9.

Framework for deriving CECVs

Given that CECVs are likely to be needed, there is a need to consider the framework for providing for these values. For this, the Commission considers that the rules-based framework for the VCR provides a useful framework.

Responsibility for determining CECVs

In line with the current arrangements for VCR, the Commission has made a draft rule that establishes the AER to be the body responsible for determining the customer export curtailment values.[457]

The Commission considers this approach to be appropriate because:

- the AER is best positioned to foresee how these values are likely to be used
- having a single body responsible for establishing these values would provide consistency and transparency of estimates and avoid unnecessary duplication and administrative costs
- the responsibility for developing these values aligns with the AER's regulatory functions, including the development of the VCR.

Objective and methodology for calculating the estimates

In keeping with the VCR framework, the Commission sees benefit in outlining a high-level objective for the valuation of customer export curtailment without providing detailed guidance on the methodology for calculating the values. The draft rule provides an objective that CECV methodology and customer export curtailment values should be fit for purpose for the current and potential uses of these values that the AER considers to be relevant.[458] For clarity, the Commission notes that the value would need to be fit for purpose for guiding the relevant planning, investment and regulatory decisions for exports.

The values may need to capture not only the detriment of export curtailment to the customers using the export service but also the potential detriment to all customers from lower levels of customer exports. The detriment of non-exporting customers from lower levels of exports may need to be captured in order to enable efficient levels of investment. The approach may also need to consider the extent to which the costs related to the export service are recovered solely from DER exporters. Some of the costs associated with the export service, such as that associated with the network's intrinsic capacity to host exports are likely to be recovered from all network users.

The Commission considers that estimating the CECVs could be complex, and there may be several approaches available. As a case in point, the AER considered five different techniques for deriving VCR estimates when developing the VCR methodology.[459] There are several factors relating to the methodology that warrant consideration, such as, how far into the future the values are projected and whether the values would change over the course of day

457 Amending electricity rule schedule 2, introducing new NER rule 8.13.

458 Amending electricity rule schedule 2, introducing new NER rule 8.13(a).

459 AER, Value of customer reliability: consultation paper, October 2018, pp. 19-24.

or years or across different customer groups. These need further consideration under a process dedicated to developing the methodology for calculating the values. Therefore, the Commission considers that it would not be appropriate to provide detailed guidance on the methodology in the NER, instead a high-level approach should be adopted.

The draft rule requires the AER to both develop and review the CECV methodology in accordance with the Rules consultation procedures set out in NER rule 8.9 (consistently with the approach to the VCR in rule 8.12). The Commission considers that this will provide transparency and accountability in the development of the methodology. Given that the values will be a new arrangement in the regulatory framework, it is important that the stakeholders can provide input into how they are calculated. This will provide stakeholders confidence in the values that are calculated using the methodology. The Rules consultation procedures provide a robust and well-understood consultation framework. The draft rule requires the AER to consult with a wide range of stakeholders including AEMO, each jurisdictional regulator, registered participants, and other people with an interest in the CECV methodology and values (which would include exporting customers).[460]

Reviewing the CECV methodology

The draft rule also requires the AER to review the methodology every five years. The Commission notes that the evolving capabilities of DER technologies may impact how customers value export services. For example, to the extent that DER exports participate in additional markets such as the ancillary services market, then the value that customers place on being able to export and the detriment to the market of export curtailment could increase. Therefore, the Commission considers that the methodology may need to be reviewed regularly to keep up to date with the ongoing changes in the industry and the potential changes in the value of exports. The rule does not restrict the AER from reviewing the methodology more frequently.

Timing of initial review

The Commission considers that initial CECV estimates should be published by 1 July 2022. This will allow the AER time to consult on and develop the methodology under the Rules consultation procedures and calculate the value estimates in a robust manner. It will also provide for the values to be considered in the next NSW DNSP reset process.

Frequency of review

The draft rule requires that the CECV estimates are updated by the AER on an annual basis. The Commission considers this provides an appropriate balance between stability of values for long term network planning and maintaining up-to-date values that reflect changing circumstances.

Publication of values

The draft rule requires publication of the values and the methodology, both when initially determined, and when any updates or adjustments occur. The Commission considers this will

460 Amending electricity rule schedule 2, introducing new NER rule 8.13(g).

improve transparency of process, and certainty of estimates for planning purposes. It will be important for the updated values to be readily available to support the relevant processes.

Conclusion

Overall, the Commission considers that requiring the AER to regularly calculate the customer export curtailment values will provide for a transparent, consistent and a low-cost approach to measuring the customer export curtailment values. The availability of robust CECVs will support efficient investment in export services and allow customers to receive the levels of export services that better meet the needs of all customers.

6 DISTRIBUTION NETWORK PRICING ARRANGEMENTS FOR EXPORT SERVICES

6.1 Introduction

A strategic objective of the Commission is to progress reforms to the regulatory framework that support Australia's transition to a fully integrated electricity system – taking advantage of the significant opportunities presented by a high DER future, and to deliver benefits to *all* electricity system users.

Small retail customers have had limited ability to date to be rewarded for adjusting their usage or exports during times when there are network constraints. Looking forward, through digitalisation, smart meters, home battery storage, advancing technologies and greater data flows, customers will increasingly be able to adjust their usage or exports without impacting their day-to-day lives. This flexibility can provide valuable services to the grid. Customers should be rewarded for this flexibility.

The rule change requests seek to maximise the potential benefits DER can provide – especially through the more efficient use of the distribution network to make energy more affordable for everyone. The regulatory framework can promote this by enabling DNSPs to price network services in a way that rewards customers for using their DER to provide services to the network when they are most valued, and integrating their behind-the-meter appliances with the network. This is consistent with the direction of the ESB's Post-2025 Market Design:[461]

> The pace of change means that it is more important for network businesses to be active in harnessing the value of DER to drive improved network efficiency. This will require networks to develop new price structures that support the adoption and connection of price responsive, active technologies, in the right locations.

6.1.1 The need for change

There is a base level of DER hosting capacity that all networks currently provide, because network assets constructed to supply load have an inherent capacity to support some reverse power flow without any additional investment. Customers have already paid for this intrinsic capacity through consumption charges.

But as distribution networks are increasingly used for the upstream transport of energy exported from customers' solar PV, the networks are approaching the limit of their 'intrinsic hosting capacity', and further use of the networks in this way is expected to become a driver of new expenditure – as reflected by some recent AER decisions.

SAPN explained:[462]

> Distribution networks designed to support consumption services have an inherent,

461 ESB, Post 2025 Market Design, Directions Paper, January 2021, p. 76.

462 SAPN rule change request, p. 4.

albeit finite, capacity to also deliver export services. While customers' take-up of DER was relatively low, networks could accommodate additional DER at near zero marginal cost. However, the inherent DER 'hosting capacity' of networks is being rapidly approached at local and system-wide levels in many NEM regions. This means that either DER customers will no longer receive the service levels for export services they have historically enjoyed, or networks will need to invest to maintain service levels.

So, a timely question is how these new DER-related investment costs should be recovered and whether pricing signals for efficient investment – in both the grid and 'behind-the-meter' – should apply to export services.

Enabling export pricing would allow DNSPs to design new network pricing structures that customers can choose as part of a 'menu of options' – as envisaged by SAPN. For example, DNSPs could offer customers who have installed solar PV and battery storage additional value for their DER investments by setting network prices to rewards those customers for shifting their dispatch to times that support better use of the network – thereby delivering broader benefits to other consumers.

Implementation of export pricing will require careful consideration. Stakeholder submissions provided diverse views from a wide range of organisations on the potential risks. The main concerns raised by some stakeholders is that export charges may undermine government climate change policies and reduce the value of solar PV investments already made by households.

6.1.2 Rule change proposal to enable export pricing

The use of export charges as a pricing tool is currently prohibited under the current regulatory framework by NER clause 6.1.4. DNSPs are allowed to recover costs, including those for the provision of export services, only through connection and consumption charges.

SAPN and SVDP proposed to enable the option for export charges to apply under the regulatory framework by removing of NER clause 6.1.4. On the 'other side of the coin', SAPN also proposed to better recognise and reward customers for the benefits their DER can provide to the grid by enabling 'negative prices'.

The AER and DNSPs would then be required to consult with retail customers and other key stakeholders on whether and (if so) how export pricing would be implemented. SAPN proposed that the current network pricing objective and principles under the NER, which promote cost reflective pricing, should generally apply to export services.

Allowing DNSPs to include export charges in their pricing structures would not change the DNSP's total revenue allowance within a regulatory period under revenue cap regulation. An increase in one part of a tariff structure would need to be offset by a reduction in other parts of the tariff.

6.1.3 Key aspects of the Commission's draft decision

The Commission's draft determination is to make a more preferable draft rule to enable export charges by removing NER clause 6.1.4, and more explicitly allowing for negative prices to enhance rewards to customers. The aim of this rule change is to create greater regulatory flexibility to efficiently manage the integration of DER. Export pricing options can apply to *all* distribution-level customers.

To be clear, the Commission's decision to enable export pricing options under the regulatory framework is not a decision to mandate the implementation of export pricing. The AER, as the economic regulator, oversees revenue determinations and pricing proposals for each DNSP. Any decision to implement export pricing would be part of the AER's regulatory process.

Under the draft rule, DNSPs will be able to offer new service options that reward customers for better utilising and supporting the grid. For example, customers may choose a service option with higher average export limits on the condition that they are willing to agree to face pricing structures that reflect network costs. This could include export charges during periods of high demand for export services, and negative export prices (eg, payments to the customer) during periods of high demand for consumption services.

The Commission's decision has the potential to result in significant long term benefits to consumers. There are good economic reasons to introduce export pricing – both in the short term to manage new DER-related investment, and the longer term to take advantage of future market and technology developments. Pricing is a common regulatory tool to send efficient signals for future expenditure, and reward customers for actions that better utilise existing infrastructure or improve network operations. Moreover, export pricing provides a way to integrate DER more effectively into the electricity system, which will deliver benefits to all distribution network users. Finally, our decision allows the community in each jurisdiction to decide how costs should be allocated – including whether the 'beneficiaries' should pay more of any new network investment costs to support export services.

Implementation of export charges is a significant change for the energy sector. Submissions highlight any decision to implement export charges could involve significant trade-offs and potentially conflicting objectives – which will need to be carefully considered by DNSPs as well as the AER.

The Commission considers the tariff structure statement (TSS) process, explained below, generally provides for adequate transitional arrangements for DNSPs to develop new tariff options and the AER in assessing TSS proposals – including consideration of 'grandfathering' provisions. DNSPs are required to undertake significant consultation and customer education. The framework provides flexibility to accommodate different network circumstances, customer preferences and government policies. We consider the current pricing framework for consumption pricing should largely apply to export services, as proposed by SAPN.

Nevertheless, to address stakeholder concerns about how export charges may be implemented, the Commission has decided to strengthen consultation requirements through the TSS process – while balancing the need for regulatory flexibility.

First, DNSPs will be required to develop and consult on a transition strategy to implement export pricing over time. Moreover, as part of their TSS, DNSPs must describe their consultation process and explain how they have addressed stakeholder concerns as a result of that engagement, including consideration of jurisdictional policies. This builds on an existing consumer impact principle that expressly allows DNSPs to phase-in new pricing structures over five years or more.[463] Ultimately, a DNSP's transition policy must be approved by the AER.

Second, DNSPs must explain the interrelationships between different aspects of their regulatory and TSS proposals, including how pricing options relate to connection policies and investment plans, in a plain language overview – assisting consumers and other stakeholders to engage in the AER's process.

Third, the AER must develop and publish *Export Tariff Guidelines* to assist change management, and promote confidence in the TSS process by creating greater transparency and certainty of:

- the AER's decision-making process and criteria, including how it interprets the network pricing principles under NER clause 6.18.5 and the above new requirements
- expectations of how DNSPs should develop their TSS proposals and present information to the AER
- how customer and other stakeholder views and preferences should be taken into account in the process.

Further, as a transitional measure, the Commission has increased the monetary thresholds for DNSPs to undertake tariff trials to promote both innovation and timely implementation of export pricing.

6.1.4 Roadmap of chapter and supporting appendices

The SAPN and SVDP proposals are outlined in more detail in section 6.2. The current regulatory arrangements are outlined in section 6.3.

The draft decision in relation to export pricing and our reasoning are set out in section 6.4. The Commission's decision draws on information and submissions presented in the rule change requests and stakeholder submissions, as well as reports provided by independent consultants and our customer impact assessment.

Summaries of the arguments presented in submissions for and against enabling export charges are provided in appendix C under sections C.1 and C.2, respectively. Submissions on SAPN's proposal to allow for negative prices, so export pricing can lead to a positive or negative charge for customers, are outlined in appendix C.3.

Several implementation issues were identified by the proponents and in submissions. In the following sections, stakeholder views are outlined on whether:

- export pricing should apply to small distribution-level customers only (appendix C.4)

463 See NER clause 6.18.5(h).

- the current network pricing principles (NER clause 6.18.5) translate to export services (appendix C.5)
- new pricing principles are required to guide cost and capacity allocation decisions made by the DNSPs (appendix C.6)
- new transitional or grandfathering arrangements are required (appendix C.7).

The Commission extended the period of time to make this draft determination in November 2020 to develop a better understanding of how export pricing would be implemented. An expert consultant, farrierswier, was engaged to examine how various parties such as the AER and DNSPs would implement export pricing, and how jurisdictional governments' preferences, stakeholder concerns and potential consumer harms would likely be addressed. Farrierswier's findings are outlined in appendix D.

Appendix E considers some key differences between the regulatory arrangements for transmission and distribution-level generation.

The Commission has undertaken quantitative analysis to better understand the potential bill impact of export pricing for DER owners. The results are summarised in section 6.4.1 below, and outlined in more detail in appendix F.

6.2 What's proposed?

6.2.1 SA Power Networks' proposal

An objective of SAPN's proposal is to enable customers to make informed choices with regard to their energy consumption and export decisions – including the DER they invest in and how these are operated and used.[464]

SAPN's proposal sought to provide DNSPs a means of enabling and customising service choices to their customers. SAPN stated:[465]

> Over time, we envisage distribution networks may provide options to customers on the level of export service they desire and are willing to pay for. The choice of options should be left to distribution networks to determine together with their customers and stakeholders, and may depend on their specific network capabilities. We envisage there could be three principal offerings with corresponding fees, including:
>
> 1. The option for a 'base' level of capacity and reliability (that is, the average reliability across customers as set in an adapted STPIS). The merit of this service being charged a tariff reflective of long run marginal cost would need consideration. This is particularly noting that customer exports may drive benefits for all customers, that may warrant some costs being recovered across all customers. Such decisions should be subject distribution networks engaging broadly with their customers.

464 SAPN rule change request, p. 10.

465 ibid, p. 25.

2. The option to receive a 'premium' service with features above those in the base service, such as higher than average export capacity. This might be enabled by distribution networks who have capabilities to dynamically manage their distribution networks, to allow a customer to export more at times when the distribution network permits and / or to have preferential treatment in terms of when the customer might receive a reduced export limit compared to other customers in the same congested area of the network who do not wish to pay for this premium service.
3. An option to receive a 'basic' service at low or zero cost, perhaps reflective of a fixed, low export capacity, aligned to the intrinsic hosting capacity of the network.

SAPN considered:[466]

> Distribution networks' ability to offer service choices will be enabled by the removal of NER clause 6.1.4. We do not observe any other required rule changes, but request the AEMC to review if there are any other regulatory barriers to customising export service offers should distribution networks seek to do so, or any regulatory barriers to customers being able to move between offers over time.

To enable customers to make informed choices in requesting export services and to provide for efficient outcomes, SAPN proposed to remove an explicit regulatory barrier in the NER, clause 6.1.4. This, SAPN said, would then allow:[467]

- the AER and distribution networks the option to decide on the appropriate combination of charging arrangements with all options available including connection charges, DUOS charges and ACS charges
- distribution networks to consider the design, circumstances and timeframe for any export charges in consultation[468] with their customers and stakeholders, particularly their respective jurisdictional governments who also retain rights under the current NER to impose obligations on distribution networks as to how DUoS charges should be structured and applied.[469]

SAPN outlined how it considers this would work in practice:[470]

- The design and approach to introducing any ongoing export charges would accord with the existing Distribution Pricing Rules in Chapter 6 of the NER and be determined via each DNSP's respective tariff structure statement, both of which are largely fit-for-purpose
- The introduction of any export charges must be carefully considered by DNSPs, under a timeframe and approach that is supported by their customers and stakeholders, as has

466 ibid, p. 25.

467 ibid, p. 23.

468 SAPN noted that deciding on the design and timeframe for application of any tariffs, including for export, necessarily require DNSPs to engage with their customers and stakeholders on how to balance considerations such as efficiency, complexity, fairness and compliance.

469 Clause 6.18.5(j) requires tariffs to comply with all applicable regulatory instruments, including jurisdictional instruments.

470 SAPN rule change request, p. 23.

occurred to date with respect to the introduction of cost reflective tariffs for consumption – whereby:

- Any such tariffs should preferably apply prospectively and not retrospectively, to avoid negative impacts on existing customers who have invested in good faith on the basis of facing no export charges to date.
- DNSPs should be able to employ a broad range of transition approaches, such as introducing charges over a period of years which may extend beyond a regulatory control period, having shadow pricing for a period of time, slowly increasing rates over time, or deciding that certain costs should not be allocated to these charges (e.g. because of benefits accruing to all customers) where this is supported by customers / stakeholders.
- The approach to transition needs to be determined via engagement with customers and stakeholders based on a clear understanding of the trade-offs in faster or slower transitions to introducing new export charges.
  - For example, although a slower transition would enable more time for existing customers to adapt to new tariffs through choices they make as their systems require replacement, a faster transition would encourage efficient operation of systems earlier, and may require costs that would otherwise be recovered from export customers to be recovered from all customers.

- The design of any export charges would aim to comply with the current Network Pricing Objective in the NER, which SAPN said is already sufficiently broad and refers to charges for directly regulated services to customers reflecting efficient costs of providing services to those customers.[471]

Additionally, SAPN proposed the following three minor amendments:[472]

1. A new rule should make it explicit that any ongoing distribution use of system charges introduced must not be applied to large embedded generator customers who are standalone generators
2. A new rule should make it explicit that any cost reflective distribution charges can also include negative prices to reward customers for any benefits that their exports provide in managing consumption driven network congestion
3. A new rule should provide guiding principles for DNSPs on how costs should be allocated between consumption and export services and potentially between different tariff charging parameters of export services.

471 Consistent with the existing pricing rules, SAPN considered the primary purpose of ongoing distribution charges would be to reflect long run marginal costs of export services – which, it said, remains an appropriate guiding theory for efficient forward-looking cost reflective price signals. (ibid, pp. 23–24)

472 ibid, p. 24.

6.2.2 The St Vincent de Paul Society Victoria proposal

SVDP proposed to amend NER Clause 6.1.4(a) to allow DNSPs to charge DER participants (per kWh) for DER exported back via the grid – the revenue for which could be used to upgrade networks to limit constraints and enable future DER penetration. SVDP explained:[473]

> For example, if a network experiences congestion on a specific line/substation it can set a DER export price for that specific line/substation. The generating consumer would then determine whether they would a) accept constraints, b) accept the cost of export or c) explore other options such as batteries and coordinated export reductions (including the involvement of 3rd party services).

SVDP considered a high DER future is likely to operate more efficiently if there are opportunities for energy management services to develop solutions that can benefit DER participants as well as the networks, and an export charge will produce a price signal that can incentivise DER participants to engage with such energy management services and be potentially rewarded for their services.[474] SVDP stated its proposed solution is not aimed at penalising households with rooftop solar, but consecutive governments' policies promoting the uptake of rooftop solar have created an imbalance in favour of solar and, potentially, at the disadvantage of other technologies, such as storage.[475]

6.3 Current arrangements

6.3.1 Prohibition of export charges

Retail customers have a connection agreement with their DNSP to receive network services. Consumption and export limits are set by DNSPs through connection contracts with their retail customers. Under Chapter 5A of the NER, DNSPs are required to develop model standing offers, and the offers must contain minimum terms and conditions as prescribed (see chapter 5 of this decision document). This connection agreement may involve the customer paying a connection fee.

The retail customer will then be charged an ongoing fee (a distribution use of system or DUOS charge) for consumption services. This applies for customers both with and without micro embedded generation, such as solar PV.

These ongoing DUOS charges recover the DNSP's efficient and prudent costs related to direct control services that are not recovered via connection charges.

DUOS charges currently only apply to consumption services. They do not apply to export services. It is explicitly prohibited under NER clause 6.1.4.

473 SVDP rule change request, p. 7.

474 ibid, p. 8.

475 ibid, p. 9.

6.3.2 The TSS process

The requirement for DNSPs to develop cost reflective network prices for consumption services was introduced by the Commission's Distribution network pricing arrangement rule change in 2014.[476]

The rule required DNSPs to develop a tariff structure statement (TSS) that outlines the proposed pricing structure for the next regulatory period – which the AER examines within the distribution revenue determination process.[477] While the AER's revenue determination sets the total amount of revenue that a DNSP may recover in each regulatory period, tariff structure design is about how this revenue is recovered, not how much revenue should be recovered. That is, the TSS only sets tariff structures as opposed to tariff levels.

The TSS must set out:[478]

- the tariff classes into which retail customers for direct control services will be divided – where the costs caused by each customer within the group are broadly similar
- the policies and procedures the DNSP will apply for assigning retail customers to tariffs or reassigning retail customers from one tariff to another
- the structures for each proposed tariff
- the charging parameters for each proposed tariff
- a description of the approach the DNSP will take in setting each tariff as part of the annual pricing proposal process for each year of the regulatory period.

A TSS must also be accompanied by a pricing schedule which sets out the indicative price levels for each tariff for each year of the regulatory period.[479] The prices in this indicative pricing schedule are not binding, but the DNSP's annual pricing proposal must demonstrate how each proposed tariff complies with the indicative pricing levels set out in the TSS or explain any material differences.[480]

The TSS process involves the following steps:

- DNSPs develop a proposed TSS to apply over the five-year regulatory control period.
- The TSS is submitted to the AER for assessment against the 'pricing principles' for direct control services – along with the DNSP's five-year revenue requirement proposal.
- The AER approves the TSS if it meets the pricing principles for direct control services and other NER requirements.
- DNSPs develop and submit their annual pricing proposals to the AER. The annual pricing proposals essentially apply pricing levels to each of the tariff structures outlined in the approved TSS.

476 See: www.aemc.gov.au/rule-changes/distribution-network-pricing-arrangements
477 NER clause 6.18.1A.
478 NER clause 6.18.1A(a).
479 NER clause 6.8.2(d1).
480 NER clause 6.18.2(b).

- The AER's assessment of the DNSP's pricing proposal is also a compliance check against the approved TSS and the control mechanism specified in the AER's regulatory determination.

The NER require DNSPs to describe how they have engaged with retail customers and retailers in developing the proposed TSS, and have sought to address any relevant concerns identified as a result of that engagement.[481]

The DNSPs' TSS consultation provides a forum for retail customers and stakeholders to raise concerns with how tariffs, both for consumption and export services, are structured. If a DNSP has not adequately addressed those concerns in its regulatory proposal, stakeholders then have an opportunity to influence the AER's decision on whether or not to approve the DNSP's proposal.

The DNSPs' TSS consultation provides a forum for retail customers and stakeholders to raise concerns with how tariffs, both for consumption and export services, are structured. If a DNSP has not adequately addressed those concerns in its regulatory proposal, stakeholders then have an opportunity to influence the AER's decision on whether or not to approve the DNSP's proposal.

Network pricing principles and pricing objective

The pricing principles under NER clause 6.18.5 include:

- (e) For each tariff class, the revenue expected to be recovered must lie on or between:
    - (1) an upper bound representing the stand alone cost of serving the retail customers who belong to that class; and
    - (2) a lower bound representing the avoidable cost of not serving those retail customers.
- (f) Each tariff must be based on the long run marginal cost of providing the service to which it relates to the retail customers assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:
    - (1) the costs and benefits associated with calculating, implementing and applying that method as proposed;
    - (2) the additional costs likely to be associated with meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant part of the distribution network; and
    - (3) the location of retail customers that are assigned to that tariff and the extent to which costs vary between different locations in the distribution network.
- (g) The revenue expected to be recovered from each tariff must:
    - (1) reflect the Distribution Network Service Provider's total efficient costs of serving the retail customers that are assigned to that tariff;

481 NER clause 6.8.2(c1a).

- (2) when summed with the revenue expected to be received from all other tariffs, permit the Distribution Network Service Provider to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the Distribution Network Service Provider; and
- (3) comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (f).
- (h) A Distribution Network Service Provider must consider the impact on retail customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the Distribution Network Service Provider considers reasonably necessary having regard to:
  - (1) the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one regulatory control period);
  - (2) the extent to which retail customers can choose the tariff to which they are assigned; and
  - (3) the extent to which retail customers are able to mitigate the impact of changes in tariffs through their usage decisions.
- (i) The structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff, having regard to:
  - (1) the type and nature of those retail customers; and
  - (2) the information provided to, and the consultation undertaken with, those retail customers.
  - (j) A tariff must comply with the Rules and all applicable regulatory instruments.

A DNSP must comply with these pricing principles in a manner that will contribute to the achievement of the *network pricing objective*.[482] The network pricing objective is that the tariffs that a DNSP charges in respect of its provision of direct control services to a retail customer should reflect the DNSP's efficient costs of providing those services to the retail customer.[483]

Purpose of consumer impact principles in promoting the NEO

There are two main roles of the 'consumer impact principles' – outlined in paragraphs (h) and (i) above – in promoting the NEO. They provide an obligation on DNSPs to:[484]

- Set network tariffs that consumers are reasonably capable of understanding, so that consumers will be capable of responding to the signals that network tariffs are intended to provide. This is particularly important in the context of moving towards more cost reflective network tariffs because, where consumers are not able to relate their usage

482 NER clause 6.18.5(d).

483 NER clause 6.18.5(a).

484 AEMC, Distribution Network Pricing Arrangements, Rule Determination, November 2014, p. 165.

decisions to the design of the network tariff, they will not be able to make efficient consumption and investment decisions regarding their use of the network.

- Take into account the impacts of network tariff changes on consumers as a result of their proposed network tariff changes. Large increases in network tariffs will have a significant impact on consumers and potentially undermine confidence in the regulatory framework. In addition, large network tariff changes reduce consumers' ability to make efficient long term investment and consumption decisions by sending inconsistent price signals.

The Commission acknowledged in its 2014 decision that there may be cases where the consumer impact principle and the cost reflectivity principles produce outcomes that are inconsistent:[485]

> This inconsistency could arise in instances where cost reflectivity may mean that changes in network tariffs potentially result in large tariff changes for some consumers.
>
> To allow DNSPs to make the necessary trade-offs, DNSPs can set network tariffs that vary from the cost reflectivity principles to the minimum extent possible to comply with the consumer impact principle. DNSPs cannot disregard the cost reflectivity principles to reduce consumer impacts or provide simpler tariffs. However, where consumers face tariffs which they cannot relate their usage decisions to, or that send inconsistent price signals, the gains from efficient pricing which the cost reflectivity principles are designed to achieve will not be realised.

It is up to retailers to reflect network tariff structures and feed-in-tariffs in their offers

Network charges are paid by retailers to DNSPs. Under the current framework, retailers have discretion to decide how to recover these costs and their other costs as part of their overall retail charges to consumers. Retailers are currently free to manage network price signals how they choose as part of their market offers.

While some jurisdictional schemes for feed-in-tariffs are paid by DNSPs to a customer's retailer, in the majority of cases, it is ultimately the retailer who determines how much the customer is paid for their exported electricity.

Customers can also buy services from their retailer or third-party service providers to help them manage their costs. For example, a retailer may pass through the DNSP's time-of-use network charges but the retailer or a third party may provide demand management services to help the customer minimise its exposure to peak prices.[486]

The role of retailers has several implications for network tariff design, as outlined by farrierswier:[487]

- customer impacts will be determined by retailers' decisions about retail tariff structures and levels rather than the decisions of DNSPs

485 ibid, p. 168.

486 Farrierwier, Insights report: Effectiveness of the TSS process and options for implementing export charges, March 2021, pp. 35–36.

487 ibid, p. 36.

- some more complex export service offerings such as those with dynamic controls, may be bundled into retail electricity packages or third-party aggregator service offerings where the pricing and signalling to control, encourage and reward dynamic behaviours for network export capacity availability and network support are packaged with other wholesale market services such as demand response.

6.3.3 In-period tariff trials

In its 2014 decision, the Commission introduced specific arrangements that allow DNSPs to develop and trial new, innovative network tariffs in response to consumer requests or changing consumption patterns. These arrangements permit DNSPs to implement, in-period, new network tariffs that are under a certain materiality threshold.[488]

NER clause 6.18.1C exempts DNSPs from the need to seek an amendment to a TSS so as to enable the introduction of a new tariff where the forecast revenue recovered by the tariff does not exceed 0.5 per cent of the annual revenue requirement, and where the forecast revenue recovered cumulatively from all such tariffs that are not included in the TSS does not exceed 1.0 per cent of the annual revenue requirement.[489] That is, these in-period tariff trials would not be required to comply with the network pricing principles.

This notwithstanding, even if the thresholds are not breached, the trial network tariff would then need to be included in the TSS developed as part of the next regulatory determination process so that it can be assessed against the pricing principles. The TSS developed at the start of the regulatory period is to contain all tariffs that the DNSP is planning to offer over the regulatory control period.

6.4 Commission's draft decision

In the context of the major transformation of the energy sector currently underway, the Commission considers the regulatory framework should have the flexibility to respond to changing customer preferences, and technology and market developments as they emerge. The Commission's decision to allow for export pricing aims to provide this flexibility, and enables DNSPs to develop tariff and service options that meet retail customers' needs and expectations.

Box 7 provides a summary of the key reform initiatives under this draft rule. The Commission agrees with SAPN and SVDP on the value of enabling export pricing to efficiently manage future DER-related investment.

The following sections outline potential bill impacts on retail customers if export charges are implemented for a network, our reasoning for making the draft rules, and our view that additional safeguards are required to help manage change.

488 AEMC, Distribution Network Pricing Arrangements, Rule Determination, November 2014, p. 93.

489 To the extent that either of these thresholds are breached, DNSPs would be required to go through an amendment process to incorporate the tariff into their TSS for the following year. At this point, the AER would be able to assess whether the tariff complies with the pricing principles.

BOX 7: KEY PRICING REFORM INITIATIVES

Building on the existing pricing framework, the Commission's more preferable draft electricity rule:

- **Creates regulatory flexibility** for new pricing options of DER that can send efficient signals for future expenditure and incentivise customers to best utilise existing infrastructure by:
  - removing the current prohibition on DNSPs to charge for energy exported into the grid (NER clause 6.1.4)
  - clarifying that distribution tariffs may include positive and negative export charges for all distribution system users.
- **Strengthens stakeholder engagement in the transition process** by requiring DNSPs to:
  - develop and consult on a transition strategy as part of their TSS to phase-in any proposed export pricing over time. The strategy must be approved by the AER
  - explain the interrelationships between different aspects of their regulatory and TSS proposals, including how the proposed pricing structures relate to connection policies and expenditure plans, in a plain language overview.
- **Promotes greater certainty and transparency of the decision-making process** by requiring the AER to consult on and publish *Export Tariff Guidelines.*
- **Supports innovation and future market developments** by:
  - increasing the thresholds for in-period tariff trials for the current and next regulatory control periods, as a transitional measure
  - addressing a barrier for DNSPs to be able to design more advanced network tariffs targeting retailers and intermediaries for end customers.
- **Improves the adaptability of the pricing framework** to emerging network issues relating to the increased use of DER – especially minimum demand periods – by broadening the reference to cost drivers under the pricing principles.

6.4.1 What this decision means for retail customers

The Commission modelled the potential impact on customer bills if networks introduced export charges. See Appendix F for more details.

Our draft decision promotes the long term interests of consumers – everyone can be better off over time if export pricing is introduced as intended. But some customers may see reduced benefits from their solar PV investment in the short term, depending on how export pricing is actually implemented. To the extent some customers pay more for new infrastructure costs that benefit them, others will see bill savings.

Most retail customers could receive a small reduction on their bills. This reflects that those customers who have not had the opportunity to invest in rooftop technology may no longer be asked to pay an equal share of the costs for distribution networks to maintain or improve export services. The bill reduction could be in the order of $2–$25 per annum depending on the DNSP.

Customers with battery storage could see more benefits. They could gain especially through negative export charges (eg, payments to customers). The bigger the battery, the greater the potential benefits.

For the customers with solar, there was a range of impacts – depending on the size of the system.

Households with large solar PV systems (above 6–8 kW) are currently earning over $1200 a year on average.[490] This includes reduced energy costs from the grid, as they supply their own load. Depending on how distribution networks design the pricing structure and the extent to which grandfathering arrangements are put in place by networks, these customers could see their benefits reduced by around $100 per year. This still leaves a significant ongoing benefit and allows new consumers to access those savings over time as networks are upgraded to provide more export hosting capacity. The Commission considers that this approach provides benefits to all electricity consumers.

Those with typical systems of say 2–4kW, who are currently earning an average of $645 a year, could earn about $30 a year on average less from their exports, while some network areas would not be materially affected.

Under a 'do nothing' approach, customers with solar systems would be worse off as they could see increasing instances of restrictions on export. For example, a restriction on export for only 10 per cent of the time for a customer with a 5kW system could increase the payback period of their system by five to six months. This increases to 14–16 months if the exports are restricted for 25 per cent of the time.

While the current TSS process generally provides a robust framework for the introduction of new tariffs to manage customer concerns about potential bill impacts and other issues, the Commission nevertheless considers that additional measures specific to the introduction of export charges may assist the transition. To successfully introduce export pricing, a coalition of consumer groups, DNSPs, the AER and retailers will need to work together to explain the need for change, manage stakeholder concerns, and communicate pricing options and the potential benefits to retail customers. To this end, the draft rule introduces new consultation requirements that promote continued sector-wide engagement and collaboration – while balancing the need for regulatory flexibility.

6.4.2 The potential benefits of enabling export pricing

As discussed in Chapter 4, the Commission's draft determination clarifies that DNSPs are required to provide export services. When significant new network expenditure is required to maintain or improve these services, price signals can help to ensure it will be the result of

490 These customers currently represent approximately 7 per cent of solar PV customers, although installation of larger systems is becoming more common. (See Clean Energy Regulator data for installed PV system sizes by postcode, available here: www.cleanenergyregulator.gov.au)

customers making informed decisions about the costs that they impose on distribution networks. The Commission's draft determination enables this option by removing NER clause 6.1.4, which has prohibited export charges from being applied.

SAPN's proposal to allow 'negative prices' for export services similarly promotes efficient use of and investment in the grid. The proponents and stakeholders widely support the idea that DNSPs should equally consider the network benefits as well as the costs of DER exports. The Commission's draft rule provides this flexibility for both export and consumption services under the network pricing objective (NER clause 6.18.5(a)) to allow charges in respect of the provision of direct control services to reflect efficient negative costs.

DNSPs and the AER, through the TSS process, are best placed to develop these new pricing options based on the network circumstances and customer preferences at the time. The existing TSS process inherently provides for flexible transitional arrangements, including consideration of the need for provision of any grandfathering rights. The Commission considers the pricing framework is generally fit-for-purpose to support the introduction of export pricing. This view is supported by farrierswier's *Insights report*, which considered the experience of the TSS process for consumption pricing reforms to date, and undertook scenario analysis designed to test how export pricing may be implemented under the current pricing framework (see appendix D).

Options to improve the economic efficiency of networks for the benefit of all

Significant new DER-related expenditure is expected in the coming years for DNSPs to provide export services. This is consistent with the view of the AER[491] and is reflected in recent distribution network revenue determinations for South Australia and Victoria.

Pricing structures that reflect the underlying economic costs of supplying infrastructure services promote efficient infrastructure use and investment. Moreover, prices can signal the network costs of providing export services and the need for future investments, and efficiently ration network capacity during peak times.

For example, network pricing structures can be designed to optimise use of the distribution networks by rewarding customers who either change their behaviour – like self-consuming when there is excess demand for use of network export services – or shift dispatch to periods of high demand for network consumption services.

This smoothing of 'demand' for consumption and export services – making best use of existing capacity – means higher productivity and lower average network costs for all system users, and new investment may be deferred. More detail on the potential value of pricing signals and how they can promote the NEO is explained in submissions and the economic literature, as outlined in appendix C.1. As noted by farrierswier, realising these potential benefits is dependent to an extent on whether retailers actually pass through the network pricing structures in some manner and how responsive customers are to price signals.[492]

491 AER, Assessing DER integration expenditure, Consultation paper, November 2019.

492 Farrierwier, Insights report: Effectiveness of the TSS process and options for implementing export charges, March 2021, pp. 33–34.

However, the Commission acknowledges that retailers operate in a competitive environment (albeit highly regulated), and their products will reflect customers preferences.

Export pricing options would be considered as part of the TSS process for each DNSP – taking into account customer and other key stakeholder views. The value of this 'optionality' is supported by several submissions (see appendix C.1.4). As stated by AusNet Services:[493]

> We do not see any reason why DNSPs should not have this option [export pricing] available. Whether this is applied or not will depend on a range of factors that are already considered by DNSPs in developing their Tariff Structure Statements (TSS), including consultation with customers and other stakeholders.
>
> If enabling export charges is simply to provide the option, rather than compel networks to adopt these, then there is limited downside. In these circumstances, export charges will only be used to improve the efficiency of price signals when supported by a networks' customers.

While the benefits of ongoing network price signals may be less applicable to larger generators given the different connection arrangements that impose 'deep' connection costs, there still appears to be benefits in creating the option. For example, for larger distribution-level generators and DER exporters that are eligible for an individually calculated tariff under the DNSP's TSS, there will be scope for the customer and DNSP to negotiate the relative balancing between up-front connection charges and on-going usage charges – while still ensuring that customer pays only its efficient share of the DNSP's costs.[494]

In the Commission's view, this regulatory flexibility is potentially valuable to all distribution-level customers. Therefore, we have decided in the draft rule to enable export pricing for all distribution customers – not just small (or micro embedded) customers.

'Horses for courses'

There may be varying views on whether the introduction of export pricing promotes the long term interests of consumers – both from jurisdiction-to-jurisdiction, and among a DNSP's customer base and key stakeholders. Indeed, while the Government of South Australia sees value in price signals for export services,[495] other jurisdictional governments may consider the introduction of export charges is inconsistent with their economic or social policy objectives. There is not necessarily one right answer. Moreover, other regulatory 'tools', including cost reflective consumption pricing, may better address network issues and stakeholder preferences. This will depend on:

- the jurisdictional circumstances at the time – including the level of hosting capacity constraints, network and investment costs, and network and non-network options available to manage export services

493 AusNet Services submission to the consultation paper, p. 6.

494 Farrierwier, Insights report: Effectiveness of the TSS process and options for implementing export charges, March 2021, p. 49.

495 SA Government submission to the consultation paper, p. 3.

- stakeholder views on how future DER-related investment costs should be allocated – including what the local community considers to be equitable
- consumer views and preferences on the connection service options that should be available to retail customers – including different service levels.

The Commission considers the regulatory framework must accommodate such jurisdictional differences to promote the NEO. Prescribing these aspects in the NER would limit each jurisdiction's capacity to respond to their particular circumstances. As stated by AusNet Services:[496]

> Consistent with many other areas of energy policy, a consistent national DER framework is to be preferred where possible. However, there are several reasons why customers in different jurisdictions may have different expectations and preferences when it comes to DER access and pricing. This could be due to differences in climate (impacting payback periods and therefore take up-rates) and State Government policies. For this reason, a framework that provides options in the NER, with the ability for jurisdictions to set complementary access standards and/ or pricing approaches, could be considered in this context.

The above factors should be taken into account as part of the TSS process for each network before any decision is made to implement export pricing. Stakeholders will have significant opportunities to influence the development of DNSP regulatory proposals and any AER decisions to implement export pricing. DNSPs have made significant improvements to the way in which they engage with consumers in recent years.[497]

The future grid: new service options enabled by this rule change

The Commission considers our decision to enable export pricing options is foundational to support effective DER integration and future market design considerations – consistent with the views of the ESB.[498]

In the future, affordable automated home energy management systems with 'set and forget' technologies are expected to be able to respond to more complex price signals with minimal customer impact. This will allow DER services to deliver the most value to distribution networks at a point in time, and maximise the returns/benefits to households. Enabling export pricing and increasing the flexibility of the network pricing principles is a step forward towards this vision.

Allowing export charges and negative prices opens up a range of potential service options that better integrate DER into the energy system. For example, customers who seek a higher level of export service than is typically offered now (say based on the intrinsic capacity of the network) may have the option to choose higher service levels. This could include higher

496 AusNet Services submission to the consultation paper, pp. 1–2.

497 AEMC, 2020 Economic regulatory framework review, p. 31.

498 ESB, Post 2025 Market Design Consultation Paper, September 2020, pp. 99–100.

average export limits, if the customer agrees to face pricing structures that reflect increased network investment costs and encourage demand response.[499] This in turn may incentivise customers to make efficient, complementary investments in behind-the-meter appliances – such as batteries, EVs and demand management devices – to maximise the value of their solar PV system investments.

Such outcomes are consistent with SAPN's vision for a 'menu of options' to be considered as part of the TSS process. The intent of SAPN's rule change proposal was to provide options to customers on the level of export service they desire and are willing to pay for.[500]

The Commission considers enabling export pricing provides greater regulatory flexibility to promote a 'level playing field' between transmission and distribution-level generation (to the extent practicable). This may be increasingly important as more distributed generation enters the system. As explained in appendix E, transmission-level generation is already charged for costs it imposes on the system – including both upstream connection and system strength costs – and further reforms to transmission network pricing arrangements are currently under consideration as part of the ESB Post 2025 Market Design review. This issue was raised by stakeholders as a risk of introducing export charges (see appendix C.2.2).

All customers of a network should have a say on whether export service costs should be allocated to an extent to those that benefit the most

By enabling export prices, network pricing structures can be developed that allocate DER-related investment costs between users and over time, in proportion to the benefits that customers are expected to receive from these services, or costs they impose on the network.

This is a key issue raised by the rule change proponents. SVDP stated:[501]

> DER is central to a lower emissions energy future and it is therefore imperative that we can achieve a high DER penetration without allowing electricity to become inexpensive for some and unaffordable for others. Inefficient and inequitable allocations of costs and benefits will not deliver the desired outcomes in the long run.
>
> Non-DER participants have already subsidised this initial shift to a DER future and while this has incentivised the DER uptake, largely in the form of rooftop solar, this does not justify ongoing subsidies from non-DER participants to DER participants into the future. Rather, we need to deliver price signals that can incentivise DER participants to engage with energy management services as well as other technologies, such as storage, to deliver a sustainable DER future.

499 As noted by farrierswier, consistent with current arrangements for access by generators to distribution and transmission networks, optional services with higher levels of exports would not provide 'firm' access to the network for exports or a 'guaranteed' level of exports. The level of certainty as to whether a customer would be able to export up to the export limit at any time, and the consequences if it was unable to do so, would primarily be a matter to be addressed in connection arrangements and DNSPs' standard terms for this service. Similar to current broadband products, consumer laws may also be relevant if customers paid more for an optional export service but were regularly unable to achieve the advertised level of service. State and territory guaranteed service level schemes (GSL) do not currently apply to export services. (Farrierwier, Insights report: Effectiveness of the TSS process and options for implementing export charges, March 2021, p. 35)

500 SAPN rule change request, p. 25.

501 SVDP, rule change request, p. 9.

Similarly, TEC/ACOSS said, "equity issues are arising, especially because people without DER are paying a higher proportion of the costs of the grid that everyone depends upon."[502] SAPN stated:[503]

> Stakeholders, in particular vulnerable customer advocates, are also concerned that the current practice of recovering network costs via tariffs only on energy consumed from the grid will in future lead to cross-subsidies from non-DER customers, including vulnerable and disadvantaged customers, to DER customers over time. While new tariffs such as SA Power Networks' 'Solar Sponge' Time of Use tariff help to address this, some stakeholders consider that more symmetrical pricing will be necessary in the long term to avoid undesirable cross-subsidies, particularly as investment to support customer exports increases in the future.

Submissions highlighted a range of views about how DER-related network expenditure should be allocated. Equity considerations are raised where those that benefit the least from network expenditure to increase export hosting capacity – ie, non-DER owners who may be of a lower socio-economic class (see appendix C.1.3) – are asked to pay an equal share of those costs.

Non-DER owners may benefit overall if increased DER exports leads to lower wholesale energy and/or essential system services costs – consistent with the AER's net benefits test for new investment. But the benefits resulting from the network investment may be highly unevenly distributed.

In the Commission's view, a broad range of retail customers and other stakeholders for each jurisdiction should have a say on how costs are allocated through the design of tariff structures (addressing bill impacts). These are not decisions that should be made at a national level. They should be based on network circumstances and customer views and preferences, and take into account government policies. 'One size' does not fit all. Regulatory flexibility is needed.

Submissions supported the need for DNSPs to consult closely with their customers, as discussed in appendix C.7.3. For example, the Government of South Australia says any framework implemented by the Commission will require a strong role for consumer engagement, as there is likely to be a broad range of consumer views in relation to network investment to support export capacity.[504] The Victorian Government highlights the critical role of DNSPs' ongoing consultation and engagement with their customers:[505]

> … to ensure customer needs are understood and that their diverse perspectives inform the development of DER integration plans. The Victorian Government considers that it is important to 'take customers along on the journey' to support their understanding of key issues and empower them to participate in decision making processes.

502 TEC/ACOSS rule change request, p. 2.
503 SAPN rule change request, p. 7.
504 SA Government submission to the consultation paper, p. 3.
505 Victorian Government submission to the consultation paper, p. 5.

The TSS process is where the 'rubber hits the road'

To justify a TSS proposal, DNSPs and the AER will be required to identify the network and customer benefits and any trade-offs before making a decision to implement export charges. As discussed by SAPN, the introduction of any export charges must be carefully considered by DNSPs, under a timeframe and approach that is supported by their customers and stakeholders, as has occurred to date with respect to the introduction of cost reflective tariffs for consumption.[506]

In its Insights report, farrierswier found:[507]

> The TSS process is currently designed to deal with a mass of complex situational detail and variance for each DNSP. This includes consideration of economic principles for efficient pricing, customer impacts, legacy pricing arrangements, legacy metering capabilities, pace of transition, jurisdictional requirements, customer and stakeholder engagement, and the desire for pricing predictability.

Under the TSS process and broader regulatory framework, the AER, each DNSP and their customers, and other key stakeholders (such as retailers and aggregators) can consider and agree on:

- tariff designs and service choices that customers value – which could include consideration of how costs should be allocated between consumption and export services
- the timeframe for implementing export pricing
- whether export charges should only apply prospectively, including any grandfathering arrangements
- whether DER that are capable of responding to dynamic network constraints set by the DNSP should be subject to export charges
- whether cost reflective prices should be location-based, if not otherwise restricted[508]
- tariff trials.

Again, these are dynamic issues and prescribing such outcomes in the NER would not necessarily promote the NEO.

Having regard to farrierswier's findings and stakeholder feedback both in submissions and through members of the technical working group (TWG), the Commission considers the TSS process is the appropriate mechanism to make regulatory decisions relating to the implementation of export pricing:

- The TSS process provides significant flexibility for DNSPs and the AER to develop pricing structures that meet a network's specific circumstances and customer preferences.
  - This includes decisions on whether tariff designs should be based on localised constraints. Although there has been limited implementation of locational pricing for

506 SAPN rule change request, p. 23.

507 Farrierwier, Insights report: Effectiveness of the TSS process and options for implementing export charges, March 2021, p. 2.

508 Currently there are jurisdictional prohibitions on locational network pricing for small customers in NSW, South Australia and Tasmania, and also measures applied outside the TSS process in Queensland to achieve an equivalent effect.

consumption pricing in jurisdictions to date, this may be a feature of future market designs.

- The TSS process is designed to provide flexible transitional arrangements – consistent with stakeholder views outlined in appendix C under section C.7.1. DNSPs are required to undertake significant consultation, customer education, and consideration of both the potential impacts on customers and how tariff classes will be communicated.
  - The DNSPs' TSS consultation provides a forum for retail customers and stakeholders to raise concerns with how tariffs, both for consumption and export services, are structured.
  - If a DNSP has not adequately addressed those concerns in its regulatory proposal, stakeholders then have an opportunity to influence the AER's decision on whether or not to approve the DNSP's proposal. The NER require the AER to take account of DNSPs' consultation, and one of the network pricing principles requires the TSS to comply with government policies.[509]
- The TSS process is well understood. Creating a new regulatory process to implement export pricing would create unnecessary complexity and regulatory burden.

It is noted the AER has requested changes to most DNSP TSS proposals for consumption services to date, including to the form of transition (ie, arrangements for mandatory assignment, opt-out, opt-in) and pace of transition. Based on its consultation with the AER, farrierswier highlighted the following examples of times the AER has intervened to either progress tariff reform or to give greater weight to the customer impact principles:[510]

- moving some networks from opt-in to opt-out assignment to cost reflective tariffs (e.g. TasNetworks)
- requiring cost reflective tariffs to be discounted relative to flat rate tariffs to incentivise their uptake in a number of jurisdictions (e.g. Endeavour Energy)
- not allowing Ausgrid's proposal to mandatorily reassign large numbers of customers given stakeholder concern over their ability to understand and engage with the new tariffs
- engaging in Ergon Energy and Energex's TSS processes including efforts to support residential, small business and large users and their representatives through numerous 'teach ins' on the regulatory process.

This supports farrierswier's finding that the existing TSS process and pricing principles:[511]

- provide for a range of different transitional tools and other mechanisms that can be used by DNSPs and the AER (in consultation with customers) to mitigate the impact of introducing export pricing on customers
- are likely to steer DNSPs towards scenarios that include measures to mitigate potential harm for exporting consumers during transition

509 NER clause 6.18.5(j).
510 Farrierwier, Insights report: Effectiveness of the TSS process and options for implementing export charges, March 2021, p. 17.
511 ibid, pp. 65–66.

- moreover, there is a high likelihood that scenarios that have higher potential for customer harm would not be proposed by DNSPs or approved by the AER, especially if consumers raise significant concerns with them during the consultation that is required as part of the TSS process.

In conclusion, farrierswier states the TSS process and pricing principles are robust to introducing export pricing, and there is no reason to expect that material consumer harms would remain after the application of the existing safeguards.[512]

Facilitating innovative tariff design to meet customer preferences

Farrierswier highlighted that the pricing framework should permit DNSPs to design network tariffs for retailers and intermediaries, not just end customers.[513]

Under the pricing framework, NER clause 6.18.5(i) states the structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff, having regard to: (1) the type and nature of those retail customers; and (2) the information provided to, and the consultation undertaken with, those retail customers.

The concern is that this clause is a barrier to DNSPs developing innovative pricing options for export services, limiting the effectiveness of this reform – as advised by AER staff, based on their experience of TSS processes and stakeholder engagement to date.

Farrierswier found there may be a case for revisiting this aspect of the pricing rules to enable pricing designs that also target retailers and energy intermediaries. This, farrierswier says, may support implementation of cost reflectivity and innovation in network tariff offerings where they are designed for business-to-business application. Farrierswier noted:[514]

- network tariff structures may need to get more complex (e.g. for export services or in a future two-sided market)
- network tariffs may be sending signals to intelligent energy control devices rather than seeking behavioural change from retail customers themselves
- large retailers have reported to the AER they will likely continue to package network tariffs into 'insurance style' retail tariffs
- innovative retailers and energy service providers may need to package multiple energy service value-streams into a simplified retail offer, which could require network signals to be balanced and at times traded off against other supply chain costs and benefits to provide net tariffs and rewards to retail customers.

In farrierswier's survey of TWG members, a retailer observed that pricing to retailers could see more innovative tariffs like locational or critical peak pricing that we have not seen at any scale to date:[515]

> Network tariffs are charged to individual customers. Transitioning towards a bulk

512 ibid, p. 65.
513 ibid p. viii.
514 ibid, p. 25.
515 ibid, p. 25.

> wholesale network tariff approach (where the network tariff was aggregated and charged to the retailer based on the load profile of the retailer's portfolio in a particular location) would incentivise retailers to introduce locational and critical peak pricing because there would be a direct economic incentive to realise greater efficiency across the retail customer base.

That said, farrierswier noted previous customer and stakeholder feedback that "end customers wishes should be kept in mind even if tariff structures are directed towards retailers", and "tariff structures should be able to be understood and managed by both retailers and customers".[516]

Commission's view

The Commission considers this matter relates to issues raised in the rule change requests, and should be addressed in order to improve the effectiveness of this package of reforms.

In explaining the introduction of NER clause 6.18.5(i) in our 2014 decision, the Commission stated, "Consumers will not be able to respond to the price signals that network prices are intended to send if they cannot relate their usage decisions to the price structure."[517] The Commission maintains this view at a principle level but accepts the current drafting of NER cl. 6.18.5(i) is a potential barrier to DNSPs developing innovative pricing options for export services – which is not consistent with the NEO.

For more advanced pricing structures which would inherently target more engaged retail customers, the Commission considers that DNSPs should be able to meet their obligation under this clause by undertaking targeted consultation with customers of the relevant 'type and nature' to specifically test their ability to understand and respond to the more advance price signals. In other words, the Commission considers this pricing principle should not require DNSPs to ensure all tariff option designs are reasonably capable of being understood by even the least informed/engaged retail customer.

As discussed above, the Commission expects that DNSPs may increasingly seek to develop more advanced pricing structures in collaboration with retailers and/or energy intermediaries (such as VPPs) – including machine-to-machine tariffs, for example. Pricing structures could be specifically designed for retailers and/or energy intermediaries to then re-package in innovative ways for end users to meet demand from customers in specific segments or with specific characteristics. This flexibility is important for the future grid.

As it currently stands, there is a high risk that such advanced tariff options would not be approved because they would not meet NER clause 6.18.5(i). Therefore, in the Commission's view, amendments to this pricing principle are required. Further, the Commission considers it would be problematic to change NER clause 6.18.5(i) for export services only – especially given the benefits of maintaining symmetry between consumption and export services to minimise regulatory complexity, and it is highly desirable for DNSPs to consider pricing

516 ibid, p. 25.

517 AEMC, Distribution Network Pricing Arrangements, Rule Determination, November 2014, p. 9.

options and trials holistically for consumption and export services. Consequentially, proposed changes to this pricing principle apply to both services.

The Commission's draft rule amends NER clause 6.18.5(i) to state:

- The structure of each tariff must be reasonably capable of being understood by retail customers that are or may be assigned to that tariff (including in relation to how usage decisions or controls may affect the amounts paid by those customers) or of being directly or indirectly incorporated by retailers or Market Small Generation Aggregators in contract terms offered to those customers, having regard to information available to the Distribution Network Service Provider, which may include:
  - the type and nature of those retail customers;
  - the information provided to, and the consultation undertaken with, those retail customers; and
  - the information provided by, and consultation undertaken with, retailers or Market Small Generation Aggregators.

Further, the AER can consult on and clarify, through the *Export Tariff Guidelines*,[518] that the amended NER clause 6.18.5(i) is not a barrier for DNSPs to design more advanced network tariffs targeting retailers and intermediaries for end customers.

Further changes to support implementation of export pricing

First, the Commission agrees with the AER's proposal to broaden the reference to cost drivers under NER clause 6.18.5(f)(2), which requires DNSPs to base tariffs on the long run marginal cost, to be more adaptable to emerging issues.[519] This clause references additional costs likely to be associated with meeting demand from retail customers at "times of greatest utilisation of the relevant part of the distribution network" – which relates more to peak consumption periods.

The growth in solar PV output in the middle of the day is lowering demand for consumption services at these times – with negative demand experienced in some cases. Minimum demands for South Australia and Victoria continued to trend downwards, with new minimum operational demand records set in late 2020.[520]

DNSPs may need to invest to support increasing reverse power flows as customers continue connecting DER, especially to manage periods of minimum demand. SAPN said this expenditure would not have otherwise been required:[521]

> The most immediate constraint in most areas is voltage management at customers' premises. Networks were designed only to accommodate the drop in voltage that occurs as load increases, and hence have little headroom to absorb the rise in voltage that now occurs when customers' inverters feed energy back into the grid.

518 See section 6.4.3 below.

519 AER submission to the consultation paper, pp. 6–7.

520 AEMO, Quarterly Energy Dynamics: Q4 2020, p. 8.

521 SAPN rule change request, p. 4.

> Addressing this is not as simple as 'lowering the voltage' across the network, as this would cause under-voltage at peak demand times. Networks need to invest to upgrade their voltage management capabilities to operate over a much greater 'dynamic range' of power flows than they were originally designed for, to manage both positive and negative extremes. This in turn requires investment in improved monitoring of voltage performance across the network.

Therefore, the draft rule amends NER clause 6.18.5(f)(2)to say, "times of greatest utilisation of the relevant service", which covers minimum demand-related network constraints – providing greater clarity of the basis for which DNSPs should be developing tariff structures (See item X in Schedule Y of the amending rule).

Second, the Commission considers a consequential change is required to the NER clause 6.18.4 principles governing assignment or re-assignment of retail customers to tariff classes and assessment and review of the basis of charging.

Specifically, the draft rule deletes current NER clause 6.18.4(a)(3), which states retail customers with micro-generation facilities should be treated no less favourably than retail customers without such facilities but with a similar load profile.

Farrierswier advised the nature of customers' exports could become a basis for assigning customers to different tariff classes.[522]

NER clause 6.18.4(a)(3) could undermine SAPN's vision to develop a 'menu of options' for retail customers to choose from to take advantage of the opportunities DER provide,[523] including engaging in multiple energy service markets. This is a key reason for the Commission's decision to enable export pricing, as discussed above.

Third, the draft rule proposes changes to the billing and credit risk pass through arrangements in the NER to support the implementation of export tariffs.

Chapter 6B provides for DNSPs to bill retailers for network charges relating to retail customers. The chapter includes rules relating to tariff reassignment and the provision of credit support. These arrangements were implemented as part of the 'NECF package' and where they apply, displace the operation of the billing arrangements in chapter 6 of the NER.[524]

The draft rule proposes to extend the arrangements in chapter 6B to allow a DNSP to bill market small generation aggregators (MSGAs) for network charges relating to exports by the retail customer of an MSGA. This is consistent with the proposed extension of the term 'retail customer' to include micro embedded generators and non-registered embedded generators (other than those connecting under Chapter 5) and is also consistent with the proposed extended meaning of micro embedded generator to include the customers of MSGAs.[525] Changes to Retail Market Procedures may be needed to implement this change and the

522 Farrierwier, Insights report: Effectiveness of the TSS process and options for implementing export charges, March 2021, p. 70.

523 SAPN rule change request, p. 25.

524 NER clause 6B.A1.1(b).

525 Draft chapter 6B, particularly amending NER clauses 6B.A1.1 and 6B.A1.2. The changes are summarised in appendix B.

transitional rules provide for AEMO to review the need for amendments and initial the amendment process if necessary.[526]

The draft rule also proposes to extend the billing and settlement provisions in NER Chapter 6 to allow a DNSP to bill an MSGA for network charges relating to export by the MSGA's customers who are not retail customers.[527]

The risk of a retailer failing to pay distribution charges due to insolvency is currently passed through to electricity users by including retailer insolvency events as pass through events under NER Chapter 6.[528] The draft rule proposes to extend the meaning of retailer insolvency event and related definitions and make consequential changes to chapter 6 to allow pass through of unpaid network charges of a failed MSGA.[529]

6.4.3 Additional customer safeguards

As just discussed, the Commission considers the current pricing framework, including the TSS process, is robust to changing circumstances over time and inherently provides for flexible transitional arrangements. Further, export pricing is optional. Enabling export pricing provides additional economic 'tools' – use of which may promote the NEO depending on a network's circumstances and customer preferences.

Despite the above findings of the robustness of the TSS process and negligible bill impacts for most customers, the Commission maintains the introduction of export charges is a significant policy change and implementation requires care and understanding. We have considered the need for additional transitional rules to mitigate customer risks, including those outlined in farrierswier's Insights report (see appendix D.3) and TEC/ACOSS' rule change request[530] – among other options.

To find a balance of providing regulatory flexibility while giving stakeholders more confidence in the TSS process, and to promote consumer engagement in the AER's decision making, the Commission has decided to introduce the following new requirements that reinforce the need for continued consultation and collaboration:

- DNSPs must develop and consult on an export tariff transition strategy, which would outline when and how each DNSP intends to phase-in any proposed export pricing over time – if this promotes consumers' interests
- DNSPs must explain the interrelationships between different aspects of their regulatory and TSS proposals in a plain language overview
- the AER must publish *Export Tariff Guidelines* specific to export services, which includes a requirement for the AER to undertake significant consultation in developing its assessment approach.

526 Amending NER clause 11.[xxx].8.

527 Amending NER clause 6.20.1.

528 NER clause 6.6.1.

529 Amending NER clauses 6.6.1(c)(6), 6.6.1(l) and in chapter 10, the draft definitions of 'billed but unpaid charges', 'failed Market Small Generation Aggregator', 'retailer insolvency costs' and 'retailer insolvency event'.

530 TEC/ACOSS rule change request, pp. 19–20.

Further, the Commission has increased the monetary threshold for DNSPs to undertake tariff trials to inform TSS proposals, and promote innovation and timely implementation of export pricing. This means DNSPs will be able to develop a better understanding of the potential bill impacts of export pricing on their customers, and potential economic benefits, in developing their TSS proposals.

DNSP requirement to develop an export tariff transition strategy

First, a DNSP must include a description of the export tariff transition strategy it has adopted to phase-in any proposed export pricing over time as an element of its TSS proposal under NER clause 6.18.1A(a). Although a DNSP may not seek to introduce export tariffs in the short term, it could outline its ongoing stakeholder engagement approach and consider possible tariff trials for export services to inform future TSS proposals.

This requirement builds on an existing consumer impact principle that expressly allows DNSPs to phase-in new pricing structures over five years or more. That is, under the pricing principles, a DNSP must already consider the impact on retail customers of changes in tariffs from the previous regulatory year, and may vary tariffs from those to the extent the DNSP considers reasonably necessary, having regard to the desirability for tariffs to comply with the pricing principles – albeit after a reasonable period of transition (which may extend over more than one regulatory control period).[531]

Second, the proposed TSS for both consumption and export services must be accompanied by an overview paper, written in reasonably plan language understandable to retail customers, which includes each of the following matters:

1. a summary explaining the proposed TSS, including specifically the export tariff transition strategy
2. a description of:
    a. how the DNSP has engaged with retail customers and other key stakeholders – including consumer groups, retailers and jurisdictional governments – in developing both the proposed TSS and transition strategy
    b. the relevant concerns identified as a result of that engagement
    c. how the DNSP has sought to address those concerns identified as a result of that engagement
3. a description of the key risks and benefits of the proposed TSS, including the export tariff transition strategy.

Third, ultimately, the DNSP's transition policy must be approved by the AER.

It is noted that this new requirement is complementary to an existing obligation on DNSPs to engage with non-network providers and consider non-network options for addressing system limitations in accordance with its 'demand side engagement strategy'[532] – which now also applies to export services (see chapter 4 of this decision document). Adoption of cost

531 See NER clause 6.18.5(h).
532 NER clause 5.13.1(f).

reflective tariff designs, including negative prices, may be an alternative or complementary to non-network options to manage network constraints.

DNSP requirement to explain how TSS fits within wider regulatory proposal

The proposed TSS overview, as discussed above, must also include a description of the interrelationships between different aspects of the regulatory proposal and proposed TSS – including connection policies and proposed expenditure. A holistic consideration, in plain language, allows consumers to better understand a DNSP's proposal and provide input. Stakeholder participation in energy market decision-making processes is an important element of achieving the NEO.

There are significant interrelationships between the various 'constituent components' of an overall regulatory proposal and AER decision. These interrelationships could include:

- underlying drivers such as forecast demand affect the efficient levels of expenditure
- trade-offs between different components of revenue – for example, investment can be deferred, but it may result in higher maintenance expenses (and vice versa)
- augmentation of a network may mean the DNSP has more assets to maintain, leading to higher operating expenditure requirements
- a DNSP's governance arrangements and its approach to risk management will influence most aspects of the proposal, including capital and operating expenditure trade-offs
- how any demand management innovation allowance relates to the application of the demand management incentive scheme.

Additionally, there are interrelationships between the regulatory proposal and TSS proposal. Indeed, the idea of cost reflective pricing is to link network tariffs to the underlying drivers of network costs.

For example, price signals can promote more efficient use of the network by 'smoothing' demand and thereby lower future investment requirements (as discussed above). Therefore, a DNSP's TSS may be directly linked to demand forecasts and its proposed costs. Further, a DNSP may consider alternatives to using price signals through tariff structures, such as procuring services through non-network options, including community batteries (as noted above). In this regard, a DNSP's demand-side engagement strategy should be consistent with the export tariff transition strategy.

These interlinkages would form part of the justification for a proposed TSS. It is important for DNSPs to clearly spell them out for all stakeholders who are engaged in the regulatory process, especially consumers. This may also assist the AER in making decisions on each constituent component of a regulatory proposal, and approving the TSS proposal and export tariff transition strategy. The additional detail prescribed by this draft rule may be particularly important in the short term, given the AER will not necessarily be able to rely on effective financial incentives to overcome information asymmetries until it has updated the STPIS to incorporate export services (see chapter 5).

In support of this policy position, although in a somewhat different context, the AER states it has called on DNSPs to present their pricing, expenditure, and demand management and connection strategies as a package:[533]

> Of the DNSPs, SAPN best demonstrated these linkages as part of its 2020-25 regulatory proposal. This was important for demonstrating how SAPN approached DER integration holistically, and how these plans fed into its broader network strategy. Given other DNSPs did not adequately demonstrate these linkages, we support the DER integration strategy becoming an obligation on DNSPs.

The Commission considers that the above arrangements also address an aspect of TEC/ACOSS' rule change request, which sought to require DNSPs to outline:[534]

- the degree with which connection, pricing and expenditure solutions are substitute or complement options; the trade-offs between different options the network considered; and why the network has proposed the particular approach it chose in its DER integration strategy
- how the network has consulted with stakeholders on the strategy and incorporated feedback into the strategy.

AER requirement to publish TSS guideline for export services

The Commission's draft rule requires the AER to consult on and publish a TSS guideline specific to export services by 1 July 2022 – the *Export Tariff Guidelines* (Box 8).

BOX 8: NEW NER CLAUSE INTRODUCING EXPORT TARIFF GUIDELINES

6.8.1B Export Tariff Guidelines

- The AER must in accordance with the distribution consultation procedures, develop and publish guidelines (the Export Tariff Guidelines) taking into account the objective in paragraph (b).
- The objective of the Export Tariff Guidelines is to provide information and guidance to DNSPs, distribution service end users, retailers, Market Small Generation Aggregators and other stakeholders about the process for development and approval of export tariffs.
- The Export Tariff Guidelines may include information and guidance about:
  - stakeholder engagement in relation to proposed export tariffs
  - the provision of information about stakeholder concerns and how they have been taken into account
  - the AER's approach (including worked examples) to applying the network pricing objective and pricing principles in relation to export tariffs

533 AER submission to the consultation paper, p. 5.

534 TEC/ACOSS rule change request, p. 11.

- any other matters the AER considers appropriate.
- The Export Tariff Guidelines are not binding on the AER or a DNSP.

This will be an important mechanism to ensure ongoing stakeholder consultation on these pricing reforms and to manage change beyond the consultation undertaken as part of this rule change process, by addressing stakeholder concerns about how export pricing is implemented over time. This includes finding ways to better manage different jurisdictional policies.[535]

Further, the guidelines will promote confidence in the TSS process by creating greater transparency and certainty of:

- the AER's decision-making process and criteria, including how it interprets the network pricing principles under NER clause 6.18.5 and the new requirements set out above
- expectations of how DNSPs should both develop their TSS proposals, possibly including examples of 'best practice' consultation by DNSPs, and present information to the AER
- how customer and other stakeholder views and preferences should be taken into account in the process.

The Commission considers the above guidance is most appropriately provided by the AER through formal guidelines, rather than prescribed in the NER. Consistent with our views, farrierswier highlighted the following potential benefits of this approach:[536]

- a guideline could retain some flexibility to applying the pricing rules for circumstances where DNSPs can demonstrate that departures from the guidance are preferable, or establish clear preconditions for certain export pricing and transition options
- public consultation on the guideline may make it easier for consumers and their representatives to engage in the process for designing export pricing rather than having to engage separately with each DNSP when developing their TSSs
- because the existing rules have been used for a while only for consumption based tariffs, there may be need for some change management to encourage DNSPs and the AER to identify and settle on how these same rules will apply to export pricing and the compliance demonstration required for this
- the guideline development and consultation process could support fit-for-purpose transitional requirements for different customer types and network circumstances
- jurisdictional policy preferences could be considered in the guideline development and consultation process.

535 Farrierswier found a key lesson from previous TSS processes is that policy constraints should be established at the commencement of TSS engagement and development processes – for example, jurisdictional preferences on export pricing could be established at the framework and approach stage of distribution determinations, so these policies can be accounted for in both service classification and TSS engagement. (Farrierwier, Insights report: Effectiveness of the TSS process and options for implementing export charges, March 2021, p. 27)

536 ibid, p. 69.

The Commission notes Jemena's view that relying on individual TSS processes for each jurisdiction to manage change will not be adequate, and its broader concerns about the slow progress of cost reflective pricing to date. Jemena considers either the NER or an AER guideline should provide decision frameworks for common TSS issues to help streamline individual TSS consultation processes, and to help manage stakeholder issues and communications.[537]

The Commission has decided that the Export Tariff Guidelines will not be 'binding' on the AER or DNSPs. It should not be seen by DNSPs as a compliance exercise. This could undermine the potential for engagement to be innovative and responsive to consumer views and preferences.

The AER is required to prepare and publish the Export Tariff Guidelines under the 'distribution consultation procedures'. This requires the AER to publish the proposed guideline, an explanatory statement and an invitation for written submissions on the proposed guideline – among other consultation requirements under NER rule 6.16.

The AER is best placed to provide guidance on cost and capacity allocation issues

As discussed in appendix C.6:

- TEC/ACOSS proposed the introduction of a new pricing principle to guide the allocation of existing and planned export capacity between prosumers.[538]
- SAPN proposed a new rule to provide guiding principles for distribution networks on how costs should be allocated between consumption and export services.[539]

The Commission considers the above issues can be best addressed through the AER's guidelines and the TSS process. These decisions should be based on the network circumstances, and consumer and government preferences at the time. A high-level principle prescribed in the rules, which provides for this flexibility for each network, would not provide meaningful certainty and clarity of how an AER decision contributes to the promotion of the NEO.

In addition to the Export Tariff Guidelines, the draft rule requires the AER to review whether updates are required to other relevant guidelines as a transitional matter.

Greater flexibility for in-period tariff trials

The Commission's draft determination to enable export charges allows DNSPs to consult with customers to conduct in-period tariff trials when developing their TSS proposals.

Export charges could be included in TSS proposals as part of the NSW, ACT, and Tasmania DNSPs' regulatory proposals, which are due to be submitted to the AER in January 2023.

537 Jemena submission to the consultation paper, p. 12.

538 TEC/ACOSS rule change request, p. 14.

539 SAPN rule change request, p. 24.

The five-yearly regulatory proposals for the other DNSPs are staggered over time. For example, Victorian DNSPs are due to submit their next round of regulatory proposals in January 2025.

DNSPs have the option to propose to amend their TSS in-period under NER cl. 6.18.1B. But this may be impractical given the level of consultation required on TSS proposals, the need to consider interrelationships with other aspects of a DNSP's revenue proposal and potential impacts on cost allocations.

Alternatively, DNSPs can implement in-period trials for tariffs under a certain threshold – namely, where the forecast revenue recovered by the tariff does not exceed 0.5 per cent of the annual revenue requirement, and where the forecast revenue recovered cumulatively from all such tariffs that are not included in the TSS does not exceed 1.0 per cent of the annual revenue requirement. In-period tariff trials are not be required to comply with the network pricing principles, as discussed in section 6.3.3 above.

With the rapidly changing energy market and ongoing reforms underway (including through this rule change process), the use of tariff trials to inform TSS proposals may become increasingly important – especially to inform TSS proposals for export pricing.

The objectives of relevant trials currently planned and underway are to help integrate DER into distribution networks and achieve more cost-reflective pricing. These trials are intended to explore how to reflect the cost of serving the increasingly diverse nature of customers, as well as sending price signals to encourage behavioural change to support system operation. The trials target both behind the meter assets, as well as large grid scale customers.

For example, possible tariff trials include:

- residential tariffs for homes with EVs to explore more dynamic network tariff structures to be packaged into innovative retail offers
- tariffs for EV charging stations to try and explore how the potential flexibility in the operation of these sites could be used to support and reward more efficient utilisation of existing network infrastructure
- third party owned batteries used for service provision
- network owned batteries which will be rented to retailers to engage in competitive services
- community battery models.

In discussions with the AER, the Commission understands the 'individual' and 'cumulative' thresholds of 0.5 per cent and 1 per cent of the DNSP's annual revenue requirement, respectively, can act as a barrier to undertaking export pricing trials concurrently with other initiatives, and to scaling up trials to progress implementation of cost reflective pricing for both consumption and export services. This threshold may also limit innovative network tariffs in response to consumer requests or changing consumption patterns, given export pricing is now an option.

The network pricing principles are an important customer safeguard and promote the NEO. Exempting a DNSP from complying with these principles is a risk – there is a tradeoff between providing adequate safeguards, and flexibility for DNSPs to be responsive to changing consumer preferences and technology/market developments.

On balance, the Commission considers increasing the cumulative threshold for tariff trials within a regulatory control period through a transitional arrangement could facilitate a valuable input into TSS proposals – informing the DNSPs' benefit–cost, customer impact and customer behaviour analysis. Further, extending the ability of DNSPs to undertake tariff trials could assist the change management process, promoting timely progression of implementation of export pricing, especially for those DNSPs that are due to submit their next round of TSS proposals later in the regulatory cycle.

Importantly, this decision does not mean DNSPs can earn additional revenue in a regulatory control period. Any revenues earned by DNSPs through tariff trials falls within an overall revenue cap on each business, which is set by the AER.

The Commission's draft rule increases the individual threshold from 0.5 per cent to 1 per cent of the DNSP's annual revenue requirement, and the cumulative threshold from 1.0 per cent to 5 per cent of the DNSP's annual revenue requirement. These higher thresholds amounts are based on discussions with the AER and in reference to other similar limits within the regulatory framework.[540]

This is a proposed transitional measure under Chapter 11 of the NER for the current and next regulatory control periods, impacting NER clause 6.18.1C.

540 The STPIS allows for 1 per cent revenue for customer service parameters and 5 per cent for all performance parameters, while the demand management incentive scheme allows for up to 1 per cent revenue each year. Similar to tariff trials, the intention of these schemes is to incentivise DNSPs to innovate to promote the long term interests of consumers.

ABBREVIATIONS

ACOSS	Australian Council of Social Service
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CESS	Capital Expenditure Sharing Scheme
CECV	Customer Export Curtailment Values
Commission	See AEMC
DAPR	Distribution Annual Planning Report
DEIP	Distributed Energy Integration Program
DMIA	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentives Scheme
DNSP	Distribution network service providers
EBSS	Efficiency Benefit Sharing Scheme
ENA	Energy Networks Australia
ESB	Energy Security Board
EV	Electric Vehicle
GSL	Guaranteed Service Level
MCE	Ministerial Council on Energy
MSGA	Market Small Generator Aggregator
NEL	National Electricity Law
NEO	National electricity objective
NERL	National Energy Retail Law
NERO	National energy retail objective
NGL	National Gas Law
NGO	National gas objective
PV	Photovoltaic
RAB	Regulated Asset Base
RIT-D	Regulatory Investment Test for Distribution
SAIFI	System Average Interruption Frequency Index
SAIDI	System Average Interruption Duration Index
SAPN	SA Power Networks
STPIS	Service Target Performance Incentive Scheme
SVDP	St Vincent De Paul Society Victoria
TEC	Total Environment Centre
TSS	Tariff Structure Statement

A LEGAL REQUIREMENTS UNDER THE NEL AND NERL

This appendix sets out the relevant legal requirements under the NEL and the NERL for the Commission to make this draft rule determination.

A.1 Draft rule determination

In accordance with s. 99 of the NEL and s.256 of the NERL the Commission has made this draft rule determination to make a more preferable draft electricity rule and more preferable draft retail rule, in relation to the rules proposed by SAPN, SVDP and TEC/ACOSS.

The Commission's reasons for making this draft rule determination are set out in section 3.4.

Copies of the more preferable draft rules are attached to and published with this draft rule determination. Their key features are described in section 3.4 and Chapters 4–6 of this determination.

A.2 Power to make the rules

The Commission is satisfied that the more preferable draft rules fall within the subject matter about which the Commission may make rules. The more preferable draft electricity rule falls within s. 34 of the NEL as it relates to:

- the activities of persons (including Registered participants) participating in the national electricity market or involved in the operation of the national electricity system[541]
- the provision of connection services to retail customers.[542]

The more preferable draft retail rule falls within the matters set out in s. 237 of the NERL as it relates to regulating the provision of energy services to customers, including customer retail services and customer connection services.[543]

A.3 The Commission's considerations

In assessing the rule change requests the Commission considered:

- its powers under the NEL and NERL to make the rules
- the rule change requests
- submissions received during first round consultation
- the ways in which the proposed rules will or are likely to contribute to the NEO and NERO
- the extent to which the proposed retail rule is compatible with the development and application of consumer protections for small customers
- the revenue and pricing principles in the NEL.

541 Section 34(1)(a)(iiI) of the NEL.
542 Section 34(1)(a)(iv) of the NEL.
543 Section 237(1)(a)(i) of the NERL.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for these rule change requests.[544]

A.4 Civil penalties

The Commission cannot create new civil penalty provisions. However, it may (jointly with the AER) recommend to the Energy Ministers Meeting that new or existing provisions of the NER or the NERR be classified as civil penalty provisions.

The Commission does not propose to recommend to the Energy Ministers Meeting that any of the proposed amendments made by the draft rules be classified as new civil penalty provisions. Where the draft rules amend provisions that are currently classified as civil penalty provisions, the Commission does not propose to recommend to the Energy Ministers Meeting any changes to the classification of those provisions.

A.5 Conduct provisions

The Commission cannot create new conduct provisions. However, it may (jointly with the AER) recommend to the Energy Ministers Meeting that new or existing provisions of the NER or the NERR be classified as conduct provisions.

The draft rules do not amend any rules that are currently classified as conduct provisions under the NEL or NERL. The Commission does not propose to recommend to the Energy Ministers Meeting that any of the proposed amendments made by the draft rules be classified as conduct provisions.

A.6 Review of operation of draft rules

The more preferable draft rules do not require the Commission to conduct a formal review of the operation of the draft rules. The Commission may however self-initiate a review of the operation of the rules (if final rules are made) at any time if it considers such a review would be appropriate, pursuant to s. 45 of the NEL and s. 232 of the NERL.

544 Under s. 33 of the NEL and 225 of the NERL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for energy.

B SUMMARY OF AMENDMENTS TO THE RULES

This appendix outlines the amendments to the National Electricity Rules (NER) and the National Energy Retail Rules (NERR) made under the more preferable draft rules.

B.1 Amendments to the National Electricity Rules

Table B.1: Changes to NER Chapter 5

NER CHAPTER 5 CLAUSE	COMMENTARY
5.1.2	Here and elsewhere in Chapter 5, it is proposed to italicise the term 'non-registered embedded generator' as the term would be defined in chapter 10.
5.1.2(d)	The table in this clause is an overview of connection processes under the NER. It is proposed to add a reference in the last row to a Market Small Generation Aggregator applying for connection on behalf of a micro embedded generator, consistent with the proposal to extend the definition of 'micro embedded generator' to include customers of MGSAs who are not retail customers.
5.2A.4(a)	Minor drafting change to correct the spelling of 'acquisition'.
5.3.1A(a)	Paragraph (a) cross-references the definition of 'non-registered embedded generator' and would be deleted, as the term would be defined in chapter 10.
Schedule 5.8 S5.8(b)(2)	S5.8(b)(2) deals with information to be included in a DAPR. Amendments would replace 'load forecasts' with 'forecasts of load and generation capacity of known embedded generating units' with a consequential change to omit the reference to generation capacity in (b)(2)(ix).
Schedule 5.8 S5.8(b)(4)	The reference to 'reliability target' in relation to STPIS would be replaced with 'relevant performance targets', as performance targets for export service would not be based on reliability measures.
Schedule 5.8 S5.8(c)(5)	Paragraph (c) deals with information about system limitations. Subparagraph (c) would be amended to refer to changes in forecast load or generation from embedded generating units that would defer a forecast system limitation. At present the clause refers only to reductions in load.
Schedule 5.8 S5.8(l)	The clause deals with information on a DNSP's demand management activities. Amendments would extend the clause to activities relating to embedded generating units, including, for micro embedded generators and non-registered embedded generators, breakdowns of export capacity sought, export capacity offered, the number of connection enquiries, connection applications, customers given zero export limits

NER CHAPTER 5 CLAUSE	COMMENTARY
	and the estimated volume of electricity that could not be exported due to system limitations.

Table B.2: **Changes to NER Chapter 5A**

NER CHAPTER 5A CLAUSE	COMMENTARY
5A.A.1 'basic connection service' and elsewhere	Here and elsewhere in chapter 5A, it is proposed to italicise the term 'non-registered embedded generator' as the term would be defined in Chapter 10.
5A.A.1 'embedded generator"	It is proposed to delete 'embedded generator' and replace it with a new term defined in chapter 10, 'embedded generating unit operator'. This avoids confusion with the term Embedded Generator.
5A.A.1 'micro embedded generator'	The definition of 'micro-embedded generator' would be moved from chapter 5A to chapter 10 and extended to cover, in addition to small customers and large customers, MSGA customers, to ensure customers of MSGAs who are not small customers or large customers are included within the scope of the definition and so able to request basic connection services under chapter 5A.
5A.A.1 'MSGA customer'	A new defined term 'MGSA customer' would be used to refer to the owners, operators and controllers of small generating units who are customers of MSGAs. This group is currently identified indirectly in clause 5A.A.3 and the new definition would be based on that clause.
5A.A.1 'non-registered embedded generator'	The definition would be moved to chapter 10, in a slightly amended form that would use the new term 'embedded generating unit operator'.
5A.A.1 'retail customer'	The definition would be moved to chapter 10 and the extended definition would apply throughout the NER. Refer to the discussion in the table below about the proposed new definition in chapter 10.
5A.A.1 'supply service'	A reference to 'import or export' would be added to 'supply service' to clarify that a 'supply service' may be either.
5A.A.3	The clause specifies that MSGAs are agents for their customers. The clause would be amended to use the new term 'MSGA customer' and to clarify that the agency arrangement applies for the purposes of chapter 5.

NER CHAPTER 5A CLAUSE	COMMENTARY
	The clause heading would be amended to align with the amended clause.
5A.B.1(b)(1)	The clause deals with submission of model standing offers for basic connection services. The new term 'embedded generating unit operator' would replace 'embedded generator'. The change is not intended to change the meaning of the clause.
5A.B.3(a)(1)	The clause deals with approval of model standing offers for basic connection services. The new term 'embedded generating unit operator' would replace 'embedded generator'. The change is not intended to change the meaning of the clause.
5A.E.4	The clause deals with payment of connection charges. Reference to MSGAs would be added to the existing references to retailers, to provide for MSGAs to pay connection charges on behalf of their customers, consistent with the MSGA acting as agent under clause 5A.A.3.
5A.F.7	The clause deals with the initial request to energise a new connection. Reference to MSGAs would be added to the existing references to retailers, to allow for MSGAs to request initial energisation for their customers. The heading would be updated to reflect the changes to the clause.
S5A.1, Part B	This part of the schedule deals with information to be included in a connection offer involving embedded generation. The new term 'embedded generating unit operator' would replace 'embedded generator' throughout. The change is not intended to change the effect of the schedule.
S5A.1, Part B(b)(1)	The reference to 'supply of electricity to the connection point' would be replaced with a reference to 'supply services at the connection point' to reflect the scope of the supply services that will be provided. Similar changes are proposed for the model connection contract under the NERR.

Table B.3: **Changes to NER Chapter 6**

NER CHAPTER 6 CLAUSE	COMMENTARY
6.1.4	This clause prohibits DUOS for the export of energy and would be deleted. References to 'users or potential users' would be amended to clarify that

NER CHAPTER 6 CLAUSE	COMMENTARY
	the phrase refers to users of services, not users of electricity.
6.2.2 and 6.2.5	References to 'users or potential users' would be amended to clarify that the phrase refers to users of services, not users of electricity.
6.2.8(a)(1)	The clause deals with general matters relating to guidelines made by the AER under chapter 6. A reference to the proposed Export Tariff Guidelines would be included in the list of AER Guidelines in this clause.
6.4.5(a)	The clause deals with the Expenditure Forecast Assessment Guidelines and would refer to the 'approach or approaches' the AER could propose to use when it is assessing expenditure forecasts, to recognise more clearly that different approaches may be used for different services. A transitional rule in chapter 11 would specify that the need for different approaches must be taken into account when reviewing the need for amendments to the Expenditure Forecast Assessment Guidelines to take into account the amending rule.
6.5.6(e)(5A) and 6.5.7(e)(5A)	The matters the AER takes into account in assessing expenditure forecasts include the extent to which the expenditure forecasts include expenditure to address the concerns of electricity consumers. The term 'electricity consumers' (not defined) would be amended to refer to 'distribution service end users' to cover retail customers (under the extended meaning) and customers buying direct from the NEM. In relation to the customer engagement, reference to 'distribution service end users or groups representing them' would be included to be clear that engagement may occur with consumer representative groups, including those with mandates to represent the interests of sub-groups of retail customers.
6.5.8(c)(1)	The clause relates to the efficiency benefit sharing scheme. The term 'electricity consumers' (not defined) would be amended to refer to 'distribution service end users' to cover retail customers (under the extended meaning) and customers buying direct from the NEM.
6.6.1(c) and (l)	As export tariffs are no longer prohibited, it is proposed that DNSPs would charge MSGAs for the distribution charges payable by MSGA customers, under proposed amendments to clause 6.20 and Chapter 6B. Consistent with this, the retailer insolvency event pass through event definition in chapter 10 would be amended to extend it to MSGA insolvency. Consequential changes to clause 6.6.1 would insert references to MSGAs where relevant.
6.6.2(b)(3)	The clause deals with the matters the AER must take into account when

NER CHAPTER 6 CLAUSE	COMMENTARY
	developing STPIS. In (3)(i), the term 'electricity consumers' (not defined) would be replaced with the new term 'distribution service end users' to cover electricity consumers, micro embedded generators and non-registered embedded generators (excluding those connected under chapter 5). In (3)(vi), the reference to customer 'willingness to pay' for 'improved performance in the delivery of services' would be replaced with a reference to the 'value to distribution service end users of improved performance'. In (4), 'where relevant' will be added as the Distribution Reliability Measures Guidelines may not be relevant to exports. A new (5) will allow the AER to take into account other matters it considers relevant.
6.6.3(b)	The demand management incentive scheme objective in paragraph (b) would be amended to clarify that it may include management of demand for export services.
6.6.3A(c)(2)(i)	The matters to be taken into account by the AER in developing a demand management incentive scheme would be amended to clarify that these may have the potential to reduce demand for export services.
6.6.4(a)	The description of the small-scale incentive scheme would be amended to clarify that different schemes may apply to different DNSPs.
6.6.4(b)(3)	The term 'electricity consumers' (not defined) would be replaced with the new term 'distribution service end users' to cover electricity consumers, micro embedded generators and non-registered embedd generators (other than those connecting under Chapter 5).
6.8.1B	This new clause would set out the requirement for the AER to make the Export Tariff Guidelines and would describe the objective of the guidelines and the information and guidance to be included in the guidelines. The clause would also specify that the guidelines are not binding.
6.8.2(c1) and 6.8.2(c1a)	Paragraphs (c1) and (c1a) describe the information that must be included in the overview paper accompanying a regulatory proposal. The two paragraphs would be merged and replace with a new paragraph that requires all matters to be in reasonably plain language and provides more detail about what must be in the overview paper, including: • information to explain the interrelationship between different parts of the proposal

NER CHAPTER 6 CLAUSE	COMMENTARY
	• information about the customer engagement process, including reference to engagement with distribution service end users or groups representing them and (in relation to the TSS) retailers and MSGAs, the concerns raised and how they were addressed • a description of the DNSP's approach to providing for the costs of distribution services provided to micro embedded generators and non-registered embedded generators • a description of the other approaches considered by the DNSP • a description of the key risks and benefits for distribution service end users of the regulatory proposal and the proposed tariff structure statement including the export tariff transition strategy • as currently required, a comparison of the DNSP's proposed total revenue requirement with its total revenue requirement for the current regulatory control period and an explanation for any material differences between the two amounts • a new requirement for a comparison (on a backward looking basis) of the DNSP's proposed capex to support the provision of distribution services to micro embedded generators and non-registered embedded generators and its actual or committed capital expenditure for that purpose and explanation for any material differences between the two amounts.
6.18.1A(a)	A new paragraph (a)(2A) would require the DNSP to include its export tariff transition strategy in the TSS. The export tariff transition strategy would be a description of the strategies the DNSP has adopted, taking into account the pricing principle in clause 6.18.5(h), for the introduction of export tariffs including where relevant the period of transition.
6.18.1B(b)(6)	The paragraph deals with customer engagement when amending a TSS. The term 'electricity consumers' (not defined) would be replaced with the new term 'distribution service end users'. The clause would also refer to 'groups representing them' to be clear that engagement may occur with consumer representative groups. The reference to engagement with retailers would be extended to refer to MSGAs.
6.18.1C(a)	The clause deals with giving notice to retailers of proposed tariff trials. The reference to retailers would be extended to refer to MSGAs.
6.18.4(a) and (b)	The paragraphs deal with assigning customers to tariffs. Paragraphs (a)(1) and (b) would be amended to clarify that 'usage' refers to use of distribution services and to remove the reference to 'load profile'.

NER CHAPTER 6 CLAUSE	COMMENTARY
6.18.4(c)	The clause deals with assigning customers to tariffs and paragraph (c) states that 'retail customers with micro-generation facilities should be treated no less favourably than retail customers without such facilities but with a similar load profile.' Paragraph (c) would be deleted as a consequence of deleting the prohibition on export tariffs.
6.18.5(a)	Paragraph (a) sets out the principle that tariffs should be cost-reflective. A new note would state that (consistent with a conventional interpretation of the principle in paragraph (a)), charges in respect of the provision of direct control services may reflect efficient negative costs.
6.18.5(f)(2)	Paragraph (f)(2) in the pricing principles refers to 'meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant part of the distribution network'. Consistent with other changes made to this chapter, this would be amended to refer to 'times of greatest utilisation of the relevant service'.
6.18.5(g)	Paragraph (g) refers to 'efficient usage'. Consistent with other changes made to this chapter, this would be amended to refer to 'efficient usage of the relevant service'.
6.18.5(i)	Pricing principle (i) currently provides that tariff structures must be at least reasonably capable of being understood by retail customers assigned to the tariff, having regard to the two matters mentioned in the clause. The principle would be amended to allow either tariff structures that are at least reasonably capable of being understood by the retail customers who are or may be assigned to them, or are reasonably capable of being incorporated by retailers or MSGAs in contract terms offered to those customers. The clause would also indicate that the relevant understanding relates to how usage decisions or controls (such as remote control equipment installed by retailers) allow the DSNPs to have regard to information provided to them including the matters specified in the clause.
6.20.1(a)(2)	The clause deals with the measures DNSPs can use to determine use of their distribution network. Consistent with other changes made to this chapter, the phrase 'half-hourly demand' would be amended to refer to 'half-hourly demand for services'. The reference to 'metered or agreed energy' would be amended to refer to 'metered or agreed energy consumption or export'.
6.20.1(b), (c) and (e)	These provisions deal with who is billed for distribution services (for example, the retailer for a retail customer) and the source of data used for billing. Reference to MSGAs would be included where applicable to provide for DNSPs to bill MSGAs for export charges and specify the

NER CHAPTER 6 CLAUSE	COMMENTARY
	source of data to be used.
6.22.2(e)	Minor change corrects an incorrect cross-reference.

Table B.4: **Changes to NER Chapter 6B**

NER CHAPTER 6B CLAUSE	COMMENTARY
6B.A1.1	Customers with DER may include customers of retailers and customers of MSGAs. When export charges are introduced, DNSPs will need a means to invoice and collect the export charges from both retailers and MSGAs. Chapter 6B already provides for retailers to be billed by the DNSP for the charges payable by the retailer's customers. It is proposed to extend Chapter 6B so that it also provides the framework for DNSPs to bill MSGAs for the network charges payable by MSGA customers. Amendments to this clause would add references to MSGAs to reflect the extended scope of the chapter.
6B.A1.2	This clause sets out local definitions used in Chapter 6B. To reflect the extended scope of this chapter, definitions that reference retailers will be extended to include a reference to MSGAs, and a new definition will give 'retailer' an extended meaning through the remainder of the chapter to avoid duplicative drafting. The meaning of 'shared customer' will be extended to include a person who is a customer of a DNSP and an MSGA.
6B.A2.2(d)	The clause refers to a 'contract for the sale of electricity only' (meaning a contract in which the customer has elected to pay the DNSP directly for network charges). This would be amended to refer to a contract for sale *or purchase* of electricity to cover contracts between MSGAs and their customers.
6B.A3.2(a)(1)	The clause deals with tariff reassignment. A drafting change would remove the phrase 'in use of electricity consumption at the customer's premises' which is not needed for the clause to operate as intended. This would extend the clause to cover changes to export that may result in a tariff reassignment.

Table B.5: **Changes to NER Chapter 7**

NER CHAPTER 7 CLAUSE	COMMENTARY
7.6.2(a)(2)	This clause describes who may appoint a Metering Coordinator for a connection point that connects, or is proposed to connect, a generating system to a distribution network but does not apply to the connection point of a retail customer. Under the draft rule, the meaning of 'retail customer' would be extended throughout the NER to include micro embedded generators and non-registered embedded generators (other than those connecting under Chapter 5). In this clause, the proposed extended meaning of 'retail customer' should not apply and so it is proposed to replace 'retail customer' with 'small customer or large customer' to preserve the current operation of the clause.
7.8.10(a)(2) and (3)	Clause 7.8.10 deals with the time by which repairs must be made where there is a metering installation malfunction. More time is allowed where the repair would require interruption to the supply of another retail customer. The proposed extended meaning of 'retail customer' should not apply in the clause and so it is proposed to replace the term with 'small customer or large customer'.

Table B.6: **Changes to NER Chapter 8**

NER CHAPTER 8 PART	COMMENTARY
New Part J	Proposed new Part J of chapter 8 provides for the AER to develop a CECV methodology which it will use to determine, for publication, the values of customer export curtailment. The values will be updated annually and the CECV methodology will be reviewed every 5 years.

Table B.7: **Changes to NER Chapter 10 - glossary**

NER CHAPTER 10 TERM	COMMENTARY
billed but unpaid charges	It is proposed that the framework in chapter 6 under which DNSPs can recover distribution charges unpaid by a failed retailer will be extended to recovery of distribution charges unpaid by a failed MSGA. The amendments to the definition of 'billed but unpaid charges' insert references to the new term 'failed Market Small Generation Aggregator'.
distribution	A minor change corrects the cross reference to the provision in chapter 5

NER CHAPTER 10 TERM	COMMENTARY
network user access	from rule 5.5 to rule 5.3AA. The rule was moved in a previous rule change.
distribution service end user	The new term replaces the undefined term 'electricity consumer' in chapter 6. It is proposed to include the reference to 'electricity consumers' in the new definition and extend the term to micro embedded generators and non-registered embedded generators who connect under chapter 5A.
embedded generating unit	As currently defined, the term has two elements: connection within a distribution network and not having direct access to the transmission network. With the use of batteries to provide network support, a potential ambiguity arises from the phrase 'connection within a distribution network' which could be interpreted narrowly to exclude DER connected through a connection assets or behind the meter, since a distribution network is generally regarded as ending at the meter or connection point. To avoid a narrow interpretation of the term, it is proposed to replace 'connection within a distribution network' with 'connection within a distribution *system*'.
embedded generating unit operator	This term would replace the term 'embedded generator' in Chapter 5A. This avoids confusion with the defined term 'Embedded Generator' which is used to refer to entities registered in that capacity.
Embedded Generator	As a consequential change, the note referring to the Chapter 5A definition of embedded generator would be deleted.
export tariff	A new definition would refer to 'a tariff for distribution services relating to the transfer of electricity generated by a distribution service end user into a distribution network, excluding charges for the provision of connection services (as defined in Chapter 5A).'
Export Tariff Guidelines	A new signpost definition would refer to clause in chapter 6 under which the guidelines will be required.
export tariff transition strategy	A new signpost definition would refer to clause in chapter 6 under which the export tariff transition strategy would be required.
failed Market Small Generation Aggregator	The framework in chapter 6 that enables DNSPs to recover distribution charges unpaid by a failed retailer would be extended to recovery of distribution charges unpaid by a failed MSGA. The proposed definition refers to an MSGA in respect of whom an insolvency official (as defined in the NER) has been appointed. This aligns with paragraph (a) of the definition of 'retailer insolvency event'.

NER CHAPTER 10 TERM	COMMENTARY
Generator micro EG connection	A consequential change would replace the phrase 'non-registered embedded generator as defined in clause 5A.A.1' with the defined term (in italics) 'non-registered embedded generator'. A consequential change would delete the phrase '(in the context of Chapter 5A)' as the term would now also be used in chapter 10.
micro embedded generator	This term would be moved from chapter 5A and amended. The current chapter 5A definition refers to a 'retail customer who operates, or proposes to operate, an embedded generating unit for which a micro EG connection is appropriate'. In the amended definition, 'retail customer' would be replaced with 'small customer, large customer or MSGA customer'. The first two terms cover the same scope as the current definition in chapter 5A. The new term 'MSGA customer' would extend the definition to customers who sell through an MSGA and for whom a micro EG connection is appropriate.
MSGA customer	A new signpost definition would provide a cross-reference to the definition in chapter 5A.
network	The phrase 'to customers (whether wholesale or retail)' would be deleted, as distribution services relate both to the flow of energy from the grid to the distribution network users and from distribution network users to the grid.
non-registered embedded generator	This term would be moved from chapter 5A and amended to replace the words 'embedded generator' with the new term 'embedded generating unit operator'.
retail customer	The term would be replaced with a new term based on 'retail customer' as currently defined in chapter 5A. The term would cover a person who is one or more of the following: • a small customer • a large customer • a micro-embedded generator • a non-registered embedded generator, other than a non-registered embedded generator who has made an election under clause 5A.A.2(c) for connection under Chapter 5. Non-embedded generators who seek a connection under chapter 5 are excluded as they are not intended to be treated as retail customers for the purposes of retail tariffs in chapter 6 or in other provisions dealing with retail customers in the NER.
Retail Market Procedures	A consequential change would extend the phrase 'for or in connection with the sale and supply of electricity to retail customers' by adding a

NER CHAPTER 10 TERM	COMMENTARY
	reference to 'export of electricity by retail customers' as the Retail Market Procedures will need to support the provision of distribution services for exports to the grid.
retailer insolvency costs	It is proposed that the framework in chapter 6 under which DNSPs can recover distribution charges unpaid by a failed retailer will be extended to recovery of distribution charges unpaid by a failed MSGA. A consequential change to paragraph (b) of the definition of 'retailer insolvency costs' extends it to cover 'the actual amount of unbilled network charges accrued by a … failed Market Small Generation Aggregator'.
retailer insolvency event	It is proposed that the framework in chapter 6 under which DNSPs can recover distribution charges unpaid by a failed retailer will be extended to recovery of distribution charges unpaid by a failed MSGA. To give effect to this change, this definition would be extended to the insolvency of MSGAs.
Voter Category	Minor change inserts a missing 'in'.

Table B.8: **Changes to NER Chapter 11 - transitional rules**

NER CHAPTER 11 PROVISION	COMMENTARY
General	This new Part would contain the transitional rules for the proposed *National Electricity Amendment (Access, pricing and incentive arrangements for distributed energy resources) Rule 2021.*
AER-made instruments	The second rule in the new Part lists the AER instruments for review and amendment (if the AER considers it necessary or desirable), to take into account the amending rule. The draft rule proposes two time frames: • The AER would have until 1 July 2022 for the Expenditure Forecast Assessment Guidelines, the Distribution Service Classification Guidelines and the Cost Allocation Guidelines. • The AER would have until 1 July 2023 for the Distribution Reliability Measures Guidelines, the demand management incentive scheme and the demand management innovation allowance mechanism. It is proposed that in relation to the Expenditure Forecast Assessment Guidelines, the AER will be required to have regard to the need for different approaches for different classes of retail customers.
Service standards incentives scheme	The third rule in the new part proposes that the AER would undertake a review to consider arrangements (which may include a STIPS) to provide

NER CHAPTER 11 PROVISION	COMMENTARY
for exports	incentives for DNSPs to maintain and improve performance in relation to network services provided to retail customers for supply from embedded generating units to the distribution network. The report would be completed by 31 December 2022 and would include the AER's recommendations for incentive arrangements.
Initial Export Tariff Guidelines	The fourth rule in the new part would require the AER to make the initial Export Tariff Guidelines by 1 July 2022, using the distribution consultation procedures.
Annual benchmarking report	The fifth rule in the new part proposes that the AER must consult in accordance with the distribution consultation procedures about how the AER will take into account the amending rule in the AER's annual benchmarking reports and must publish a report on the outcome of the consultation by 1 July 2022.
Initial CECV methodology	The sixth rule in the new part provides for the AER to develop and publish the initial CECV methodology and determine and publish the initial customer export curtailment values by 1 July 2022.
Sub-threshold tariffs	The seventh rule in the new part proposes to increase, for the regulatory control period in which the rule is made and the subsequent regulatory control period, the thresholds for tariff trials. The individual threshold would lift from 0.5 percent to 1 percent, and the cumulative threshold would lift from 1 percent to 5 percent.
Retail Market Procedures	The eighth rule in the new part would require AEMO, by 1 July 2022, to review and where AEMO considers it necessary or desirable propose amendments to the Retail Market Procedures to take into account the Amending Rule.
DAPR – new information	The final rule in the new part would provide that a DNSP is not required to include the information in new clauses S5.8(l)(3) and (4) in a DAPR that has a DAPR date falling before the first anniversary of the date the rule is made.

B.2 Amendments to the National Energy Retail Rules

Table B.9: **Changes to the NERR**

NERR CLAUSE	COMMENTARY
Rule 56A	This rule requires a retailer, on a request by a small customer or a customer authorised representative, to provide information about that customer's energy consumption for the previous 2 years. The draft rule proposes to extend this to information about a customer's

NERR CLAUSE	COMMENTARY
	energy export (as well as consumption). The heading to the rule would also be amended to reflect the change.
Rule 56B	This rule deals with the provision of historical billing or energy consumption information of a small customer. The draft rule proposes to extend this to historical billing or energy consumption or export information. The heading to the rule would also be amended to reflect the change.
Rule 86A	This rule requires a distributor to provide information about a customer's energy consumption for the previous 2 years. The draft rule proposes to extend this to information about a customer's energy export (as well as consumption). The heading to the rule would also be amended to reflect the change and a minor typographical error would be corrected.
Rule 86B	This rule applies to the provision of information about gas and corresponds to rule 86A. In order to maintain consistency, minor drafting changes would be made in the rule. These are not intended to alter the meaning or scope of the rule.
Schedule 1, clause 9.4A	This schedule sets out the 'Model terms and conditions for standard retail contracts'. Clause 9.4A reflects the requirements of rule 56A about the provision of consumption information. Changes to the standard clause would align the clause with the proposed amendments to rule 56A.
Schedule 2, model terms and conditions for deemed standard connection contracts	This schedule sets out the 'Model terms and conditions for deemed standard connection contracts'. The terms apply to the provision of 'customer connection services' which under the NERL is defined to include the provision of connection and supply services. Supply services is not defined in the NERL, but taking into account chapter 5A of the NER (put in place at the same time as the NERL and NERR), the term is broad enough to cover services that allow for delivery of electricity from the distribution system to a customer (import) or from a customer to the distributor (export). The proposed rule would amend the model terms to clarify the application to both forms of supply service (import and export). The changes would cover the following: • **Preamble**: in the Preamble, referring to 'supply services for the premises' in place of 'the energy supplied to the premises' • **various**: in clauses 4.1 and 6.6(a), using the phrase 'start to use supply services' in place of 'start to take supply of energy' and in clause 4.1, including by way of clarification 'for example by taking a supply of energy'

NERR CLAUSE	COMMENTARY
	• **various**: in clauses 4.2(a), 6.2(c) and 11.3, changing references to 'the supply of energy for the premises' to 'supply services for the premises' • **scope**: in clause 5.2, referring to 'the sale of energy supplied to your premises' in place of the 'sale of energy to your premises' • **compliance with laws**: in clause 6.3, referring to 'customer connection services we provide for your premises' (or 'the premises') in place of 'to your premises' • **liability**: in clause 8(a), referring to the 'electricity supply service' in place of 'electricity supply' and in 8(b), referring to 'the condition or suitability of your services' in place of 'the condition or suitability of energy'. • **interruptions to import**: in the heading to clause 10, referring to interruptions to 'supply services' in place of 'supply' • **interruptions to export**: in clause 10, adding a new clause 10.5 to confirm that the distributor may temporarily interrupt or curtail the supply services provided for export from small generators connected to the distribution system, with consequential changes to the headings of clauses 10.1 • **access to information**: in clause 15.2A, changes to align the clause with the proposed amendments to rule 86A • **complaints**: in clause 16.1, referring to 'a complaint relating to customer connection services under this contract, including supply services' in place of 'a complaint relating to the supply of energy to the premises' • **explanation of terms**: in the definitions, removing 'services relating to the flow of energy to your premises' from 'customer connection services' (replacing it with 'supply services') and defining 'supply services' to mean 'services relating to the flow of energy to or from your premises'. It is also proposed to make drafting corrections in clause 6.6(c) (deleting 'at the time' from the phrase 'at the time when') and clause 12.1 (to remove 'if ... if' phrases).
Schedule 3, new Part 17	A new Part would be included in Schedule 3 to set out the transitional provisions for the proposed *National Energy Retail Amendment (Access, pricing and incentive arrangements for distributed energy resources) Rule 2021*. The transitional rules would require retailers and distributors to implement the changes to their standard terms by 30 September 2021. The changes could be made earlier if wished.

C SUMMARY OF SUBMISSIONS RELATING TO EXPORT PRICING

This Appendix chapter summarises submissions on SAPN and SVDP's rule change requests to enable export pricing, and highlights relevant economic literature and expert consultant views. This information was taken into account by the Commission in making the decisions explained in Chapter 6, under section 6.4.

C.1 Support for enabling export charges

The AER considers removing NER clause 6.1.4 should help drive better price signals governing network investment to support exports, and should unlock a range of options for service and tariff combinations.[545] This is consistent with views expressed by a range of stakeholders (section C.1.1).

Network tariffs can be designed to reflect how customers' actions can affect the DNSPs' long run costs. Therefore, customers' responses such as reducing demand and exporting at peak times can be built into the DNSPs' pricing structures. As explained by CEPA:[546]

- First, price signals can inform customers of the additional costs (savings) that will arise if, on average, there is a permanent increase (decrease) in the use of the network. This signal, as discussed in section C.1.2, is forward-looking and can reflect the costs the network will incur if usage increases, or the costs that it can avoid if usage falls.
- Second, price signals can help allocate the existing (sunk) costs of the network to those that value it (section C.1.3). The majority of costs a network needs to recover from customers are to cover the return of and on capital. These costs, once incurred, are largely fixed.

These potential benefits of price signals are well-founded in economics. NERA, the expert consultant that advised the Commission on the 2014 network pricing reforms, similarly considered:[547]

> There are compelling reasons to link more closely network tariffs with the underlying drivers of network costs. First, it promotes efficient use of electricity networks by ensuring that only those users that most value the network during high cost times use the network, while encouraging use of the network during low cost periods. Second it promotes efficient investment in electricity networks and technologies that use or produce electricity, as usage is linked to the preparedness of users to pay the true cost of providing services when required. Finally, it is a fairer charging system as electricity users directly contribute to the costs that they impose on the network as a consequence of their electricity use.

545 AER submission to the consultation paper, p. 3.

546 CEPA, Distributed Energy Resources Integration Program – Access and pricing: Reform options, April 2020, p. 39.

547 NERA, Economic Concepts for Pricing Electricity Network Services, July 2014, p. 1.

SAPN and SVDP recognised in their proposals that implementation of export charges may be helpful in some circumstances, but not necessarily in other instances. It is about creating options to enable customer service choices going forward (section C.1.4).

SAPN considered enabling price signals to reward customers creates an option that individual networks could explore, if appropriate to their respective circumstances, with their stakeholders and the AER through the TSS process, as an alternative to more traditional non-tariff reward schemes such as demand-response payments.[548] Similarly, SVDP said its proposal to remove NER clause 6.1.4 creates an option that can allow DER participants to contribute to DER-related expenditure and/or be rewarded for services they provide to the network.[549]

The Commission, along with the other market bodies, are working together with the ESB to identify and address current and future challenges and opportunities associated with integrating DER into the electricity system. Enabling export pricing is considered foundational to future market design considerations, especially two-sided markets (section C.1.5).

C.1.1 Submissions in favour of enabling export charges

The AER considers:[550]

- the proposals should help provide a platform for better pricing signals governing exports of DER onto the electricity system – which should in turn help facilitate efficient network investment to support DER exports
- improved network price signals should help to drive innovation from retailers, aggregators and other new service providers – these parties could offer a range of tariff and service combinations to assist owners of DER to optimise the use of their assets, either for export purposes or for their own use.

The Government of South Australia highlighted its strong support for cost reflective pricing of electricity consumption, and says an accurate cost-reflective pricing mechanism for DER exports could also be established to send appropriate pricing signals to consumers:[551]

> This allows consumers to make informed decisions regarding investment in DER and for those that do invest, their individual usage pattern that will influence their exports to the distribution network.
>
> As with cost reflective pricing for electricity consumption, export pricing has the potential to lower or alleviate the need for network investment in the long run and therefore reduce the risk of higher network prices. Potentially, a DER pricing mechanism could assist in achieving the objective of South Australia's Energy Solution of minimising power system security issues by managing the level of DER exports, including during periods of low electricity demand.

548 SAPN rule change request, p. 8.

549 SVDP rule change request, pp. 6–8.

550 AER submission to the consultation paper, p. 2.

551 SA Government submission to the consultation paper, p. 3.

Although applying export charges would not increase DNSPs' total revenue allowance, Energy Network Australia (ENA) and the DNSPs unanimously support greater regulatory flexibility of the pricing arrangements to efficiently manage their networks:

- ENA states recognition within the regulatory framework of the provision of export services to customers is interlinked with the efficient recovery of these costs, and cannot be considered in isolation. ENA submits the regulatory regime should accommodate export charges to provide efficient price signals and improve equity.[552]
- Ausgrid considers proposals to remove NER clause 6.1.4 would allow DNSPs to: engage with customers and the AER on appropriate mechanisms to facilitate efficient integration of DER; and reduce future network costs, leveraging behavioural response by customers or measures taken by retailers in response to price signals.[553]
- AusNet Services says if enabling export charges is simply to provide the option, then there is limited downside, and export charges would only be used to improve the efficiency of price signals when supported by a DNSPs' customers.[554]
- CitiPower Powercor and United Energy submit a regulatory regime that accommodates export charges will enable more efficient prices signals to be provided to customers upon which to base their DER investment and operations decisions, and improve the allocation of costs between those customers consuming from the grid and those exporting to the grid.[555]
- Endeavour Energy states DNSPs should also be able to signal the efficient use of DER to customers through the efficient and equitable allocation of the costs and benefits associated with DER use on its network.[556]
- Energy Queensland considers its customers expect Energex and Ergon Energy Network to effectively manage prices while enabling and connecting DER and, as such, supports reforms that promote efficient investment in and operation of the network by DNSPs, fair and equitable allocation of costs and efficient use of the network by customers.[557]
- Essential Energy says the removal of NER clause 6.1.4 to ensure that future expenditure on export capacity is cost-effective, and that customers are incentivised to operate DER resources in a manner which maximises economic utility for all stakeholders.[558]
- Evoenergy submits DNSPs should have the option to charge for export services.[559]
- Jemena states the regulatory framework should have the flexibility to charge for grid export services.[560]

552 ENA submission to the consultation paper, p. 15.
553 Ausgrid submission to the consultation paper, p. 11.
554 AusNet Services submission to the consultation paper, p. 6.
555 CitiPower/Powercor/United Energy submission to the consultation paper, p. 2.
556 Endeavour Energy submission to the consultation paper, p. 2.
557 Energy Queensland submission to the consultation paper, p. 1.
558 Essential Energy submission to the consultation paper, p. 1.
559 Evoenergy submission to the consultation paper, p. 14.
560 Jemena submission to the consultation paper, p. 11.

- TasNetworks considers it would be inappropriate to require DNSPs to meet the demand for hosting DER without also enabling them to recover the cost of doing so from the beneficiaries of that DER.[561]

In their submission, Sidorenko and Fernando provide an overview of relevant academic literature and consider, from an economist's view, that 'pricing can help solve the problem':[562]

> This rule change proposal, if successful, would enable the congestion pricing of network hosting capacity.
>
> Introduction of a cost-reflective price for exports can:
>
> - internalise the externality and place value on the use of the resource
> - incentivise distributor to invest in the resource that now generates value
> - enable optimal use of the existing resource (using TOU or demand pricing)
> - open new markets and services (leading to dynamic efficiency).
>
> The industry has been guided by these principles in its journey towards cost reflective network tariffs for consumption. We consider that extending these principles to introduce network charges for exports would help avert the tragedy of the solar commons. From an economic standpoint, SVDP's and SAPN's proposal to remove clause 6.1.4 of the NER is in the long-term interests of consumers and should be supported.

The Australian Energy Council (AEC) and the following retailers also support enabling export charges:

- AEC's submission, which attaches an independent report by Oakley Greenwood, states NER clause 6.1.4 should be removed and DNSPs be allowed to levy charges that signal the efficient forward-looking costs of making those services available.[563]
- AGL considers the introduction of export charges facilitates improved investment certainty for DER customers.[564]
- EnergyAustralia accepts it is appropriate for changes to be made to NER clause 6.1.4 to enable DNSPs to impose export charges on DER customers, where there is a direct and relevant need for expenditure to enable the grid to receive those exports.[565]
- Red Energy and Lumo Energy submit the regulatory framework should provide price signals to maximise network efficiency and deliver cost savings to consumers through lower network costs – and this should apply equally across the distribution system, to fairly and efficiently allocate costs with a view to driving net reductions across all consumers.[566]

561 TasNetworks submission to the consultation paper, p. 2.
562 Alexandra Sidorenko (Ausgrid) and Roshen Fernando (ANU) submission to the consultation paper, p. 4.
563 AEC submission to the consultation paper, attaching Oakley Greenwood independent report, p. 7.
564 AGL submission to the consultation paper, p. 2.
565 EnergyAustralia submission to the consultation paper, p. 2.
566 Red Energy and Lumo Energy submission to the consultation paper, p. 1.

Both the Major Energy Users (MEU)[567] and the Energy Users Association of Australia (EUAA)[568] support removal of NER clause 6.1.4. EUAA submits:[569]

> We support the SVDP/SAPN proposal to remove NER clause 6.1.4. This will provide networks with the flexibility to create different pricing structures to meet the varying needs of potential customers. This can include a combination of connection, volumetric and other charges that for example, vary in a non-linear way with export capacity and time of day when exports are being made. Customers will then have a direct and efficient signal that they can use to decide their individual efficient level of exports. Part of that decision will be to decide whether to increase self-consumption at particular times of the day and use a battery to delay export to a higher value time of the day.

Of the consumer groups:

- Energetic Communities states: "We do not support charges for export services to existing customers who have made their investments into DER in good faith. [But] ... we'd support charges for export services, as long as all consumers are charged fairly. This is likely to mean export charges when the export delivers market benefits, with non-DER customers also been charged for the export services component."[570]
- In support of enabling export charges, Renew submits consumers who are driving additional net costs in the system could pay those costs, and then get to enjoy the benefit of what their extra expenditure has enabled.[571]
- The Customer Advocate considers it is not unreasonable for DNSPs to charge for export services, provided it is time and demand-based to reflect the true impact on the network.[572]

Should export charges be cost reflective or 'postage stamp'?

The current pricing objective and principles under the NER promote cost reflective pricing. CEPA considered that it would be appropriate to price exports in a cost reflective manner:[573]

> Cost-reflectivity would allow exporters to compare the value of using the network with the costs of using the network. This would support productive and allocative efficiency, align with the current pricing objective, and promote consistency between import and export charges.

Some stakeholders support export charges but are less sure if price signals should be cost reflective and have suggested alternative approaches.

567 MEU submission to the consultation paper, p. 2.
568 EUAA submission to the consultation paper, p. 1.
569 ibid, p. 4.
570 Energetic Communities submission to the consultation paper, p. 7.
571 Renew submission to the consultation paper, p. 11.
572 The Customer Advocate submission to the consultation paper, p. 5.
573 CEPA, Distributed Energy Resources Integration Program – Access and pricing: Reform options, April 2020, p. 113.

For example, Red Energy and Lumo Energy state they have consistently argued that cost reflective network pricing must be structured in a manner that is simple for consumers to understand and respond to: "On this basis, we support a change to the regulatory framework to allow the networks to recover the costs of integrating distributed energy resources into their network as a simple, flat volumetric charge."[574]

The MEU submits:[575]

> As a left field solution, the MEU makes the suggestion that all end users be charged network costs based on their peak demand. Under this approach, a residence using a peak demand of 6 kW would pay less than one using a peak demand of 10 kW and if the paid for peak demand is exceeded, a supply relay in the end user's residence trips and the end user would have to turn off an appliance and reset the relay to continue its supply. Exporters could then be limited to a fixed proportion of their peak import as a peak export amount.

In contrast, ARENA states:[576]

> Given that facilitating exports does not constitute an 'essential service' for customers (as opposed to ensuring reliability of supply) there seems little in-principle justification for 'postage stamp pricing' to recover the costs of hosting capacity improvements.

Similarly, the Clean Energy Council (CEC) considers:[577]

> A flat per kWh charge (or even an up-front or annual connection charge) would be simple to implement but would not provide the right signal to influence behaviour. A time-varying export charge would be more likely to influence customer behaviour to reduce exports when the network is congested.

ERM Power submits:[578]

> South Australian Power Networks' (SAPN) and St Vincent de Paul's (SVDP) proposals for distribution charges for export merit further consideration. If implemented properly, where costs reflect the net marginal costs of export by DER to the distribution network, the rule change would provide an incentive for self-consumption, storage or better sizing of PV installations relative to a premises' consumption. We believe a properly implemented export charge would need to be levied on a time-of-export rather than a flat charge across all exports regardless of when they occur. This would encourage exports from DER at times where DER export would be helpful to the power system and only impose a cost where DER exports resulted in a negative power system impact.

574 Red Energy and Lumo Energy submission to the consultation paper, p. 1.

575 MEU submission to the consultation paper, p. 4.

576 ARENA submission to the consultation paper, pp. 1–2.

577 CEC submission to the consultation paper, p. 5.

578 ERM Power submission to the consultation paper, p. 2.

Stakeholder feedback through the DEIP process

Stakeholder feedback from the DEIP consultation process, including through several workshops and submissions, provided in-principle support for enabling network export charges to send efficient price signals to retailers, other energy service providers, and customers to allocate network hosting capacity costs associated with DER in an efficient, affordable and equitable way. The DEIP Outcomes report stated this should extend to:[579]

- Enable price signals that incentivise efficient future investment in and operation of distribution networks, for both consumption and export services, to maximise the benefits of DER for all energy users – regardless of whether they have access to DER or not.
- DNSPs consult with their customers to understand community preferences for how costs of new or future investments in hosting capacity services are allocated.
- Where network hosting capacity is increased to facilitate DER services, and those customers that are expected to directly benefit can be clearly identified, in principle they should pay the costs of that investment.
- The efficiency and equity benefits should be considered against the increased complexity created by export charges, and the desire for distribution/transmission competitive neutrality.

C.1.2 Forward looking price signals

Infrastructure prices can be structured to reflect the underlying economic costs of supplying infrastructure services, which would promote efficient infrastructure use and investment. NERA stated:[580]

> In practice the promotion of efficiency requires the setting of prices that encourage the optimal use of existing infrastructure assets while signalling to users the cost of an additional unit of a good or service. This pricing approach ensures that consumers obtain the maximum benefit from infrastructure that has already been constructed, while also signalling to network businesses how much they value expansion to existing network capacity.

Moreover, NERA explained:[581]

> It is well established in economic theory that setting prices equal to marginal cost, ie the cost of producing an additional unit of a good or service, will promote efficient use and production of goods and services.
>
> In the context of network pricing, consumers faced with the cost of an additional unit of network infrastructure capacity will make efficient network usage decisions and also provide signals to network businesses about the demand for capacity expansion.

579 DEIP Access and Pricing Reform Package: Outcomes report, June 2020, p. 31.
580 NERA, Economic Concepts for Pricing Electricity Network Services, July 2014, p. 3.
581 ibid, pp. 4–5.

Applying the same economic principles, CEPA advised the introduction of export pricing could help improve the efficient use of the distribution network by sending signals to exporters, via time-of-use (TOU) pricing:[582]

> TOU pricing for the forward looking costs that increases (decreases) in export capacity cause (avoid) would send signals to exporters as to when there are constraints on the network and, with location-specific pricing, which locations have or do not have spare export capacity. This price signal could be instead of or complementary to a physical constraint signal. This would work in the same way to cost-reflective consumption pricing.

Submissions on the value of price signals

AEC/Oakley Greenwood state:[583]

> The provision of a price signal that reflects the forward-looking costs of export behaviour is valuable because it gives a point of reference against which alternatives can be assessed. For example, an export price would make self-consumption during times of export congestion more attractive, which could potentially result in a range of options becoming attractive to the DER participant including shifting the use of certain appliances such as a pool pump or dishwasher to those times, or installing on-site storage and using it (or using existing on-site storage capacity) more efficiently (particularly where charges for export that impose costs on the network are coupled with price signals that reward export when and where it reduces cost in the electricity supply chain, as discussed below).
>
> … It is also important to note that the provision of a cost-reflective price signal can enlist innovation from intermediaries that can provide benefits to the electricity supply chain and the customer. The price signal provides a potential value proposition for specialised third-party agents who can earn revenue by assisting the end customer in modifying consumption or export behaviour in ways that reduce charges or earn financial rewards.

EnergyAustralia submits cost-reflective pricing for DER will educate and enable customers to participate in DER when preferred/required by the network.[584] Further:[585]

> Accurate price signals will benefit the network in enabling retailers and customers to participate in export at times that are conducive to limiting impacts (voltage, oversupply) or improving outcomes (undersupply) on the network. It will enable retailers to more accurately apportion network and wholesale price signals, which will establish opportunities for scaling up DER in the network.

582 CEPA, Distributed Energy Resources Integration Program – Access and pricing: Reform options, April 2020, p. 93.

583 AEC/Oakley Greenwood submission to the consultation paper, p. 7.

584 EnergyAustralia submission to the consultation paper, p. 3.

585 ibid, p. 11.

ERM Power submits:[586]

> … the end result of these rule changes should be improved signals for DER investments, so that consumers have better incentives to better integrate DER into the system as a whole and therefore provide greater overall value. This could be achieved by better sizing and orienting panels to maximise self-consumption, or by installing battery storage to enable excess energy to be dispatched into the grid at peak times rather than (typically) in the middle of the day. This needs to be done in such a way that further investments in solar PV and potentially storage are not disincentivised.

Ausgrid states that if exports become a distribution service that distributors are required to accommodate, causers (who are also direct beneficiaries) will be able to signal their willingness to pay for the service.[587]

Getting ahead of future DER-related expenditure

In a recent journal article exploring network tariff design in an increasingly distributed, decentralised and decarbonised power system, Rai highlights efficient signals are needed for both 'withdrawals' and 'injections' to manage import and export congestion, and that the importance of such price signals is growing:[588]

> While it can be beneficial to wait for DER uptake to reach levels that necessitate new tariffs – as is the case with the "solar sponge" tariff – the danger is that uptake occurs faster and earlier than expected, resulting in significant cross-subsidies from ex-DER to cum-DER customers, and in higher network augmentation costs while the wrong price signals remain in place. This reactive approach to tariff design allowed the air-conditioner-induced acceleration in peak demand during the 2000s, and the more recent rooftop PV-induced voltage issues. Unless tariffs are designed somewhat pro-actively, inefficiencies and inequities are likely to also occur in relation to the operation and response of EVs and barriers to the wrong price signals.

The need to get ahead of future expenditure needs is highlighted in submissions. For example, EnergyAustralia states:[589]

> The proposed change may seem premature for a market that is currently benefitting from the inclusion of DER; however, the issues experienced in the South Australian and – to a lesser extent – the Queensland network establish the need for change. To enable the forecast significant DER integration (by 2050, DER may contribute up to 45% of the energy generation capacity), DNSPs will be required to invest in their networks to ensure they are providing a service that is suitable to customers consuming energy and those that are exporting energy.

586 ERM Power submission to the consultation paper, p. 1.

587 Ausgrid submission to the consultation paper, p. 12.

588 Rai, A., Network Tariffs in an Increasingly Distributed, Decentralised and Decarbonised power system, IAEE Energy Forum, Third Quarter 2020, p. 13.

589 EnergyAustralia submission to the consultation paper, p. 2.

> Enabling a future where augmentation is routinely required to accommodate the expanse of DER in a network, should include the capacity for the allocation of the associated costs to be apportioned to those that will benefit most.

Evoenergy submits:[590]

> DNSPs should have the option to charge for export services. DNSPs are best placed to decide the timing of when charges should be introduced based on when the inherent capacity of the existing network has reached its limits and new charges are required to recover the costs of export capacity investment. DNSP capability for analysis needs to be enhanced before export service charges and minimum standards are developed in the ACT.
>
> As DER penetration rates increases, Evoenergy will be required to invest to relieve the limits to the network's hosting capacity and recover the costs through cost reflective charges from exporters. The costs of the additional investment should be borne by the customers who directly benefit the most, that is exporters.

Several other DNSPs put forward similar views. Endeavour Energy considers cost-reflective price signals for export services should reduce future investment requirements by incentivising the efficient use of DER.[591] Essential Energy says DNSPs should be able to send price signals to customers of export services as a method of mitigating network congestion at select times, as well as rewarding customers who store their energy and export it at a time where it provides optimal value to the network.[592] Ausgrid states:[593]

> Together with the drive towards cost-reflective consumption tariffs, export tariffs will complement optimal pricing solutions with the effect reducing the need for future network augmentation costs and placing downward pressure on network prices for all customers.

C.1.3 Equitable and efficient allocation of costs

In its report for ARENA's DEIP process on access and pricing, CEPA advised that cost-reflective pricing can align with equity considerations:[594]

- It distributes costs fairly between customers, who differ in terms of their ability to engage with the energy system.
- It also promotes the fair and efficient allocation of risk by placing network costs on those who benefit from the costs being incurred.

Based on significant stakeholder feedback, the DEIP Outcomes report stated the electricity sector and customers alike require predictable regulatory frameworks that recognise existing

590 Evoenergy submission to the consultation paper, p. 14.
591 Endeavour Energy submission to the consultation paper, Appendix A, p. 5.
592 Essential Energy submission to the consultation paper, p. 3.
593 Ausgrid submission to the consultation paper, p. 11.
594 CEPA, Distributed Energy Resources Integration Program – Access and pricing: Reform options, April 2020, p. 113.

investments, support efficient future investment, and allocate risks as well as costs fairly.[595] As such, the DEIP Outcomes report considered the regulatory framework should enable a 'beneficiary-pays approach' whereby a network's pricing structure can allocate the investment costs between users and over time, in proportion to the benefits that customers are expected to receive from these services.[596]

Submissions on how costs can be allocated in a more equitable and efficient way

Several submissions highlighted the value of enabling equitable and efficient pricing structures to allocate network costs associated with export services. For example:

- AGL considers the removal of NER clause 6.1.4 has the potential to address equity concerns regarding the extent to which non-DER participants cross-subsidise DER customers' use of the distribution network.[597]
- ENA submits enabling export charges will provide options to improve equity in allocating the costs and benefits of DER, and provides a mechanism for those that highly value export access.[598]
- Endeavour Energy says enabling export changes would allow DNSPs to reduce cross-subsidies that may exist in the allocation of the costs and/or benefits associated with DER export enablement.[599]
- Jemena says charging for export services would remove the cross-subsidy inherent in the current arrangements, as long as the network tariffs were appropriately priced.[600]

Moreover, EUAA states:[601]

> We see the principle of paying for the export of generation as an important principle as it recognises that with the changing nature of our energy system comes a range of new participants who benefit from it. It also recognises there are those who can't take advantage of new technology to reduce their exposure to network costs who may end up paying a disproportionate amount of these costs leading to unfair and in equitable outcomes.

The MEU considers:[602]

> End users in the distribution network that do not export into the market do not cause the problem being faced where exporters (ie DER exporters – prosumers) are creating the need for more distribution (and transmission) network investment to address the congestion or voltage issues they cause, yet these non-exporters are potentially expected to carry some or all of the costs to enable the export by these prosumers.

595 DEIP Access and Pricing Reform Package: Outcomes report, June 2020, p. 33.
596 ibid, p. 31.
597 AGL submission to the consultation paper, p. 9.
598 ENA submission to the consultation paper, p. 15.
599 Endeavour Energy submission to the consultation paper: Appendix A, p. 5.
600 Jemena submission to the consultation paper, p. 11.
601 EUAA submission to the consultation paper, p. 1.
602 MEU submission to the consultation paper, p. 2.

> While it can be argued that end users might be a benefit from lower costs from the supply of this DER (and so might be considered to be beneficiaries) there is no quantitative evidence that this will be the case. Further, while the local end users might incur the costs for the distribution augmentation, the benefit may well go to other end users more widely in the market and thereby not deliver a net benefit to the end users incurring the additional costs.

Essential Energy says:[603]

> There is a well-established body of evidence that cross-subsidies currently exist through costs being imposed on the network by DER exports, which cannot be recovered from only those customers with DER installations. Several of the proponents outline that select customer groups including vulnerable and disadvantaged customers, are currently disproportionately contributing to network cost recovery, relative to customers with DER installations. This situation is only likely to increase in materiality over time.

Evoenergy states the potential benefits of enabling export charges include:[604]

- fewer limits being placed on residential customers exporting base levels of electricity in jurisdictions experiencing network constraints
- provides a price signal for exporting from batteries and solar
- costs of building network capacity for export, whether capex or opex, are borne by energy exporters rather than all consumers (including those who do not export)
- limits potential for cross subsidy from customers without DER contributing to the augmentation costs that directly benefit DER customers
- late adopters of DER technology are not required to fund the full augmentation costs when network limits are reached
- customers have an opportunity to request higher levels of export capacity at a premium charge
- consistent with the pricing principles for cost reflective pricing.

TasNetworks submits:[605]

> If DNSPs are going to be asked by consumers to integrate more DER in the future, such as rooftop solar panels, batteries, electric vehicles and smart appliances, it is essential that this be done in a way that benefits all electricity users. It is also essential that the cost of doing so is recovered equitably from the beneficiaries of the network investment required to service the growing number of customers with DER.

Jemena considers:[606]

603 Essential Energy submission to the consultation paper, p. 3.
604 Evoenergy submission to the consultation paper, pp. 14–15.
605 TasNetworks submission to the consultation paper, p. 1.
606 Jemena submission to the consultation paper, p. 13.

> If implemented efficiently, DER has benefits to the distribution network, DER proponents and the shared customers. The recognition of these benefits in effect is the allocation of benefits to one or more of those beneficiaries. In short, with the distribution network reflecting the broader customer base, the sharing of benefits is left to be decided between the DER proponents and the broader customer base.
>
> Processing benefits has two issues, the first issue is measuring the benefits, and the second is to apportion them between the two groups.
>
> In the current context, the benefits are:
>
> 1. the avoided costs when compared to a counterfactual case of not having DER; and
> 2. the avoided cost of not connecting DER or constraining off. This occurs when the cost to connect DER is more costly than the benefits it provides.
>
> In both of these cases, the framework should be flexible enough to allow the cost signal to flow to both the DER proponent and shared customers.

Energetic Communities states:[607]

> … currently not all consumers can access the financial and environmental benefits of DER. Energy is an essential service and needs to be affordable and accessible to all. We need energy policy and regulation that is fair and encourages DER uptake and utilisation in a way that enables access and benefits for all consumers and communities. We must avoid punitive measures for both prosumers or consumers and ensure DER integration does not come at a cost to other energy users, especially low-income, vulnerable and locked out households.
>
> … There are overall market benefits of DER export, not to mention self-consumption when it reduces peak demand, leading to lower wholesale prices, network costs and cheaper bills to all end users. Nonetheless, current pricing arrangements, including asymmetric price recovery, are leading to economically inefficient investment, reduced deployment of DER and penalising those without, especially low-income households and renters locked out of DER. Cost recovery needs to occur so that the networks can provide export capacity efficiently (not over or under investment), but this cost recovery must occur fairly. By the same token, prosumers must also be rewarded when their exports lead to benefits for all end users.

The relationship between rooftop solar PV uptake and income / wealth

The Commission's literature review, as outlined below, suggests middle to high income households mostly invest in solar PV in Australia. So, to the extent there are cross-subsidies between DER and non-DER-households, low income households may be disadvantaged. This was highlighted by SVDP in its rule change request as an equity concern.

607 Energetic Communities submission to the consultation paper, p. 1; 7.

A recent study of rooftop solar PV uptake in Australia, based on household-level Australian Bureau of Statistics data, showed higher household wealth was found to be a predictor of higher solar uptake, except for at very high wealth levels (93rd percentile and above):[608]

> In 2015-16, there was an inverse-U effect of log net wealth, with a positive marginal effect of net wealth on solar uptake until very high net wealth levels. There is a positive relationship between the proportion of income from private pensions (including superannuation) and solar uptake, even when controlling for age. Larger houses and households are more likely to install solar panels. Use of green power is a useful predictor of whether households install solar. Key constraints for solar uptake include living in apartments and renting. Households in older homes are less likely to install solar panels, all else equal. Log income was not found to have a significant average effect on actual installations, but there was some evidence of a positive effect on intended uptake.

Further studies showed a 'middle income' effect where rooftop solar PV uptake is highest among middle income households,[609] and evidence of inequality in receipt of solar subsidies:[610]

> … The lower seven wealth deciles receive significantly lower policy payments than the highest-wealth decile for both the FiTs [(feed-in tariffs)] and the SRES [(Small-scale Renewable Energy Scheme)]. This similarity is reasonable given that both policies result in payments to those who can afford the initial investment, along with higher payments to households who can afford larger solar systems. However, there may be greater inequality among the lower-wealth deciles for the FiT payments, as the second- and third-lowest wealth deciles receive significantly lower payments than the fifth wealth decile. The SRES does not display this type of inequality within the lower-wealth deciles.
>
> Our study shows substantial evidence of inequality in receipt of solar subsidies and this can be perceived as inequitable. High upfront costs effectively excluding some low-wealth households from the opportunity to share in the socially-funded subsidies could be perceived as unfair. The advantages of higher-wealth households are being amplified by the subsidy designs by giving larger total subsidies for larger installations. …

Another study found low-income households are more likely to rent than middle- or high-income households, and that renters install rooftop solar PV at lower rates than homeowners due to property right constraints and the difficulty of co-ordinating with landlords.[611]

608 Best et al., Understanding the determinants of rooftop solar installation: evidence from household surveys in Australia, Australian Journal of Agricultural and Resource Economics, 63(4), July 2019, p. 936.

609 Best et al., Evaluating the effectiveness of Australia's Small-scale Renewable Energy Scheme for rooftop solar, Energy Economics, 84, August 2019.

610 Best et al., Equity and effectiveness of Australian small-scale solar schemes, Ecological Economics, 180, October 2020, p. 7.

611 Zander, Unrealised opportunities for residential solar panels in Australia, Energy Policy, 142, July 2020.

A Queensland study found a major driver of uptake is concerns about rising bills, but low-income households were more likely to cite financial constraints preventing them from investing in solar.[612]

This is in contrast to Solar Citizens' research – the findings of which are only summarised in its submission:

> All three rule change proposals reference a need to address an inequity in the electricity system – the view that non solar households are cross subsidising solar households. Inherent in this argument is a belief that households without solar will experience significant bill relief as a result of this rule change. If there is no practical impact on the bills of vulnerable households, it begs the question as to why go to the expense of making this rule change.
>
> However, to the extent that the DUOS fees positively will reduce some consumers' bills, they will impact on the bills of all households without solar, including the disproportionate number of high income households that choose not to invest in solar. As our own research has shown, non solar households are disportionately (sic) found in the highest socioeconomic decile:
>
> Rooftop solar PV uptake is proportionately more common in households in the middle and lower socio-economic deciles than in the higher socio-economic deciles. Rooftop solar PV uptake is proportionately the highest in the lowest socio-economic decile and lowest in the highest socioeconomic decile.
>
> Far from being an equitable measure, this rule change could have the perverse effect of rewarding high income consumers without solar, and penalising lower income households with solar.

C.1.4 Optionality

Several submissions highlight the value of optionality. Enabling export charges would create the potential for greater customer service choices. Pricing is generally seen as a valuable economic tool, as discussed above. Part of the Commission's consideration is whether enabling export charges creates a useful new 'tool in the toolkit' for the DNSPs and AER to manage efficient investment in and operation of the network, with the option to apply this price signal (only) if it promotes the NEO – as discussed in Chapter 6.

The AER states a principles-based approach rather than the NER banning certain options outright, promotes innovation and flexibility to adapt arrangements over time to the evolving challenges of the energy system transition, including meeting decarbonisation targets.[613]

AusNet Services submits:[614]

612 Bondio et al., The technology of the middle class: Understanding the fulfilment of adoption intentions in Queensland's rapid uptake residential solar photovoltaics market, Renewable and Sustainable Energy Reviews, 93, 2018, pp. 642–651.

613 AER submission to the consultation paper, p. 3.

614 AusNet Services submission to the consultation paper, p. 6.

> We do not see any reason why DNSPs should not have this option available. Whether this is applied or not will depend on a range of factors that are already considered by DNSPs in developing their Tariff Structure Statements (TSS), including consultation with customers and other stakeholders.
>
> If enabling export charges is simply to provide the option, rather than compel networks to adopt these, then there is limited downside. In these circumstances, export charges will only be used to improve the efficiency of price signals when supported by a networks' customers.
>
> We note that there are alternative ways to improve the efficiency of price signals provided to customers, including reform of existing tariff structures. Many of the practical barriers that have prevented significant shifts away from historical pricing structures over the last decade, also apply to the introduction of export charging.

ENA states:[615]

> A capacity of the regulatory regime to accommodate export charges increases the options available to enable efficient price signals to be provided to customers, better allocates the costs and benefits of DER, and provides a mechanism for those who highly value export access.

AGL states:[616]

> … the nature of customer owned DER should also inform a greater focus on the extent to which the proposals empower customers with choice so that they can realise the greatest benefit from their own investment. The advent of DER technologies means that many customers now have a choice as to whether they purchase electricity through the traditional centralised source or generate it themselves in their homes or workplaces. In our view, a competitive market underpinned by customer choice has the greatest potential to realise the benefits of DER for the broader energy market system and should be preferred over control-based approaches.

Renew also highlights the value of 'optionality', whereby solutions should have regard to potential future customer choices, technology and market framework uncertainty.[617] Further, Renew states:[618]

> In summary, the project found that there are a number of low-cost measures that can significantly increase hosting capacity, and that while more work is needed to develop a more robust methodology for determining the shared value of DER exports, it's clear that many of the low and moderate cost approaches will be cheaper than the value of DER unlocked. Some of the higher cost approaches (such as dynamic export limiting)

615 ENA submission to the consultation paper, p. 3.

616 AGL submission to the consultation paper, p. 3.

617 Renew submission to the consultation paper, p. 5.

618 ibid, p. 2.

> are likely to be more necessary and more cost-effective in the future – but if implemented ahead of that time they could deliver private benefits in excess of their cost and thus may be a useful option for DER owners who are prepared to pay some extra charges to unlock those benefits, if such an option is allowable under the existing framework or with new rules. Such a strategy could be an example of a nuanced approach to cost recovery where costs consistent with shared benefits are allocated between all consumers, and additional costs to consumers willing to pay extra for the private benefit available.

As highlighted by CEPA, "if there is plenty of spare capacity then the price signal to customers to reduce demand (exports) can be relatively weak."[619] Similarly, ARENA submits:[620]

> It is appropriate to consider two-way tariffs where they reflect genuine cost pressures for a network business in facilitating a particular level of service and where new cost recovery approaches can deliver more efficient and fairer outcomes for consumers. It is important to acknowledge, however, that many parts of the LV network retain significant hosting capacity and as such, we expect that costs associated with facilitating DER exports (or other DER services) should be locationally specific, and comparatively low, in most cases.

C.1.5 Future market vision

The ESB stated the proposed distribution access and pricing reforms are foundational to support effective DER integration.[621] Further, the ESB considers the ongoing implementation of tariff reform being carried out by the AEMC and AER to move towards more cost reflective and time of use structures are important reforms.[622]

The ESB says the clearest opportunity from the energy transition is the development of a two-sided market – whereby energy services will be able to be bought and sold in a dynamic way, responding to consumer preferences and price signals.[623] The ESB explained:[624]

> In simple terms, a two-sided market has all its participants responding to price based on their cost and value preferences. The parties who participate in the market are exposed to its outcomes, with buyers only supplied to the extent that they buy through the market and sellers only supplying to the extent they sell through the market.
>
> For the NEM, a two-sided wholesale market would be informed by quantity and price inputs from both consumers and producers of electricity and would enable more efficient participation in the market by even small consumers like homes and small

619 CEPA, Distributed Energy Resources Integration Program – Access and pricing: Reform options, April 2020, p. 44.

620 ARENA submission to the consultation paper, p. 1.

621 ESB, Post 2025 Market Design, Consultation Paper, September 2020, pp. 99–100.

622 ESB, Post 2025 Market Design, Directions Paper, January 2021, p. 77

623 ESB, Moving to a two-sided market, consultation paper, April 2020, p. i.

624 ibid, p. ii.

> businesses.
>
> Technological advances and digitalisation mean that consumers will not need to monitor electricity prices and decide how or when to participate. These decisions would be set up to happen autonomously or in an agreed way via their retailer or aggregator.

The DEIP Outcomes report stated the future energy system will have to accommodate two-way, dynamic interactions between customer-owned DER assets and the grid, requiring a regulatory framework that supports decisions by industry that respond to consumer preferences and offers customers efficient price signals.[625]

The prohibition on network export charges is a barrier to this future market vision, as highlighted by submissions. For example, CitiPower, Powercor and United Energy consider the introduction of export tariffs are necessary over the long term as we transition to a two-sided market.[626] Similarly, the AER states:[627]

> Removing this clause will enable two-way pricing so a fuller range of services that electricity customers request can be valued and provided (including for example, access to the wholesale electricity market). Similarly, two-way pricing will enable DNSPs to pay DER owners for the services they provide to support the network, such as demand response and voltage management. As such, we expect this update will enable a range of positive market developments that facilitate network support services and revenue streams for DER owners.

Ausgrid considers:[628]

> Classification of export services as distribution services enables future provision of value-adding services in a two-sided market, including potential creation of new services, entry of innovative market players, increased competition and consumer choice. Creation of new markets that operate over the shared network will improve the efficiency of network utilisation and provide additional value to new users who would share in the total efficient network costs. These dynamic efficiency effects of the proposed rule change are in the long-term interests of consumers.

AGL submits that as the market for DER services evolves beyond wholesale energy provision towards ancillary services and network support services, network pricing arrangements need to be flexible enough to accommodate the spectrum of market benefits that DER can provide.[629]

625 DEIP Access and Pricing Reform Package: Outcomes report, June 2020, p. 32.

626 CitiPower/Powercor/United Energy submission to the consultation paper, p. 2.

627 AER submission to the consultation paper, p. 6.

628 Ausgrid submission to the consultation paper, p. 11.

629 AGL submission to the consultation paper, p. 9.

C.2 But significant concerns raised about implementing export charges

Stakeholder submissions have highlighted several concerns with SAPN and SVDP's proposals to enable export charges. In particular, stakeholders are concerned that implementation of export charges would undermine Australia's commitment to reduce emissions, risk the value of household solar PV investments made in good faith, and create a competitive disadvantage for micro embedded generators (eg, household solar PV). Many of these issues were raised by stakeholders during the DEIP consultation process too.

It is noted that the Commission makes its decisions on rule changes with reference to the NEO. These objectives do not specifically require the Commission to have regard to the long term interests of consumers with respect to climate change or the environment.[630] Instead, the NEO directs the Commission to consider the achievement of economic efficiency in the long term interests of consumers with respect to specified matters, being the price, quality, safety, reliability and security of the supply of electricity or electricity services.

However, clearly, climate change can have very serious economic consequences and is a policy issue that has material impacts on the electricity and gas sectors. In order to make decisions that meet the NEO, the Commission considers whether its decisions are robust to any impacts on price, quality, safety, reliability and security of supply of energy or energy services, if these matters are impacted by 'mitigation' or 'adaptation' risks that manifest due to the issue of climate change.[631]

C.2.1 Environmental policies and DER investments already undertaken

DER is helping Australia significantly reduce its greenhouse gas emissions and will be a major contributor to future energy generation. DER investments are made by retail customers not just as a source of revenue. Climate change mitigation, government incentives, self-sufficiency and 'peer effects' are other key factors noted in the relevant literature. Private individual 1 submits:[632]

> The proposal to charge for both consumption and export reflects the ongoing failure to properly understand and characterise solar cell owners. Most do not characterise or consider themselves as producers trying to make money. Most solar cell owners see themselves as providing a community benefit, both in terms of providing additional energy, especially on high demand days, while reducing Australia's energy emissions.

AusNet Services states:[633]

> The integration of Distributed Energy Resources (DER) is an area that presents opportunities for customers to manage their energy costs and generate clean energy, reducing total emissions required to meet their energy needs.

630 AEMC, Applying the energy market objectives, July 2019, p. 8.

631 ibid, pp. 8–9; 11.

632 Private individual 1 to the consultation paper, p. 2.

633 AusNet Services submission to the consultation paper, p. 1.

The Commission understands stakeholders are concerned that the prospect of export charges will potentially undermine these important environmental policy objectives and the value of households' DER investments to date – as highlighted in the following submissions.

Browne submits:[634]

> The climate science is clear – we must transition away from fossil fuels, as the emissions released from burning coal, gas, oil etc are worsening climate change, global warming and rising sea levels.
>
> Rooftop solar is an important part of making this transition. It costs a lot to install rooftop solar (and especially to install a battery), and solar owners should not incur an additional financial penalty, when our collective actions are assisting the government intention of slowing down climate change.

Unfolding futures states:[635]

> We have been very concerned about the enormous impact of Australias coal fired power on our environment for over 30 years. Electricity generation produces about one third of Australia's emissions, which are widely reconised (sic) as contributing to destructive climate change. We decided in 2004 to invest in solar panels to help reduce our emissions and to provide a symbol to our neighbours that citizens can make a contribution to reducing emission.

Robertson (private individual) submits:[636]

> … I do not believe that people who invest in PV should be discouraged from selling surplus energy to distributors for distribution and sale to consumers. Among other objections, this amounts to a form of 'double taxation', but my major issue is that it imposes yet another obstacle and disincentive to what amounts to the most urgent and existential problem facing humanity at the moment, namely rampant climate change, runaway bushfires, rising sea level and species extinction.
>
> Private PV represents something of a 'freebie' in the fight against climate change, and it should be accepted as a blessing in itself rather than an opportunist grab for revenue.

James (private individual) states:[637]

> I think that it is so very very wrong to charge everyday people for importing energy INTO the grid after they have spent their own money installing solar for clean energy, trying to do the right thing for the planet. Something that our government have made clear they have no intention of doing and tlwill (sic) go out of their way to not only avoid promoting clean renewable energy but to penalise those individuals trying to do

634 Phile Browne (private individual) submission to the consultation paper, p. 1.

635 Unfolding futures submission to the consultation paper, p. 1.

636 Derek Robertson (private individual) submission to the consultation paper, p. 1.

637 Christine James (private individual) submission to the consultation paper, p. 1.

> the right thing for the future. Not only will you charge us for giving you free energy, you will then charge us highly inflated prices to buy it back. Big coal and gas generators don't (sic) have to pay for supplying electricity into the network, so why should solar homes and businesses who have made a personal investment in rooftop solar? Please reject this proposal to charge Australian households for importing energy into the grid.

Planet Ark Power states:[638]

> Whilst the electricity system needs to be well-managed through the safe transition to a renewable energy future, it should not do so by penalising existing DPV/DER customers, nor adversely impacting the investment case for new DPV/DER systems. This would be counterintuitive and in conflict with the achieving of our national and state based renewable energy targets – either real or implied.
>
> … The DNSP may need to collect export charges or a fee for required gird support for increasing DER to fund network upgrades. This may be through energy retailers who are measuring and charging customer use. However, we believe the better and more equitable solution is that any charges or fees should not be imposed for customers who have invested in on-the-grid and behind-the-grid solutions and the integration of incentive programs?

The Customer Advocate submits:[639]

> The vast majority of consumers who have invested in DER, in particular rooftop PV, have done so with the primary intention of reducing the household energy bill. Any change that imposes new costs on consumers is not only likely to be viewed poorly, it could drive counter-intuitive behaviours.

Energetic Communities states it does not support charges for export services to existing customers who have made their investments into DER in good faith, as noted above.[640]

Diamond Energy states:[641]

> This clause [NER cl. 6.1.4] is vital to the principles of the Australian electricity grid, it is the essence of the NER that avoids 'double taxation' and enables investment (allocation of resources) aligned to minimising losses across the network.
>
> Any change must be carefully considered, as the proposal to remove this clause will have dire and perverse effects.

ERM Power states:[642]

638 Planet Ark Power submission to the consultation paper, p. 3; 12.
639 The Customer Advocate submission to the consultation paper, p. 2.
640 Energetic Communities submission to the consultation paper, p. 7.
641 Diamond Energy submission to the consultation paper, p. 2.
642 ERM Power submission to the consultation paper, p. 1.

> … any charge that results from this process – be it an export tariff or a supplementary connection charge – should not be retrospective. Consumers have made investments based on existing market settings and changes such as those proposed could undermine these assets.

Changing weather submits charging for exports may only incentivise solar owners to self-consume to a higher extent.[643]

C.2.2 Competitive neutrality concerns

Submissions identify export charges could distort competition between transmission and distribution-level generation. CEPA explained:[644]

> If exporters connected to the distribution network face DUoS charges but those connected to the transmission network do not, then exporters located on the distribution network may not be able to 'compete' on a level playing field (i.e., competitive neutrality is not achieved). If generators connected to the distribution network receive different services to those on the transmission network, i.e., firm access, then this may offset the network charges.

The Victorian Government states:[645]

> Under current arrangements in the NEM, generators do not pay for the use of the transmission or distribution system. A strong rationale would be required to discriminate and apply charges to only some generation types – small distributed generation – when all forms of generation benefit from the use of the network and impose some costs.

Solar Citizens states it is inequitable to charge solar owners when generators in the transmission network are not charged for accessing the network.[646]

The Australia Institute considers there is a need for consistent principles:[647]

> Charging the emerging class of DER generators for their use of the network would not be consistent with how legacy generators are treated. Large generators connected to the transmission network do not pay to use it. The SAPN proposal would not see large embedded generators charged either.
>
> This inconsistency is a significant weakness in the rule change proposals. It would be inequitable to charge solar households when other generators are not charged for accessing the network. This benefits the incumbents and the expense of innovation.
>
> At the very least, if the Commission wishes to create charges for DER generators, a fair

643 Changing weather submission to the consultation paper, p. 1.

644 CEPA, Distributed Energy Resources Integration Program – Access and pricing: Reform options, April 2020, p. 37.

645 Victorian Government submission to the consultation paper, p. 5.

646 Solar Citizens submission to the consultation paper, p. 2.

647 Australia Institute submission to the consultation paper, p. 4.

> principle would be that the DER households should be rewarded for the benefits of their energy and services at the same time as they are made to pay for any net costs they create for networks and thus other consumers.
>
> We suggest that the simplest way to achieve this consistency of principles would be to defer this rule change and place it within the P2025 DER workstream. That would allow DER charges to be dealt with comprehensively at the same time as payments and related DER integration challenges such as technical standards.

The MEU states:[648]

> … clause [6.1.4] reflects the implicit requirement that generation connected to the transmission network is not to incur network use of system charges for export – generators connected to transmission only pay shallow connection costs. The MEU considers there needs to be consistency between network charges for export regardless as to whether the export is into distribution or transmission networks.
>
> The MEU has been a consistent supporter of the view that generation into transmission networks should pay for use of the shared transmission system (ie pay transmission use of system charges) – this approach reflects a beneficiary pays process.

Tesla submits:[649]

> Design of new tariffs will also need to consider the costs of DER participation to avoid creating an playing field whereby DER asset holders pay more to participate in energy markets over their asset life than utility scale assets. This will ensure that smart DER assets are not disadvantaged by the outsized network fees above what an equivalently sized utility scale generator would pay over the same period.

James (private individual) states:[650]

> Big coal and gas generators don't have to pay for supplying electricity into the network, so why should solar homes and businesses who have made a personal investment in rooftop solar?

CSR considers export charges should not apply at distribution level unless the market changes and this is expanded to apply for all new generation and include transmission network services providers.[651]

C.2.3 DER is good for everyone

Equity issues and notions of fairness discussed in section A.1.3 above are not straight-forward and often subjective. All consumers may be better off overall if the AER approves expenditure for DNSP proposed DER-related projects that promote 'net market benefits' – for

648 ME submission to the consultation paper, p. 2.
649 Tesla submission to the consultation paper, p. 4.
650 Christine James (private individual) submission to the consultation paper, p. 1.
651 CSR submission to the consultation paper, p. 2.

example, whereby higher network costs are more than offset by lower wholesale market prices. So, increased DER should lower everyone's electricity bills overall.

Solar Citizens submits that even without the positive decarbonisation benefits, the evidence points to solar having a positive impact on costs for all energy consumers such that its continued uptake should be encouraged, and pay back periods minimised. Solar Citizens states:[652]

> Our concern is that the imposition of DUOS fees, particularly in the context of rapidly lowering feed in tariffs, will discourage investment in solar, as it will inevitably extend the pay back periods. If investment in rooftop solar is providing a net benefit to all consumers, then it holds that reducing the amount of rooftop solar exports will negatively impact all consumers.

Energetic Communities does not support simply removing NER clause 6.1.4:[653]

> This would be a blunt approach and would leave it open for DNSPs to either over or under recover costs, leading to economic inefficiencies. We agree with TEC/ACOSS that equity principles would demand that in the case of there being market benefits, cost recovery should be borne by all consumers. This could be in the daily service charge, not the variable component of the bill. As with much of tariff reform, there is still no visibility of how retail tariffs reflect network tariffs.

Renew states:[654]

> … it is appropriate for network end-users to share efficient costs where the expenditure provides a shared benefit, but not to the extent that costs materially exceed the value of shared benefits. Investors in DER can derive a private benefit that exceeds the shared benefit, and it is appropriate for them to contribute collectively to additional costs of network expenditure above the efficient cost for shared benefits to deliver these private benefits. In practice, the evidence seems clear that a considerable amount of DER enablement can occur at costs below the value of the shared benefits delivered. …

Diamond Energy submits:[655]

> DER can provide material benefits to the network, if managed effectively. Removing clause 6.1.4 will reduce the value of these benefits and fails to recognise the broader benefits that optimisation of embedded generation and DER can provide to the Brid (sic).

Private individual 1 submits:[656]

652 Solar Citizens submission to the consultation paper, pp. 1–2.
653 Energetic Communities submission to the consultation paper, p. 9.
654 Renew submission to the consultation paper, p. 1.
655 Diamond Energy submission to the consultation paper, p. 3.
656 Private individual 1 to the consultation paper, pp. 1–2.

> The proponents' concerns about matters of equity in the market are relevant and admirable. In particular, there is significant value in the principle that consumers who cannot afford a particular activity in the electricity market should not experience increased prices based on the cost of additional infrastructure needed to accommodate that activity. However, it is a principle that has not been applied consistently in the past and runs the risk of pitting individuals and small consumers against each other, while creating rules for a market that entrenches existing power dynamics to the benefit of existing, large scale producers of energy.
>
> … Solar cell owners are not in it for the money per se. While solar cell owners do consider costs and benefits before installing solar cells, they are not seeking to make a profit. Instead, they want a fair return for their contribution. In this context, the money is a signal about whether their contribution is valued by the community. A charge to provide additional energy sends the message that the contributions of solar cell owners is not welcome. The proposal not to apply export charges to entrenched, commercial producers of high emission energy will only compound that perception. These perceptions may contribute to a decision not to install solar cells or to limit any personal investment to the amount needed for self-consumption. This will not address inequity in the market. Excess solar has a role to play in decreasing the wholesale price of energy, which has benefits for retail consumers, including those who cannot afford to generate their own power.

Planet Ark Power states:[657]

> We recognise the impact that DER has had on all customers and the entire energy market and system and fully support the principle that customers who are not able to invest in solar should not be burdened with those costs. Current DER impacts have primarily been driven by continued consumer investment in rooftop PV electricity generation.
>
> It should be noted however that, in the longer term, allowing more DER into the network creates greater market competition and will place downward pressure on prices. Assuming these lower prices are passed on to consumers, this will positively impact those unable to install their own solar systems for the variety of known reasons.

Unfolding futures attached to its submission a previous report by Energy Synapse, written on behalf of Solar Citizens Australia, which found:[658]

> Despite contributing only 2% to electricity generation, this study found that small solar PV systems put significant downward pressure on wholesale electricity prices in the NSW market. If there was no small solar installed in NSW, we estimate that the volume weighted average price of wholesale electricity would have been $29–44/MWh (33-

657 Planet Ark Power submission to the consultation paper, p. 3.

658 Unfolding futures submission to the consultation paper, Energy Synapse attachment, p. 3.

> 50%) higher than the actual price of $88/MWh. This equates to a $2.2–3.3 billion cost saving to the NSW market (see Figure 1). Thus, each megawatt hour of power that was produced by small solar lowered wholesale costs by $1,400–2,200. This benefit is shared by all consumers, regardless of whether or not they have installed solar PV systems.
>
> In addition to electricity pricing, small solar PV was also found to significantly reduce both the severity and length of peak demand. Severity is defined as the maximum five minute electricity demand on a given day. The length of peak demand is the number of hours in a given day that are within 5% of the maximum five minute demand. An examination of the top 10 demand days during the study period found that small solar reduced the severity of peak demand by an average of 432 MW or 3%. Even more significantly, small solar was found to reduce the length of peak demand by 58%, from an average of 5.3 hours to 2.2 hours.

C.2.4 Some stakeholders consider more evidence is required

Some submissions call for further evidence to be provided to justify the proposed rule change, including benefit–cost and customer impact analysis. For example, the Victorian Government submits:[659]

> The Victorian Government does not support export charging, as the case for implementing this element of the proposed reforms has not been demonstrated at this time. A comprehensive cost benefit analysis would be required to understand customer views, impacts on DER and non-DER customers and potential distortion to efficient generation investment if export charging is considered further.

Further, the Victorian Government states it supports enhancing customer choice around service access and mechanisms to reward customers where their DER provides material benefits to the system, but:[660]

> Enabling export charges is not the only pathway to achieve this and other desired outcomes. As CEPA's report to the AEMC on reform options noted, the access levels and standards that customers receive must first be clearly defined before charges are introduced. The ability to robustly and consistently measure and regulate the services being provided is also a critical consideration before allowing customers to be charged.

Tesla submits:[661]

> Tesla recommends AEMC's network access and pricing review be informed by an evidence-based approach that draws on available DER field data to assess the impacts and benefits of any future tariff structures. We recognise that the devil will be in the detail in respect of the potential customer impacts of this rule change, and careful

659 Victorian Government submission to the consultation paper, p. 4.

660 ibid, p. 4.

661 Tesla submission to the consultation paper, p. 2.

> consideration should be given to ensure that the customer costs do not outweigh the benefits of any new tariff or cost structure.
>
> Attempts to introduce cost-reflective pricing to encourage efficient price signals for investment and consumer behaviour should be balanced against the likely risk that new export charges could limit new investment in DER if not structured appropriately.

Origin considers:[662]

> The goal of providing economically efficient signals should be balanced against practical considerations. Notably, the administrative cost of determining the impact of any specific DER can be significant compared to the incremental impact of the system on the network, especially for smaller systems. The AEMC should ensure that any signals based on estimates of average impact do not place inefficient costs on smaller systems, and lead to unintended costs.
>
> The AEMC's rule change process should evaluate how the price signals from DNSPs are intended to be communicated to customers, and how this will drive consumer behaviour. At this stage the proposal only describes a high-level concept, with little practical explanation on how it would be implemented.

Moreover, Origin states:[663]

> A consumer with DER has contact to the NEM through either a retailer or an aggregating market participant (such as a market small generation aggregator, or a demand response aggregator). The rule change assessment should consider mechanisms to ensure that these market participants are able to effectively pass through these signals to the end user in a way that does not materially increase the complexity of the end user's tariffs or inefficiently increase costs. Additionally, incentives for DER do not have to be financial to encourage specific responses. For example, we have been investigating the potential of behavioural demand response, both stand-alone and with automated devices.

Private individual 1 submits:[664]

> Price signals such as export charges assume the existence of the rational actor. The reality is that most owners of solar panels are not such active participants in the market on a daily basis that they will adjust their behaviour in response to export charges. Fine grade behavioural responses, such as increased self-consumption and decisions about when to divert excess energy to a battery and when to export to the grid, will not be achieved in individual solar cell owners without an intermediary, such as a technology innovation that monitors network capacity and releases energy to the grid at points of capacity. Whether this technology is possible or marketable is

662 Origin submission to the consultation paper, p. 5.

663 ibid, pp. 5–6.

664 Private individual 1 to the consultation paper, pp. 1–2.

> speculative and should not be assumed in making rule changes.
>
> As such, the price signal sent by export charges will be experienced by solar cell owners (current or prospective) at the point of a purchasing decision. The signal sent by export charges is that solar cells are an unwelcome inconvenience to a network built for the benefit and use of large scale producers. It will be experienced as paying for a network twice – first as a consumer and then as a producer.

Planet Ark Power considers:[665]

> In the NEM distribution and retail utilities have all struggled to introduce tariffs that attract customers to participate and signup for new structures. There are many reasons for this being the current rules on 'cost reflective pricing' as opposed to outcomes based measures and the processes to engage, communicate, inform and encourage customers to move from the standard offers in the market. Any proposed changes for tariffs need to consider these items in how they can be delivered and not just designed.

CEC submits the AEMC's Consultation paper assumes that customers will continue to want to export energy to the grid, even when there is a charge to do so. However, CEC says, that could change as the value of energy during daylight hours continues to decrease. CEC therefore recommends the AEMC undertake analysis that considers customers' likely response to changes in the value of exported energy. CEC considers there is a strong possibility that the proposed reforms will hasten moves toward maximising self-consumption, instead of exports.[666]

Red and Lumo consider:[667]

> Should the Commission decide to remove the prohibition on networks charging for exporting to the distribution system, cost reflective network pricing must be structured in a manner that is simple for consumers to understand and respond to. As a result, any cost recovery of exporting to the distribution system must be introduced as a simple, flat volumetric tariff. This is easily understood and an accepted method of cost recovery for distributed energy resources. Further, it would not result in any significant changes to the mechanism by which individual distributed energy resources are credited onto customer bills. Additionally, this type of simple tariff would lower any implementation burden as it is consistent with the current processes.
>
> We acknowledge that there is likely to be a strong desire by networks to introduce tariffs that are extreme, and attempt to encourage efficient use of the distribution system with complex price signals. Retailers and consumer representatives must play a central role in tariff development, as they will be able to provide feedback and insights from consumers. Consistent with our position on cost reflective consumption tariffs,

665 Planet Ark Power submission to the consultation paper, p. 12.

666 CEC submission to the consultation paper, p. 3.

667 Red Energy and Lumo Energy submission to the consultation paper, p. 3.

> consumers need to first have a basic understanding of how this new arrangement might operate and affect their bills prior to any complexity being added. We strongly encourage the Commission to take this into consideration and include the concepts of fairness and simplicity into any drafting amendments made to the regulatory framework.
>
> The Commission must also consider how the introduction of any additional charges will operate with retail price regulation, specifically the Victorian Default Offer (VDO) and the Default Market Offer (DMO). As the Commission must also consider the consumer protection test under the NERO, we acknowledge that a simple arrangement will be consistent with retail price regulation. Should the Commission allow a peaky demand export charge that penalises injections into the distribution system at inappropriate times, this will be passed onto the retailer by the network. The VDO or DMO may prevent that charge from being passed on, forcing retailers to absorb the cost and therefore the intended price signal will not reach the distributed energy resource owner. This is inconsistent with the intent of the rule change proposals and the NEO and NERO.
>
> Red and Lumo consider the proposal by SA Power Networks that the tariffs be considered as part of the Tariff Structure Statement (TSS) process providing them with the opportunity for the tariff to be introduced in a cost reflective manner. Noting our recommendations above, we urge the Commission to consider the implications of the consumer protections test, if it determines that a rule change be made.

The MEU is of the view that there are other aspects that must be addressed in the analysis of the three rule changes proposed, including:[668]

- While the proposed rule changes are focused on addressing a problem in the distribution network between prosumers and the nearby substation, the impacts will also be felt further into the distribution networks between the substation and transmission network and even into the transmission network. These must be assessed.
- How to manage the benefits that a first mover gets (using up the available capacity) thereby imposing costs on subsequent exporters seeking to connect. Should the late comers carry all of the costs or should they be socialised in some way?
- Should existing prosumers continue to receive “free access” for their exports or should all exporters incur a share of the costs, regardless as to whether their part of the network is augmented or not.
- There is the implicit concept that end users of the same class are treated the same regardless of their location within each network. Prosumers in one part of the network might not be constrained or cause costs from network augmentation yet a prosumer of the same class in another part of the network will be exposed to costs. Is this equitable?
- What are the network costs that are to be attributed to the export – incremental cost, marginal cost, full cost, share of existing assets needed to enable the export?

668 MEU submission to the consultation paper, pp. 3–4.

- The value of the export varies over time so what is the process to value the export to demonstrate the net benefit if there is one?
- A network provider will have the ability to argue for a capex allowance to enable the export by a prosumer, but the network provider might also not immediately implement the augmentation. So, the prosumer will incur a cost for "premium access" but the network provider might impose export limits at times on other prosumers who expected to be able to export but have not paid the premium.
- There needs to be clarity on whether augmentation assets that are provided under the "normal" network charges for import should be part of the charge for export (eg expanding the provision of tap changing on transformers).
- Any new rule should allow flexibility in operation so that the lowest cost solution can be implemented so that efficiency is achieved.

In summary, MEU states:[669]

> The MEU recognises that its response does not necessarily address the specific rule change proposals nor the questions raised in the consultation paper. In fact, the MEU response seems to raise more questions. We consider that there needs to be considerably more analysis of the impacts of the different proposals and the concepts inherent in them. Specifically, the MEU considers that there has not been sufficient recognition of the much wider impacts in the market resulting from the proposed changes than what might occur from merely addressing residential PV solar output into the distribution network where there is export congestion being observed.

C.2.5 Practical implementation issues

Practical implementation of export charges may be challenging and somewhat costly, including communicating the options to customers and transaction costs. Submissions identified such potential costs and practical implementation issues more broadly.

Ausgrid states:[670]

> The costs of enabling export charges relate to the costs of customer engagement and consultation, communications, and implementation of changes to distributors and retailers billing systems. Market systems (eg MSATS, B2B) would also need to change. There could also be costs to the existing customers with DER if they were to be exposed to the new charges.

PIAC considers that DUOS-type charges for export capacity are unlikely to ever be in the consumer interest:[671]

> While they may have merit in a very distant future if DER becomes the primary source of distributed energy, an ongoing, DUOS-style charge for export capacity would require

669 ibid, p. 4.
670 Ausgrid submission to the consultation paper, p. 12.
671 PIAC submission to the consultation paper, p. 2.

> comprehensive changes to network and retailer charging and billing systems, tariff setting processes, and cost and risk allocation.

Jemena submits:[672]

> It would be a requirement that meters capture the "B" data stream to enable the measurement of grid exports; it would be mandatory for DER proponents to have this type of meter in place. The costs of these meters are already captured in jurisdiction arrangements (Vic) or through metering completion (all other NEM jurisdictions). Some modifications to billing systems would be required; however, these are not expected to be significant.

Solar citizens expressed uncertainty about how the price signal could target capacity constrained locations:[673]

> The St Vincent's rule change request proposes limiting the imposition of DUOS fees to those who are currently export constrained. We struggle to see how this would work in practice – would the imposition of fees be limited to those specific locations where upgrades are required? Would costs be recovered via DUOS over a set period from one customer only?

Solar Citizens further considers:[674]

- The imposition of DUOS fees on solar households may only have limited practical impact on the bills of vulnerable consumers.
- The imposition of fixed network charges, higher in Australia than other countries, means that households with solar PV are already paying higher per kwH than other consumers for electricity imported from the grid.

EnergyAustralia supports a considered approach to the application of cost reflective tariffs, with a particular emphasis on ensuring DER customers are not adversely impacted by a potential double exposure of export and consumption charges.[675] Further:[676]

> An extensive outreach and information campaign will be required by networks, consumer and industry groups, and retailers, to educate existing DER customers of the requirement for the changes, and how export will be charged. The burden should not fall on any one participant.

Firm Power submits:[677]

> There are inherent difficulties in structuring network tariffs that are fully cost-reflective,

672 Jemena submission to the consultation paper, p. 11.
673 Solar Citizens submission to the consultation paper, p.3.
674 ibid, p. 2.
675 EnergyAustralia submission to the consultation paper, p. 11.
676 ibid, p. 12.
677 Firm Power submission to the consultation paper, p. 5.

> completely transparent (especially via retailer passthroughs) and are therefore socially accepted. This is especially the case with export services, where some customers may desire and be willing to pay for hosting capacity, but other customers may not desire such service features and therefore not want to be imposed with higher costs. Volumentric (i.e. kWh) type cost recovery also does not provide the right incentive to promote hosting capacity and results in an unavoidable cost to DER users which leads to inequitable outcomes.
>
> Instead, DNSPs should be incentivised to contract balancing service providers to increase the efficiency and utilisation of network assets, thereby increasing DER hosting capacity. Balancing service providers are best placed to provide the least cost improvement in network operations, especially when NEM-wide benefits are also considered.

ERM Power states:[678]

> … the imposition of any export charge should only reflect the additional costs imposed on the distribution network to facilitate DER exports and should be assessed net of the benefits that DER provides including the deferral of network upgrades that would have been required absent the installation of DER.

Origin states:[679]

> Whilst we are generally supportive of the economic arguments made in favour of a price signal placed on exports, we are not convinced that the proposals have fully addressed the practical impacts on DER customers. Some customers may find the change too complex whilst others may not be able to respond to the proposed price signal. Whilst we understand that retail customers do not need to face the exact distribution price charge, there needs to be a practical way to pass this through which will involve a trade-off between accuracy and simplicity. The rule changes proposals have not made the case for how this would occur.
>
> Further, the implementation of such an export charge may be influenced by related changes at the jurisdictional or network level. For example, South Australia is currently implementing a range of changes to distributed solar systems including the requirement for remote disconnection as well as new solar sponge tariffs. Western Australia has also recently announced changes to its solar feed-in tariffs moving from one flat rate to a peak and off-peak rate. These changes at the state level could largely outweigh the price signals from the export tariffs proposed in this rule change.

Further, Origin explains:[680]

> Currently, networks services are funded from consumers through Distribution Use of

678 ERM Power submission to the consultation paper, p. 2.

679 Origin submission to the consultation paper, p. 1.

680 ibid, p. 7.

> System (DUOS) charges. A new framework for recovering costs for export services will require a mechanism for evaluating what part of network's incremental costs relates to DER provision, and what is related to the provision of energy to consumers. This would be a complex task and the rules framework should ensure that DER providers are not cross subsiding the normal operating costs of the network from charges to DER. Additionally, determination of DUOS should account for this separate revenue stream.
>
> An example of the difficulty in allocating costs is the management of voltage in the network. High voltage issues can be caused by multiple DER exporting into the grid at the same location. However, while DER is contributing to voltage issues, these are due to a wide variety of factors. Placing an export change on a DER provider to manage voltage issues could act as a substitute for obligations on the DNSP to maintain security.

Changing weather says: "we all need to acknowledge publicly how difficult it might be politically to move away from postage stamp pricing or to treat the solar owner cohort as a different customer class and allocate resources to alternative non-punitive approaches."[681]

TasNetworks submits:[682]

> Notwithstanding TasNetworks' support for the rule changes proposed by SAPN, we think that it is imperative that any rule change eventuating from the proposals received by the AEMC does not prevent jurisdictional variations in the service standards that DNSPs are expected to provide to customers with DER. It is also vital that variations in the cost-recovery arrangements applied by individual networks and variations in the timing for the introduction of DER service obligations and export charges are also possible under any rule change.
>
> As one of the first DNSPs that any amended rules resulting from these rule change requests could potentially apply to, TasNetworks does not consider that there is either sufficient time before the start of the 2024–29 regulatory period to plan for the implementation of DER service standards or develop export charges. Nor is there a need – in Tasmania, at least – to introduce DER service obligations and export charges in such a short timeframe. It is likely to be some time before DER levels approach the limit of the Tasmanian distribution network's inherent capacity to host DER, which gives TasNetworks time to work with customers and stakeholders, including the Australian Energy Regulator (AER), to develop service standards, incentive schemes and DER charging arrangements which will be acceptable to the AER and to our customers. It is expected that this work will, in fact, consume much of the coming regulatory period, largely due to the amount of data which will need to be gathered and the level of community and stakeholder consultation that will need to be undertaken.

681 Changing weather submission to the consultation paper, p. 1.

682 TasNetworks submission to the consultation paper, p. 2.

CEC considers:[683]

> There is a significant amount of work being undertaken by industry and DNSPs to enable dynamic control for DER. Dynamic control is expected to make an important contribution to addressing the issues of voltage management on the low voltage distribution network.
>
> Will dynamically controlled DER be subject to the same export charging regime as other DER? It would be unfair to charge dynamically controlled DER for exports if it is not contributing to the problems being addressed by the access and pricing rule change proposal.

The Customer Advocate submits:[684]

> As we learned from the practical experience of the uptake of time-varying tariffs through the smart meter rollout in Victoria, a good idea does not always translate to the adoption with open arms. There is a real risk that consumer pushback may trigger political influence on the adoption of the proposal (or otherwise).

Red and Lumo consider:[685]

> The consultation paper does not consider whether the rule change will satisfy the NEO or the NERO in delivering net benefits to consumers in light of existing arrangements. Red and Lumo note that should the Commission decide to make a rule, there are jurisdictional impediments in Victoria that renewable energy and other retail customers must be treated equally and placed on the same tariffs.
>
> Red and Lumo note that the National Energy Retail Law provides the ability for a jurisdiction to mandate retailers provide for specific standing offers to small customers with interval meters. Further, that the networks must not only comply with the National Electricity Rules, but also any jurisdictional pricing obligation. We request that the Commission obtain advice and consider any existing arrangements when making its draft determination.

In considering the implementation issues, Energetic Communities states:[686]

> A major issue is also around climate change. There are many voices contributing to working out the best way forward on charging for export services. Some see it as a right to export, others see many pros and cons. If there is a perceived or real injustice for new prosumers, some may decide not to install or to leave the grid, which is a dis-benefit to everyone. Implementation must ensure zero carbon energy is increased. This speaks to the importance of communication and education, and the principle that the structure of each tariff must be reasonably capable of being understood by retail

683 CEC submission to the consultation paper, p. 5.

684 The Customer Advocate submission to the consultation paper, p. 2.

685 Red Energy and Lumo Energy submission to the consultation paper, p. 4.

686 Energetic Communities submission to the consultation paper, p. 9.

> customers. If the rule change is to include opt-in purchasing of additional capacity, it should be clear this is only for those who want it. It needs to be clear that the rule change is essentially business as usual for existing customers. This should also not be left to retailers, as they will have their own marketing, offers and retail tariffs. The overall picture, including reasoning, disadvantages and advantages for prosumers and other end users should be made clear. This should include information and context such as what component is for cost recovery for export services, who pays for it, additional income still available to prosumers, overall network benefits, and when these don't apply. That is, communication and education should keep all consumers informed, not be a marketing exercise and clearly demonstrate exactly how these reforms will increase DER and charge prosumers and other end-users fairly.

In addition to the issues raised in the above submissions, practical questions arise as to whether DER customers should be able to recover export charges as an input cost – as would be expected in a competitive market. CEPA explained:[687]

> If exporters are faced with network charges they will attempt to pass these additional costs on to customers. This is the main assumption that underpins the introduction of export charges at the transmission level for registered generators. If generators faced transmission related costs, they would incorporate these costs in their bids, and if they are dispatched then they will recover these costs. If the addition of these charges to their bids mean that they are not dispatched, then either they need to lower their bid in order to be dispatched or a lower cost generator/ demand response is dispatched instead. In the former, the generator would have to bear the network costs rather than passing them on to consumers.
>
> Exporters connected on distribution networks who only receive FiTs may not be able to recover their DUoS charges unless the FiTs are adjusted to take account of DUoS charges. The latter might involve the FiTs having an explicit uplift for DUoS charges.
>
> If micro-generators are eventually exposed to the wholesale market price, their ability to recover the DUoS charges will be dependent on the competition in the market.
>
> DUoS charges can be set in a way as to send signals to exporters on the most efficient location and time to export. However, there is a risk that, depending on the extent that competition or the FiTs permit, charging for exports may only achieve a short-term reallocation of costs from consumers before they are recharged back.

C.2.6 Alternative mechanisms to export charges

Some stakeholders agreed costs could be allocated more equitably but are less clear if applying export charges is the best approach to minimise cross-subsidies between DER and non-DER households.

687 CEPA, Distributed Energy Resources Integration Program – Access and pricing: Reform options, April 2020, p. 37.

PIAC recommends that any major reforms to pricing of export or generation capacity should follow, not precede, the full implementation of cost-reflective pricing of consumption:[688]

> Without intervention or reform, equity issues will arise as households without DER pay a higher proportion of network costs and network limitations prevent some households from investing in their own DER.
>
> These barriers to the efficient uptake and use of DER can be addressed, and the impacts greatly reduced, by the introduction of more cost reflective tariffs for consumption.
>
> Applying more cost reflective tariffs for consumption (such as peak demand charges or critical peak pricing) would better reflect the impact consumers place on the network and incentivise optimising their DER systems for self-consumption. Households would thereby be incentivised to shift load to coincide with solar generation, orient solar panels to face west (and/or east) to coincide better with energy consumption and to store excess solar generation for use during times of higher demand. This would help limit the impact of DER on networks open up more network capacity for exporting DER in a more deliberate and efficient way.

Energetic Communities states:[689]

> A key equity issue with DER is that cost recovery (whether for the DER itself or building export capacity) is often through a cross-subsidy. Cross subsidies can be positive if they lead to a broader benefit to all consumers, including those paying the cross subsidy and if the overall benefit is positive (i.e. if the cross subsidy is less than the benefit), or if it redresses an existing imbalance (e.g. the Community Service Obligation). An issue with DER nonetheless is that the cross subsidy can be disproportionately paid for by non-DER households if recovered through the variable charge of the customer bill. While non-DER households may see market benefits from increased DER exports, the actual cost of enabling the DER exports should be spread equally and equitably to all beneficiaries, and therefore not just through a variable component, which is only reduced for the DER household who can reduce their grid electricity demand through the solar and other DER. State governments have the power to pay these FiT costs more progressively through internal revenue, as the Queensland government did until recently in the case of the mandatory regional feed in tariff. A similar mechanism could be used. An alternative would be to use the daily charge to recover costs, thereby spreading them across all grid connected consumers who get the market benefits of the DER.

Ecojoule Energy submits it partly accepts the argument that export charges can encourage efficient investment to support export services and decrease levels of inequity between those who have solar PV and those who don't. However, Ecojoule Energy suggests that there are better mechanisms (eg, STPIS) for recovery of costs that would be less complex to

688 PIAC submission to the consultation paper, p. 1.

689 Energetic Communities submission to the consultation paper, p. 8.

administer and would be less likely to be perceived by the community as an instrument to slow down the uptake of renewables.[690]

Private individual 2 submits:[691]

> I expect St Vincent De Paul Society wants Roof Top solar power exporters to carry the burden of Net Work up grades so power costs are reduced for the poorer people of the community, since St Vincent De Paul see many of the poorer people of our society come through their doors seek financial help with power bills.
>
> Seems the government is not supporting the poorer people of our community well enough and St Vincent De Paul wants Roof Top Solar exporters to foot the bill on behalf of the Government.
>
> The Grid is changing and every body needs to contribute. Millions can afford their electricity bill, So, current electricity charges do not seem to be to high for most.
>
> The Government needs to make more money available to St Vincent De Paul and other charities so they can look after the poor better.

The Australian Power Quality and Reliability Centre at the University of Wollongong states:[692]

> The APQRC recognises the inherent inequity, specifically identified by The St Vincent de Paul Society Victoria (SVDP), that exists at present whereby costs associated with network augmentation and other activities to support energy export are shared by all consumers regardless of benefit. As such, the APQRC supports the view of SVDP and SA Power Networks (SAPN) that changes should be made to the appropriate rules to remove impediments in the NER to DNSPs recovering their costs associated with supporting export of electrical energy. However, the APQRC is not in a position to determine whether the best option for recovery of costs is a direct charge to consumers or some other incentive scheme or regulatory adjustment.

AGL considers:[693]

> Having regard to SAPN's proposed export tariff that would be cost-reflective, it is not clear how the proposal would actually support greater market access for DER. We agree with the proponents that increased use of distribution networks by DER to export electricity into the system will eventually drive the need for new network expenditure as the inherent 'hosting capacity' of the existing assets is used up. However, in the absence of an overall net change in distribution networks' expenditure outlook, we do not consider that the linkage of export charges to improved investment and certainty for DER customers has been made clear.
>
> In our view, investment certainty is likely to be better supported by the proposed

690 Ecojoule Energy submission to the consultation paper, p. 1.

691 Private individual 2 to the consultation paper, p. 1.

692 Australian Power Quality and Reliability Centre at the University of Wollongong submission to the consultation paper, p. 1.

693 AGL submission to the consultation paper, p. 10.

> changes to distribution networks services obligations and incentives schemes. In particular, the introduction of a 'net market benefit' test as a guiding principle for planning and investment could better support network expenditure decisions in circumstances where it is demonstrated to provide a benefit for the broader energy market system.

C.3 The 'other side of the coin': enabling negative prices

Dynamic pricing signals, both positive and negative, and for consumption and export services, can be used to lower costs for all users. CEPA explained:[694]

> It is important to note that a DNSP, if it is able to, should set cost-reflective tariffs such that changes in a retail customer's demand profile (without exporting), for example from positioning their solar panels to face west to shift generation into peak times, are rewarded through lower DUoS charges. If the retail customer is able to export at peak time, which helps the DNSP avoid costs, they should be rewarded.

To this end, SAPN's proposal to allow for *negative* customer charges, as discussed in Chapter 6 under section 6.2.1, aims to enhance price signals to reward customers for actions that better utilise the network or improve network operations. SAPN said this would allow for tariffs that explicitly consider not only the costs caused by serving a customer, but also the costs avoided for other customers, and would serve as an enabler for DER network support services. SAPN proposed that negative pricing should be optional for DNSPs to consider in their circumstances via their tariff structure statement (TSS).[695]

Ausgrid summarises:[696]

> Network pricing should recognise this symmetry by charging users when they impose costs on the network and rewarding customers when they avoid network costs. This enables all customers to play a role in reducing network costs for everyone.
>
> For instance, a customer exporting during a peak export event may increase network costs, but another customer could assist in avoiding those costs by increasing their demand. Rewarding the second customer could be accomplished if negative prices are allowed, or if reward payments are provided by other means. The value of the reward would be based on the LRMC of the corresponding service – consumption or export – within their own peak periods.

SAPN noted DNSPs also have non-tariff options to reward customers, such as demand response payments to customers.[697]

694 CEPA, Distributed Energy Resources Integration Program – Access and pricing: Reform options, April 2020, p. 39.

695 SAPN rule change request, p. 24.

696 Ausgrid submission to the consultation paper, p. 15.

697 SAPN rule change request, p. 24.

C.3.1 Stakeholders widely support a negative pricing option

The AER supports SAPN's proposal for the NER to explicitly acknowledge that cost reflective distribution charges can also include negative prices. The AER expects this additional clarification would facilitate DNSPs to incentivise electricity customers to provide network support services at times when they are needed.[698]

Ausgrid states:[699]

> Extension of pricing principles under clause 6.18.5 to export services is reasonably straightforward. We are supportive of a two-way tariff framework that could include negative tariffs to reward customers for network services their DER provides (eg, for exports during peak load times) – noting that this can also be done through network support payments and that the rules need to retain the flexibility to allow both options.

AusNet Services states:[700]

> The current NER do not prohibit networks entering financial agreements with DER customers/ service providers when these provide benefits to the network. This may be complemented by negative export charges where these are applied by DNSPs.

EnergyAustralia strongly supports the appropriate consideration of the benefits that DER services provide to DNSPs, which it says can be achieved through a combination of SAPN's proposal for negative prices and the TEC/ACOSS proposal for a market benefits test to considered the potential benefit DER may have on the network.[701]

ERM Power considers:[702]

> … the regulatory framework can better recognise the benefits DER services provide to DNSPs. SAPN's proposal for negative prices for instance, is a novel solution that could provide an incentive to export at times of peak demand in the network – in the evening peak for instance. In this way, a negative export charge would effectively add on to existing feed-in-tariffs and could act as an incentive for battery storage or re-orienting solar panels.

In support of SAPN's proposal, Renew states:[703]

> … to reflect that DER brings benefits to networks in the right circumstances even if in other circumstances it drives costs, DNSPs choosing to charge for exports to recover costs should also be required to pay or otherwise account for exports that reduce costs. In sum, it is appropriate for DNSPs to consider the net outcome of costs and benefits when determining both the level of hosting capacity that can be delivered at

698 AER submission, p. 6.

699 Ausgrid submission to the consultation paper, p. 12.

700 AusNet Services submission to the consultation paper, p. 7.

701 EnergyAustralia submission to the consultation paper, p. 12.

702 ERM Power submission to the consultation paper, p. 3.

703 Renew submission to the consultation paper, p. 12.

> no additional cost beyond what is realised by customers as benefits, and the quantum and application of additional charges and payments to DER customers wishing to export above the baseline allowance that reflect additional costs and benefits those exports create.

Solar Citizens states solar households should be rewarded for the benefits of their supply, not just the imposition of costs.[704]

Planet Ark Power states:[705]

> DER enablers that also provide grid firming or stabilising services should be recognised and compensated accordingly particularly where the integration of these solutions result in foregone spending in infrastructure upgrades by DNSPs.

Rheem states consumers should be rewarded for curtailing energy export (by increased self-consumption or export limiting by choice) during periods of excess energy production.[706]

Energetic Communities supports the regulatory framework recognising the benefits DER services provide to DNSPs and believes that this should be explicit and enforced through the TSS process.[707]

AEC/Oakley Greenwood state:[708]

> All three of the proponents recommend that DER participants be rewarded for the use of their DER in ways that provide benefits to the electricity supply chain (and networks in particular). We fully support this position and agree with Rule change proponents that the regulatory arrangements should recognise the benefits provided by export services.
>
> We do not propose to offer up a specific, preferred export tariff structure as part of this response, but note that a menu of options that could serve as models for pricing structures that could be implemented to reflect the benefits that DER can provide to networks and the upstream portions of the electricity supply chain was the subject of an ARENA study.
>
> …
>
> We have some concern with negative pricing. To the extent that the way it is implemented makes it a difficult value stream to be accessed by third-parties (for example, VPP operators or other aggregators) such a price signal could reduce innovation and restrict customer choice in access to some DER value streams.

Evoenergy states:[709]

704 Solar Citizens submission to the consultation paper, p. 2.
705 Planet Ark Power submission to the consultation paper, p. 13.
706 Rheem submission to the consultation paper, p. 1.
707 Energetic Communities submission to the consultation paper, p. 10.
708 AEC/Oakley Greenwood submission to the consultation paper, pp. 9–10; 11–12.
709 EvoEnergy submission to the consultation paper, p. 17.

> … it may be beneficial to incentivise customers to manage their exports in a manner that assists DNSPs to control the challenges DER introduces to the network from voltage swings and thermal imbalances. Retailers may need to agree to pass through to customers the rewards DNSPs wish to provide.

Endeavour Energy submits DNSPs should be able to apply charges (positive or negative) to export services where it is efficient to do so,[710] but notes:[711]

> In our view networks can offer rebates under the existing pricing rules. However, the clarification proposed by SAPN would confirm our understanding. However, we note direct network support payments are likely to be simpler and more effective as direct reward payments are less likely to be lagged and not dependent on the customer's retailer passing it through.

AGL supports the proposals that the regulatory framework could better recognise and reward customers for the benefits their DER provide. But AGL anticipates a range of operational challenges in implementing reward pricing, so AGL does not consider it should be implemented in the context of export charges at this point in time – until the broader tariff reform program is progressed.[712]

C.4 Should export charges (if enabled) only apply to small customers?

In proposing to remove NER clause 6.1.4, SAPN considered a new rule should make it explicit that export charges must not be applied to large embedded generator customers who are standalone generators, on the basis that:[713]

- the primary purpose of these generators is to provide energy to the NEM, rather than generating for a mix of self-consumption and export and they currently already pay connection charges for network augmentations
- not charging these generators maintains regulatory symmetry with dedicated generators who are connected to transmission networks and which do not currently pay ongoing transmission charges (only connection charges).

There were mixed submissions on whether export charges should only apply to small customers, as outlined below.

C.4.1 Those for

Renew agrees with SAPN's proposal to exclude large distribution connected generators, for the reasons SAPN articulates (above).[714]

Ausgrid submits:[715]

710 Endeavour Energy submission to the consultation paper: Appendix A, p. 5.
711 ibid, Appendix A, p. 6.
712 AGL submission to the consultation paper, p. 10.
713 SAPN rule change request, p. 24.
714 Renew submission to the consultation paper, p. 13.
715 Ausgrid submission to the consultation paper, p. 15.

> We consider there are merits in the SAPN's proposal to exempt large stand-alone generators from the application of DUOS charges, to maintain competitive neutrality with transmission. Charges to the stand-alone market generators (primary generators) connected to the distribution network should not prevent the efficient entry of generation and should not put them at competitive disadvantage to transmission connected generators.
>
> We consider it would be desirable not to exempt large customers with embedded generation from the potential application of DUOS charges. This would maintain symmetry with consumption, where large customers fund their connection via a combination of connection charges and tariffs.

AusNet Services states:[716]

> It is difficult to define the size of the generators that these reforms should apply to, particularly without knowing the detail of the reforms to be implemented. However, unless there is an intent to adopt similar reforms for large scale generation, including those on the transmission network, to preserve competitive neutrality, these reforms should only apply at the small end of the generation spectrum, and only capture small scale DER. This may nevertheless still create an inequity between aggregated energy services and large-scale generation.

Endeavour Energy says:[717]

> … the prohibition of DUOS charges for the export of energy should remain for larger generators. We also note the concurrent Integrating Storage rule change process will consider the issue of what network charges should apply to the energy consumed by bi-directional resource providers (i.e. large batteries).

Firm Power supports SAPN's proposal to explicitly exclude large embedded generators (and batteries) who are standalone generators from ongoing distribution charges – saying this has been a major barrier to the deployment of bi-directional technologies like batteries in distribution networks.[718]

Evoenergy notes large customers may also be charged for export capacity, if their capacity applications pass the requirements of a network technical study.[719]

Diamond Energy states:[720]

> We note that SAPN's proposal does identify the need for a 'new rule' to maintain and protect the existing NER rights for 'large embedded generator customers, who are stand-alone generators'. ... however it is important that the current definition of

716 AusNet Services submission to the consultation paper, p. 7.

717 Endeavour Energy submission to the consultation paper: Appendix A, p. 6.

718 Firm Power submission to the consultation paper, p. 5.

719 EvoEnergy submission to the consultation paper, p. 17.

720 Diamond Energy submission to the consultation paper, p. 3.

> "Embedded Generators" included via Clause 6.1.4 is maintained, and is not watered down if a 'new rule' is enacted.

C.4.2 Those against

AER states:[721]

> While TEC/ACOSS request that their proposed rule changes only apply to small customers, the reasons behind this are unclear. We are uncertain about the rationale for having different arrangements for one customer class in the NER. Doing so could create unnecessary inconsistency and complexity.

AGL says:[722]

> We also do not consider that the proposed reforms should only apply to small customers. Rather, the access and pricing arrangement should be consistent for all distribution connected customers, noting that for larger commercial and industrial customers there is scope to negotiate access arrangements through connection agreements.

Planet Ark Power states:[723]

> … these reforms should also apply to industrial and commercial customers that to date have largely been restricted from providing DER into adjacent networks. As above, where these customers can provide grid firming or stabilising solutions then they should have their export restrictions removed and be compensated where they provide verifiable, low cost support services to the adjacent network.

AEC/Oakley Greenwood state:[724]

> The reason for providing a price signal is to signal the costs that DER can impose on (or the benefits it can provide to) the network. There does not appear to be any reason why the price signal should apply differently to customers of different sizes, given this intent.
>
> We note that the price signal should apply to all customers even in the case that SAPN proposes whereby customers that limit their export to the capability inherent in the network infrastructure built to meet customer consumption demand would not be charged for that level of export. This charge would provide an economically efficient price signal to these customers regarding exports above the inherent capability of the network, but importantly, would NOT provide a signal that would assist them in monetising the benefits of changing their export behaviour within the 'free' allowance

721 AER submission to the consultation paper, p. 7.

722 AGL submission to the consultation paper, p. 11.

723 Planet Ark Power submission to the consultation paper, p. 13.

724 AEC/Oakley Greenwood submission to the consultation paper, p. 9.

> provided by this mechanism.
>
> SAPN proposes that large embedded DER generators that are connected to the distribution network should NOT be subject to export charges. Their rationale for this does not appear to be that generators connected at different voltage levels have different types of impacts on the costs of the respective networks, but rather that imposing those charges at the distribution level would create a regulatory asymmetry between larger embedded generators and generators that are connected to the transmission system. We agree that symmetrical regulatory treatment of generators that connect to the network at different voltages is a legitimate consideration in reviewing and reforming the Rules. However, we do not believe that it makes sense to allow economically inefficient pricing in one part of the market just because a similarly inefficient price signal exists in another part of the market. More specifically, even if transmission system pricing is not as economically efficient as it could be, this does not constitute a convincing rationale for introducing inefficient price signals at the distribution level.

C.5 Do the current pricing principles translate to export services?

The NER require DNSPs to include a description (with supporting materials) in their regulatory proposals of how the proposed TSS complies with the pricing principles – which is then subject to the AER's assessment and approval. The pricing principles are outlined in Chapter 6 under section 6.3.2 above.

Stakeholders commented that the current pricing principles remain largely flexible. For example, Endeavour Energy submits:[725]

> The pricing objective and principles in the NER remain fit-for-purpose and should enable networks, in consultation with stakeholders and as determined by the AER, to allocate costs and develop tariffs for export customers in an efficient manner and in consideration of the customer impacts. We do not consider it is necessary to prescribe export pricing structures and doing so would be out-of-step with the pricing approach taken for the other network services we provide. It also creates practical issues like the potential need for separate RABs and could exacerbate the risk of cross-subsidy or mispricing opportunities between import and export pricing.

Ausgrid states:[726]

> In line with the symmetry between consumption and export services, pricing principles in the NER (clause 6.18.5) should also apply to export services. With the introduction of export charges, tariff structures and tariffs are likely to become more complex. It may be necessary to review the NER requirement that 'the structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to the

725 Endeavour Energy submission to the consultation paper, p. 3.

726 Ausgrid submission to the consultation paper, p. 14.

> tariff'. With the two-way pricing and potentially more complex tariffs, pricing signals would be sent to retailers/aggregators who can repackage them into retail products for their customer, differentiated by customer preferences. Customer representative views will be particularly important on this question.

Essential Energy considers all tariffs should be based on the LRMC of providing the service to which it relates to that retail customer to allow customers to be incentivised to operate DER systems in a manner which is efficient.[727]

However, the AER considers some amendments may be required:[728]

> … the pricing principle to base tariffs on long run marginal cost might be more adaptable to emerging issues (e.g. minimum demand) if it referenced cost drivers in general, rather than cost drivers associated with times of greatest network utilisation.

Also, some stakeholders questioned the appropriateness of the pricing principle relating to locational costs.

An important feature of marginal costs for electricity network services is that they vary between customers, times of use and location. NERA considered that to ensure that appropriate price signals for supplying network services are provided, the marginal cost needs to be defined with reference to those factors that drive the incurrence of costs into the future.[729] The current pricing principles explicitly promote locational pricing – to the extent it is practical to implement and meets customer preferences for each jurisdiction.

Actual implementation of locational pricing has been very limited in Australia to date. It is a highly contentious issue, and seemingly raises conflicting equity and fairness considerations. Submissions highlighted these contrasting views.

C.5.1 Concerns raised about locational pricing

The Customer Advocate submits:[730]

> It is not unreasonable for DNSPs to charge for export services, provided it is time and demand-based to reflect the true impact on the network. Consumers with embedded generation should not be penalised for:
>
> - The connection of embedded generation where most or all of the energy generated is self-consumed, or
> - Energy is exported at a time or location where such export has little or no negative impact on the operation of the network (i.e. within the 'operating envelope')

Renew states:[731]

727 Essential Energy submission to the consultation paper, p. 3.

728 AER submission to the consultation paper, pp. 6–7.

729 NERA, Economic Concepts for Pricing Electricity Network Services, July 2014, p. 5.

730 The Customer Advocate submission to the consultation paper, p. 5.

731 Renew submission to the consultation paper, pp. 2–3; 12.

> While charging differently by substation is most cost-reflective, it seems overly complex and could potentially lead to significant locational inequity – rural customers in particular may be subject to very high charges. Making it consistent across an entire network would be the simplest approach, and supports a network-wide DER Integration Strategy that may involve investment in different parts of the network at different times – though at the expense of being unable to give locationally specific price signals. Perhaps a middle ground of some variation between a few distinct areas with markedly different hosting capacity within each network would strike the right balance between cost-reflectivity, simplicity, and equity.
>
> … there are pros and cons of postage stamp vs nodal approaches to tariff setting. A single tariff applied across a DNSP's entire network has the benefit of simplicity, and also fits better with the reality, expressed by SAPN in their proposal, that works to increase hosting capacity typically comprise a number of 'lumpy' investments that may need to occur sooner in some parts of the network than elsewhere (if at all). Conversely, localised charges can be more cost-reflective and incentivise the behaviour or investment that suits local circumstances or conditions.

EnergyAustralia believes locational pricing can be an effective form of stimulating or disincentivising investment in specific areas, there are however issues with ensuring these triggers are current, and able to be easily provided to customers.[732]

ERM Power considers:[733]

> The design of pricing arrangements may face a challenge in that there will need to be a balance struck between providing a strong locational signal so that in areas with excess hosting capacity there is less of a cost than in areas which are at or close to their limit. However, a locational signal may be at odds with the current postage-stamp pricing regime for distribution networks, tariffs that are reasonably capable of being understood by retail customers and the scope for retailers to pass on these costs in a transparent fashion, especially in light of the Default Market Offer and Victorian Default Offer. Any charge imposed must not unfairly target consumers in a network area where export capability is close to limit as this would be inconsistent to how costs for upgrading of the distribution network in a particular network area for energy consumption is socialised across all basic and standard network connections within that total distribution network area.

C.5.2 Submissions in favour of maintaining this flexibility

ARENA states:[734]

> DER customers will generally have smart meters which support more dynamic incentive arrangements and ideally, any export pricing will be able to evolve over time

732 EnergyAustralia submission to the consultation paper, p. 4.

733 ERM Power submission to the consultation paper, p. 3.

734 ARENA submission to the consultation paper, pp. 1–2.

> to reflect the location and timing of network constraints. This will support efficient investment and operational signals for DER and ensure the best use of existing hosting capacity. ARENA projects are demonstrating how DER can respond to time and locationally varying price signals and operating envelopes issued by a distribution business. … Our projects indicate that it will likely be retailers and aggregators, rather than customers themselves, that manage the additional associated complexity.

Ausgrid states:[735]

> We support application of the LRMC based prices for consumption and exports (within their own peak periods). We agree with SVDP's view that locational signals are important to ensure efficient integration of DER. We also consider that future tariff structures could include tariffs for the local use of network, for the flows that are exchanged and traded within the local distribution area. All these opportunities can be addressed under the current pricing principles provided the symmetry of consumption and export charges.

Ausgrid further states:[736]

> There might also be local variations of the rewards and costs (note that locational pricing is provided for under the current NER). SVDP's proposal puts forward locational pricing. SAPN does not propose locational pricing but suggests consideration be given to locations of network constraint. We consider that the flexibility of the principle should be maintained, to enable distributors to propose the best structures that suit their network needs, comply with jurisdictional and Rule requirements and are supported by customers.

Origin states:[737]

> … to ensure the most efficient signal is communicated to the market, the export charge should ideally be at a very granular level, such as feeder or postcode. However, this may be complex or costly to implement and the tendency may be to use an easier approach which smears the price across an entire network area. The AEMC should undertake further analysis on how to optimise a cost-effective but granular signal.

CEC submits:[738]

> Voltage management is inherently location specific. Export charges should be location specific if the aim is to align causation of voltage management challenges with the costs of voltage management response. If export charges are not location-specific, the AEMC should explain how issues of equity and efficiency will be addressed and how cross-subsidies between solar customers will be addressed.

735 Ausgrid submission to the consultation paper, p. 12.

736 ibid, p. 15.

737 Origin submission to the consultation paper, p. 5.

738 CEC submission to the consultation paper, p. 5.

EUAA states:[739]

> We are concerned that a postage stamp export price across a network would be inefficient and perpetuate the inequitable cross-subsidies. There are obvious efficiency and equity benefits in having a locational export price that reflects the varying levels of spare export capacity at different points in the network. Networks should have the flexibility to define regional export prices based on their level of knowledge of particular regional differences in costs of augmentation and benefits of additional DER.

AEC/Oakley Greenwood state:[740]

> Given that the cost imposed, or benefits offered, by the operation of DER are inherently local, postage-stamp pricing will necessarily be less economically efficient than area-specific price signals would be. They will result in over-export in some areas and at some times, and under-export in others. The greater the penetration of DER in given locations and over a distribution service area as a whole, the larger these effects may become. Cost-reflective price signals provide the best way of informing prosumers of the economic impacts of their investment decisions and operating behaviour. Given that (a) the days and times of day on which congestion and voltage constraints are expected to occur are readily forecastable, (b) the metering and system cost information exists to provide cost-reflective pricing to all customers with DER systems, (c) the management and dispatch of these systems will likely become more frequently undertaken by third parties and/or automated systems, and (d) the decisions of those customers can affect the prices levied on all customers, we strongly recommend that the AEMC give serious consideration to measures that would result in the pricing of export services (and export benefits) being as cost-reflective as possible subject to the costs of developing and administering those prices.
>
> However, we also note that the introduction of locational pricing that reflects the costs and benefits of DER export will require non-trivial changes to the billing systems and operating procedures of both electricity distribution businesses and retailers. As a result, it is likely that an appropriate transition period will be needed for their implementation.

C.6 Proposed new principles to guide cost and capacity allocation decisions

Allocating network hosting capacity is the process of determining how much network access each customer is able to use at any given time without breaching the physical limits of the grid.

TEC/ACOSS proposed the introduction of a new pricing principle to guide the allocation of existing and planned export capacity between prosumers. This, TEC/ACOSS considered, could

739 EUAA submission to the consultation paper, p. 4.

740 AEC/Oakley Greenwood submission to the consultation paper, p. 8.

be implemented by amending the pricing principles in NER clause 6.18.5 with the intention to ensure that "whatever the level of DER export hosting capacity, it is allocated fairly rather than on the basis of 'first come, first served' or by auctioning it off to the highest bidder."[741]

SAPN proposed a new rule should provide guiding principles for distribution networks on how costs should be allocated between consumption and export services, and potentially between different tariff charging parameters of export services.[742] SAPN said the aim would be to:[743]

- provide transparency to customers, and guidance to DNSPs to minimise administrative burden in their respective distribution determinations
- make it explicit that tariffs applied specifically to export services should not be allowed to recover the costs of the intrinsic capacity in the network to host exports
- provide flexibility for DNSPs to consider their individual circumstances.

Submissions on these two proposals are highlighted below in sections C.6.1 and C.6.2, respectively.

C.6.1 First come, first served?

The Victorian Government supports the development and application of principles to guide a transition towards allocating export capacity more equitably:[744]

> Greater fairness between early adopters and those installing later may be achieved through:
>
> - investments by distribution network operators to dynamically manage exports, allowing DER exports most of the time, with restrictions imposed only when networks exceed their operational limits;
> - distribution network operators ensuring anticipatory but prudent development of network capacity to meet customer expectations with appropriate regulatory obligations and incentives to achieve whole of system benefits from DER
> - enabling technologies and standards, including smart meters.
>
> The 'first come, first served' basis on which export capacity is currently allocated does not meet community expectations or the objectives of the Solar Homes program. The benefits of solar and the ability to export should be available to Victorian electricity customers regardless of when they have decided to install their system.

AusNet Services states:[745]

> The allocation of export capacity involves a myriad of equity issues. Currently, customers who connected DER systems early have benefitted by having greater access to export than customers who connected systems later on or will connect in future.

741 TEC/ACOSS rule change request, p. 14.

742 SAPN rule change request, p. 24.

743 ibid, p. 24.

744 Victorian Government submission to the consultation paper, p. 4.

745 AusNet Services submission to the consultation paper, pp. 4–5.

> The majority of customer with existing embedded generation have a legally binding connection agreement with their DNSP. These agreements can only be altered by means mutual agreement. Hence applying changes in the regulatory framework for existing connections is difficult. Therefore, any changes to the principles governing the allocation of export capacity – whether set out in the NER or in jurisdictional legislation – should be founded on broad stakeholder support.

AGL submits:[746]

> We anticipate some complexity in developing an appropriate methodology for allocation that is fair to all DER customers and also ensures efficiency in the sense of enabling access to aggregators who may be best placed to provide services into market.

Endeavour Energy considers:[747]

> The pricing objective and principles already provide a suitable framework for guiding the allocation of residual and incremental export capacity costs. This allocation should be determined under the existing pricing rules in consultation with customers and stakeholders during the determination process. NER clause 6.18.5 does not embed a 'first come, first served' or auction approach to allocating DER export hosting capacity.
>
> We consider a DER access/service standard can more directly address concerns around fairness in the allocation of DER export hosting. As noted above, other industry reviews are more directly considering the issue of minimum DER access standards. Also, mirroring the connection process and principles that apply to import/consumption services are likely to be suitable for the connection of export services.

EUAA states:[748]

> … there is not enough detail of what the proposed amendment to NER clause 6.18.5 to ensure DER export capacity is allocated 'fairly', actually means. We know it does not mean 'first come, first served' or by auctioning it off to the highest bidder. There are many legitimate definitions of 'fair' and it is difficult to express a view in the absence of a clear definition. We are concerned that one view, among many, of 'equity' and 'fairness' will hinder efficient network investment and DER expansion.

Ausgrid submits:[749]

> With the symmetrical treatment of consumption and exports supported by pricing, new rules on allocation of hosting capacity in the NER are not needed. The current rules are based on principles of economic efficiency that should equally apply to export pricing.

746 AGL submission to the consultation paper, p. 8.

747 Endeavour Energy submission to the consultation paper: Appendix A, p. 3.

748 EUAA submission to the consultation paper, p. 4.

749 Ausgrid submission to the consultation paper, p. 8.

> Without the symmetrical treatment of consumption and exports supported by pricing, an alternative approach would be to mandate a certain level of DER hosting capacity, or to establish tradeable property rights over hosting capacity. Both approaches require extensive changes to the regulations (and potentially legislation), are expensive to implement and administer, and overall are not as efficient as the proposed rule change that would see the definition of distribution services extended to include exports.
>
> Total Environment Centre (TEC) and Australian Council on Social Services (ACOSS)'s proposal to establish rules on allocation of hosting capacity becomes unnecessary if consumption and export services are treated symmetrically and are supported by pricing.
>
> We also note that because of the nature of the services, an opt-in model to purchase hosting capacity is challenged by the free-rider problem. It would potentially be cost prohibitive to exclude certain users from getting the benefits of the enhanced hosting capacity funded by other users, resulting in under-provision of hosting capacity via opt-in schemes. This needs to be balanced against consumer choice considerations.

Further, Ausgrid says:[750]

> We are supportive of causer/impactor pays principle of allocating costs across customer classes. This contributes to overall efficiency and cost reflectiveness of our tariffs.
>
> With the distribution network becoming a multi-product firm, it is important to maintain principles of cost allocation across the basket of services. We consider that impactor pays principle should be used to allocate costs across users, and that marginal cost pricing should apply to guide customer decisions at the margin, to ensure efficiency. Consultative engagement with customers can be used to set priorities/weights of interests of consumers and exporters when a conflict arises.

Jemena considers:[751]

> The ability to connect DER in a particular location changes over time. Moreover, the timing can be influenced by other DER proponents deciding to connect their DER in that same location. Within this context, there are three scenarios in which hosting capacity can be taken up or becomes available to new DER proponents:
>
> - Existing allocated capacity – For these types of connections, grandfathering provisions should apply. Investments are made in the context of the underlying frameworks at a point in time; this includes the rules and laws of the day. Based on this, we consider grandfathering of existing investments and therefore, the grandfathering of existing allocated capacity, is required to maintain investor

750 ibid, p. 14.

751 Jemena submission to the consultation paper, pp. 8–9.

confidence. The absence of grandfathering creates retrospective changes to investment decisions, which puts individual investors at risk.

- Existing free capacity – We consider this should be allocated on a first-come, first-serve basis; to reserve hosting capacity for future requests that may never arise, could result in locking up economic benefits or inefficient investment. If appropriately priced (see below) the direct and indirect beneficiaries will realise the economic benefits as soon as possible.
- New capacity – Should only be created when needed. Creating capacity in case customer want it at a future date could be inefficient because the capacity may never be used.

Allocating hosting capacity implies some sort of sharing, but reserving prevents unlocking benefits. In essence, the principles should focus on realising the benefits as soon as possible so as not to over-invest in the network.

We do not consider a minimum reserve and retrospective change are efficient. However, through normal planning processes, capacity will be created in the location and the time required efficiently.

Plantet Ark Power states:[752]

> A considered approach to allocation of export capacity which takes into consideration the technology solutions a customer is using to export to the grid should be included. A customer benefiting the grid should be compensated or provided with incentives and a greater export allowance.

Evoenergy submits:[753]

> There should be a principle that the primary purpose of the network is for energy consumption and that the provision of export capacity is a secondary purpose of the network. This will ensure that in a resource constrained environment, a DNSP should ensure that they provide for electricity consumption first.
>
> Evoenergy anticipates that all eligible DER customers requesting export capacity would be allocated the minimum standard of export capacity available.

Energetic Communities considers:[754]

> Setting principles in the allocation of export capacity can provide understanding to the intent of any obligations, guidance and certainty to DNSPs in implementing those obligations. This will further allow consumer advocates and other stakeholders to clearly provide feedback to DNSPs and the AER as to the success of those obligations, and improve stakeholder support and faith in the market.

752 Planet Ark Power submission to the consultation paper, p. 10.
753 Evoenergy submission to the consultation paper, pp. 12–13.
754 Energetic Communities submission to the consultation paper, pp. 6–7.

> Principles will also reduce disparity between prosumers in different areas. As there are no set principles to follow, DNSPs are dealing with export capacity in different ways. Having principles will mean prosumers and consumers are been treated equally no matter who their DNSP is, where they are located or when they install their DER.
>
> Energetic Communities supports a principles-based approach to policy and regulation. We would like the NER to include principles for export capacity based on fairness and equity. These include equity regardless of when and where you connect your DER in comparison to existing and future customers and avoid penalty for those with less capacity to pay. A key principle is also the right of DER owners to receive a reward if their export or grid services lead to market benefits.
>
> While we also agree that the DNSP should only be influenced by what it has control over, the principle should nonetheless consider impacts installation have on other installations as far as practical. For example, increased headroom could reduce potential impacts between installations. CEPA (2020b) suggests that while the AER (with some alterations) accepted SA Power Networks' proposal to provide extra headroom, there is uncertainty as to how the AER will assess other and future proposals, indicating that including these principles in the NER could increase certainty as to how the AER will consider future DNSP proposals.
>
> Another principle is one of transitioning to a sustainable and zero carbon electricity system. This would suggest increasing export capacity where possible, quickly and fairly (a fast and fair transition). An appropriate NEO would increase the likelihood of amending the NER. However, as discussed, the NEO is still not fit for purpose for decarbonising the grid, nor integrating decarbonisation with security, reliability and affordability. Reputational incentives with strong metrics around sustainability may be the next most appropriate mechanism, but only regulation will ensure decarbonisation will occur fairly and as rapidly as science-based targets demand.

Renew states:[755]

> TEC/ACOSS's proposal to allocate unlocked hosting capacity fairly is admirable but challenging to deliver on. A documented, principles-based approach will be needed – and it will need to be consistent with whatever grandfathering provisions are decided on.
>
> …
>
> Renew is extremely concerned about the temporal inequity that exists when early adopters of DER have greater ability to derive value due to unlimited or less limited exports than later adopters. And this temporal inequity also has a socioeconomic dimension, because early adopters are disproportionately wealthier households, while more recent DER investors are more likely to be lower income households because they have only been able to afford DER after prices came down low enough and, for

755 Renew submission to the consultation paper, p. 3; 9.

many, thanks to recent state government rebate programs.

Newer DER households – and in particular, lower income DER households – are thus are more likely to have exports constrained than more established ones. So as DNSPs increase their hosting capacity as a result of the changes discussed above, the allocation of new hosting capacity should seek to redress the balance where practicable. This would require a DNSP to articulate a per-customer export allowance that reflects the network's target hosting capacity (as expressed in the DERIS), and a principle to allocate new hosting capacity as much as possible to customers who are constrained below that limit. Clearly this may need to be done at a localised level, because it may be more cost-effective and practicable in some areas of a network than others to increase hosting capacity. It should also be recognised that per-customer need not only be implemented as fixed export limits: where some form of dynamic limiting is practicable and cost-effective, it may well be a more effective way of optimising DER integration while still managing capacity limits at peak times.

Regulation of allocation principles is being considered as part of reforms to introduce dynamic operating envelopes

The Distributed Energy Integration Program (DEIP) is exploring the value that dynamic operating envelopes (DOEs) could offer to the energy transition.[756] This workstream aims to:

- build a shared understanding of the opportunities and challenges
- share insights on approaches currently under investigation
- identify reforms that could be implemented to establish DOEs.

Operating limits are the limits that an electricity customer can import and export to the electricity grid. These limits are agreed between DNSPs, customers and the AER as part of the customer connection or regulatory process. Currently, in most cases, operating envelopes are fixed at conservative levels regardless of the capacity of the network because they are static and need to account for 'worst case scenario' conditions.

DOEs are where import and export limits can vary over time and location. Dynamic rather than fixed export limits could enable higher levels of energy exports from customers' solar and battery systems by allowing higher export limits when there is more hosting capacity on the local network.

At a November 2020 workshop, over 40 participants from across the industry – including consumer groups, networks, research organisations, market bodies, retailers, aggregators and other organisations – met to discuss national regulatory and policy design issues relating to DOEs. Participants considered several key policy and regulatory topics, including regulation of allocation principles.

If DOEs are widely implemented, it may override TEC/ACOSS' proposal to introduce a new pricing principle to guide the allocation of existing and planned export capacity between

756 See: https://arena.gov.au/knowledge-bank/deip-dynamic-operating-envelopes-workstream-national-regulatory-and-policy-design-issues/

prosumers. Regardless, the issue of regulation of allocation principles for DOEs is analogous to how hosting capacity services could be allocated. Stakeholder feedback from the workshop, summarised below, may therefore inform consideration of TEC/ACOSS' proposal – in addition to the submissions highlighted above.

Workshop participants considered that the overriding objective for allocating network capacity and who performs the calculations that determine the DOE for each customer need to be determined as a priority, and allocation principles and the specific allocations should be reviewed to ensure that they are fair and equitable. Further:[757]

> The party that develops the allocation principles will need to integrate diverse considerations represented by various stakeholders including:
>
> - Consumer representatives and advocates, and potentially consumers directly, must be able to contribute preferences about allocation principles. It is important to ensure that there are clear financial incentives and objectives to engage with customers while developing these allocation principles.
> - Governments may contribute to the allocation principles through federal or jurisdictional legislation.
> - AEMO can propose relevant system security use cases and considerations.
> - The AEMC can consider economic outcomes and consumer protections as detailed by the NEO and current national electricity rules.
> - DNSPs will contribute allocation principles that ensure physical and operational limits are respected alongside other considerations related to safety and flexibility.
>
> Using the allocation principles, DNSPs will develop technically robust methods for calculating and publishing DOEs within their network.
>
> The AER could review and monitor the DNSP methods (not just the specific allocations) and ensure consistency with allocation principles. The AER will also need to consider related expenditure proposals.

C.6.2 How should costs be allocated between services (if export charges are enabled)?

Although it does not suggest specific drafting, SAPN proposed a new rule should provide guiding principles for DNSPs on how costs should be allocated between different tariff charging parameters of export services. SAPN said tariffs applied specifically to export services should explicitly not be allowed to recover the costs of the intrinsic capacity in the network to host exports.[758]

AusNet Services agrees that a principle should be designed to govern cost allocation between consumption and export services.[759]

757 ARENA, DEIP Dynamic Operating Envelopes Workstream: National Regulatory and Policy Design Issues, Workshop summary notes, 12 November 2020, p. 3.

758 SAPN rule change request, p. 24.

759 AusNet Services submission to the consultation paper, pp. 6–7.

Evoenergy considers that a new principle for cost allocation between consumption and export services is not required – DNSPs' cost allocation methodologies are the appropriate place to address the allocation of costs between services, rather than in the NER.[760]

C.7 Are additional transitional arrangements required?

Although there are some contrasting views, stakeholder submissions largely consider the TSS process is 'fit-for-purpose'. Several submissions considered the need for more specific grandfathering arrangements and highlighted the importance of consumer engagement.

These submissions are outlined below.

C.7.1 Strong stakeholder support for TSS process to manage transition

The AER supports DNSPs being able to consider the option and design of both import and export charges, and says the existing TSS process is 'fit' for ensuring that DNSPs only introduce such tariffs in close consultation with customers and in compliance with the distribution pricing principles:[761]

> The TSS process inherently operates as a transitional process, as well as a way to take different jurisdictional circumstances and stakeholder preferences into account. Before introducing any new tariff class a DNSP will undertake detailed consultation that takes factors specific to its customers and jurisdiction into account. If there is reason to implement grandfathering arrangements, the NER already provide the flexibility for DNSPs to negotiate this with their customers in the development of the regulatory proposal. DNSPs may also consider the application of sub-threshold tariffs to trial more cost reflective options under NER clause 6.18.1C. We consider the flexibility that the NER provide for such negotiations to take place through the TSS process has been successful to date as it has allowed DNSPs to take jurisdictional-specific circumstances and customer preferences into account.

ENA recommends the development and introduction of any export charges should be led through the existing formal TSS process, which will allow for strong consultation with customers and stakeholders on the design and timing of any export charges. ENA explains:[762]

> In the development of the TSS, a DNSP is required to engage with customers, and provide an overview to the AER of how they have sought to address any relevant concerns identified as a result of that engagement. Stakeholders are also afforded the opportunity to provide formal comment to the AER on a DNSP's proposed TSS through the regulatory determination process.
>
> The TSS provides an indicative tariff schedule for each year of the five-year regulatory control period but a DNSP is also required to submit annual pricing proposals to the AER that are compliant with the AER's final decision made through the regulatory

760 Evoenergy submission to the consultation paper, p. 16.

761 AER submission to the consultation paper, p. 7.

762 ENA submission to the consultation paper, pp. 15–16.

> determination process.
>
> The TSS process requires consultation with customers and stakeholders, and would require that export charges – if deemed efficient under the network pricing objective – are introduced under a timeframe and approach supported by customers and stakeholders, and with AER oversight.
>
> The network pricing principles in the NER require DNSPs to manage the impacts on customers of changes to network tariffs. DNSPs, on the consumption side, typically do this by considering transitions of various kinds, and Energy Networks Australia considers that these measures will also be required for any export tariffs. There will be trade-offs between faster or slower transitions, and these issues should be subject to close consultation with key stakeholders, including jurisdictional governments, through the TSS process.

CitiPower, Powercor and United Energy submit:[763]

> We support the removal of clause 6.1.4 of the NER and believe the introduction of export tariffs are necessary over the long term as we transition to a two-sided market. These could be facilitated through the Tariff Structure Statement which we discuss with our stakeholders prior to lodging with the AER. We would plan for extensive stakeholder engagement prior to submission including consultation with our customer advisory panel (CAP).

Essential Energy states:[764]

> Assuming the removal of clause 6.1.4, Essential Energy agrees with SAPN that an appropriate transition towards a suitable level of export pricing charging arrangements, will be determined sequentially through the existing chapter 6 pricing rules and tariff structure statement, which is examined by the AER during the distribution revenue determination process.
>
> Customer engagement and preferences will be central to these DER tariff decisions. This is especially true as network expenditure to facilitate greater integration of DER, is slightly different from traditional network expenditure as it is expected to impact directly on investment decisions made by customers with DER installations. Customer consultation is typically led through engagement with individual DNSP customer advisory groups and jurisdictional stakeholders, based on a clear understanding of the trade-offs in faster or slower transitions in introducing new export charges. Informed by this engagement, DNSPs could offer a range of options for customers to select a level of export service they desire and are willing to pay for.
>
> The AER, in its role as the economic regulator, will consider the extent to which DNSPs have engaged with their stakeholders in preparing both tariff proposals and

763 CitiPower/Powercor/United Energy submission to the consultation paper, p. 2.

764 Essential Energy submission to the consultation paper, pp. 3–4.

> expenditure forecasts. Given each DNSP is facing unique circumstances on their individual networks, there is unlikely to be a one size fits all approach and industry will seek to draw upon lessons from DNSPs that are facing DER integration issues first.
>
> Essential Energy considers that from an implementation perspective, the SAPN proposal contains simplicity appeal in that it can be applied through the removal of clause 6.1.4, combined with the existing chapter 6 pricing rules, structures, and objectives of the NER, with minimal supplementary structures required. By and large, participants, the AER and jurisdictional stakeholders are familiar with these existing processes.

Ausgrid considers, as with any changes to tariffs, appropriate transitional arrangements should be considered and is required under the existing provisions in the NER.[765] Ausgrid submits:[766]

> We consider that the Tariff Structure Statement (TSS) consultation process should apply to export tariffs. Export services classified as standard control services would become part of the TSS.
>
> We consider that distributors should engage with customers and jurisdictional governments on export tariffs as part of developing their TSS, to be approved by the AER. If classified as standard control services, exports tariffs will become part of the total tariff table, and the revenue from these tariffs will contribute to the total revenue cap.

Further, Ausgrid states:[767]

> We consider that the existing requirement in the NER pricing principles to consider customer impacts provides a sufficient mechanism to address the transition towards cost reflective tariffs both for consumption and export. We do not consider that this should be explicitly prescribed in the NER.

Endeavour Energy considers:[768]

> We consider the existing pricing framework is reasonable and will allow networks to address these issues in consultation with customers, stakeholders and the AER through the determination process. We do not consider additional principles or arrangements are needed or should be specified in the NER.

Evoenergy submits the existing regulatory processes should apply to the new export capacity service, including the TSS process and pricing principles. Further:[769]

765 Ausgrid submission to the consultation paper, p. 12.
766 ibid, p. 14.
767 ibid, p. 14.
768 Endeavour Energy submission to the consultation paper: Appendix A, p. 6.
769 Evoenergy submission to the consultation paper, p. 16.

> … transitional and/or some grandfathering arrangements are likely to be needed. DNSPs may implement the transitional arrangements that are appropriate for their customer base, rather than prescribing arrangements in the NER. Grandfathering will be required for the new suburbs in the ACT where developers have made capital contributions. Any future incremental investment above initial baseline service levels may be subject to the new charges.
>
> Customer engagement on this issue will be very important.

AusNet Services states:[770]

> Implementing export tariffs will face many of the same implementation issues that exist in reforming consumption tariffs to become more cost reflective. This includes transitional issues. While there would be benefits to increasing standardisation of tariffs across the NEM, development of new tariffs need to be addressed by individual DNSPs through consultation with its customer base and other stakeholders when developing Tariff Structure Statements, as the most desirable approaches may be unique to each network based on our differing historical approaches and future needs.

Renew states:[771]

> … consumer confidence will be maximised if there is transparency and accountability in the way charges are set and applied. Export tariffs should be subject to the same requirements as consumption tariffs with respect to cost-reflectivity, assessment of consumer impacts, and so on through a similar process to the TSS process used with network tariffs currently. The difference between the essentiality of energy consumption and the optionality of energy exports should inform the process and the customer impact assessments, as well as the role of broader market mechanisms such as FiTs and third-party energy services.

AGL does not support further transitional arrangements:[772]

> AGL supports the introduction of these reforms in a timely manner to address equity concerns of non-DER customer and establish a financial stream to support distribution networks' planning and investment into the future. While we appreciate the need to mitigate the impact of export charges on DER owners anticipated return on investment, we do not anticipate that the scale of these charges would have a material impact, given that these charges would be contained to the network use of system costs. We also understand that the AER would apply its own transitional arrangements to minimise any undue customer impact associated with these reforms.

770 AusNet Services submission to the consultation paper, pp. 6–7.
771 Renew submission to the consultation paper, p. 12.
772 AGL submission to the consultation paper, p. 11.

Contrasting views on the TSS process

Jemena states that if the regulatory framework enables export charges, DNSPs will consult with customers and other stakeholders – including the jurisdictions – to seek their views on whether DNSPs should charge for grid export services.[773] Though, Jemena considers:[774]

> There is a possibility that removing barriers to export pricing will not alone result in any meaningful change. If the AEMC identifies benefits associated with having export pricing as opposed to not preventing them, then the AEMC should consider the lost opportunity associated with "kicking the can down the road" via TSS processes that DEIP have recognised as slow and not delivering for customers.
>
> The TSS process can be costly and time-consuming for DNSPs, AER, customer advocates, customers, retailers and other market participants and still potentially result in minimal change – the Victorian tariff evolution over the last two regulatory periods being a prime example. Similarly, export pricing provides the potential for winner and loser debates to lead to practical inertia as it has happened in Victoria for consumption tariffs.
>
> To obtain meaningful change, the AEMC should consider what common areas can be resolved by engagement processes now (and fit in the Rules) or via an AER guideline process, and therefore taken out of future individual TSS consultation processes. This could also lead to benefits associated with alignment for customer communications and simplicity for retailers.
>
> Practically, the AEMC could consider whether there is room in the Rules or for an AER guideline to include:
>
> - A common approach to calculating export LRMC
> - How the LRMC should be used to set export prices
> - A common export charge structure (albeit potentially different peak periods)
> - A common framework for applying locational differentiation and applying transitions.

The Australia Institute states:[775]

> We can envisage a large number of solar consumers being unhappy with what they might perceive as a confusing and unfair 'solar tax'. There may be three points at which DER households would potentially need to have fair access to the decision making process.
>
> Firstly, if there are network-level determinations made by the AER which include decisions that directly impact the revenue earned by households, then they should be consulted. How would this work? How would household consumers access a decision

773 Jemena submission to the consultation paper, p. 11.

774 Jibid, p. 12.

775 Australia Institute submission to the consultation paper, p. 5.

> making process largely designed around companies?
>
> Secondly, there may be more fine-grained decisions made by distribution networks, for example about the set charges levied on DER households at the level of individual substations or lines, according to the St Vincent de Paul Society Victoria proposal. DER households could also have claim on a right to fair access to this decision making process.
>
> Thirdly, each DER household will undergo its own process of negotiation with the distribution network about the ability to export. There would presumably need to be fair processes for DER consumers to make their case at this point. Then there would potentially have to be a fair process for households to appeal any decision.
>
> It seems like the rule change could result in an unreasonably complicated consultation process for solar households.

Planet Ark Power recommends transitional arrangements to allow existing customers to assess and choose paths for either accepting charges, not exporting or moving more off the grid.[776]

C.7.2 Mixed views on the need for specific grandfathering arrangements

Renew states:[777]

> … there is clearly an equity issue when many current DER households have less limited exports then future DER households will have. Many of these consumers invested in more expensive systems and did so under the expectation that the value would be redeemed in part via unfettered feed-in. Retrospectively changing the rules and unduly impacting their value proposition is problematic. Grandfathering existing DER households is appropriate to a point, but hard to justify indefinitely. An appropriate middle-ground would be to grandfather existing DER for a fixed time period, or until a trigger point such as an inverter replacement is reached. Inverter replacement as a trigger has an additional advantage that inverters meeting current and future standards are more able to facilitate dynamic limiting and manage voltage issues thus limiting possible adverse impacts in the first place.

EUAA states:[778]

> There would need to be rules around grandfathering e.g. where a location moves from unconstrained to constrained, those who connected when unconstrained would continue to not be charged for their existing level of exports but they would be charged for any expansion in their exports when the location is constrained, as would new exporters in that now constrained location.

776 Planet Ark Power submission to the consultation paper, p. 13.

777 Renew submission to the consultation paper, p. 12.

778 EUAA submission to the consultation paper, p. 4.

Origin states:[779]

> If a distribution charge for exports is allowed, consideration will need to be given to potential grandfathering arrangements. As a starting point, the new arrangements could apply to new purchases of solar systems from a prospective date. This could include those customers who are upgrading existing systems or inverters.
>
> A more difficult decision would be how to transition existing DER customers to the new arrangements. One potential solution is to allow a transition period, of approximately 3–4 years. This would ensure that the economic payback period on which a customer had invested in their system had generally been maintained.

ERM Power states:[780]

> As part of the AEMC's deliberations on this rule change, we add that a cut-off date for grandfathering purposes will need to be determined and this should be set at such a point in time that it does not lead to a surge in demand in order to beat the cut-off date. The experience of state-based feed-in tariffs and other support has shown that installations tend to surge in order to take advantage of more favourable conditions, such as access to premium feed-in tariffs or higher up-front subsidies. Should the AEMC make these rule changes, ERM Power recommends that a cut-off date should be set close to the date of release of the final determination so as to minimise the risk of a rush to install and to avoid the risks to recent investments based on the current market settings.
>
> We also consider there will be a need to determine to whom or what the grandfathering arrangements apply to: the owner or the installation/premises. For example, if a home with an existing solar PV installation is sold, does the new owner have access to the grandfathering arrangements? Or is it tied to the original owner at the time of the cut-off date? Similarly, the AEMC will need to consider how grandfathering arrangements apply to systems which have been upgraded or had battery storage added.

In contrast, AEC/Oakley Greenwood state:[781]

> Grandfathering impedes economic efficiency. If put in place it would mean that a sizeable portion of the market (almost 25% of the households in the NEM) will not see and therefore not be able to respond to price signals that could reduce overall electricity supply chain costs – even if some of those customers would potentially have been able and willing to respond to those price signals.
>
> We recognise that existing DER participants have made their investment decisions in good faith based on the information, pricing and incentives available at the time of that decision. However, those decisions and their outworkings in DER export behaviour may

779 Origin submission to the consultation paper, p. 7.

780 ERM Power submission to the consultation paper, p. 3.

781 AEC/Oakley Greenwood submission to the consultation paper, pp. 10–11.

> be producing outcomes that increase costs for the electricity supply chain and therefore other customers and/or constrain the access of other customers to the benefits of DER ownership and operation. It should also be recognised that DER participants' decisions would also have depended on assumptions they made (consciously or not) about other factors, including the level of retail prices and the level and continued availability of the FiT. Grandfathering has not generally been considered with respect to those factors, so it seems disproportionate and inconsistent to consider grandfathering for a possible change in network tariff structures.
>
> Grandfathering existing DER participants from cost-reflective prices for DER export services will only continue inefficient impacts, and as such, we see no reason for a grandfathering arrangement and particularly one that would permanently exclude these DER participants from cost-reflective export service pricing. In sum, it should be recognised that providing such 'protection' is essentially an equity measure, not a measure deriving from the NEO.
>
> If the AEMC decides to provide some level of grandfathering for existing DER participants we strongly recommend that it investigates means by which cost-reflective export service pricing can be introduced that would avoid absolute disadvantage to current DER participants while also minimising the number of DER participants to whom non-cost-reflective pricing applies. In this regard we note that data exists that would allow calculation of the expected payback period for systems installed in previous years in each of the NEM's distribution service areas. The expected payback period could be used to identify a minimum grandfathering period for each system and that period associated with that NMI.
>
> This is only one idea; there may be other, better approaches and we strongly recommend that the AEMC investigate this and implement an approach that is fair to current DER participants while minimising the volume of DER capacity over time that is not subject to cost-reflective export service pricing.
>
> We further note that the transition to such cost-reflective pricing is expected to take some time. In this regard, we feel it is also important, when and if the decision is made to implement cost-reflective DER export pricing, that this intent be publicly announced and that the introduction of such prices would apply to all DER systems purchased after the date of that announcement. Such an approach will minimise the number of future DER participants for whom a claim could be made for grandfathering and minimise the economic inefficiencies that would be incurred by a continuation of the current lack of export service and benefit pricing.

EnergyAustralia also does not support 'grandfathering' arrangements as the impacts of DER on the network (positive and negative) predominantly result from existing DER:[782]

> We appreciate the impacts on customers that have invested 'in good faith'; however,

782 EnergyAustralia submission, p. 12.

> expect that any imposed export charges will result in increased benefits that will offset the negative impacts, i.e. cost-reflective tariffs which will guide DER customer's choice on when to export and consume, and improved capacity to export with increased expenditure of DNSPs to improve network reliability and export services.

C.7.3 Consumer engagement

The Victorian and South Australian government submissions highlighted the importance of consumer engagement as part of the TSS process. The Government of South Australia says any framework implemented by the Commission will require a strong role for consumer engagement, as there is likely to be a broad range of consumer views in relation to network investment to support export capacity.[783] The Victorian Government highlights the critical role of DNSPs' ongoing consultation and engagement with their customers:[784]

> … to ensure customer needs are understood and that their diverse perspectives inform the development of DER integration plans. The Victorian Government considers that it is important to 'take customers along on the journey' to support their understanding of key issues and empower them to participate in decision making processes.

Sidorenko and Fernando state:[785]

> While regulatory change to enable pricing of exports would address the market failure and lead to the more efficient outcomes, its success ultimately depends on the active engagement and acceptance by communities. New community energy use schemes such as community batteries and peer to peer trading, supported by two-way tariff structures capable of rewarding customers for the behaviour that helps avoid future costs, could turn a potential Tragedy of the Commons into an opportunity to empower local commons in shaping the distribution networks of the future.

The AER notes:[786]

> … whether the customer chooses to export their DER or alternatively use the electricity themselves (to offset their own usage) should be a matter of choice for the customer, noting that different customers will have different preferences in relation to how they choose to engage with the retailers and aggregators and the products they wish to purchase.

The South Australian Council of Social Services (SACOSS) states:[787]

> We agree with the proposed approach of SA Power Networks to have an element of choice for solar customers in relation to their exports and the potential to be rewarded

783 SA Government submission to the consultation paper, p. 3.

784 Victorian Government submission to the consultation paper, p. 5.

785 Alexandra Sidorenko (Ausgrid) and Roshen Fernando (ANU) submission to the consultation paper, p. 5.

786 AER submission to the consultation paper, p. 2.

787 SACOSS submission to the consultation paper, p. 2.

for export of solar generation at times that benefit the network. However, there is also some concern about the complexity of the arrangements and ensuring simplification for all energy consumers and prosumers will be important.

D FARRIERSWIER INSIGHTS REPORT

D.1 Effectiveness of the TSS process and options for implementing export charges

The Commission engaged expert consultant, farrierswier, to provide an independent assessment of the implementation of consumption pricing reforms, under the current pricing framework, to develop a better understanding of how export pricing may be implemented. This informs the likelihood of successful implementation of export pricing, and whether the pricing framework provides adequate customer safeguards to manage the transition. Farrierswier considered:[788]

- how DNSPs and the AER would be likely to implement export pricing under the existing TSS process or a potentially modified TSS process
- how the preferences and potential concerns of jurisdictional governments, customers and other stakeholders would be considered and addressed as part of the TSS process.

Farrierswier's approach to develop these insights included:[789]

- surveying members of the TWG and DNSPs about the first two rounds of TSS processes to date
- developing potential scenarios for tariff structures and approaches to transition that illustrate the variety of potential ways an export pricing rule change could be implemented
- reviewed the current pricing rules and experience of their application to identify any challenges these may present for export pricing, and how the rules could address issues identified for export pricing.

D.1.1 Lessons learnt

Following the AEMC's 2014 network pricing rule change, the AER has been assessing TSS proposals since late 2015. The first round of approved TSSs took effect for all DNSPs in 2017. Most DNSPs are into their second TSS period,[790] and the AER is currently reviewing the second round of Victorian TSSs for determination by April 2021 which will apply from 1 July 2021.

Farrierswier found the TSS process has evolved considerably over this time, whereby:[791]

- customer engagement now generally starts three years prior to a TSS period
- this engagement often starts by co-designing pricing objectives with customers, which have included notions of equity and fairness
- a wide range of customers and stakeholders have been engaged in the process

788 Farrierwier, Insights report: Effectiveness of the TSS process and options for implementing export charges, March 2021, p. vi.

789 ibid, p. vi.

790 The NSW, SA, Qld and ACT DNSPs are currently in their second TSS period. The NT DNSP only transitioned to AER determinations from its 2019-24 determination, and so is in its first TSS period.

791 Farrierwier, Insights report: Effectiveness of the TSS process and options for implementing export charges, March 2021, pp. 12–19.

- many DNSPs have been commissioning independent research to inform the development of the TSS proposals, including behavioural economic research
- all DNSPs have identified that engagement has shaped their TSS proposals
- most DNSPs had TSS changes requested by the AER during its review process, especially to either progress tariff reform or to give greater weight to the customer impact principles
- jurisdictional government involvement was common but not always timely
- the 'second round' of TSS processes benefited from process refinements, including the AER undertaking sector-wide engagement through a series of 'roundtables'
- 'retail safeguards' benefited the round 2 process.

Farrierswier found the Commission's 2014 reforms have not achieved all the stated objectives, although there have been significant consumer engagement improvements:[792]

1. Improved cost reflectivity – enable consumers to make more informed and efficient usage and investment decisions
   a. Outcome so far: limited progress for small customers – it is widely recognised that retailer pass through of network signals for residential and small business customers has been negligible to date.
2. Lower average prices for consumers in the medium to long term as some consumers respond to the price signals
   a. Outcome so far: too early to assess, given most small customers do not face price signals yet and there are many other factors that affect average prices that may make it hard to identify any impact from tariff reform.
3. Customer protection through improved consultation and customer impact principles
   a. Outcome so far: recognised success – engagement is starting on average three years before the commencement of the new TSSs and associated tariffs, it is involving a broad range of customers and stakeholders, and it is influencing tariff structures and arrangements for tariff transition (as discussed above).

Farrierswier identifies the following lessons from the experience of the first two TSS rounds for consumption pricing reforms and stakeholders' feedback that may be relevant to future TSS processes, including implementation of export pricing.

Delays to tariff reform and benefits realisation

Retailer support and the extent of pass through into retail tariffs

Farrierswier considered whether retailers pass on network tariff signals or engage with these price signals on their customers' behalf will likely be a key determinant of the outcomes of export pricing reforms. Retailers are not passing on network tariff signals to small customers at any scale yet. In response to farrierswier's survey of the TWG, a retailer observed that

792 ibid, pp. 19–24.

pricing to retailers could see more innovative tariffs like locational or critical peak pricing that we have not seen at any scale to date.[793]

The network pricing principles under NER cl. 6.18.5 say the structure of each tariff must be reasonably capable of being understood by retail customers who are assigned to that tariff, having regard to the type and nature of those retail customers, and the information provided to, and the consultation undertaken with those retail customers.[794]

Farrierswier states whether this pricing principle remains appropriate will depend on whether DNSPs should be designing tariffs to facilitate particular behaviours by end retail customers or by the intermediaries that supply them. Farrierswier further notes:[795]

- network tariff structures may need to get more complex, including in a future two-sided market scenario
- network tariffs may be sending signals to intelligent energy control devices rather than seeking behavioural change from retail customers themselves
- large retailers have reported to the AER they will likely continue to package network tariffs into 'insurance style' retail tariffs
- innovative retailers and energy service providers may need to package multiple energy service value-streams into a simplified retail offer, which could require network signals to be balanced and at times traded off against other supply chain costs and benefits to provide net tariffs and rewards to retail customers.

Requirements for cost reflective tariffs to be opt-in

The requirement for cost reflective tariffs to be opt in was a feature of many round 1 TSS decisions by the AER and was mandated by the Victorian Government. Since then, the AER has required an opt out approach to tariff assignment and encouraged greater rates of reassignment to cost reflective tariffs for round 2 TSSs. The AER's policy positions on assignment further explain that:[796]

- existing customers who receive a smart meter under a fault meter replacement program should be given a 12 month 'grace period' prior to cost reflective tariff reassignment to understand their consumption data and which structure may best suit them
- DNSPs can offer customers choice in cost reflective tariff, however, DNSPs should no longer offer customers who are on a cost reflective tariff the ability to opt-out to anytime energy network tariffs, unless cost reflective tariffs are offered at a discount to incentivise take up.

Farrierswier finds:[797]

> Given customers' bill outcomes are determined by retailer behaviour, a lesson may be

793 ibid, p. 25.
794 NER cl. 6.18.5(i).
795 NER cl. 6.18.5(i).
796 AER, Attachment 18: SA Power Networks 2020–25 Draft decision: Tariff structure statement, October 2019, Appendix B.
797 Farrierwier, Insights report: Effectiveness of the TSS process and options for implementing export charges, March 2021, p. 27.

that it is unnecessary and potentially counter-productive to the pace of tariff reform (including for export pricing) to have an opt in menu of network tariffs (or even potentially allowing opt out). Where choice in network tariff is offered, the lesson may be that choice should be limited to being among cost reflective tariffs.

This issue is also likely to be relevant for export pricing. The implications of the above lesson are that mandatory network tariff assignment with customer choice exercised at the retail level is likely to avoid customer harms whilst best supporting benefit realisation, and that benefits realisation may be aided where networks can design their tariff signals for retailers and intermediaries alone.

Interventions by jurisdictional governments

Jurisdictional government policies have impacted the TSS process.

Noting such interventions have not always been timely in the past, farrierswier states it may be important to consider if there are regulatory mechanisms to ensure policy constraints are established at the commencement of TSS engagement and development processes.[798]

Farrierswier considers DNSPs and the AER could seek to test jurisdictional preferences on export pricing at the framework and approach stage of distribution determinations so that this can be accounted for in both service classification and TSS engagement.[799]

Lessons on the role of and approach to attributing and reflecting costs in network tariffs

Under the network pricing principles:

- Each tariff must be based on the long run marginal cost (LRMC) of providing the service to which it relates to the retail customers assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:
  - the costs and benefits associated with calculating, implementing and applying that method as proposed
  - the additional costs likely to be associated with meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant part of the distribution network
  - the location of retail customers that are assigned to that tariff and the extent to which costs vary between different locations in the distribution network.[800]
- The revenue expected to be recovered from each tariff must reflect the DNSP's total efficient costs of serving the retail customers that are assigned to that tariff.[801]

Farrierswier observes:[802]

798 ibid, p. 27.
799 ibid, p. 27.
800 NER cl. 6.18.5(f).
801 NER cl. 6.18.5(g).
802 Farrierwier, Insights report: Effectiveness of the TSS process and options for implementing export charges, March 2021, p. 29.

- the cost estimation rules have necessitated extensive cost modelling and estimation by DNSPs
- the focus of tariff structures to date has been on the extent to which costs vary depending on the time of day
- in practice, very little regard has been had to locational issues
- some jurisdictions require uniform state-wide pricing for small customers, but that is not a legal requirement in all states and territories.

Farrierswier questions the value arising from prescribing the LRMC economic cost concept for both consumption and export pricing:[803]

> … applying this LRMC rule to export charging parameters could add a lot of compliance cost and further imprecision to LRMC estimates for limited benefit given LRMC estimates are already imprecise, potential benefit of short-run signalling and scope for other binding jurisdictional or customer preference requirements to drive prices below this economic cost concept.

Farrierswier did not consider this issue further in its scenario analysis – given there are ways to overcome the need to comply with this rule for export charging parameters and TWG members did not support changes to this pricing principle. Further, farrierswier notes that the rules already provide a degree of discretion as to how LRMC is calculated and applied in tariff design, although additional clarification or changes may be warranted.[804]

Export pricing-based versus consumption-based reforms

There are several key differences between export and consumption pricing, as highlighted by farrierswier:[805]

- Not all electricity customers will seek an export service from their DNSP. This may mean export services have less of the 'essential service' characteristics that are commonly considered to apply to electricity consumption services.
- Existing customers with distributed generation have not needed to pay for export pricing to date, and have in many jurisdictions received mandated export subsidies in the form of feed-in-tariffs set by jurisdictional governments or jurisdictional regulators.
- Large distributed generators, such as registered generators over 5MW that are connected to the distribution network, may compete with transmission-connected generators – which are not currently required to pay for ongoing use of the transmission network.
- Export pricing is only possible where a smart meter is installed. This means customers who seek export services are more likely to already be on a cost-reflective network tariff for the consumption-based charges.

803 ibid, p. 31.
804 ibid, p. 31.
805 ibid, pp. 31–32.

D.2 Scenarios analysis

Farrierswier assumed the prohibition on export charges is removed. It then designed scenarios to test threshold export pricing design and application variables that can affect the potential for negative impacts on customers, benefits realisation, the application of particular pricing rules and customer protections, and variations in the nature of the export service being provided and the benefits being realised from the reform.

Farrierswier structured scenarios in order from the highest potential for negative customer impacts through to the lowest, and sought to recognise the path dependency of the need for transitional measures. Farrierswier assessed customer impacts for both export customers and non-export customers.

The scenarios assumed the Commission would make a decision to enable export pricing so farrierswier could 'stress test' how the current pricing framework would perform in each scenario, assess the extent to which identified issues would be addressed and reform benefits realised, and identify any potential rule amendments that may further support implementation of export pricing.

The key insights from each scenario are shown in table D.1 below.

Table D.1: Farrierswier scenarios and insights

SCENARIO	DESCRIPTION OF SCENARIO	INSIGHTS
1. Jurisdictional prohibition	DNSPs are prohibited by jurisdictional governments from establishing tariffs based on exported energy, but are still required to provide export services and permitted to recover the costs of providing and using export services through existing network access and consumption-based tariffs.	This scenario can be accommodated within the current rules, but only the supply-side benefits of DER export integration could be achieved, and all customers would continue to pay for export services irrespective of their ability and decision to export.
2. Highest impact	Each DNSP introduces one mandatory export tariff with no optionality for customers in network tariffs and immediate reassignment of existing exporters to this tariff. Tariff levels reflect both incremental export costs and a reallocation of residual costs. Tariffs involve export charges but not payments (i.e. no rebates for export at beneficial times or locations) and are set full tariff levels on day 1 without a pricing transition. All retailers pass on the network export tariffs in full in their retail offers. This scenario may benefit some customers (primarily customers without generation, who will receive a reduction in their network charges), but is intentionally designed to have the highest risk of negative impacts for some customers with generation.	This scenario has the greatest bill impact on export customers with the greatest savings for non-export customers. All reform benefits are largely achieved, though there is scope for further enhancement. This scenario may be possible within the current rules, but there is a high risk that it would infringe the current pricing principles and would not be approved by the AER. Significant additional consumer engagement, compliance demonstration and assessment would be required by DNSPs and the AER, respectively. As a result, farrierswier expects that this scenario is unlikely to be proposed by DNSPs without some form of transitional arrangements to make it more likely satisfy the customer impacts principles.

SCENARIO	DESCRIPTION OF SCENARIO	INSIGHTS
3. Retailer choice	Same network tariff specification as scenario 2 applies, however, some retailers either do not pass on the network tariffs or do not do so to the full extent. This allows customers to opt out of network export charges through their choice of competitive retail offer.	This scenario is capable of the same benefits realisation and customer impacts as scenario 2, however, the extent of these will be determined by the decisions of retailers and their customers. The rule compliance issues are the same as under scenario 2, with a high risk that the proposed tariffs will not comply with the current rules and will not be approved by the AER (noting that the AER is unlikely to know for certain at the time of approval of the first TSS containing export prices whether those prices will be passed on by retailers).
4. Incremental pricing	Builds on scenario 3 by only attributing incremental costs to export charging parameters. This avoids reallocating currently shared costs to export prices. It supports lower export prices and means that exporting customers only pay export charges that reflect the expected future costs of providing export capacity to serve them. This approach also reduces implementation costs by overcoming the need for DNSPs to revise their existing access and consumption-based tariffs and compliance models.	This scenario is possible under the current rules (particularly if supported in customer engagement) and could enhance allocative efficiency relative to scenarios 2 and 3. It could be an effective way of managing potential consumer harm and complying with the consumer impacts principle. It could have much less compliance burden because it could avoid needing to rebalancing existing consumption-based tariffs. A potential downside of this approach is that it could impede DNSPs' ability to efficiently recover their residual costs from export tariffs where doing so would best comply with the pricing

SCENARIO	DESCRIPTION OF SCENARIO	INSIGHTS
		principle requirement to minimise distortions to the price signals for efficient usage. For example, if export services are seen as a less essential service than electricity consumption services and exporters can still make a net profit from exports after accounting for retail feed in tariffs, then they may have a less price responsive demand for network use than do some electricity consumers (e.g. lower income or vulnerable customers). In these circumstances it may be efficient and consistent with the NEO to allocate residual costs to export services.
5. Transition from export entitlement	Introduces optionality for customers regarding the type of export service they want and how much they are willing to pay for different levels of service. It captures how the nature of the export service could be implemented in the bidirectional tariff structure by having differential prices for charging parameters that link to different forms and scales of export. Farrierswier assumes the tariff structure has existing access and consumption-based charging parameters and three new export charging parameters are added: •	This scenario is possible within the current rules. It introduces export service choice in a manner that can minimise customer impacts of immediate export pricing implementation. It further enhances allocative and dynamic efficiency relative to prior scenarios. It likely requires more consultation to explain a greater range of export service options and corresponding tariffs. It also introduces questions about how the level of export service capacity provision and performance is monitored, and the need for customers to understand that any optional services will not confer a 'firm' or 'guaranteed' right to always

SCENARIO	DESCRIPTION OF SCENARIO	INSIGHTS
	• Static limit exports block 1 – low or no charge for exports up to the average existing static limit applied by that DNSP for customers of that type • Static limit exports block 2 – a (higher) charge for firm exports purchased between block 1 and a specified firm export cap • Dynamic control customer-initiated exports – an incentive-based charge for exports above block 1 set at a price lower than block 2 for variable export capacity provided through a dynamic operating envelope.	export that amount of energy.
6. Cost and reward	Builds on scenario 5 by adding an export charging parameter that rewards exports that are likely to reduce network costs. An export rewards charging parameter would be set to provide an incentive rebate (negative tariff) paid to customers in certain circumstances. This could apply to exports that occur when called upon by the DNSP, eg, through notification of an upcoming rebate period (like a critical peak rebate tariff) or some form of dynamic control (like some existing demand response services). Alternatively, it could be a simpler structure where exports in a predefined time window are rewarded on the basis that	This scenario is possible under the current rules, maximises the extent of benefits realisation for all forms of efficiency and has the most favourable customer impacts for exporters and non-exporters of any of the export pricing scenarios.

SCENARIO	DESCRIPTION OF SCENARIO	INSIGHTS
	exports during that period are likely to alleviate network congestion.	

Source: Farrierwier, Insights report: Effectiveness of the TSS process and options for implementing export charges, March 2021, pp. 58–65.

D.3 Farrierswier findings

Farrierswier found the TSS process and pricing principles are robust to introducing export pricing, and there is no reason to expect that material consumer harms would remain after the application of the existing safeguards. This is based on the experience of the TSS process for consumption pricing reforms to date, and scenario analysis designed to test how export pricing may be implemented under the current pricing framework (see table D.1 above).[806]

In particular, farrierswier states:[807]

- The existing TSS process and pricing principles provide for a range of different transitional tools and other mechanisms that can be used by DNSPs and the AER (in consultation with customers) to mitigate the impact of introducing export pricing on customers.
- The existing TSS process and pricing principles are likely to steer DNSPs towards scenarios that include measures to mitigate potential harm for exporting consumers during transition – for example, through some combination of how residual costs are allocated, providing a choice of network export tariffs and/or including export rewards as in scenarios 4 to 6, as those scenarios are more likely to comply with the current rules and be approved by the AER
- While scenarios that have higher potential for customer harm, most notably scenarios 2 and 3, are not explicitly prohibited by the rules, the current TSS requirements mean that there is a high likelihood that these scenarios would not be proposed by DNSPs or approved by the AER, especially if consumers raise significant concerns with them during the consultation that is required as part of the TSS process.
- All of the scenarios involve a trade-off between the size of potential increases in network charges for exporting customers and the size of potential reductions in network charges for non-exporting customers, noting that:
    - it is likely to be preferable to use the existing TSS process to balance these considerations and determine the most appropriate scenario following consultation by DNSPs and the AER with customers for each DNSP
    - where the balance between these considerations lies may vary across networks depending on local conditions such as the extent of DER uptake and the level of export constraints.

Potential transitional requirements

Farrierswier states if the Commission considered that the potential for customer impacts was too high under some scenarios, the Commission could:[808]

806 ibid, p. 65.
807 ibid, pp. 65–66.
808 ibid, p. 66.

- amend the rules to require all DNSPs to adopt a specified approach to the transition to export pricing, or to include certain prescribed features in their proposed approach to transition, or
- amend the rules to require the AER to develop and consult on an export pricing guideline.

Farrierswier put forward several options for potential transitional requirements, namely:[809]

- Require export rebates – any DNSP that introduces export charges must also introduce a negative pricing option
- Phase in export prices over time – any DNSP that introduces export charges must phase them in over a specified timeframe
- Require 'optionality' – any DNSP that introduces export charges must also offer a tariff option that does not include export charges (for example, no export charge for a basic service with a lower export limit)
- Prohibit the reallocation of sunk costs to export charges – DNSPs could be prohibited from reallocating any existing costs from consumption charges to export charges
- Prohibit the allocation of residual costs to export charges – DNSPs could be prohibited from allocating any residual costs to export charges (for example, export charges must be set at LRMC with all residual costs allocated to consumption charges).

The Commission has considered the advantages and disadvantages of such customer 'safeguards' and legal complexity of implementing them, as discussed in Chapter 6.

A further option explored by farrierswier is for the AER to develop a guideline on the approach to export pricing. Farrierswier highlights the potential benefits of this approach:[810]

- a requirement for a guideline would be easier to draft and implement than the above transitional requirements
- a guideline could retain some flexibility to applying the pricing rules for circumstances where DNSPs can demonstrate that departures from the guidance are preferable, or establish clear preconditions for certain export pricing and transition options
- public consultation on the guideline may make it easier for consumers and their representatives to engage in the process for designing export pricing, rather than having to engage separately with each DNSP when developing their TSSs
- because the existing rules have been used for a while only for consumption based tariffs, there may be need for some change management to encourage DNSPs and the AER to identify and settle on how these same rules will apply to export pricing and the compliance demonstration required for this
- the guideline development and consultation process could support fit-for-purpose transitional requirements for different customer types and network circumstances
- jurisdictional policy preferences could be considered in the guideline development and consultation process.

809 ibid, pp. 66–68.
810 ibid, p. 69.

Potential pricing measures

Farrierswier identified the following additional steps it considers the Commission could take into account that promote the objective of the rule changes, which we have considered in making this draft determination:[811]

- Consequential rule changes – some rules that require modification to explicitly reference exports in order to continue to apply as intended
- Potential rule clarifications – some rule clarifications that the AEMC could consider to remove doubt about the function of some rules and thereby lessen regulatory burden in complying with and administering those rules for DNSPS and the AER respectively
- Timing of introduction of export charging – some rule changes the AEMC could consider if it wanted to mandate certain approaches to the introduction of export pricing
- Retail pricing – retail pricing measures that could complement the reform

811 ibid, pp. 69–72.

E TRANSMISSION AND DISTRIBUTION GENERATION

E.1 Flexibility to maintain competitive neutrality between transmission and distribution-level generation

As highlighted in Appendix C under section C.2.2, submissions identify export charges at the distribution-level could change the balance of competition between transmission and distribution-level generation. The principle of competitive (or more accurately, technology) neutrality, which promotes efficient competition outcomes, requires that generation at either level does not enjoy competitive advantages or suffer from a competitive disadvantage due to the regulatory framework. These 'artificial' advantages and disadvantages may lead to an inefficient mix of production across transmission and distribution-level generation.

Competitive balance distortions are an important consideration, especially given the broader policy goal is to support the transition to a fully integrated electricity system – with DER competing in multiple markets. The differences between transmission and distribution-level generation are complicated, especially when trying to account for scheduled vs non-scheduled generation.

Rather than creating a risk of competitive neutrality distortions, enabling export charges creates additional flexibility to 'level the playing field' to the extent practicable – and accounts for potential reforms of transmission arrangements in the future.

The current regulatory arrangements for system strength remediation for new connections in fact create an advantage to micro embedded generators. The so called 'do no harm' provisions, explained in more detail below, require generators to contribute to the costs they impose on the system related to system strength – in addition to the 'deep' connection costs created by their connection, including all cost of augmenting the network if capacity for their connection is not available.

Instead of imposing a significant upfront cost on household customers, enabling ongoing export charges creates a more practical way for retail customers to contribute to any costs they impose on the grid related to voltage or system strength issues, and potentially promotes competitive neutrality with transmission-level generation.

E.2 System strength remediation for new connections – 'do no harm'

The 'do no harm' requirements for new connecting generators commenced in November 2017. The rule places an obligation on new connecting generators to 'do no harm' to the level of system strength necessary to maintain the security of the power system. The obligation applies to generators connecting to both the transmission network *and* distribution network under NER clauses 5.3 and 5.3A. This specifically does not apply to the connection of micro embedded generation, such as residential solar PV, which is handled in NER chapter 5A instead.

The 'do no harm' framework requires that new entrants undergo a system strength impact assessment – undertaken using the methodology and power system model set out in the system strength impact assessment guidelines developed and published by AEMO. These guidelines specify what AEMO considers to be an 'adverse system strength impact'. That is, 'doing harm'. They also provide guidance on the different network conditions, dispatch patterns and other relevant matters that should be examined when undertaking an assessment.

The new connecting generator is required to fund the provision of any required system strength connection works or remediation schemes to address the impact of its connection on system strength. This places an incentive on new connecting generators to either design their systems to operate at lower levels of system strength or to connect at locations within the network where there is sufficient system strength.

The obligation on new connecting generators only applies at the time the connection is negotiated, based on the information available at the time. Once established, the obligations are incorporated into the connection agreement between the generator and the network service provider.

Since late 2017, the Commission found this requirement has resulted in new connecting generators spending considerable amounts on remediation works, and experiencing delays related to reaching agreement on the scale of works required, procurement and commissioning.[812]

Therefore, the Commission has undertaken an investigation into system strength frameworks in the NEM.[813] In our final report, the Commission recommended a new mechanism, the system strength mitigation requirement (SSMR), to provide clear price signals – based on the marginal cost of providing system strength – for new generators who demand system strength connecting under clause 5.3 and 5.3A. At a high-level, this requirement will retain and improve on elements of the existing 'do no harm' arrangements, while reflecting the increased provision of system strength from the supply side reforms.[814]

812 AEMC, Investigation into system strength frameworks in the NEM: Final report, October 2020, p. 30.

813 See: www.aemc.gov.au/market-reviews-advice/investigation-system-strength-frameworks-nem

814 AEMC, Investigation into system strength frameworks in the NEM: Final report, October 2020, chapter 3.

F CUSTOMER BILL IMPACT ANALYSIS

F.1 DER – The impact of export charges on consumer bills and the incentives for investment in solar PV and battery technology

This analysis looks at the impact of export charges for distributed energy resources, including solar PV and batteries, on the bills of customers with these assets installed, the bills of customers without these assets installed and the incentives for investment in solar PV and batteries over time.

F.1.1 Summary of results

Based on the dataset used and the assumptions made, the Commission finds export pricing would have:

- a minor negative impact on the energy bills of customers with solar PV systems relative to their revenue earned. Also, there is a small negative impact on incentives to invest in solar PV, which is proportionally higher for larger systems (eg, greater than 6–8 kW)
- a minor negative impact on the energy bills of customers with solar PV and battery systems relative to their revenue earned. Incentives to invest in battery, where the owner also has a solar PV, are marginally higher
- a small beneficial impact on the energy bills of customers without solar PV/batteries. Where upgrades to the network are required to accommodate large solar PV exports, customers without solar PV would no longer share the cost of upgrading the network.

F.1.2 Data used

The Commission used AEMO Net System Load Profile (NSLP) data to generate the profile for 12 different networks with total consumption based on an annual usage of 5 MWh and 10 MWh. To provide a benchmark of actual data to validate these outcomes, actual customer data in the Ausgrid and SAPN networks was analysed.

The Ausgrid data contained usage and solar generation information data on 3,567 residential customers in 30 minute intervals between May 2017 and May 2018.

The SAPN data contained usage and solar generation information on 1,586 residential customers in 30 minute intervals for the 2019 financial year.

The time of use (peak, shoulder and offpeak) and flat retail tariffs for each network were sourced from the Energy Made Easy and Victorian Energy Compare Website.

The time of use (peak, shoulder and offpeak) and flat retail tariffs for each network were calculated based on pricing proposals.

For solar PV installation and operation, BOM weather and irradiance data from the 2018 calendar year was processed and restructured into a format that the System Advisory Model (SAM) would accept. The analysis then took the 12 different network locations, 10 different system PV sizes, and 2 azimuth angles (240 scenarios in total) and then requested PV output from SAM throughout the year. The load and PV output was then merged and used to calculate the retail and network costs before and after Solar PV installation.

For battery installation and operation, an optimisation was developed, for each customer with a battery installed, based on a Tesla Powerwall 2 with 14 kWh of capacity, 90% efficiency, and a 3.3 KW charge/discharge rate.

F.1.3 Approach to the analysis

The Commission used this data to calculate network bills for each representative customer in this data set. Retail bills for each customer were then created using the standard market offer in each jurisdiction in the timeframe.

Solar PV systems up to 10 kW in size were considered in increments of 1 kW from 0 to 10. For battery installation, a single 14 kW system was considered with a maximum discharge rate of 3.3 kWh.

These representative bill outcomes were then used to assess:

- How solar PV, and different sizes of Solar PV alters the bill for these customers
- How much each representative customer exports to the grid, depending on different sizes of solar PV installation.
- The impact of export charges on the bills of these customers, depending on different sizes of solar PV installation.
- The impact of export charges on the bills of these customers, with a battery installation and different sizes of solar PV installed.

F.1.4 How are export charges determined and applied

The Commission considered how export charging might alter customer bills considering three different approaches for determining and applying the charge:

- Volumetric (c/kWh)
- Volumetric time of use with charges for export during the day and payments, or rebates, for export during the evening (c/kWh)
- Demand charges ($/Kw) based on maximum output

These charges were applied with a target recovery from each solar exporting customer, in each year of $10-$100, based on indicative input from networks on the charges that would be required from each exporting customer in order to recover the cost of the upgrade to networks required. The results presented here assume the top end of this range or $100 per annum per exporting customer, for a typical 5 kW system.

For volumetric charges, the export charge total is divided by total solar output of a 5 KW system to give an export charge in c/kWh to apply to all PV system sizes.

For volumetric time of use (c/kwh) charges the export charge total is divided by total system output between 10 am and 4 pm. This charge is then applied to the kWh output of all system sizes during the solar PV output period. Outside these times, the solar exporter receives a rebate of 30% of the network tariff for each kWh exported.

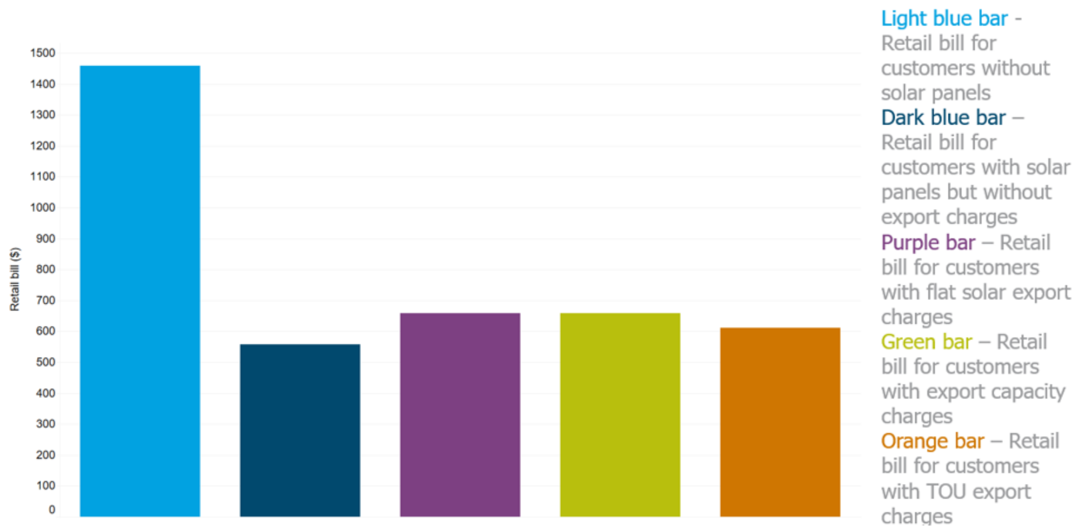
For demand charges ($/kW), the export charge total is divided by the maximum measured kW output of a 5 KW system. This value is then multiplied by the maximum kW output of all the other PV system sizes analysed.

This provided a range of charges according to the total export charge targeted between $10-100 per annum as follows:

- Flat export charge 0.00-0.02/$/kWh
- TOU export charge 0.00-0.02/$/kWh
- Max export capacity 2.93-29.31/$/KW

Modelling the impact of a $100 charge using the three different methods reflects that while charges do change customer outcomes, savings from solar PV installation are still significant. Furthermore, the TOU export charge has the least impact on incentives for the installation of solar PV and the ongoing benefits derived from that installation, as can be seen in the figure below.

Figure F.1: Customer bills with and without PV and three export charge approaches



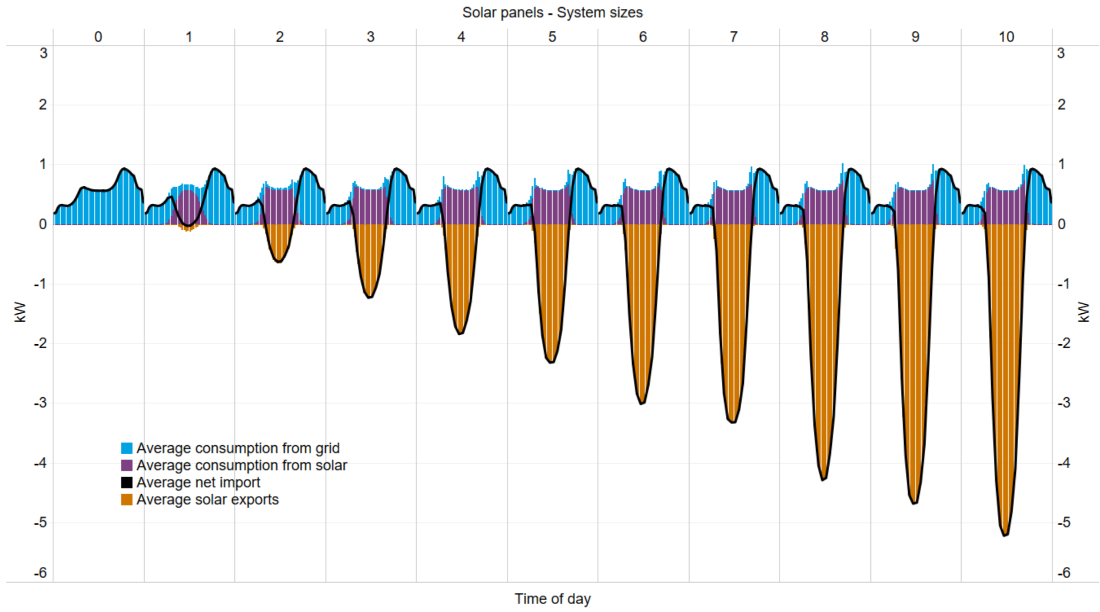
Source: AEMC analysis, AEMO, Ausgrid and SAPN data
Note: Assumes 5 kW system, no battery, Ausgrid network, north facing, 5 MWh self usage, flat retail tariff

F.1.5 Analysis findings

Significant exports from Solar PV

Broadly we can see from the analysis that exports exceed self consumption for most systems, and for moderate and larger systems there are significant net exports to the grid.

Figure F.2: Solar PV exports to the grid for different system sizes

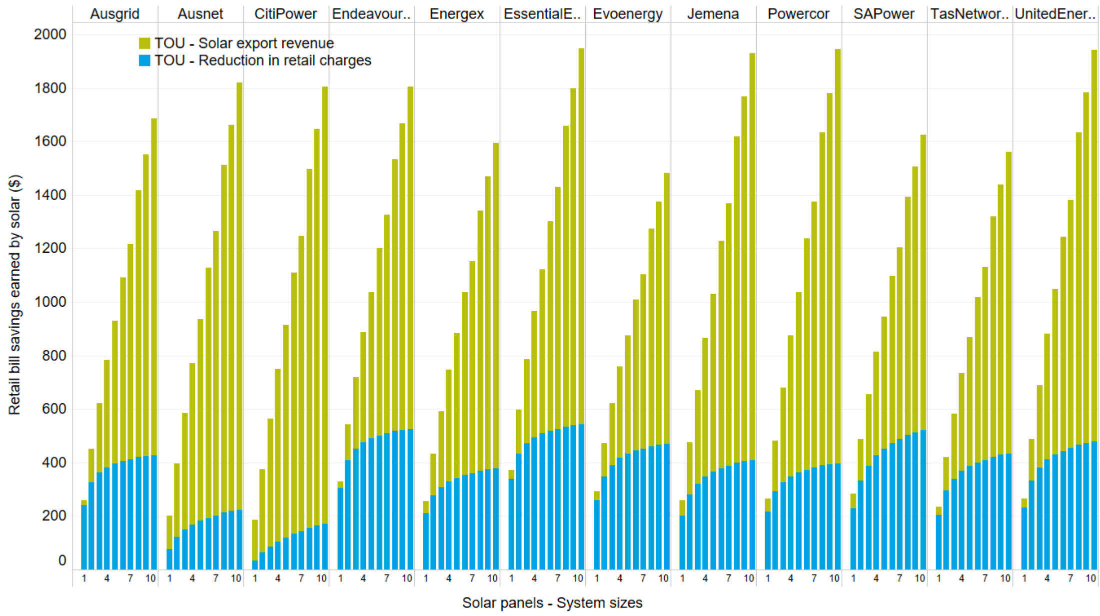


Source: AEMC analysis, AEMO, Ausgrid and SAPN data
Note: Assumes 5 MWh customer in Ausgrid, all PV system sizes

Benefits of solar PV to owner are more from export than self consumption, even for moderate sizes

The benefits of solar PV to the asset owner are predominantly from export, rather than self consumption, this is particularly the case as system size increases. The chart below demonstrates that for systems in excess of 3 kW, export revenue provides the majority of the annual return for a solar PV installation.

Figure F.3: Retail bill savings for solar PV sizes, through self consumption and export



Source: AEMC analysis, AEMO, Ausgrid and SAPN data
Note: Shows retail bill savings by export or reduced self consumption, 5 MWh customer, TOU tariff

Batteries help to reduce the import profile and curb exports

Battery installation reduces draw from the grid during peak times and impacts the export profile of a PV system, regardless of size. This has a bearing on the impact of export charges, in particular where the battery system is sized optimally to match the output of the solar PV generation.

The impact of export charges on solar PV, and solar PV with a battery installed

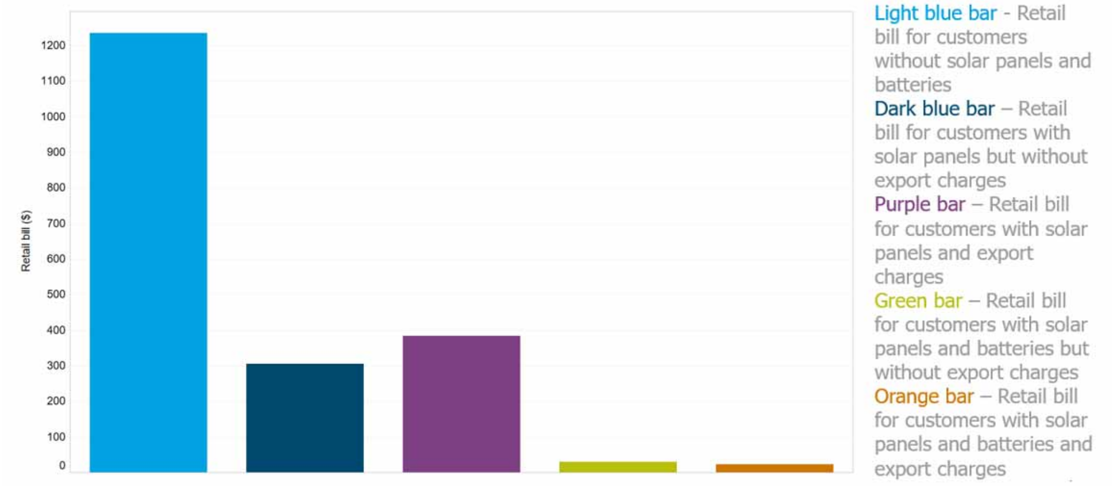
Export charges have an impact on customer savings from the installation of solar PV, but this is a small portion of the overall savings. In the chart below, the move from the light blue to the dark blue column denotes the benefit of installing a 5 kW system for a 5 kWh customer. The move to the purple column denotes the impact of a $100 export charge on this customer.

The move to the green bar from the dark blue bar denotes the benefit of installing a battery, in terms of the impact on the annual bill. The move to the orange bar then reflects that for a 5 kW system, export charges would in fact further reduce the bill for this customer, largely due to the rebate paid to the exporter during off peak hours, and the fact that during peak hours the battery helps the customer to better manage its export profile in order to minimise export charges.

The impact is minimised where export charges are levied as a TOU tariff.

The impact of export charges is at its greatest for larger system sizes.

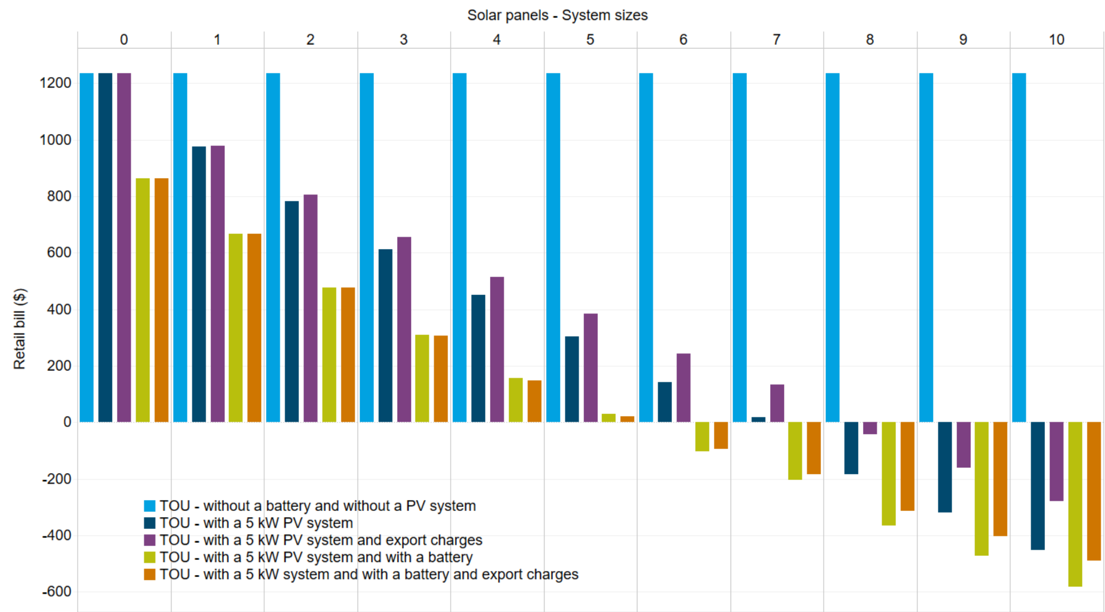
Figure F.4: The impact of export charges on customer bills for a 5 kW system



Source: AEMC analysis, AEMO, Ausgrid and SAPN data
Note: Assumes 5 MWh customer in Ausgrid, 5 KW system, north facing

Export charges for customers with a battery have little or no impact on the return from solar PV and battery installation, as can be seen above. This varies with size, however. A small impact can be observed for sizes above 7 kW, as can be seen in the chart below between the green (PV plus battery, no export charge) and orange (PV plus battery plus export charge).

Figure F.5: The impact of export charges on customer bills for all system sizes analysed



Source: AEMC analysis, AEMO, Ausgrid and SAPN data
Note: Assumes 5 MWh customer in Ausgrid, All system sizes, north facing

Export charges create a small additional incentive for customers with PV to invest in a battery. This incentive is also for the battery system to be reasonably matched with the solar PV output. Compared to the overall incentive for a battery, this additional incentive is small.

F.1.6 The impact of export charges on solar PV, and solar PV with a battery installed

Export charges have an impact on customer savings from the installation of solar PV, but this is a

Where network augmentation is required to accommodate growth in solar rooftop PV exports, this cost needs to be recovered from consumers. There are different options for how these costs can be recovered. Export charges are one of those options. Customers with no solar or batteries can be expected to pay less under export charging, given the additional costs associated with solar export are paid for by exporting consumers.

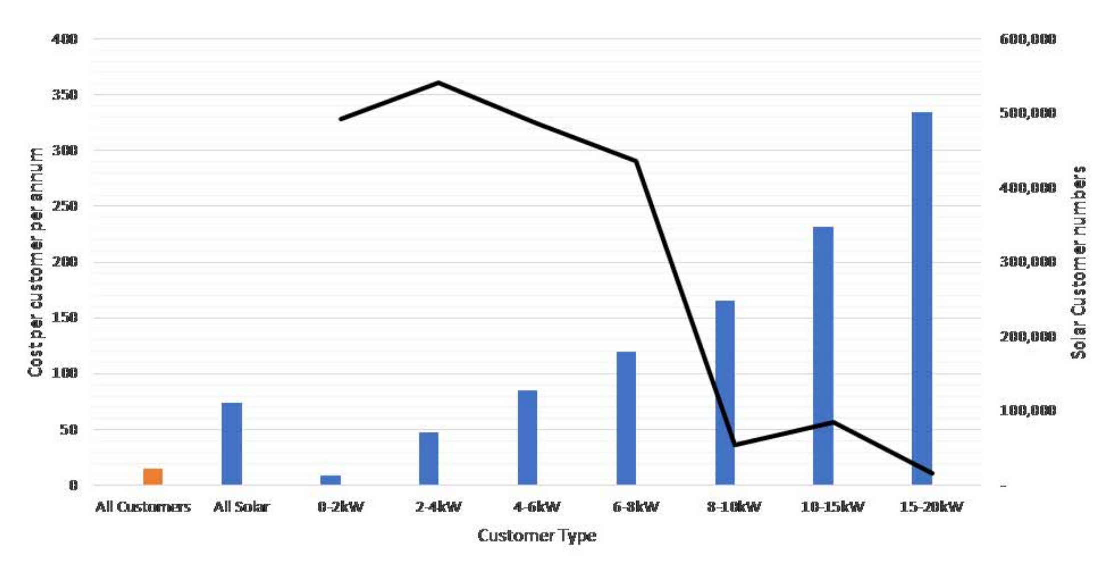
This is perhaps a fairer outcome considering different types of consumer across the NEM. Where the costs of export are recovered from all consumers, consumers without solar PV and batteries would have a tendency to subsidise solar PV customers, but in particular large solar PV customers and large solar PV customers without battery technology. And yet the burden of the export charge, as can be seen from this analysis, is small compared to the revenue derived from export. In other words, those customers deriving the most benefit, pay the most, but this is still small as a portion of the overall benefit of installing a large solar PV system.

There are in effect three potential scenarios for consumers, in a world with greater installed solar, and greater capacities associated with rooftop systems.

1. No upgrade to the distribution network is undertaken. There is no additional investment in the network to accommodate solar PV export. There is no investment cost, no customers are required to pay additional network charges, however, solar PV rooftop generation is constrained off, further investment in large systems for export is disincentivised and wholesale prices are higher over time than they would otherwise be as a consequence.
2. The distribution network is upgraded by DNSPs to accommodate the increased solar PV export, but the costs are spread over all customers, including customers with neither solar nor batteries installed
3. The distribution network is upgraded by DNSPs, but the cost is recovered through export charges on customers exporting into the grid. Customers without solar and batteries, who are not exporting to the grid, are not charged any additional cost for the augmentation of the distribution network.

The Commission's analysis of total revenue recovered under scenarios 2 and 3, indicates that under a scenario of export charges, a fairer distribution of costs is made. In particular customers with no solar PV or battery are not subsidising customers with large or very large solar PV systems.

Figure F.6: Cost recovery for network augmentation for export, all customers and solar customers at different sizes



Source: AEMC analysis, AEMO, Ausgrid, SAPN and CER data
Note: Assumes an average across all networks, and an export charge of $100 per customer for a 5 kW system.

Figure F.6 above shows the outcome of the analysis of these two scenarios. Under the first scenario, where all customers pay, in orange above, the average cost per customer across all networks is $14 per annum. All customers pay this cost to allow for the growth in solar export to the grid.

Under the second scenario, only solar PV households pay export charges. Even though the export charge is set based on a figure of $100 per annum for a typical 5 kW system and then multiplied by the actual output of the system (either larger or smaller), this on average provides for $74 per customer per annum, largely due to the rebates solar customers earn under the TOU methodology.

It is only the large solar customers, particularly those above 6-8kW that pay a significant export charge each year, and this would impact the least customers across the NEM at the current time. Where these costs seem large, in excess of $200 for a 10 kW system for example, these should be taken in the context of the significant export revenue earned by systems of this size. Comparing export charges in figure 6 with export revenue in Figure 3 demonstrates that export costs are still a small portion of the export revenue earned by very large system sizes.

As such export charges have a small impact on the incentives for new solar PV systems, particularly small and moderate systems sizes, and even at large sizes, the majority of the revenue incentive remains. The incentives for solar PV installation with a battery, are relatively unchanged, or slightly improved given the ability of a battery system to better manage the export profile, and export for rebates, under a system of export charges.