Attachment 18 - Tariff Structure Statement Part B - Explanatory Statement

2025-30 Regulatory Proposal

January 2024

SA Power Networks

Empowering South Australia

Company information

SA Power Networks is the registered Distribution Network Service Provider for South Australia. For information about SA Power Networks visit sapowernetworks.com.au.

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Disclaimer

This document forms part of SA Power Networks' Regulatory Proposal to the Australian Energy Regulator for the 1 July 2025 to 30 June 2030 regulatory control period. The Proposal and its attachments were prepared solely for the current regulatory process and are current as at the time of lodgement.

This document contains certain predictions, estimates and statements that reflect various assumptions concerning, amongst other things, economic growth and load growth forecasts. The Proposal includes documents and data that are part of SA Power Networks' normal business processes and are therefore subject to ongoing change and development.

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Note

This attachment forms part of our Proposal for the 2025-30 Regulatory Control Period. It should be read in conjunction with the other parts of the Proposal.

Our Proposal comprises the overview and attachments listed below, and the supporting documents that are listed in Attachment 20:

Document	Description
	Regulatory Proposal overview
Attachment 0	Customer and stakeholder engagement program
Attachment 1	Annual revenue requirement and control mechanism
Attachment 2	Regulatory Asset Base
Attachment 3	Rate of Return
Attachment 4	Regulatory Depreciation
Attachment 5	Capital expenditure
Attachment 6	Operating expenditure
Attachment 7	Corporate income tax
Attachment 8	Efficiency Benefit Sharing Scheme
Attachment 9	Capital Expenditure Sharing Scheme
Attachment 10	Service Target Performance Incentive Scheme
Attachment 11	Customer Service Incentive Scheme
Attachment 12	Demand management incentives and allowance
Attachment 13	Classification of services
Attachment 14	Pass through events
Attachment 15	Alternative Control Services
Attachment 16	Negotiated services framework and criteria
Attachment 17	Connection Policy
Attachment 18	Tariff Structure Statement Part A
Attachment 18	**Tariff Structure Statement Part B - Explanatory Statement**
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1 Executive Summary

As the primary network distributor in South Australia, SA Power Networks will play a key role in enabling the transformation of the energy industry as it seeks to phase out fossil fuels in favour of clean energy. It is imperative that through this transition that we maintain a reliable, resilient and safe electricity network whilst also empowering customers to navigate the new energy future.

We have consistently heard from customers that they are seeking an affordable and equitable energy supply, with cost of living pressures being top of mind for an increasing number of South Australians.

Distribution network tariffs enable SA Power Networks to recover Australian Energy Regulator (**AER**) approved revenues by charging retailers who then pass these charges onto customers. This revenue allows us to build, operate and maintain our distribution network to deliver electricity to our customers. Our 2025-30 Tariff Structure Statement (**TSS**) has been prepared under the requirements of Chapter 6 of the National Electricity Rules (**NER**), AER Export Tariff Guidelines May 2022 (**Guidelines**) and AER Legacy metering services – Guidance note November 2023 (**Guidance note**). Our forecast sales and demand assumptions are based on the August 2022 Electricity Statement of Opportunities (**ESOO**) Central scenario published by the Australian Energy Market Operator (**AEMO**). In South Australia there was an immaterial increase in volumes in AEMO's August 2023 ESOO Central scenario and so it was determined to use the August 2022 scenario, which aligns with the capital expenditure modelling.

In the 2025-30 Regulatory Control Period (**RCP**), SA Power Networks is proposing a TSS which builds upon the significant structural changes proposed and implemented in the 2020-25 RCP. Whilst most of the existing tariffs will largely be fit for purpose in the 2025-30 RCP we have considered how some tariff structures can be adapted to address the key challenges identified in the 2025-30 RCP. Key additions to our tariff proposal for the 2025-30 RCP for consumption tariffs include:

- Customer choice volumetric tariffs for customers who predominately meet their energy needs through electricity.
- Segmenting the Small Business tariff class into Small 0-40MWh p.a. and Medium 40-160 MWh p.a. to achieve a more cost-reflective pricing differential between customers in these sub categories.
- New flexible demand tariffs for Large and Major Business customers to encourage avoidance of consumption during peak demand periods and reward flexibility to maximise the utilisation of the distribution network.
- New generation tariffs for customers (e.g. solar farms, batteries) connecting at Zone Substation and Sub Transmission.

In addition to consumption tariffs, for the first time and in accordance with recent changes in the NER, SA Power Networks is proposing new export tariffs for customers with small embedded generation systems, defined as less than 30kW in export capacity. Introducing export tariffs allows us to increase the capacity of the distribution networks to host more solar, whilst also increasing the ability of others to access solar. If accepted, our proposal would result in all Residential, Small and Medium Business customers with these systems being assigned to an export tariff from 1 July 2025.

These proposals have been shaped by feedback received from customers and stakeholders during an extensive engagement program over 2022 and 2023.

To help residential customers and small businesses understand the impact of SA Power Networks proposed tariff structures, we have developed illustrative examples of the impact of network charges. We have also completed this analysis on a subset of residential customers, small business customers and those experiencing vulnerability in accordance with our Vulnerable Customer Strategy (**VCS**). Refer to Figure 1 to Figure 3 for the impact of network charges on different residential and small business customer profiles / personas. Note: network charges comprise of distribution charges, transmission charges and SA Government scheme costs, otherwise known as Network Use of System (**NUoS**).

These customer and business personas consider specific usage profiles, Customer Energy Resources (**CER**) uptake and household/business size. They offer valuable insights into potential pricing impacts for customers broadly fitting these personas, however it must be noted that individual customer outcomes will differ depending on actual usage profiles and the extent to which retailers pass through our cost reflective pricing signals.

For each persona, we have estimated the annual network bill based on the single rate tariff and compared that to both default and customer choice time of use tariff options. We have also considered the impact of customers/businesses shifting their load to cheaper times of the day.

Figure 1: Annual network bill impacts for Residential customers 2025/26 ($ nominal)

Profile	In their present situation, they are...	Average annual usage	RSR	Moving to RTOU	Moving to RTOU and shift usage	Moving to RESELE	Moving to RESELE and shift usage	Export charge and credit*
Pensioner without Solar	• One person household who is often home during the day • Lower than average usage • Most energy consumed during peak time windows	2,520	**$622**	**(5.7%)** ($35)	**(8.0%)** ($50)	**(5.5%)** ($34)	**(8.2%)** ($51)	-
Couple without Solar	• Working professional couple with limited time at home and moderate flexibility to shift energy usage • Most energy consumed during peak time windows	3,960	**$842**	**(7.0%)** ($59)	**(9.6%)** ($81)	**(4.4%)** ($37)	**(7.7%)** ($65)	-
Family without Solar	• Four person household with limited flexibility to shift energy • Higher than average usage • Most energy consumed during peak time windows	8,540	**$1,547**	**(3.9%)** ($60)	**(7.2%)** ($112)	**(8.4%)** ($130)	**(11.5%)** ($178)	-
Family with Solar 6.0kW Panels 6.0kW Inverter	• Rooftop solar enables them to reduce energy usage from the grid and their overall electricity bill • They do not have a battery and so most energy from the grid is consumed during peak time windows	5,100	**$1,018**	**+5.6%** +$57	**+2.0%** +$20	**+3.9%** +$40	**+0.4%** +$4	+$2 **($74)**
Family with Solar and Battery 6.6kW Panels 5.0kW Inverter	• Rooftop solar enables them to reduce energy usage from the grid and their overall electricity bill • They have a battery and smart appliances which enable them to shift usage from peak to lower priced time windows	2,300	**$587**	**(13.4%)** ($78)	**(15.1%)** ($88)	**(17.8%)** ($105)	**(19.5%)** ($114)	+$2 **($58)**
Family with Solar, Battery and EV 11.5kW Panels 7.0kW Inverter	• A large household with an all-electric home • Higher than average usage due to electrification and EV • They have a home battery and smart appliances and so can shift usage from peak to lower priced time windows	15,520	**$2,620**	**(21.1%)** ($552)	**(22.7%)** ($596)	**(26.3%)** ($689)	**(27.7%)** ($726)	+$3 **($3)**

*Export credit is only available with RESELE | Residential Electrify
Source: SA Power Networks analysis

Figure 2: Annual network bill impacts for Small Business customers 2025/26 ($ nominal)

Profile	In their present situation, they are…	Average annual usage	BSR	Moving to SBTOU	Moving to SBELE	Moving to SBELE and shift usage	Moving to MBTOUD	Export charge and credit*
Physio	A physio operating during standard business hours, including half day on Saturday.	7,684	**$1,431**	**(4.1%)** ($59)	**(13.1%)** ($188)	**(14.5%)** ($208)	**+0.7%** $10	-
Café	A café operating from 7am to 2pm.	19,141	**$3,218**	**(17.8%)** ($574)	**(27.0%)** ($868)	**(27.8%)** ($894)	**(23.2%)** ($745)	-
Sporting club with Solar 27.0kW Panels 27.0kW Inverter	A community sporting club with a large solar capacity.	15,176	**$2,599**	**(24.0%)** ($625)	**(7.6%)** ($197)	**(10.3%)** ($267)	**(0.1%)** ($3)	**$ 200** **($129)**
Farm with solar 99.9kW Panels 82.8kW Inverter	Large solar capacity reduces their energy consumption from the grid during the day, with most consumption from the grid happening after 5pm.	45,213	**$7,282**	**(16.5%)** ($1,203)	**(2.7%)** ($195)	**(5.9%)** ($431)	**(8.4%)** ($610)	Not subject to export tariff >30kW
School with solar 8.0kW Panels 8.0kW Inverter	Solar reduces their energy usage from the grid however due to the high consumption, most generation is consumed during the day.	148,505	**$23,385**	SBTOU and SBELE tariffs are not applicable as the customer's demand is higher than 120 kVA			**(4.7%)** ($1,099)	All export is within free allowance

*Export credit is only available with SBELE | Small Business Electrify
Source: SA Power Networks analysis

Figure 3: Annual network bill impacts for customers who may be experiencing vulnerability 2025/26 ($ nominal)

Profile	In their present situation, they are…	Average annual usage	RSR	Moving to RTOU	Moving to RTOU and shift usage	Moving to RESELE	Moving to RESELE and shift usage	Export charge and credit*
Customer experiencing financial difficulties	• One person household • Smart energy user with lower-than-average energy usage • Most energy is consumed during solar sponge time windows	1,340	**$439**	**17.4%** ($77)	**18.0%** ($79)	**20.2%** ($89)	**20.7%** ($91)	-
Customer with disabilities	• Two person household with smart appliances • Most energy consumed during off peak time windows	4,970	**$997**	**15.1%** ($151)	**16.9%** ($168)	**21.2%** ($212)	**22.6%** ($225)	-
Culturally and linguistically diverse customer 5.1kW Panels 5.0kW Inverter	• Family of four with solar • Rooftop solar enables them to reduce energy usage from the grid and their overall electricity bill • They have a battery and smart appliances which enable them to shift usage from peak to lower priced time windows	4,400	**$910**	**29.0%** ($264)	**29.8%** ($271)	**36.6%** ($333)	**36.9%** ($336)	**$1** **($28)**
Customer experiencing Isolation 4.5kW Panels 4.0kW Inverter	• One person household with limited flexibility to shift load • Most energy consumed during peak window	2,750	**$657**	**+7.9%** +$52	**+4.8%** +$31	**+8.4%** +$55	**+5.1%** +$34	**$9** **($29)**
Customer relying on life support systems 5.0kW Panels 5.0kW Inverter	• Two person household with moderate flexibility to shift load • They have a battery and smart appliances which enable them to shift usage and have lower usage in peak windows compared to the average customer.	4,070	**$859**	**17.9%** ($153)	**19.4%** ($167)	**24.8%** ($213)	**26.0%** ($223)	**$-** **($6)**

*Export credit is only available with RESELE | Residential Electrify

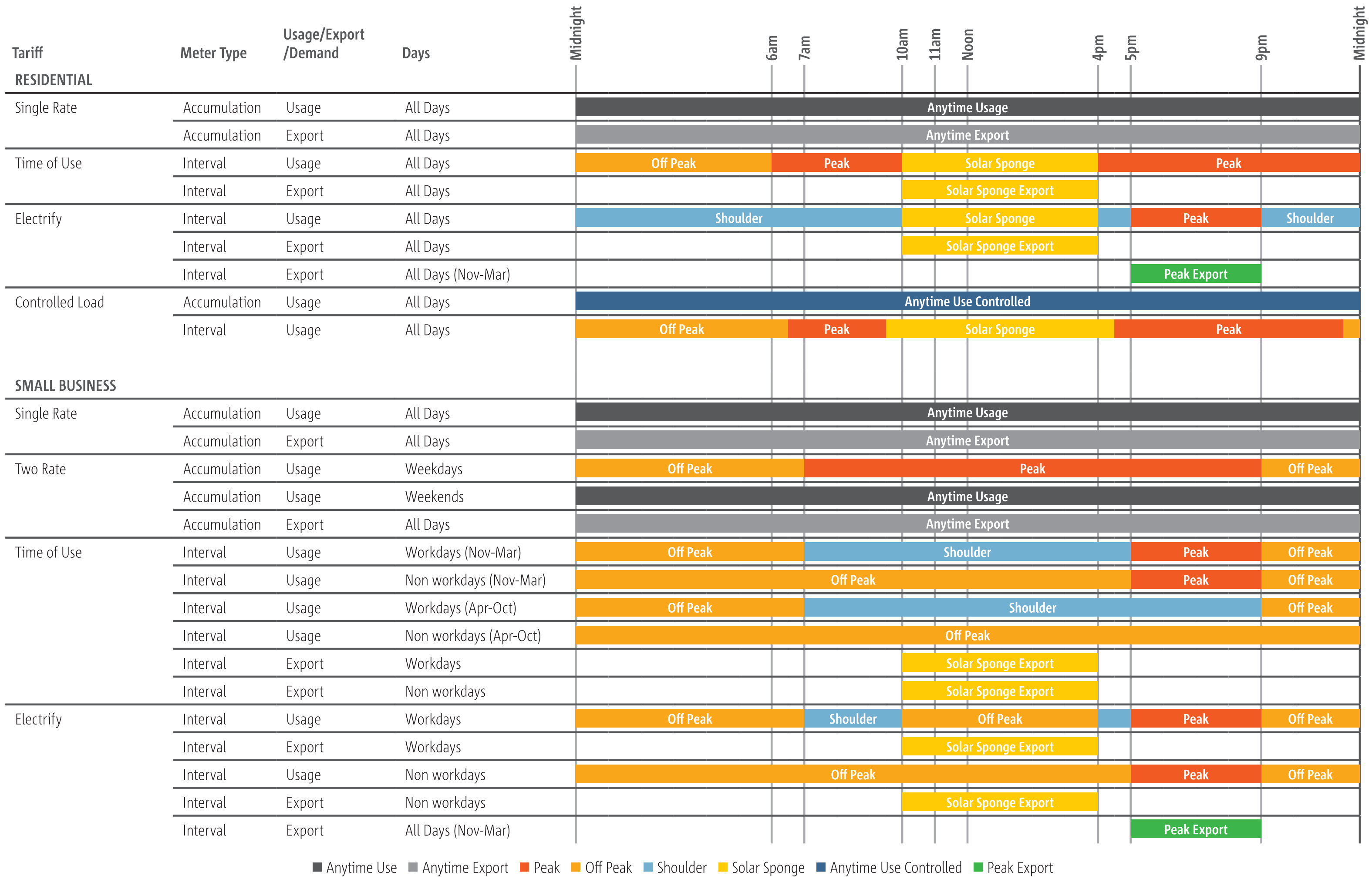
Source: SA Power Networks analysis

With the continued uptake of interval meters, South Australia is well positioned on the journey to more cost reflective distribution tariffs. In the 2025-30 RCP we propose to continue our current tariff assignment policy which assigns all interval metered customers to a Time of Use (**ToU**) tariff, with no opportunity to opt out. For Residential customers, cost reflective ToU pricing can, on average, help customers reduce their annual distribution charges comparative to the single rate pricing.

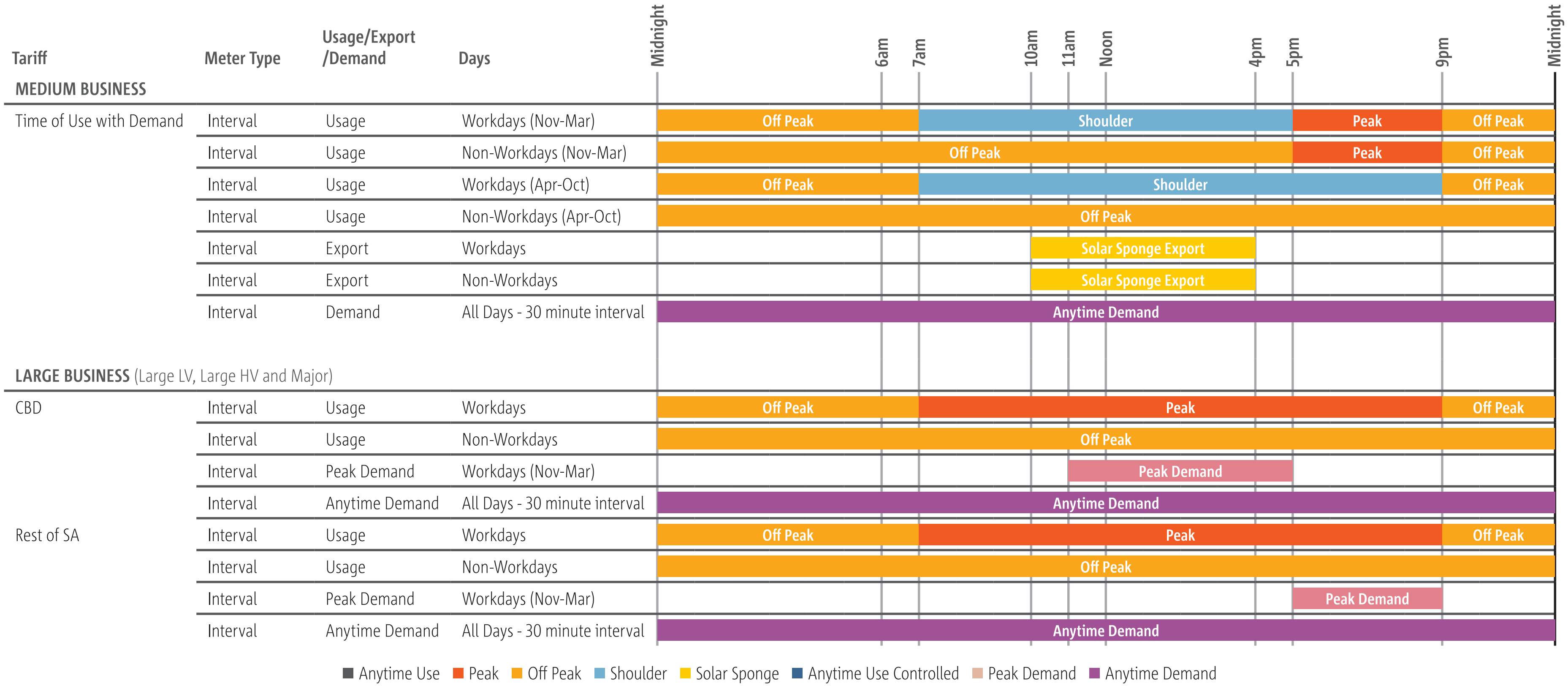
The proposed TSS for the 2025-30 RCP supports an efficient energy transition by encouraging more efficient utilisation of the current distribution network through pricing signals which incentivise behavioural change. Such changes in our customers' energy patterns will keep future distribution costs down and benefit all South Australians. As we move to a more electrified future, having a distribution network which can efficiently support the increased throughput long term will put downwards pressure on overall prices.

Figure 4 outlines the tariff time windows proposed in 2025-30 RCP.

Figure 4: Proposed tariff time windows for 2025-30 RCP



All tariffs are based on local time (ACST/ACDT) except for Controlled Load. Controlled Load is based on ACST and must have a randomised start time of at least one hour.



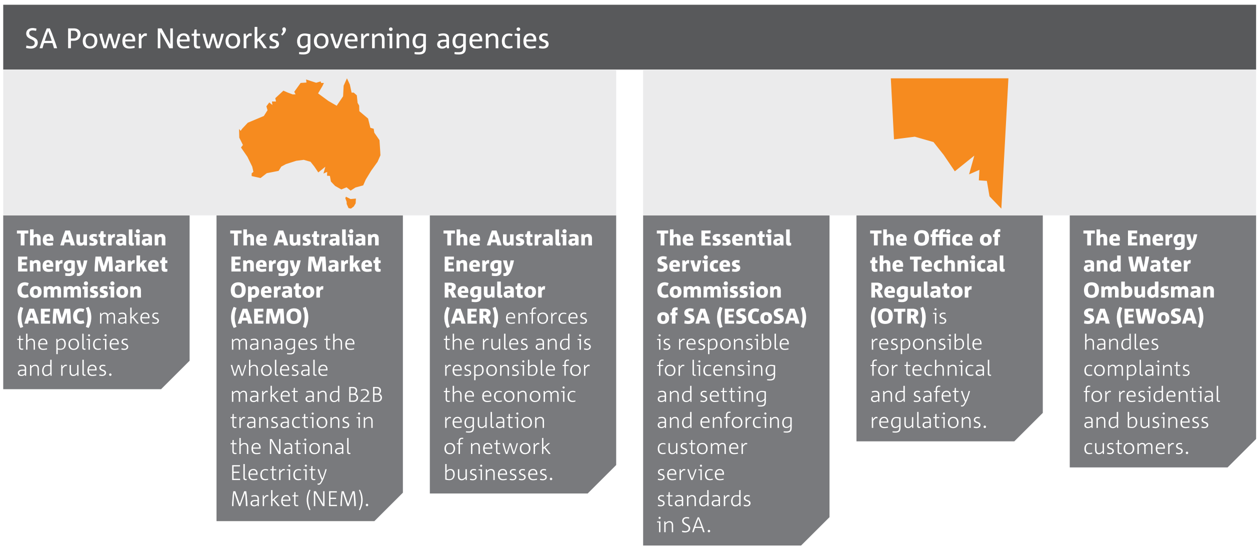
All tariffs are based on local time (ACST/ACDT) except for Controlled Load. Controlled Load is based on ACST and must have a randomised start time of at least one hour.
Major Business Peak Demand time window could vary based on transmission pricing requirements.

2 Characteristics of our distribution network

2.1 Who we are

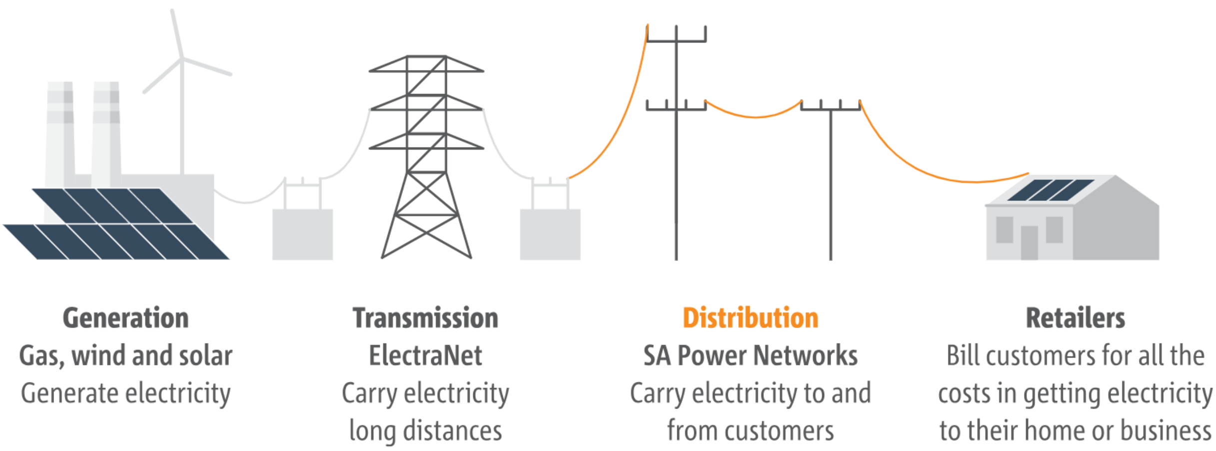
SA Power Networks is an electricity Distribution Network Service Provider (**DNSP**) which operates within the National Electricity Market (**NEM**). We are governed by a number of agencies, rules and regulations at the National and State levels as shown in Figure 5.

Figure 5: SA Power Networks' governing agencies



The electricity supply chain consists of generation, transmission, distribution and retailers as shown in Figure 6. In South Australia, ElectraNet provides the electricity transmission services and we provide the electricity distribution services to over 920,000 customers ranging from isolated farms in rural areas to industry precincts, regional and metropolitan residential homes, businesses and city centres.

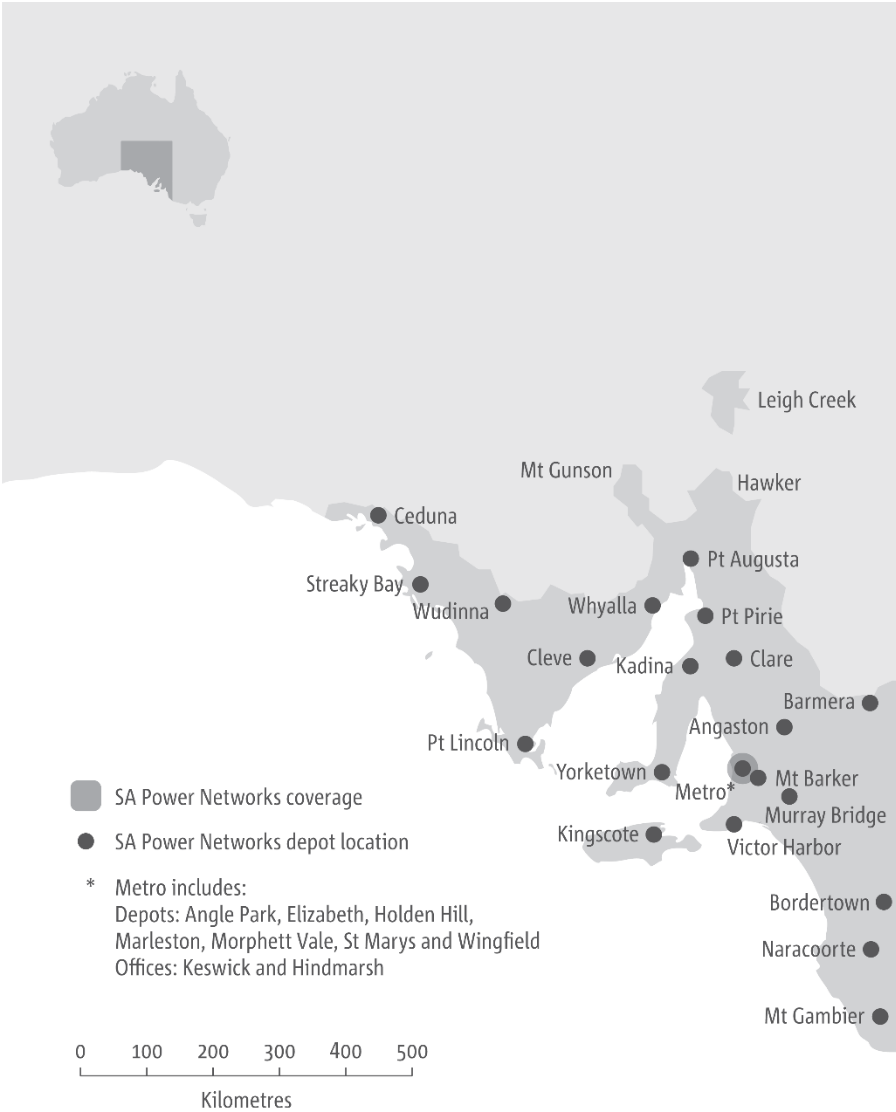
Figure 6: The South Australian electricity supply chain



2.2 Our distribution network

The electricity distribution network in South Australia is vast, covering more than 178,000 square kilometres along a coastline of over 5,000 kilometres. The distribution network extends across difficult and remote terrain and operates in demanding conditions and stretches for over 90,000km, and includes over 400[1] zone substations, 77,500 street transformers, more than 620,000 Stobie poles, and 200,000km of overhead conductors and underground cables. The extent of SA Power Networks' operations in South Australia is shown in Figure 7.

Figure 7: SA Power Networks' service area



In general, the distribution system connects to 275 kilovolt (**kV**) and 132kV transmission connection points supplied by ElectraNet. Our sub transmission network, operating at 66kV and 33kV, supplies and links zone substations. In turn, these zone substations step down the voltage, typically to 11kV. Primary distribution feeder powerlines and cables connected at 11kV distribute power to localised distribution substations (street transformers) which step down the voltage further to 400V (three phase) low voltage. Low voltage circuits from these street transformers then connect to individual customers' services[2]. Customers supplied at low voltage can either be connected to a single phase (230V) or to three phases at 400V (phase to phase).

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[1] Inclusive of connection point substations and dedicated customer substations.
[2] Larger customers may connect at higher voltage steps in the network.

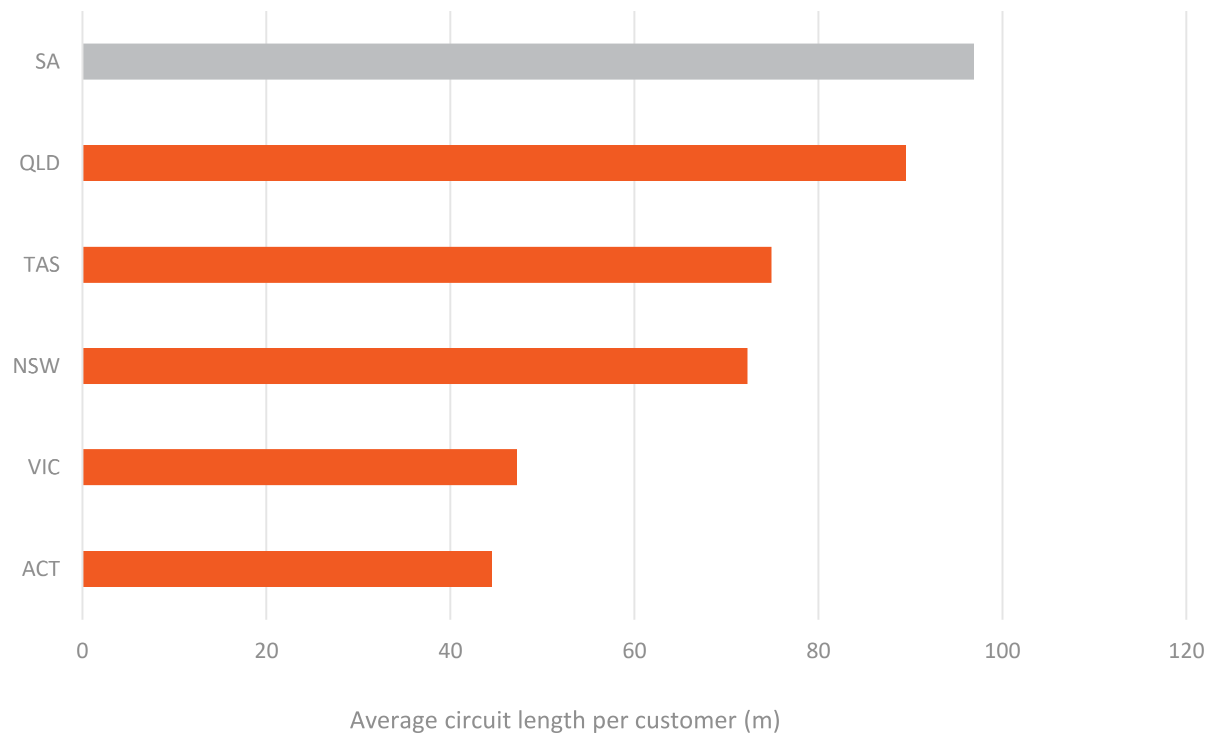
In lower-density rural, and especially remote areas, a single-phase system operates at 19kV. Approximately 30 percent of the distribution network is comprised of these long ‘single wire earth return’ (**SWER**) lines.

Except for much of the coastal area, South Australia is very sparsely settled. Approximately 70 percent of SA Power Networks’ customers reside in major metropolitan areas, including the great majority of business and commercial customers. However, the extensive area serviced by our distribution system results in 70 percent of the distribution network infrastructure (in terms of circuit length) delivering energy to the remaining 30 percent of customers. Compared with other states, South Australia has relatively few regional centres, and they are generally small and sparsely located.

2.3 Customer density

The average customer density per kilometre of distribution line in South Australia is the lowest in the NEM as indicated in Figure 8. As a result, we own and operate more distribution network per customer than other jurisdictions. Other DNSPs with low customer densities are largely rural networks operated by Ergon in Queensland and Essential Energy in New South Wales.

Figure 8: Circuit length per customer for each state and territory (meters per customer)



Source: AER Annual Benchmarking Report 2023

The South Australian Government has imposed a requirement on SA Power Networks to maintain State-wide pricing for ‘small customers’, defined as those customers whose annual consumption does not exceed 160 MWh p.a.[3] In order to meet this requirement, SA Power Networks employs a tariff averaging approach for its distribution tariffs.[4,5]

[3] National Energy Retail Law (Local Provisions) Regulations 2013 Section 5(2).

[4] Certain customers with non-standard connections are charged on a site-specific basis to reflect the nature of their connection to the network.

[5] For larger business customers with energy consumption in excess of 40GWh p.a. or have a maximum demand greater than 10MW, locational transmission use of system (**TUoS**) charges apply.

Without this 'country equalisation scheme', cost reflective distribution network charges would result in a substantial increase in distribution network costs for many rural customers. This enduring policy commitment from the South Australian Government effectively prevents us from integrating location-based price signals into our tariffs for small customers. As a result, pricing reform in South Australia primarily focuses on ToU pricing mechanisms.

For Large Business customers in the CBD of Adelaide the pricing structure is designed to offer the same pricing signals as their counterparts in other parts of South Australia. However, there is a distinct pricing window for the CBD that reflects the timing of local peak demand, ensuring that pricing remains cost reflective to local conditions.

2.4 Our operating environment

Adelaide and much of South Australia has a dry climate featuring greater extremes of summer temperature than most other Australian capitals. Extended periods of heatwave conditions can occur in summer (November 2009, January 2014 and January 2019 are examples of extended heatwaves). During these heatwave periods, summer daytime temperatures can exceed 40°C for several days in a row and overnight minimums can remain above 30°C for some of those days.

Our distribution network must supply the peak demands experienced in these heatwave conditions. Although there is an abundance of solar in South Australia, peak demands now typically occur during the evenings when the sun as gone down and there is no solar export.

2.5 Our customer demand profile

In the South Australian distribution network, customer demand is primarily influenced by two main groups: Residential and Small Business customers. The demands from these customer segments exhibit remarkable volatility, largely driven by weather conditions and their impact on customer air conditioning loads and solar exports.

Air conditioning

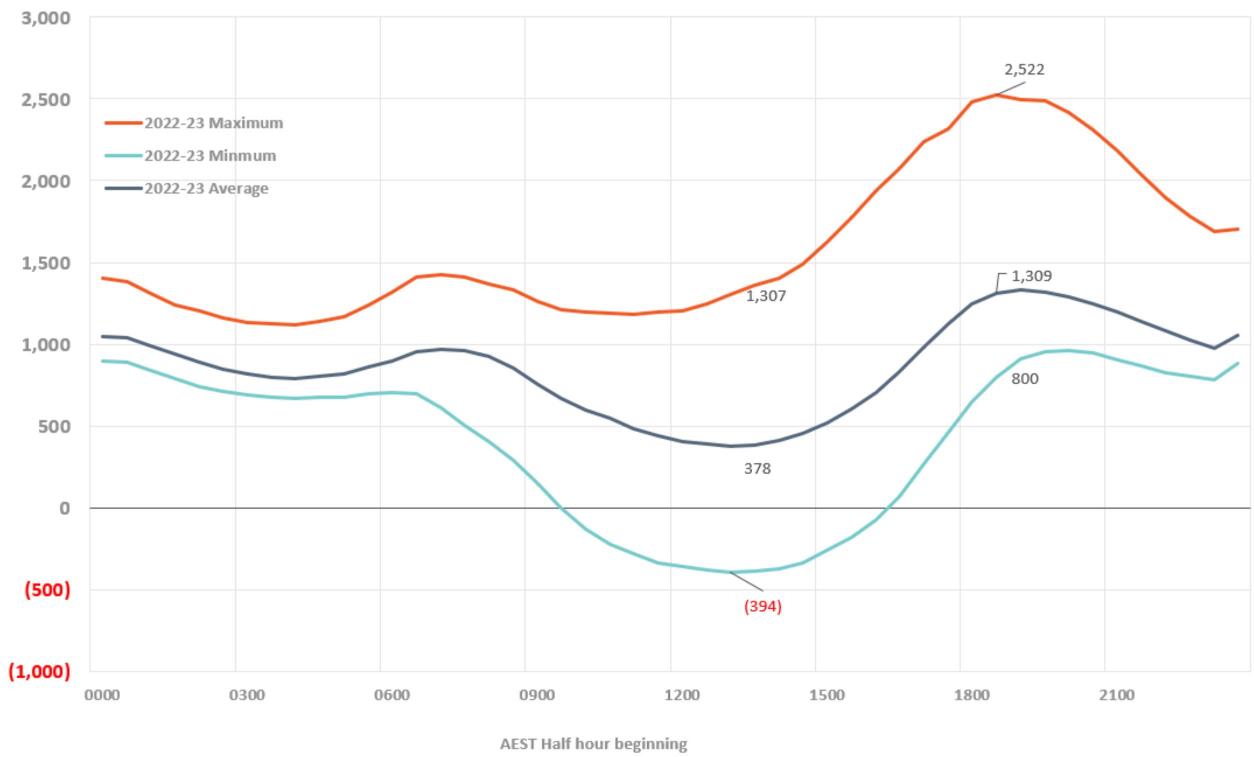
During much of the summer season, South Australia experiences warm, albeit relatively mild, weather interspersed with periods of extreme heatwaves. Over the past few decades, these extreme weather events have led to an extraordinary surge in the demand for air conditioning. More than 90 percent of households are now equipped with air conditioning, and the air-conditioned floor space in these homes continues to grow, albeit more recently with more energy-efficient cooling systems. While individual customers may use their air-conditioning systems throughout the summer, it is during extreme heatwaves that a significant spike in distribution network demand occurs, as a larger number of customers rely on their systems to keep cool.

Rooftop solar

More recently, there continues to be growth in both size and number of rooftop solar installations among small customers in South Australia. As at October 2023 almost 350,000 homes and businesses have installed rooftop solar, more than one in three premises, with a combined panel capacity of 2.5 GW. Self-consumption of the electricity generated by these systems reduces the overall customer demand during daylight hours, particularly in the solar period. Additionally, the surplus energy exported into the distribution network has substantially reduced the need for traditional power generation. In recent years, this trend has been so pronounced that the distribution network has increasingly become a net exporter of electricity into the transmission system at certain times of the day.

Figure 9 illustrates the dual challenges that the distribution network faces due to the interplay of air conditioning and rooftop solar with weather conditions. The maximum profile reveals a significant evening peak in demand on a hot workday (**WD**) during the summer, whereas the minimum profile represents a mild, sunny day when the surplus electricity generated by rooftop solar surpasses the customer demand on the distribution network, resulting in a net reverse flow of power.

Figure 9: SA Power Networks' 2022/23 Minimum, Maximum and Average daily MW demand profile (excludes Major Customers)



Source: SA Power Networks analysis

Major customers are excluded from the analysis as they exert significant, but very localised influence and so their effect can distort the interpretation of the impact on the distribution network as a whole. The analysis is based on the most recent data which was from the third La Niña summer in succession and so, whilst South Australia experienced some hot weather over the past three summers, it was not as extreme as heatwaves in the past (for example January 2019).

Negative Demand

Reverse power flows on the distribution network have been observed for several years now, driven by South Australia's high penetration of rooftop solar. Initially, this phenomenon of reverse power flows was limited to specific zone substations in suburbs with substantial rooftop solar penetration. Over time, reverse flows have become more widespread on our distribution network, now occurring at most zone substations whenever the weather is sunny and mild. Notwithstanding this, coincident distribution demand remained positive due to the influence of Major customers.

On September 26, 2021, a significant shift occurred when we had the first instance where net distribution network demand from ElectraNet's transmission network was negative. That is, the distribution network became a net exporter of electricity. Since then, these instances, have become more frequent.

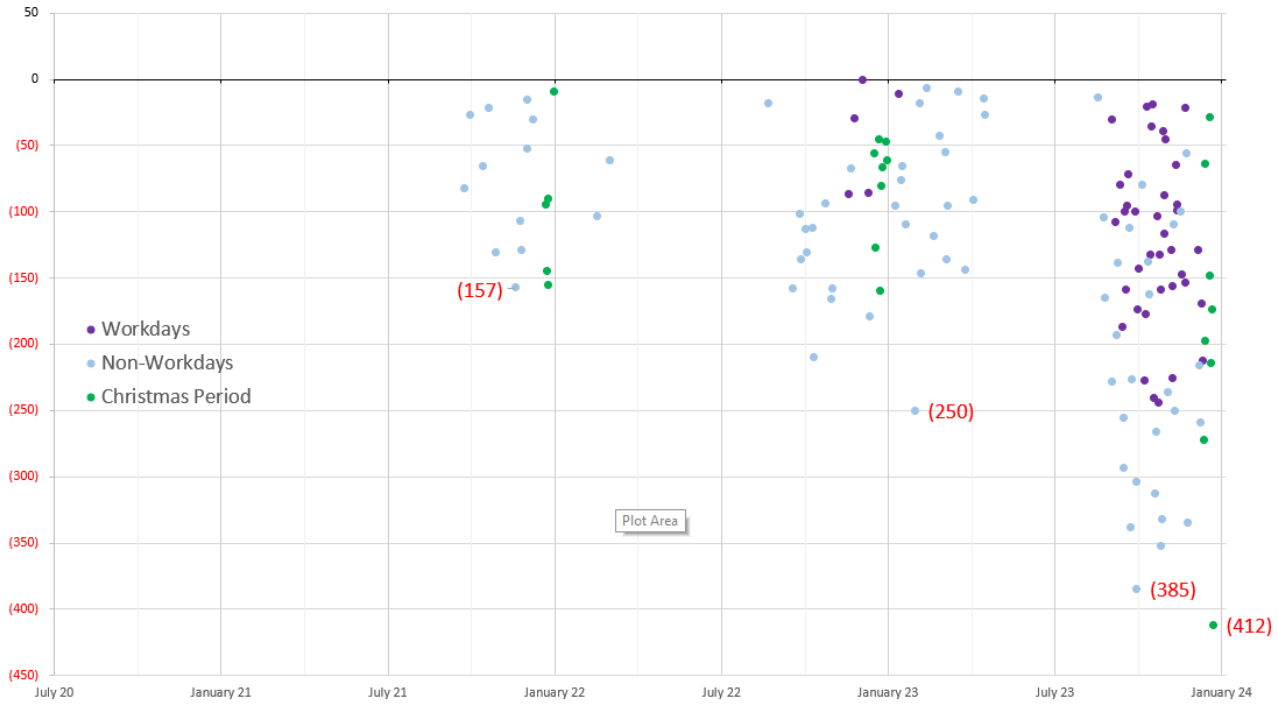
In the 2021/22 regulatory year, this phenomenon was observed on 18 days between September 26, 2021, and March 6, 2022. Negative demand was primarily limited to non workdays (**NWD**) (weekends and public holidays) and the usual shutdown days during the Christmas period. The most extreme instance of distribution network negative demand during this period reached -157MW.

In 2022/23, negative demand was first observed on August 28, 2022, and last recorded on April 23, 2023. This year saw a noteworthy change, with negative demands appearing a month earlier and persisting six weeks longer compared to the previous year. A total of 36 days experienced negative demands during the 2022/23, including some on WDs. The most significant negative demand observed was 93MW lower than in 2021/22, reaching -250MW.

In 2023/24, this trend has continued to intensify. Up to December 31, 2023, the distribution network has experienced 74 days with negative demand, including a new record of -412MW on December 31, 2023. This was also the first time state-wide operational demand in South Australia was negative. Interestingly, the differentiation between WDs and NWDs has diminished. Out of the 74 days, 28 occurred on NWDs, while 38 were on WDs and 8 during the Christmas period. This indicates that a critical mass of rooftop solar installations has been reached, such that, on sunny and mild days, the distribution network experiences negative demand regardless of the demand from other customer segments.

Figure 10 visually represents the progression of negative demands from July 1, 2020, through December 31, 2023.

Figure 10: Negative demand days in 2020-25 RCP



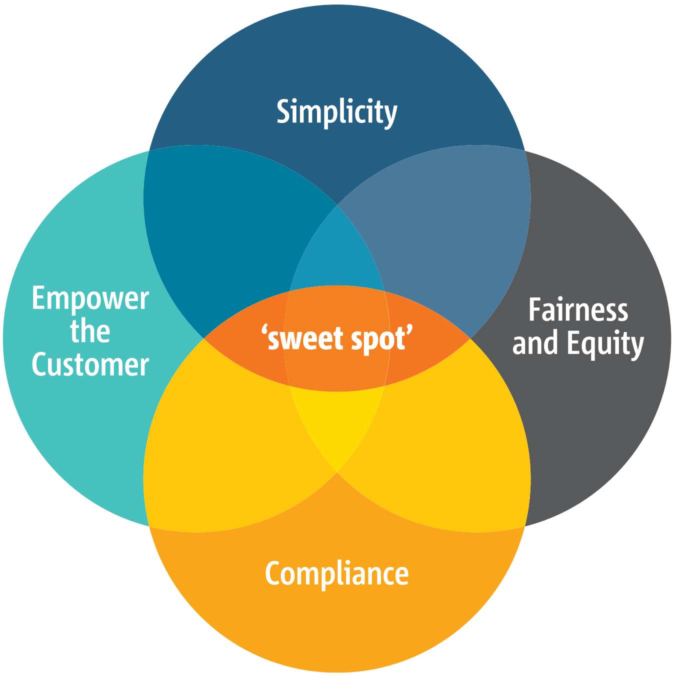
Source: SA Power Networks analysis

3 Customer impact principles

In the development of our 2025-30 RCP tariff structures, we remain guided by the Customer Impact Principles which were developed by stakeholders to inform our first Tariff Structure Statement in 2017 shown in Figure 11:

- Empower the Customer – Customers should be allowed to see, understand and manage their own behaviour. Understanding, through the provision of information, is central to making the system work.
- Fairness and Equity – Fairness requires the system to recognise the diversity of customers and that some households and some businesses are particularly vulnerable to sudden changes. Education, sufficient lead-in times and the provision of complementary measures are seen as having key roles.
- Simplicity (to inform decision making) – Tariffs have to be understandable if customers are going to respond to them. To be understandable, tariffs need to be simple and transparent.
- Compliance – Tariffs must be compliant with the NER and capable of acceptance by the AER.

Figure 11: Customer impact principles



4 Stakeholder engagement

SA Power Networks embarked on a comprehensive stakeholder engagement program for the development of our 2025-30 Regulatory Proposal. Details of this program are outlined in **Attachment 0 - Customer and stakeholder engagement program**. Within this program, extensive engagement was conducted on tariffs and for the first time we engaged on both consumption and export tariffs.

We proposed a number of topics to engage on with our Tariff Working Group (**TWG**), a standing reference group who SA Power Networks engages with on a business as usual basis, to help inform, develop and refine our TSS for the 2025-30 RCP. We collaborated with the group to determine which topics should form part of our Tariff Focused Conversation workshops.

A series of 10 Tariff Focused Conversation workshops, as outlined in Figure 12, were held over a five month period with a broad and diverse range of stakeholders. These included our existing TWG participants as well as representatives from other organisations to ensure a cross section of South Australians were represented. The pre-existing knowledge held by a number of members in the group developed over years of business as usual engagement, allowed us to discuss and consider tariff issues at a deeper level, develop additional analysis and ultimately refine our thinking for the tariffs proposed for the 2025-30 RCP. The staging of our tariff workshops allowed the development of our tariff structures to be an iterative process. We were able to take some questions from the group on notice and respond at the following session with further analysis and deeper insight to ensure that they felt empowered to make informed decisions and provide robust challenge. This was favourably received by stakeholder participants.

We were transparent with our stakeholders regarding the intended level of engagement on each of the tariff topics. Many of our current tariff structures remain fit for purpose over the 2025-30 RCP and, while it was still important to inform stakeholders of this, our conversations focused on deeper levels of engagement where they could have the most influence. With that said, we note that we did revise our approach in several areas of our current tariff structures, despite having no intention to do so at the beginning of the engagement process.

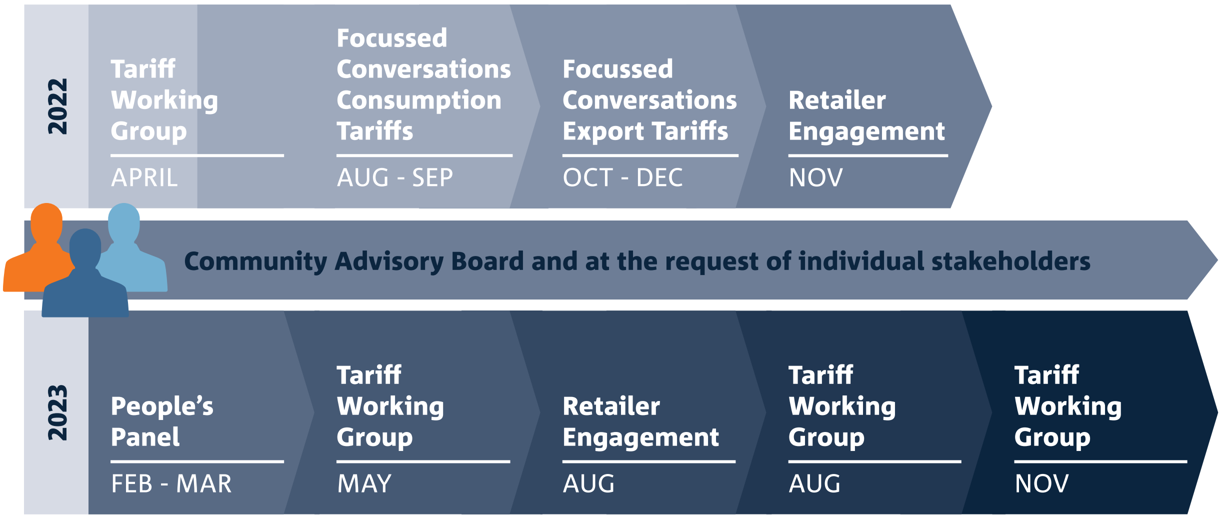
Figure 12: Focused Conversation workshops

Outside of the formal Focused Conversation workshops we held additional information sessions as requested by stakeholders to ensure they felt supported in the development of their tariff knowledge and confident to actively participate in the workshops.

Retailer engagement was also key in developing the TSS. SA Power Networks formally engaged with retailers via workshops in 2022 and 2023. We also held individual sessions with retailers to allow them to raise questions or provide comments, recognising that they may not have wanted to actively engage in a group forum. A number of the new tariffs being proposed in the TSS for the 2025-30 RCP originate from trial tariffs over the 2020-25 RCP and the evolution of these tariffs has been as a direct result of retailer engagement.

Figure 13 summarises our TSS engagement over 2022 and 2023.

Figure 13: Tariff Structure Statement engagement



Whilst all stakeholder feedback was considered, not all stakeholder viewpoints could be incorporated into the final tariff structures.

Table 1 summarises how our tariff structures have been influenced by stakeholder engagement.

Table 1: Stakeholder feedback and SA Power Networks Proposed Response

Tariff Structure	Stakeholder Feedback	SA Power Networks Proposed Response
Residential Time of Use default tariff	14 hour Peak window is too wide.	Increase Solar Sponge and Off Peak by one hour each and therefore reduce Peak by two hours, whilst maintaining the incentivising nature of the tariff in a simple structure.
Residential Prosumer	Demand is a difficult concept to understand.	Close demand tariff and create a volumetric prosumer tariff – Residential Electrify.
Time of Use Controlled Load	Tariff should be based on ACST and not local time. Having local time would require meter reconfigurations twice per year at the ongoing cost to the retailer.	Retain existing time zone of ACST.
Small Business tariff class <160 MWh p.a.	A pricing differential should be created given the disparate consumption levels of customers <160 MWh p.a.	Segmenting the Small Business tariff class into Small 0-40MWh p.a. and Medium 40-160 MWh p.a. Small customers would have the same supply charge as Residential customers. Medium customers would have a higher supply charge but lower consumption charges. Medium customers would be assigned to Medium Business Time of Use Demand with the option to opt out if their demand is <120kVA.

Small Business tariff sub classes	Customers consuming around 40MWh p.a. are not materially disadvantaged when transitioning between Small and Medium Business tariffs.	Considered pricing outcomes for customers with different annual usage profiles when developing the pricing relativities for Medium Business Time of Use Demand.
Small Business Time of Use Electrify **<120 kVA** customer choice tariff	Can a tariff be created which incorporates a Solar Sponge price signal similar to Residential customers.	A new customer choice tariff was developed with a Solar Sponge price signal which then required strong pricing signals in the Peak window to ensure appropriate revenue recovery for the tariff class.
Small Business Time of Use Demand <160MWh p.a. and >120kVA	Customers should be able to opt out of this tariff. Demand charges are particularly challenging for public EV charging stations with high demands and low consumption.	Allowing customers with >120kVA to opt out of demand charges would result in a price increase for all customers in the Small Business tariff class. This option is not considered to be progressing tariff reform and cost reflective pricing. This tariff is being re labelled as Medium Business Time of Use Demand in 2025-30 RCP.
Large Business Flexible tariffs	Including a charging parameter based on forecast temperature is highly variable, inconsistent and difficult for customers.	SA Power Networks will include actual temperatures as part of the charging parameter.
Major Generation	Generation customers connected at Zone Substation and Sub Transmission do not have a tariff available for them.	Developed generation tariffs for Zone Substation and Sub Transmission following the same structure as existing generation tariffs.

5 Key challenges we are trying to address

Tariffs are a key enabler of SA Power Networks' strategic direction for the 2025-30 RCP which promotes, amongst other things efficient use of the distribution network, equity for customers and enabling more greener, affordable energy. Whilst it is widely acknowledged that tariffs are a medium to long term price signal for our customers, it is important that our pricing direction aligns and supports the objectives of the distribution network over the 2025-30 RCP.

We have identified the following challenges and opportunities facing the distribution network in the 2025-30 RCP and shaped our tariffs to respond to:

- Increase in electrification;
- Home Electric Vehicle (**EV**) charging;
- Public EV charging; and
- Managing Solar on the distribution network.

The proposed accelerated interval meter deployment recommended by the AEMC in 2025-30 will enable more cost reflective pricing. Tariffs which are cost reflective and incorporate ToU pricing will be pivotal in managing these challenges efficiently.

Increase in electrification

The 2025-30 RCP sees a material uplift in forecast energy distributed through our distribution network because of increased electrification in both residential and business segments. The transition to EVs is part of a broader trend that will see homes and businesses progressively move towards more electrification in the 2025-30 RCP, replacing gas appliances with electric ones to access lower cost energy and reduce emissions. Not only will these appliances be electric but they are also becoming increasingly 'smart', able to be managed and scheduled to take advantage of solar and at times when grid electricity is cheapest. This presents a tremendous opportunity for the distribution network and our customers.

By 2030 electrification within the residential sector is expected to contribute 7 percent of the total energy distributed by the network, whilst electrification within the business sector is forecast to contribute 19 percent of total energy throughput.

SA Power Networks is responding to this challenge by developing a customer choice ToU tariff for customers who predominantly or solely meet their energy needs with electricity, but have sufficient flexibility in their appliances, e.g. EVs, heat pumps, energy storage etc, to optimise their usage outside peak demand periods. These customers are expected to have an above average energy consumption, so the tariff is structured to provide more opportunities throughout the day to access lower cost electricity outside of distribution network peak periods. Residential Electrify has stronger pricing signals than the default Residential Time of Use tariff.

By putting in place systems and processes to enable customers to take advantage of smart EV charging and the future smart, electrified home, as we have for rooftop solar with flexible exports, we can keep much of this new load out of peak times, soak up excess daytime solar, and deliver much more energy through our existing assets. This will reduce costs to all customers in the long term.

Home EV charging

EV uptake is poised to accelerate in Australia with more affordable EV models becoming available, efforts underway to deploy public charging infrastructure, including the South Australian Government's state-wide charging network, and national policy reforms driven by the Commonwealth Government's new EV Strategy. By 2030 we expect to see about 200,000 EVs on the road in South Australia with 3 percent of total energy attributable to EVs.

The majority of EV charging happens within the home and it is important that this charging does not increase network demand in current peak time periods or create new peak periods, both of which could drive inefficient augmentation, resulting in inefficient customer outcomes.

SA Power Networks is responding to this challenge via ToU pricing signals encouraging both Off Peak and Solar Sponge charging in the default Residential Time of Use tariff. Both time windows within the tariff have been extended to 6 hours each. A 6 hour Off-Peak period allows an EV owner to get a sufficient charge overnight for a daily commute without a dedicated wall charger. These pricing signals are also reflected in our ToU Controlled Load tariff which is a customer choice tariff, whilst Residential Electrify has even broader time windows with effectively 20 hours of the day at discounted prices to encourage maximum utilisation of the distribution network.

Public EV charging

Public EV charging stations will draw material power demand from the distribution network and dominate the usage of local distribution network assets. It is important that these customers are subject to a pricing signal with demand charges. Without such a signal we would not be promoting efficient use of the distribution network and would ultimately result in increased augmentation expenditure.

SA Power Networks is proposing to continue its current tariff assignment policy for those customers who consume less than 160 MWh p.a. and with maximum demand of greater than 120kVA with the Medium Business Time of Use Demand tariff. This tariff assignment policy is important when the proposed increase in distribution network augmentation in the 2025-30 RCP is being partially driven by EVs.

Managing Solar on the distribution network

As at October 2023 almost 350,000 homes and businesses have installed solar, more than one in three premises, with a combined panel capacity of 2.5 GW. Uptake continues to grow strongly as homes and businesses respond to high energy prices, while falling solar system costs mean that the average system size is also increasing each year. 99 percent of solar systems less than 30kW in capacity and accounted for 72 percent of energy exported in 2022/23. Rooftop solar is the largest source of generation in the state.

For the first time, in the current RCP on mild sunny days when demand is low and energy exports are high across the entire distribution network, we have experienced negative demands. This is a material change for a distribution network that has been designed to manage traditional summer peaking loads. For the 2025-30 RCP, SA Power Networks is responding to this challenge both through changes to consumption tariff structures and introducing new export tariffs.

The Solar Sponge time window is proposed to continue in all Residential tariff structures and will feature in the pricing signal of the new customer choice Small Business tariff Small Business Electrify. The proposed time window has been extended by 1 hour, to have a 6 hour window at the lowest price of the day. The Time of Use Controlled Load tariff will continue to have the same pricing signals as the default Residential Time of Use tariff. To date, SA Power Networks has seen significant Retailer response to this pricing signal with 29 percent of ToU controlled load at December 2023 now moved into the Solar Sponge window period.

In addition to consumption pricing signals, for the first time export tariffs are being proposed for the 2025-30 RCP. These tariffs will recover the forecast cost of upgrades to the distribution network to enable more solar on our network while maintaining the current export service levels. They will only be levied from those customers who export energy and therefore directly benefit from these network upgrades, rather than from all customers (including those who cannot export energy into the distribution network) as is the case now. These upgrades will maintain current export service levels at 95 percent or more (that is, no limit on exports for at least 95 percent of the time) for at least 95 percent of customers.

Export tariff structures have been designed to encourage customers to limit their export of energy from solar panels into the distribution network at peak solar times during the day by instead using the power in their home or business, or by storing it in batteries to use in the evening. Section 11.5 of this document outlines the proposed export tariff structure in further detail.

6 Distribution network demand in South Australia

Our tariff development is informed by our understanding of how the distribution network is utilised at different times of the day, different days of the week and in different geographical areas.

The proposed tariff time windows in the 2025-30 RCP will remain largely unchanged from the current windows. These windows reflect the times that maximum and minimum demands occur on the distribution network.

Key time windows (local time ACST/ACDT) in our proposed 2025-30 RCP tariff structures include:

- Residential tariffs: Solar Sponge 10:00am – 4:00pm (2020-25 RCP: 10:00am – 3:00pm)
- Small and Medium Business tariffs: Peak usage November to March 5:00pm – 9:00pm (Unchanged)

- Large and Major Business tariffs: Peak Demand November to March (Unchanged)
  - 11:00am – 5:00pm CBD Workdays (Unchanged)
  - 5:00pm – 9:00pm Rest of SA All Days (Unchanged)

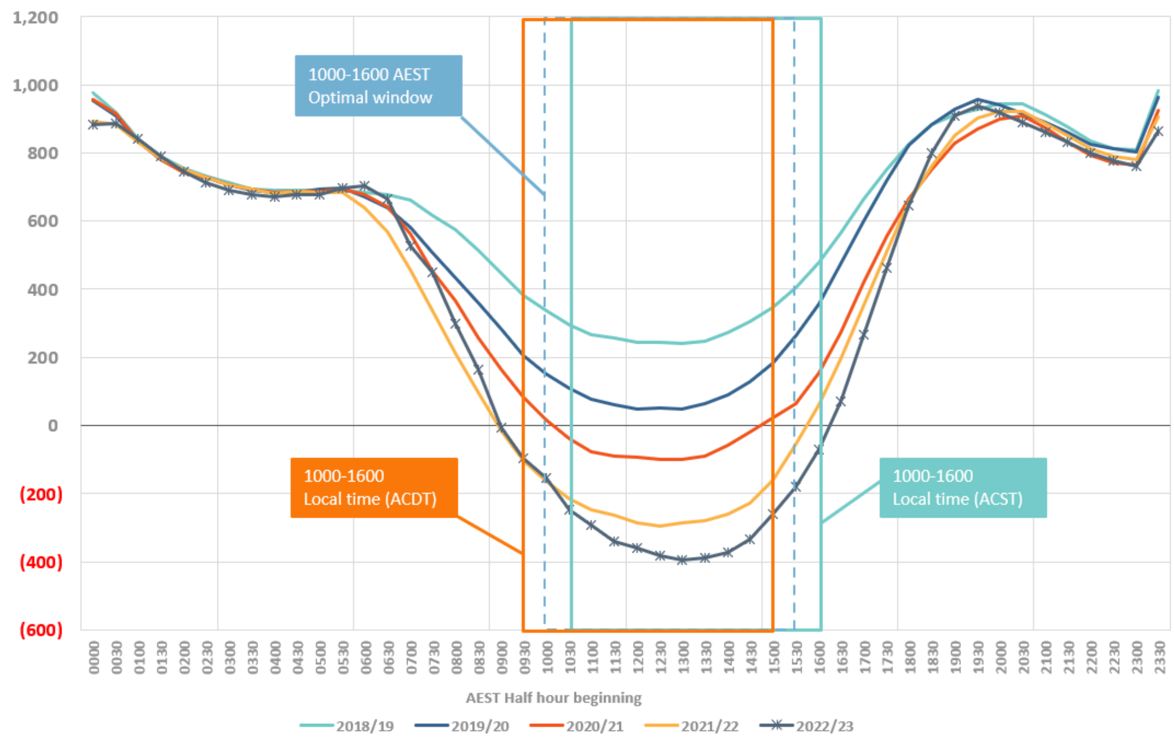
6.1 Residential

The Solar Sponge time window is the default tariff structure for all customers with interval meters in our Residential tariff class. We are proposing to increase the Solar Sponge time window by 1 hour to 4:00pm which allows for a six hour window at the lowest priced time, when the distribution network has the highest available consumption capacity. This time window broadly aligns with distribution network minimum demand data trends we have seen emerge in the current 2020-25 RCP.

Based on the historical five year data in Figure 14, the most accurate Solar Sponge window all year round would be 10:00am – 4:00pm AEST (blue dash box) or in South Australia 9:30am – 3:30pm ACST April to September (orange box) and 10:30am – 4:30pm ACDT October to March (teal box). These seasonal time windows provide more accurate price signalling but introduce more tariff complexity. SA Power Networks deliberately avoids seasonal pricing signals in Residential tariffs: they are complex for customers to interpret and respond to, and for Retailers to implement. All of our Residential tariff structures have a maximum of three time/price windows. Based on these factors, we consider the proposed one hour seasonal variability in the Solar Sponge time window strikes the right balance between providing cost reflective price signals to encourage load shifting and tariff simplicity for customers to understand and respond to and for retailers to implement.

The Solar Sponge time window proposed is an annual time window based on local time ACST/ACDT.

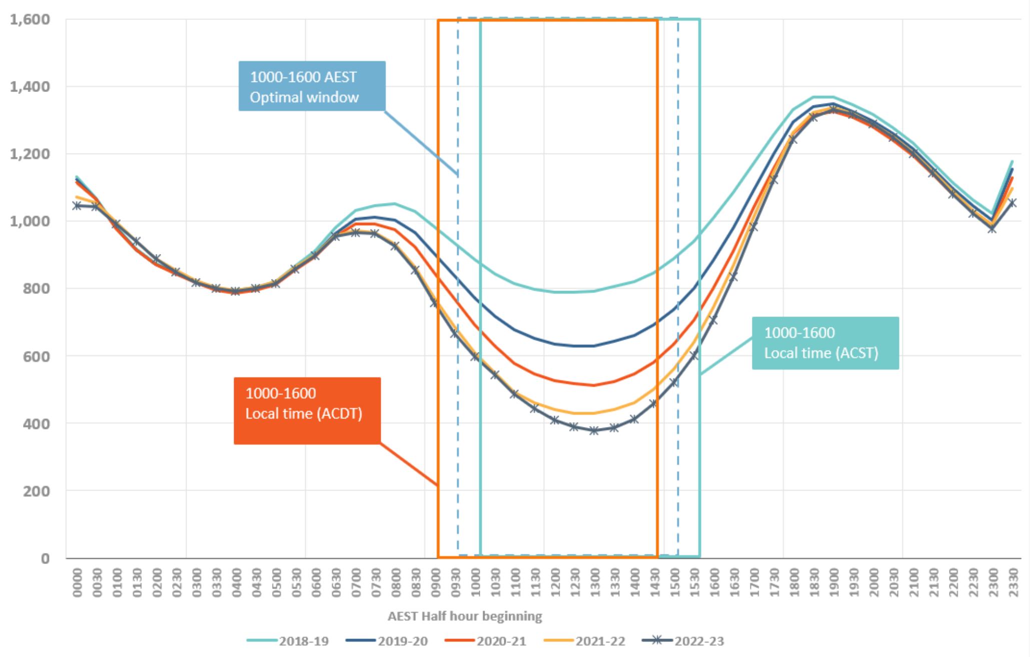
Figure 14: SA Power Networks distribution network Minimum MW demand profile (excluding Major Customers including Embedded Generation)



Source: SA Power Networks analysis

Whilst Figure 14 illustrates the minimum demands we are experiencing on the distribution network, it is important to note that the average demand profile also follows this same trajectory. Figure 15 illustrates the average demand profile over the past five years.

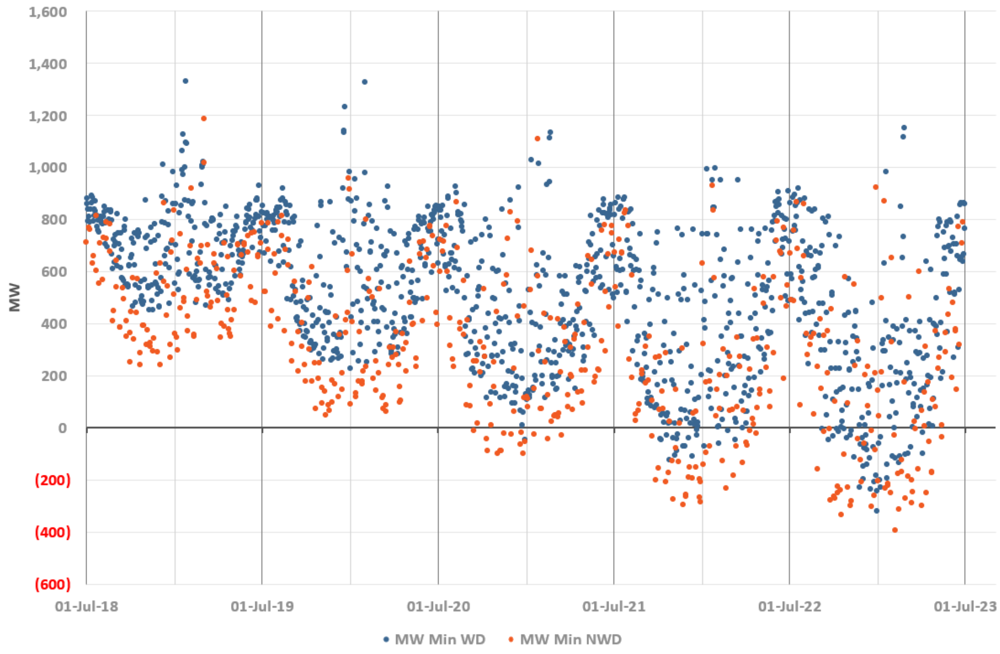
Figure 15: SA Power Networks distribution network Average MW demand profile (excluding Major Customers including Embedded Generation)



Source: SA Power Networks analysis

In the last five years there has been a continual downwards trend of minimum distribution network demand. Figure 16 illustrates that in 2020/21 the distribution network experienced its first negative demand days (15), with all but one day being a Non workday (Saturday, Sunday or Public Holiday), albeit during the Christmas period. Each subsequent year has seen an increase in frequency of negative demand days and a mix between WDs and NWDs. Coupled with increased event frequency is the spread of minimum demand values, ranging between 1,151 MW and -394 MW in 2022/23. Five years ago, the spread was much more concentrated with minimum demand values, ranging between 1,331 MW and 240 MW in 2018-19. On 31 December 2023 South Australia experienced negative operational demand for the first time.

Figure 16: SA Power Networks distribution network Minimum MW demand categorised by WD and NWD (excluding Major Customers including Embedded Generation)



Source: SA Power Networks analysis

6.2 Business

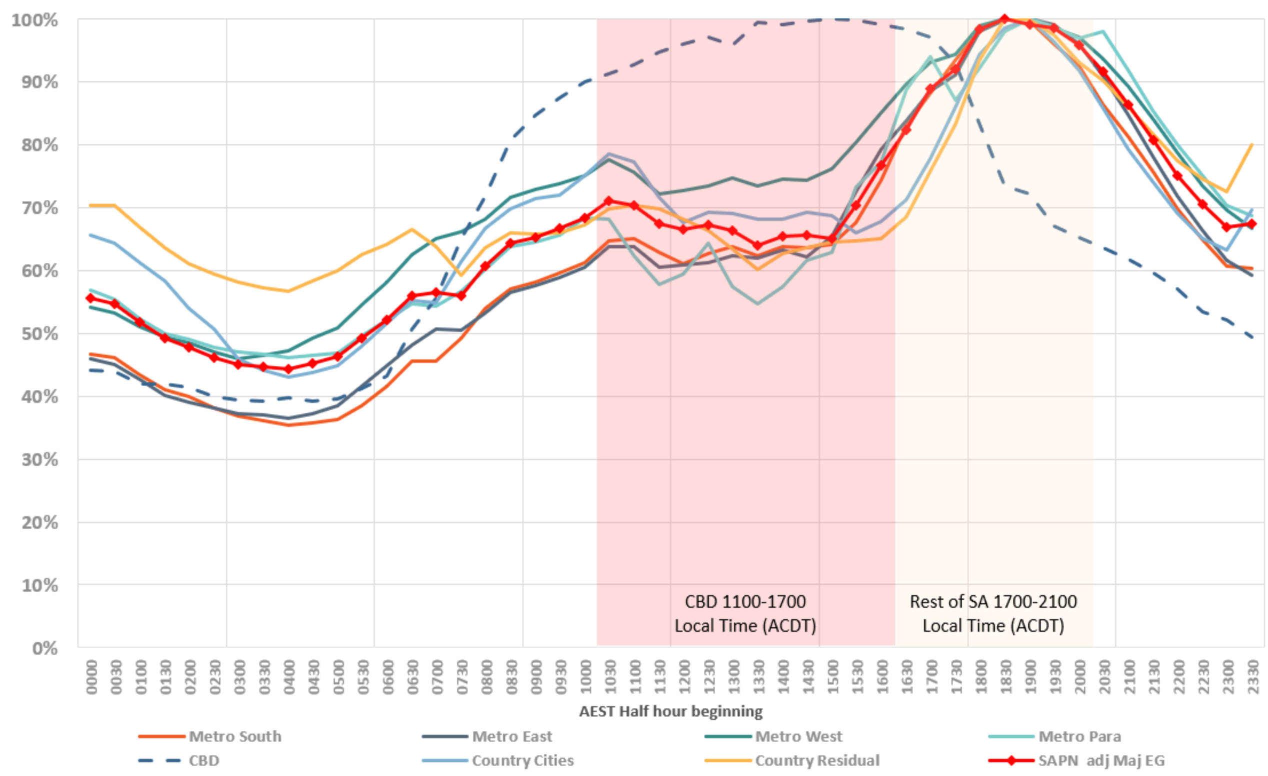
Peak Demand time windows are proposed to stay the same as the 2020-25 RCP with the current differentiation between CBD and the Rest of SA continuing.

Figure 17 illustrates the distribution network load profile in 2022/23 continues to support the Peak Demand time windows in November to March:

- 11:00am – 5:00pm CBD Work Days
- 5:00pm – 9:00pm Rest of SA All Days

The CBD has higher commercial loads and lower solar penetration. Peak Demand occurs earlier in the day with 91 percent of demand occurring at 11:00am and flatter than the Peak Demand profile in the Rest of SA. The Rest of SA has a similar Peak Demand profile, with 82 percent of demand occurring at 5:00pm rising to 100 percent at 7:00pm and falling back to 92 percent at 9:00pm compared with a range of 86-98 percent within the sub regions as identified in Figure 17 e.g. Metro South, Country Cities etc. These profiles support the two differentiated time windows for Peak network use.

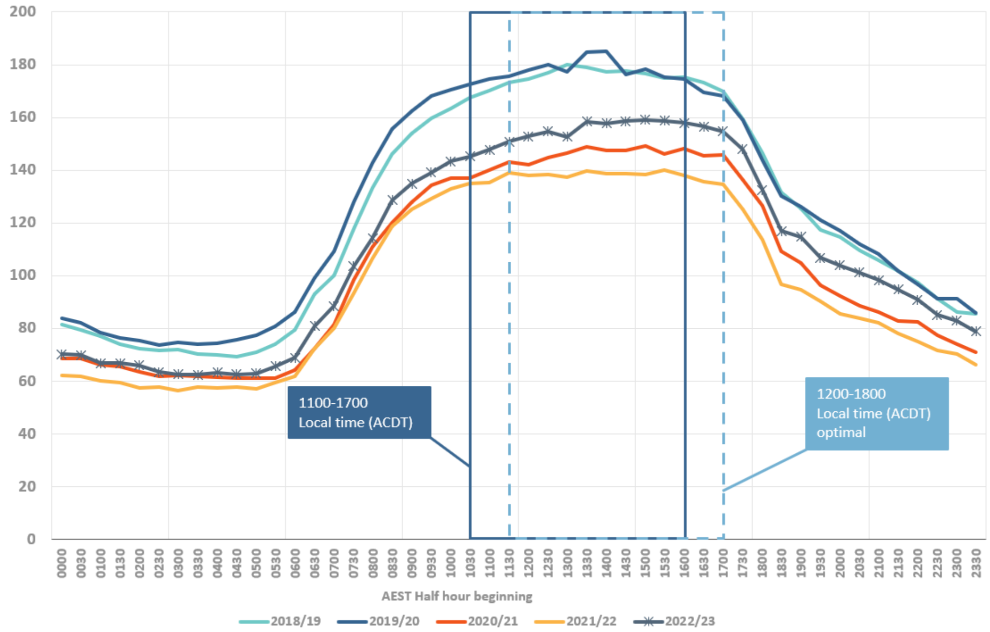
Figure 17: 2022/23 Maximum by half hour vs Maximum for year



Source: SA Power Networks analysis

Based on the historical five year data the most accurate Peak Demand window for CBD would be 12:00pm – 6:00pm ACDT as illustrated in Figure 18. Whilst this would capture the highest demand time intervals, there is not a material difference between 11:00am – 5:00pm ACDT and 12:00pm – 6:00pm ACDT to warrant a change in tariff time windows for Peak Demand. The Peak Demand time window for the CBD was introduced in 2020-25 and we consider it fit for purpose with the structure incorporated by Retailers today. The shift of one hour would add unnecessary complexity for stakeholders when the outcomes would not materially change.

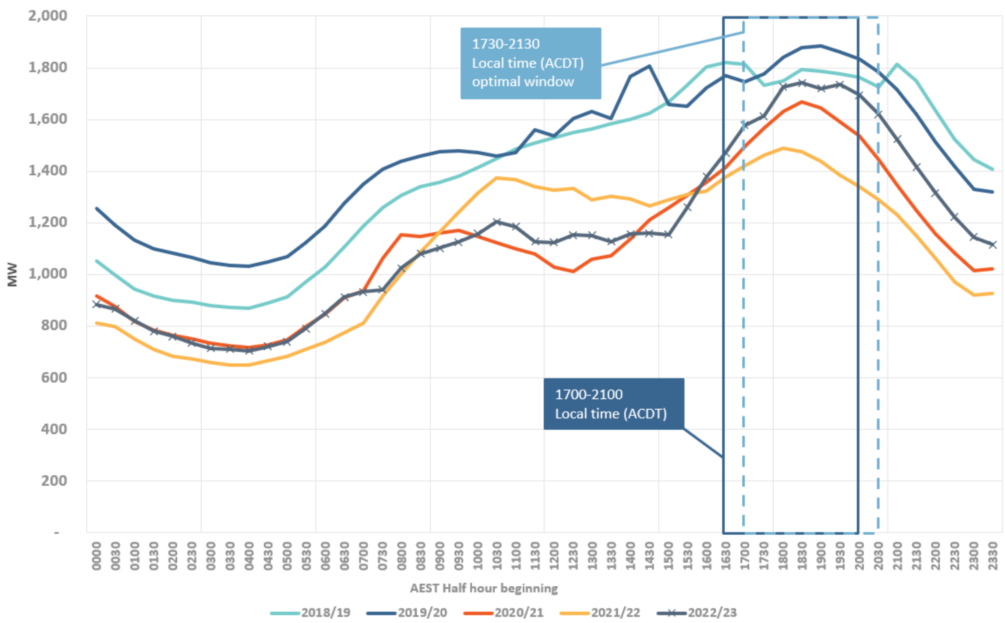
Figure 18: CBD Extreme MW day demands (excluding Major Customers including Embedded Generation)



Source: SA Power Networks analysis

For the Rest of SA based on the historical five year data the most accurate Peak Demand window would be would be 5:30pm – 9:30pm ACDT as illustrated in Figure 19. Whilst this would capture the highest demand time intervals, there is not a material difference between 5:00pm – 9:00pm ACDT and 5:30pm – 9:30pm ACDT to warrant a change in tariff time windows for Peak Demand. The Peak Demand time window for the Rest of SA was introduced in 2020-25 and we consider it fit for purpose with the structure incorporated by Retailers today. The shift of one hour would not materially change the outcomes but would add complexity for key stakeholders including Retailers and customers. Such complexity often leads to unsuccessful implementation.

Figure 19: Rest of SA Extreme MW day demands (excluding Major Customers including Embedded Generation)



Source: SA Power Networks analysis

We will continue to assess distribution network demand over the 2025-30 RCP and reevaluate the tariff time windows for 2030-35 RCP.

7 Forecasts

The forecasts that underpin our proposed TSS for the 2025-30 RCP have been based on the August 2022 AEMO ESOO.

The ESOO 2022 presents four scenarios: Slow Change, Progressive Change, Step Change, and Hydrogen Superpower. AEMO considers the Step Change scenario, also known as Central scenario, as the most likely scenario to materialise over the 2025-30 RCP. SA Power Networks has developed its forecasts based on the ESOO 2022 Step Change scenario.

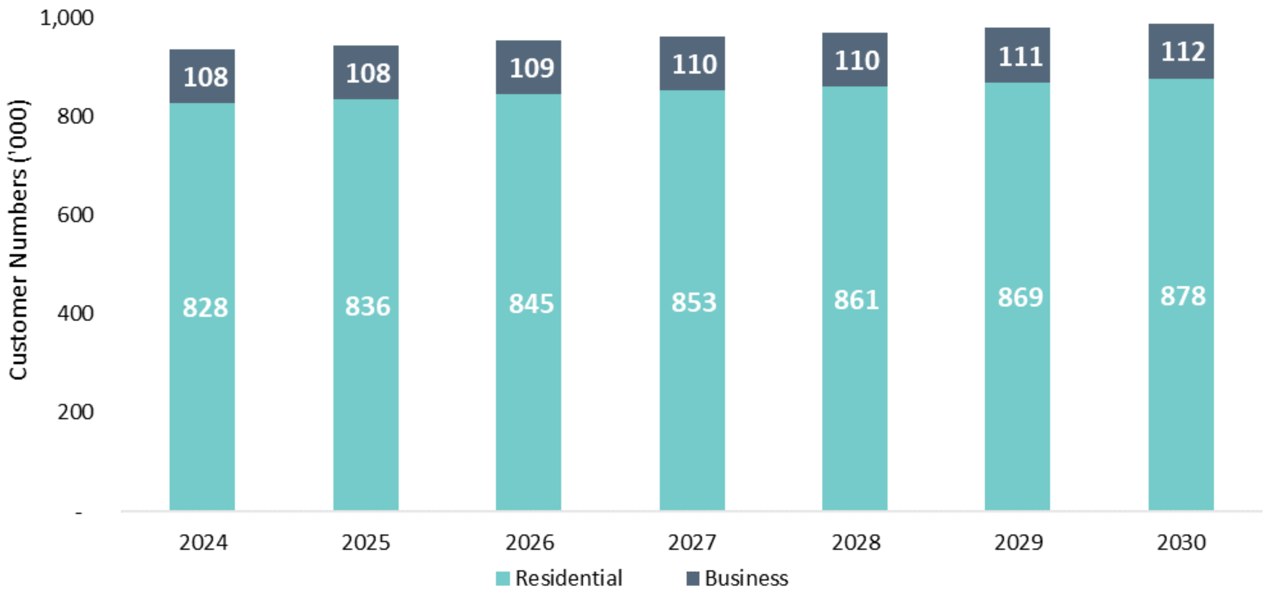
Our forecasts for the 2025-30 RCP comprise of:

a. Customer growth
b. Distribution network energy volumes
c. Maximum demand
d. Customer Energy Resources

7.1 Customer growth forecast

SA Power Networks has calculated a 10 year historical average growth rate based on historical customer numbers reported in our Regulatory Information Notices, to forecast Residential and Business customer numbers in the 2025-30 RCP. Residential customers are forecast to grow annually by 0.97 percent and Business customers by 0.58 percent. The Residential forecast growth rate broadly aligns with the AEMO forecast of 1.14 percent. There is no corresponding business customer growth forecast prepared by AEMO.

Figure 20: SA Power Networks customer numbers forecast to 2030



Source: SA Power Networks analysis

7.2 Distribution network forecast energy volumes

Consumption

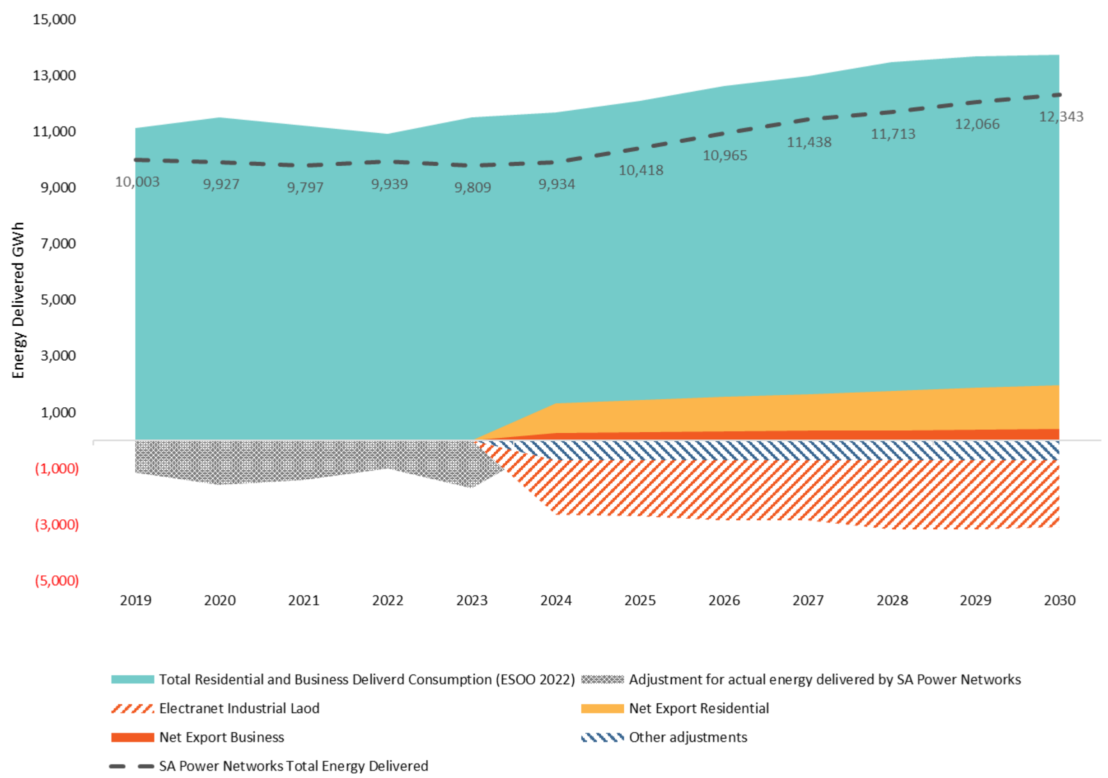
AEMO has developed the ESOO 2022 volume forecasts for South Australia, considering underlying demand, connection growth, growth in CER (solar and batteries), and the impact of energy efficiency. The ESOO 2022 volume forecasts are state-wide energy volume forecasts, that is, what the NEM generators deliver to South Australian customers. This differs from the energy volumes that SA Power Networks delivers to its customers.

We have made the following adjustments to the ESOO 2022 volume forecasts to ensure volumes represent distribution network throughput only:

- we include forecast new export energy from Residential and Business customers, who export energy into the distribution network for use by other customers; and
- we exclude volumes for customers directly connected to ElectraNet's transmission network.

The volume forecasts for SA Power Networks delivered energy are illustrated in Figure 21.

Figure 21: SA Power Networks distribution network volume forecast GWh to 2030



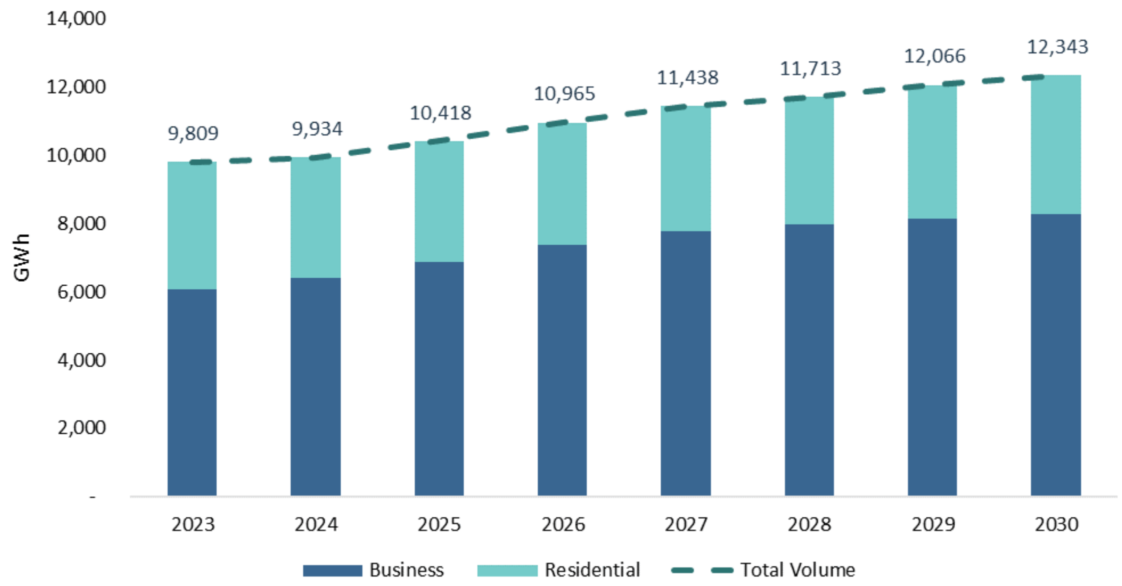
Source: SA Power Networks analysis

Figure 21 shows the building blocks and adjustments to the ESOO 2022 volume forecasts to derive the distribution network volume forecasts. The dotted line represents the volume forecasts to be delivered by SA Power Networks.

Between 2019 and 2023, energy volumes have been adjusted to recalibrate the AEMO energy volumes to SA Power Networks' actual volumes delivered. From 2024 onwards, AEMO energy volumes are adjusted to exclude transmission customers and include net solar exports from Residential and Business. The net solar

export forecasts are based on our internal analysis for Residential and Business customers and recognise the impact of batteries, virtual power plants, and behind-the-meter consumption.
Total energy delivered is expected to increase by 2,534 GWh (26 percent) in 7 years to 2030. The breakdown of the total energy delivered for Residential and Business is outlined in Figure 22.

Figure 22: SA Power Networks distribution network total volume forecast GWh to 2030

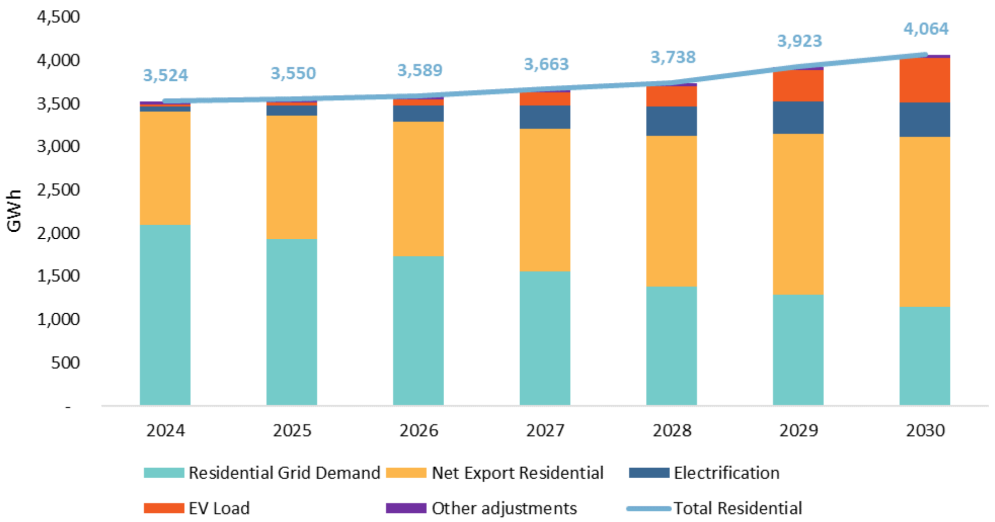


Source: SA Power Networks analysis

This volume growth is driven primarily by the business sector. Business volumes are expected to grow by 36 percent from 2023 to 2030. Residential volumes are also growing albeit not at the same rate. Residential volumes are forecast to grow by 9 percent from 2023 to 2030.

Residential volumes delivered are expected to grow by an average of 3 percent annually from 2026 to 2030, primarily driven by EV load and electrification, as illustrated in Figure 23. Net export from Residential customers is also expected to grow, reducing energy sourced from the distribution network. EV load and electrification are forecast to comprise approximately 12 percent and 10 percent respectively, of total Residential energy delivered by 2030. EVs are expected to grow within the Residential sector driven by factors including reduced ownership costs, increased supply, the growth of the second-hand EV market. The electrification of gas cooktops, gas space heating, and hot water heating within the Residential sector will increase the energy consumed in the coming years.

Figure 23: SA Power Networks Residential volume forecast GWh to 2030

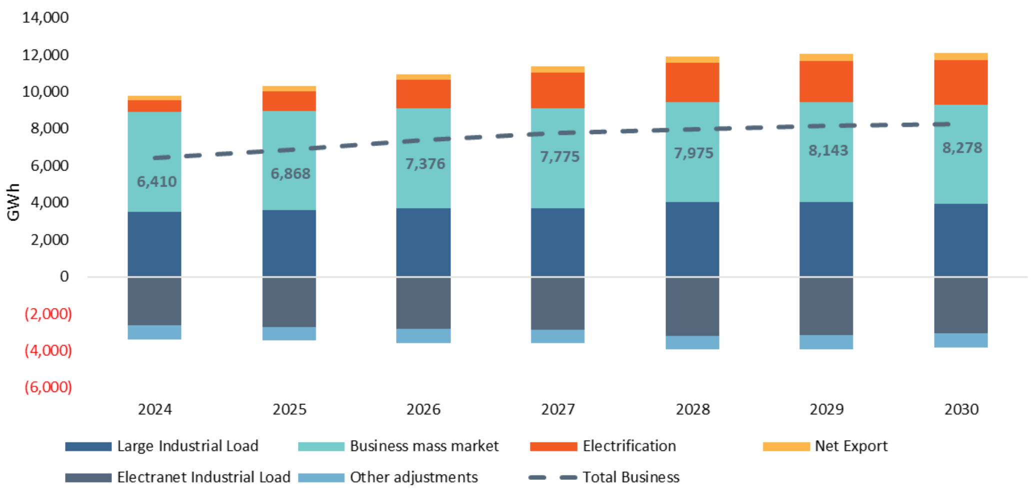


Source: SA Power Networks analysis

Business volumes delivered are expected to grow by an average of 4 percent annually from 2026 to 2030 as illustrated in Figure 24. The key driver of energy growth in the Business sector is electrification (including electrification of transport). In comparison to 2024, the electrification of business is expected to grow by 281 percent in 2030, contributing 1,768 GWh to total Business energy delivered.

Transport electrification includes electrification of public transport, ride-sharing and autonomous vehicles. The South Australian Government's strategy to achieve net zero by 2050 will continue to drive public transport electrification in South Australia. For example, in 2023, the South Australian government introduced the first fully electric bus[6] and completed the electrification of the Gawler rail line[7]. In addition, electrification from Business sectors such as manufacturing to achieve decarbonised operations is also likely to drive energy consumption.

Figure 24: SA Power Networks Business volume forecast GWh to 2030



Source: SA Power Networks analysis

[6] https://www.dit.sa.gov.au/news/feed?a=1310135.
[7] https://www.premier.sa.gov.au/media-releases/news-items/gawler-line-goes-all-electric-for-a-cleaner,-quieter-ride.

Figure 25 outlines the detailed volume forecasts for the 2025-30 RCP by customer segments which form the basis of our 5 year indicative pricing.

Figure 25: SA Power Networks volume forecast by customer segment to 2030

			Year ending 30 June				
	2024	2025	2026	2027	2028	2029	2030
Residential							
AEMO Forecast	2166	2081	1,998	1,970	1,949	2,014	2,058
Adjustments	1358	1470	1,591	1,693	1,789	1,908	2,006
SAPN Sales Forecast	**3,524**	**3,550**	**3,589**	**3,663**	**3,738**	**3,923**	**4,064**
comprises							
- Residential	*3059*	*3092*	3,137	3,218	3,298	3,489	3,637
- Controlled Load	*464*	458	452	446	440	434	428
Business							
AEMO Forecast	6031	6462	6,940	7,315	7,495	7,638	7,754
Adjustments	(843)	(844)	(815)	(790)	(769)	(745)	(725)
SAPN Sales Forecast	**5189**	**5618**	**6,126**	**6,525**	**6,725**	**6,893**	**7,028**
comprises							
- Unmetered	*98*	*98*	98	98	98	98	98
- Small Business	*1394*	*1512*	1,651	1,760	1,815	1,861	1,898
- Large LV Business	*2920*	*3166*	3,457	3,686	3,801	3,897	3,975
- HV Business	*777*	*842*	920	981	1,011	1,037	1,058
Major Business							
AEMO Industrial Forecast	3503	3577	3,706	3,712	4,052	4,035	3,946
Adjustments	(2,281)	(2,327)	(2,456)	(2,462)	(2,802)	(2,786)	(2,696)
SAPN Sales Forecast	**1,221**	**1,250**	**1,250**	**1,250**	**1,250**	**1,250**	**1,250**
comprises							
- Zone Substation	*528*	*528*	528	528	528	528	528
- Sub-Transmission	*693*	*693*	693	693	693	693	693
Total							
SAPN Sales Forecast	**9,934**	**10,418**	**10,965**	**11,438**	**11,713**	**12,066**	**12,343**

Source: SA Power Networks analysis based on ESOO 2022 Forecast
Adjustments: Solar, battery export, exclusion of ElectraNet (transmission connected) customers and calibration differences between historical actuals and forecast.
Note: Numbers in table may not add due to rounding

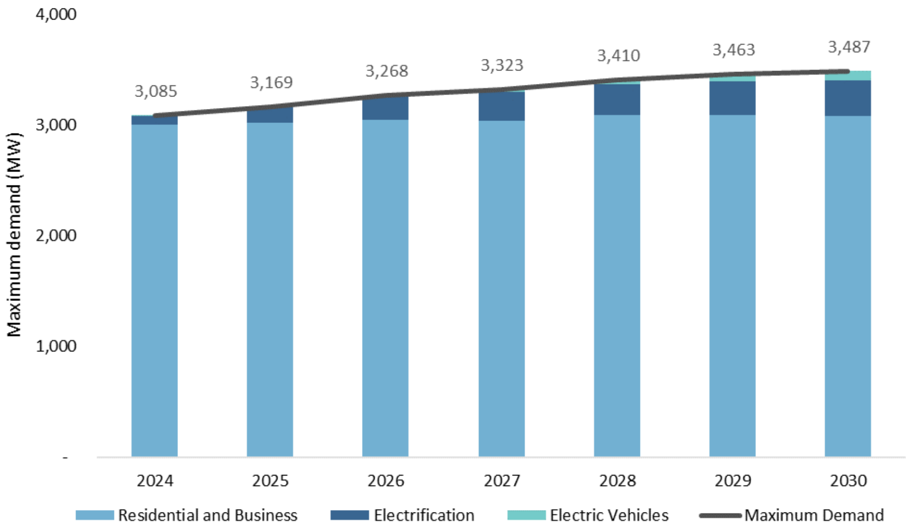
Export

SA Power Networks export energy forecast for the 2025-30 RCP is detailed in Section 11.

7.3 Maximum demand forecast

The maximum demand forecasts per ESOO 2022 are expected to steadily grow during the 2025-30 RCP, as outlined in Figure 26.

Figure 26: SA Power Networks maximum demand forecasts to 2030



Source: ESOO 2022 Forecast

The average annual maximum demand forecast growth rate between 2026 and 2030 is 1.94 percent. AEMO is forecasting maximum demand to grow across the NEM markets to support energy consumption growth. This is primarily driven by electrification and EV load, partially offset by solar and battery storage growth. Electrification is expected to increase the maximum demand as new electric appliances are added within the residential and business sectors replacing gas appliances.

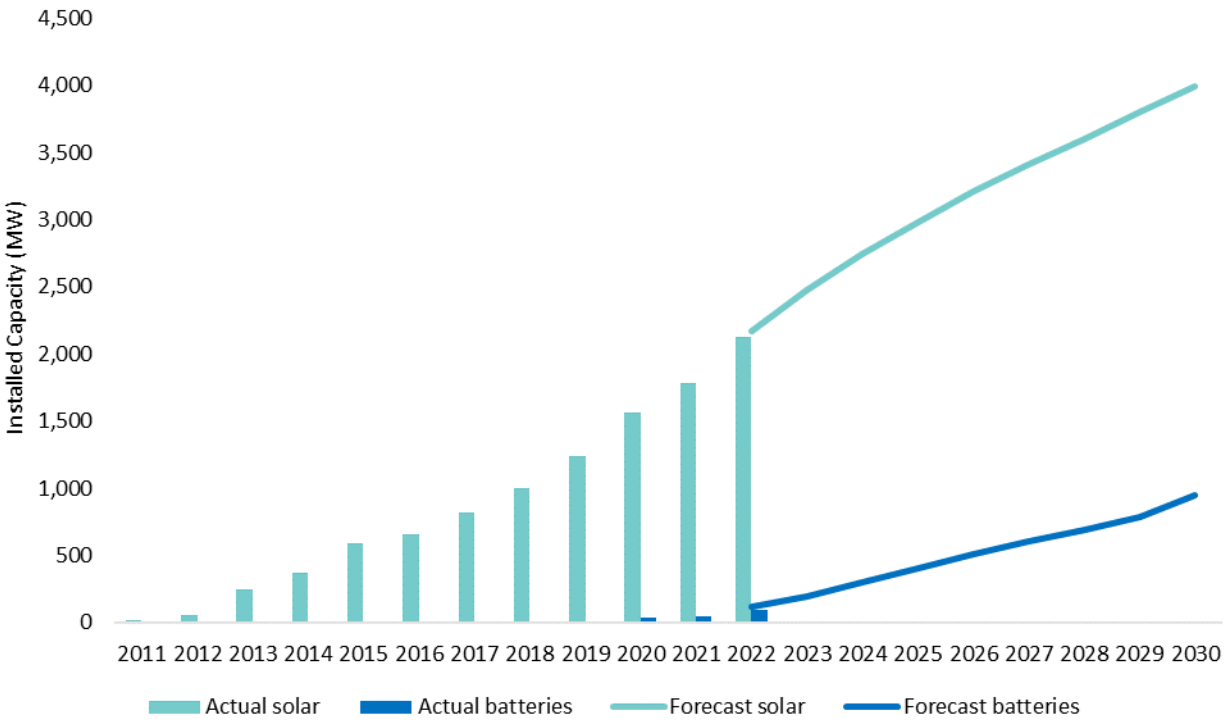
7.4 Customer Energy Resources

Solar and battery

SA Power Networks forecasts that solar installations and batteries will continue to grow in South Australia. Solar is expected to continue to grow in the 2025-30 RCP however the growth rate is expected to decline year on year as it reaches the saturation point of the technology adoption curve. The battery percentage growth rate is higher than the solar percentage growth rate as more and more customers are likely to adopt batteries in the coming years.

The cumulative capacity of solar and battery is outlined in Figure 27.

Figure 27: Solar and battery capacity forecast

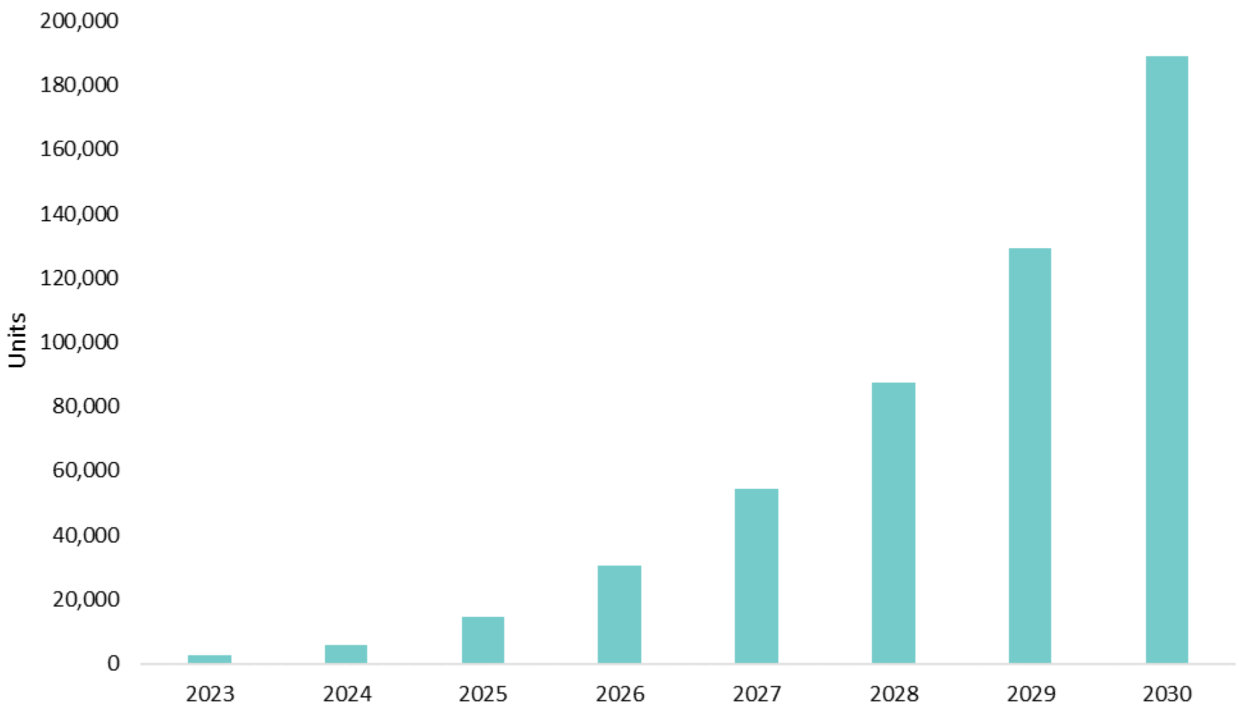


Source: ESOO 2022 Forecast

The key benefit of batteries is the ability to load shift, where customers with batteries are likely to charge their batteries during the day to maximise their solar generation or access the distribution network at the cheapest time of the day. This allows for discharge and consumption during other times of the day, most likely in the peak when prices are most expensive. The growth in battery installations is driven by the continued solar uptake, reduced cost of ownership, an increase in smart appliances, and SA Power Networks initiatives such as flexible exports and export tariffs.

Electric Vehicles

Figure 28: Electric Vehicle Forecast



Source: ESOO 2022 Forecast

EV numbers are expected to grow significantly in the 2025-30 RCP, with an average annual growth of 68 percent during the regulatory period. The growth is driven by the availability of more affordable models, public charging infrastructure growth, and further policy reforms proposed in the Commonwealth Government's Electric Vehicle Strategy.

8 Tariff design, development and assignment

8.1 Tariff classes

Tariff classes group retail customers together on an economically efficient basis with the aim to avoid unnecessary transaction costs. Tariff classes are defined by attributes such as supply voltage, annual consumption and customer type. SA Power Networks does not differentiate between customers with or without CER for consumption tariffs or on the type of meter installed. The type of meter determines which tariff the customer is assigned to within the tariff class.

Section 8 of this Explanatory Statement discusses consumption tariffs. All export tariff discussion is contained in Section 11.

In the 2025-30 RCP SA Power Networks proposes to retain the existing tariff classes with the addition of a new Small Business 0-40MWh p.a. and Medium Business 40-160MWh p.a. sub tariff class reflecting stakeholder recommendations. Table 2 outlines the 2025-30 RCP proposed tariff classes.

Table 2: 2025-30 RCP Proposed tariff classes

Tariff Class	Distribution Network Connection
Residential	• Connected to Low Voltage (**LV**) distribution network
Small Business • Small 0-40MWh p.a. • Medium 40-160MWh p.a.	• Connected to LV distribution network • Business customers using <160MWh p.a.
Large Business LV	• Connected to LV distribution network • Business customers using >160MWh p.a.
Large Business High Voltage (HV)	• Connected to 11kV HV distribution network
Major Business	• Business customers requiring a minimum of 5,000 kVA capacity • Connected to 11kV bus at Zone Substation or Sub Transmission system (33/66kV)

Each tariff class has a default and a customer choice tariff and these tariffs include some or all of the following charging structure elements:

- Daily fixed supply charge ($/day) recovers some of the distribution network connection costs.
- Peak demand charge to send a forward Long Run Marginal Cost (**LRMC**) signal for upstream assets ($/kVA/day).
- Anytime demand charge that recovers the costs of local connection/distribution network assets used by that customer ($/kVA/day).
- Volume charge to recover residual costs not recovered by demand charges ($/kWh).

8.2 Tariff design

In the development and refinement of SA Power Networks' proposed tariffs in the 2025-30 RCP we considered the application of the NER pricing principles to ensure our TSS is compliant with the NER. We want to ensure that all customers are, at a minimum, paying the incremental cost to join the distribution network. We also wish to avoid the potential for tariffs to exceed the stand alone cost of supply, thereby removing incentives for inefficient distribution network bypass. Our tariff design supports our tariff recovery across demand, usage, supply and export charges as covered in Section 12.

8.3 Tariff structures

In the 2025-30 RCP SA Power Networks is proposing tariff structures which build upon the significant structural changes implemented in the 2020-25 RCP. Whilst most of the existing tariffs are largely fit for purpose, we have considered how the existing tariff structures may be adapted to address the key challenges identified in the 2025-30 RCP.

8.3.1 Residential

Residential Time of Use

Our default Residential tariff for interval metered customers, Residential Time of Use, is proposed to continue in the 2025-30 RCP. It has Peak, Off Peak and Solar Sponge pricing signals to encourage customers to change their consumption behaviour, where they can efficiently do so. These price signals encourage shifting load into lower priced time windows where the distribution network has the highest available capacity and away from periods where the distribution network is more constrained. The time windows proposed for the 2025-30 RCP will increase the Solar Sponge and Off Peak windows by 1 hour each and therefore reduce the Peak window by 2 hours.

The proposed extension of the Solar Sponge window enables customers an additional hour to shift load during the day and encourages, for example, preheating and cooling of homes during the lowest priced time window. For simplicity we also propose to increase the Off Peak window to 6 hours. The additional hour in Off Peak allows for an EV owner to get a sufficient charge overnight for a daily commute without a dedicated wall charger. SA Power Networks considers these ToU pricing signals as key ways of managing increased forecast residential EV charging in the 2025-30 RCP as the Residential Time of Use tariff encourages EV charging outside of Peak windows.

The change in time windows impacts the relativities of Peak, Off Peak and Solar Sponge pricing comparative to the 'anytime' Residential Single Rate tariff. When determining these relativities it was important that, on average, a Residential Time of Use customer continue to have a similar outcome compared to being on the Residential Single Rate tariff.

All Residential interval meter tariffs are proposed to have a 6 hour lowest priced Solar Sponge window.

Residential Electrify

Residential Electrify is an energy based customer choice (opt-in) tariff designed for customers who predominantly or solely meet their energy needs with electricity, but have sufficient flexibility in their appliances, e.g. EVs, heat pumps, energy storage etc, to optimise their usage outside peak demand periods. These customers are expected to have an above average energy consumption, so the tariff is structured to provide more opportunities throughout the day to access lower cost electricity outside of distribution network peak periods.

This tariff began as a trial tariff in 2021/22 (Residential Time of Use Plus) with a peak usage signal contained to the summer months. This tariff evolved to Residential Electrify based on feedback from retailers indicating that seasonality in a tariff added complexity and that customers were more likely to respond to a year round pricing signal.

Residential Electrify is proposed to have stronger pricing signals than the Residential Time of Use default tariff and a simpler structure than the 2020-25 RCP Residential Prosumer customer choice tariff by having no demand component. Residential Electrify has been designed as the new prosumer tariff and is proposed to replace Residential Prosumer in the 2025-30 RCP. This proposed tariff is designed to be a customer choice tariff.

Residential Single Rate

SA Power Networks is not proposing any changes to the Residential Single Rate tariff structure in the 2025-30 RCP. It is expected that customer numbers on this tariff will decline as the proposed accelerated interval meter deployment recommended by the AEMC in 2025-30 takes place.

The Residential customer tariffs for 2025/26 are set out in Table 3.

Table 3: Residential tariffs 2025/26 NUoS forecast ($ nominal)

Residential Tariff	Tariff Structure	Meter	Supply Charge $ p.a.	Metering Charge $ p.a.	Anytime Usage c/kWh	Peak Usage c/kWh	Off Peak Usage c/kWh	Shoulder Usage c/kWh	Solar Sponge Usage c/kWh
Residential Single Rate	Supply Charge + Anytime Usage	Accumulation	$219.98	$13.47	$0.1538	$-	$-	$-	$-
Residential Time of Use	Supply Charge + ToU Usage	Interval	$219.98	$13.47	$-	$0.2008	$0.1004	$-	$0.0503
Residential Electrify	Supply Charge + ToU Usage	Interval	$219.98	$13.47	$-	$0.3389	$-	$0.1006	$0.0301

8.3.2 Controlled Load

Time of Use Controlled Load

Time of Use Controlled Load tariff structure is proposed to continue for interval-metered customers, mirroring the Residential Time of Use tariff structure and pricing relativities in the 2025-30 RCP. To ensure diversification of loads we will continue to stipulate that the commencement of controlled load must be randomised by one hour. The tariff structure accommodates this by including an additional 30 minute window at the beginning and end of both the Solar Sponge and Off Peak windows.

In South Australia, Retailers are responsible for the control of the interval metered Controlled Load and to date, we have seen great success with Retailers responding to our price signals. In December 2023, 29 percent of Controlled Load shifted to the Solar Sponge time window and it is expected that this shift will continue to increase. Encouraging additional load to shift into these low and increasingly negative demand periods of the day via pricing signals plays a role in alleviating congestion in the low voltage distribution network.

SA Power Networks places no restrictions on the type of load that can be connected to a controlled load circuit. Therefore, this tariff is fit for purpose if a customer with an EV wanted to manage their charging in this way. Whilst SA Power Networks does not consider the controlled load mechanism as the optimal way to manage residential EV charging, it is a tariff option available for customers at their request.

Time of Use Controlled Load is not offered in isolation and must be paired with Residential Time of Use or Residential Electrify.

Off Peak Controlled Load

SA Power Networks is not proposing any changes to the Off Peak Controlled Load tariff in the 2025-30 RCP. As an accumulation meter tariff, SA Power Networks owns the accumulation meter and therefore controls the time clock. There will be no changes to these manual time clocks in the 2025-30 RCP. The accelerated interval meter deployment recommended by the AEMC in 2025-30 will transition customers to ToU tariffs in accordance with our tariff assignment policy. ToU tariffs allow for dynamic management of controlled load by the Retailer, or by the customer if they elect to not to have a secondary controlled load circuit and have all load on one circuit.

The Controlled Load customer tariffs for 2025/26 NUoS are set out in Table 4.

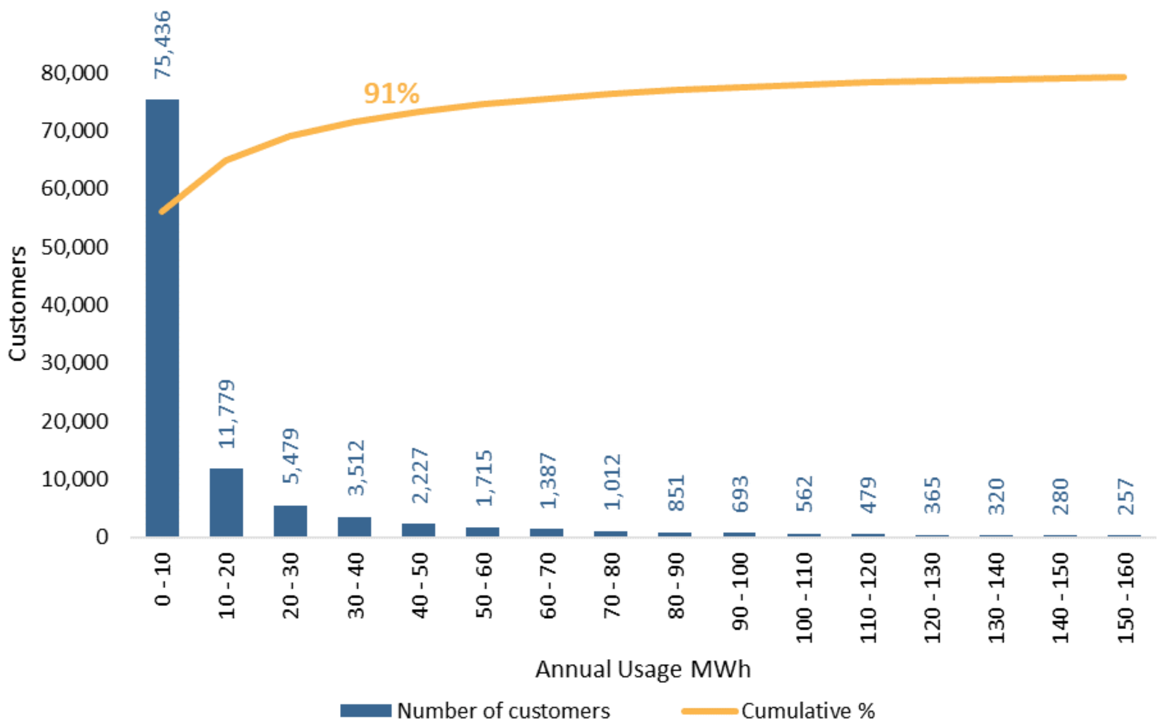
Table 4: **Controlled Load tariffs 2025/26 NUoS forecast ($ nominal)**

Controlled Load Tariff	Tariff Structure	Meter	Supply Charge $ p.a.	Anytime Usage c/kWh	Peak Usage c/kWh	Off Peak Usage c/kWh	Shoulder Usage c/kWh	Solar Sponge Usage c/kWh
Off Peak Controlled Load	Anytime Usage	Accumulation	$-	$0.0769	$-	$-	$-	$-
Controlled Load Time of Use	ToU Usage	Interval	$-	$-	$0.2008	$0.1004	$-	$0.0503

8.3.3 Small Business

Small Business customers are defined by SA Government legislation[8] as consuming less than 160MWh p.a. The vast majority, 91 percent, of Small Business customers have usage between 0-40MWh p.a. as shown in Figure 29. As a result of stakeholder feedback we are proposing to segment the Small Business tariff class into two tariff sub classes: Small 0-40MWh p.a. and Medium 40-160 MWh p.a. This enables the creation of a pricing differential to recognise the disparate consumption nature of Small Business customers. In creating these new tariff structures and pricing relativities, consideration has been given to those customers who are near the 40MWh p.a. threshold to ensure they are not materially disadvantaged when transitioning from a Small to a Medium customer.

Figure 29: Small Business customers consumption profile MWh p.a.



Source: SA Power Networks analysis

[8] National Energy Retail Law (Local Provision) Regulations 2013 Section 5(2).

Small Business Time of Use

Customers with usage between 0-40 MWh p.a. and demand less than 120kVA are proposed to have the same daily supply charge as Residential customers, recognising that their distribution network usage is similar. There are no proposed changes to the time windows or the pricing relativities from the 2020-25 RCP tariff structure. If a customer has demand greater than greater than 120kVA we propose to assign them to Medium Business Time of Use Demand.

Medium Business Time of Use Demand

Customers with usage between 40-160MWh p.a. are proposed to have a higher daily supply charge paired with a lower-priced usage charge reflecting the increased consumption volumes. The demand tariff structure is proposed to be the default tariff structure for Medium Business, however a customer will have the opportunity to opt out if their demand is less than 120kVA and switch to the Small Business Time of Use tariff. There are no proposed changes to the time windows from the 2020-25 RCP Small Business Time of Use Demand tariff structure. The pricing relativities have changed to reflect the creation of a pricing differential between Small and Medium Business.

Small Business Electrify

Small Business Electrify, is an energy based tariff designed to encourage consumption during the middle of the day when there is an abundance of solar energy being exported into the distribution network. This concept is an extension of our original Solar Sponge window in our Residential tariffs. This proposed tariff was created in response to stakeholder feedback and includes strong pricing signals in the Peak window to encourage customers to shift load outside this time. The demand thresholds of 120 kVA still apply, that is, this tariff is accessible to those customers with less than 120 kVA demands. This proposed tariff is designed to be a customer choice tariff.

Business Single Rate | Business Two Rate

SA Power Networks is not proposing any changes to the Business Single Rate and Business Two Rate tariffs in the 2025-30 RCP. It is expected that customer numbers will decline as the accelerated interval meter deployment recommended by the AEMC in 2025-30 takes place.

24 Hour Unmetered

SA Power Networks is not proposing any changes to 24 Hour Unmetered tariff in the 2025-30 RCP.

Table 5: Small Business tariffs 2025/26 NUoS forecast ($ nominal)

Small Business Tariff	Tariff Structure	Meter	Supply Charge $ p.a.	Metering Charge $ p.a.	Anytime Usage c/kWh	Peak Usage c/kWh	Off Peak Usage c/kWh	Shoulder Usage c/kWh	Anytime Demand $/kVA/Day
Business Single Rate	Supply Charge + Anytime Usage	Accumulation	$219.98	$13.47	$0.1559	$-	$-	$-	$-
Business Two Rate	Supply Charge + ToU Usage	Accumulation	$219.98	$13.47	$-	$0.1757	$0.0877	$-	$-

Small Business Tariff	Tariff Structure	Meter	Supply Charge $ p.a.	Metering Charge $ p.a.	Anytime Usage c/kWh	Peak Usage c/kWh	Off Peak Usage c/kWh	Shoulder Usage c/kWh	Anytime Demand $/kVA/Day
Small Business Time of Use	Supply Charge + ToU Usage	Interval	$219.98	$13.47	$-	$0.2339	$0.0878	$0.1628	$-
Small Business Electrify	Supply Charge + ToU Usage	Interval	$219.98	$13.47	$-	$0.2962	$0.0873	$0.1528	$-
Medium Business Time of Use Demand	Supply Charge + Annual Demand + ToU Usage	Interval	$505.16	$13.47	$-	$0.1896	$0.0713	$0.1320	$0.0746
Off Peak Controlled Load	Anytime Usage	Accumulation	$-	$-	$0.0769	$-	$-	$-	$-
Unmetered	Anytime Usage	Unmetered	$-	$-	$0.1023	$-	$-	$-	$-

8.3.4 Large Business

SA Power Networks is proposing to continue with the default tariff structures established for Large Business in the 2020-25 RCP with no changes to time windows or pricing relativities. Large Business incorporates business customers with greater than 160 MWh p.a. usage and who are connected at LV, HV, Zone Substation or Sub Transmission. These tariff structures are comprised of the following charging structure elements:

- Supply charge – Can vary based on supply point reflecting the specific local asset connection costs
- Peak Demand – Highest average daily demand during November to March:
  - For CBD customers 11:00am – 5:00pm |6 hour window
  - For Rest of SA customers 5:00pm – 9:00pm | 4 hour window
- Anytime Demand – Highest 30 minute demand interval during the last 12 months
- Energy – Time of Use LV | HV:
  - Peak 7:00am – 9:00pm Workdays and 5:00pm – 9:00pm Non workdays
  - Off Peak all other times
- Energy – Anytime Use Major Business

Peak demand pricing windows differ between the CBD and the Rest of SA to recognise the locational differences of Peak Demand load profile.

Large Business | Flexible

SA Power Networks is proposing flexible tariff structures for Large Business customers at all voltage steps: LV, HV, Zone Substation and Sub Transmission. Flexible tariffs are designed to reward efficient use of the distribution network. This flexibility aims to avoid or defer distribution network augmentation. If a Large Business can be flexible in when they use the distribution network, then we propose to reward them with a discounted Anytime Demand tariff for the flexible component of their usage. The flexible Anytime Demand amount must be at least 500kVA and not less than 20 percent of total Anytime Demand.

The tariff structure also redefines the Peak time window which is a component of all Large Business tariff structures. For customers on a flexible tariff, Peak Demand would only apply during November to March between 11:00am – 5:00pm (CBD) or 5:00pm – 9:00pm (Rest of SA), on days when the temperature is 38 degrees or above as measured at West Terrace Adelaide or as otherwise agreed with regional customers. Outside of this time, the Anytime Demand tariff price would apply.

These tariffs began as trial tariffs in 2022/23 and have evolved to now be proposed in the TSS.

Table 6: Large LV Business tariffs 2025/26 NUoS forecast ($ nominal)

Large LV Business Tariff	Tariff Structure	Meter	Supply Charge $ p.a.	Peak Usage c/kWh	Off Peak Usage c/kWh	Peak Demand $/kVA/Day	Anytime Demand $/kVA/Day	Anytime Demand Flexible $/kVA/Day
Large LV Business Annual Demand	Supply Charge + Annual Demand + ToU Usage	Interval	$3,000.01	$0.0716	$0.0448	$0.3009	$0.0630	$-
Large LV Business Annual Demand Flexible	Supply Charge + Annual Demand + ToU Usage	Interval	$3,000.01	$0.0716	$0.0448	$0.3009	$0.0630	$0.0315
Large LV Business Monthly Demand	Supply Charge + Monthly Demand + ToU Usage	Interval	$3,000.01	$0.0716	$0.0448	$0.4596	$0.0630	$-

Table 7: Large HV Business tariffs 2025/26 NUoS forecast ($ nominal)

HV Business Tariff	Tariff Structure	Meter	Supply Charge $ p.a.	Peak Usage c/kWh	Off Peak Usage c/kWh	Peak Demand $/kVA/Day	Anytime Demand $/kVA/Day	Anytime Demand Flexible $/kVA/Day
HV Business Annual Demand	Supply Charge + Annual Demand + ToU Usage	Interval	$15,999.99	$0.0556	$0.0348	$0.2324	$0.0849	$-
HV Business Annual Demand Flexible	Supply Charge + Annual Demand + ToU Usage	Interval	$15,999.99	$0.0556	$0.0348	$0.2324	$0.0849	$0.0425
HV Business Annual Demand <500kVA	Supply Charge + Annual Demand + ToU Usage	Interval	$3,000.01	$0.0716	$0.0448	$0.3009	$0.0630	$-
HV Business Monthly Demand	Supply Charge + Monthly Demand + ToU Usage	Interval	$15,999.99	$0.0556	$0.0348	$0.3486	$0.0849	$-

Table 8: **Major Business tariffs 2025/26 NUoS forecast ($ nominal)**

Major Business Tariff	Tariff Structure	Meter	Supply Charge $ p.a.	Anytime Usage c/kWh	Peak Demand $/kVA/Day	Anytime Demand $/kVA/Day	Anytime Demand Flexible $/kVA/Day
Zone Substation	Supply Charge + Annual Demand + Anytime Usage	Interval	Individually calculated	$0.0235	$0.1639	$0.0658	$-
Zone Substation Flexible	Supply Charge + Annual Demand + Anytime Usage	Interval	Individually calculated	$0.0235	$0.1639	$0.0658	$0.0329
Sub Transmission	Supply Charge + Annual Demand + Anytime Usage	Interval	Individually calculated	$0.0205	$0.1365	$0.0274	$-
Sub Transmission Flexible	Supply Charge + Annual Demand + Anytime Usage		Individually calculated	$0.0205	$0.1365	$0.0274	$0.0137

8.3.5 Generation

Large Business

SA Power Networks is proposing to continue with the 2020-25 RCP tariff structures in place for customers who are generating energy. A customer assigned to a generation tariff can include a solar farm or battery and this tariff focuses on the demand requirements of that operation. It is important to note that generation tariffs are not export tariffs.

SA Power Networks has had an increasing number of customer inquiries seeking to connect at the Zone Substation and Sub Transmission levels and so we are proposing new generation tariffs for customers connecting at these higher voltage steps to reflect the needs of these customers.

The tariff structure will mirror the consumption tariff structure of Zone Substation and Sub Transmission with the exception of usage. All generation tariffs have no energy usage component.

Large Business | Flexible

We are also proposing flexible tariff structures for Large Business generation customers at all voltage steps: LV, HV, Zone Substation and Sub Transmission. These flexible tariff structures mirror the Large Business consumption flexible tariff structures. If a Large Business generator can be flexible in when they use the distribution network, then we propose to reward them with a discounted Anytime Demand tariff for the flexible component of their usage. The flexible Anytime Demand amount must be at least 500kVA and not less than 20 percent of total Anytime Demand.

The tariff structure also redefines the Peak time window which is a component of all Large Business tariff structures. For customers on a flexible tariff, Peak Demand would only apply during November to March between 11:00am – 5:00pm (CBD) or 5:00pm – 9:00pm (Rest of SA), on days when the temperature is 38 degrees or above as measured at West Terrace Adelaide or as otherwise agreed with regional customers. Outside of this time, the Anytime Demand tariff price would apply.

These tariffs began as trial tariffs in 2022/23 and have evolved to now be proposed in the TSS.

Table 9: Large & Major Business Generation tariffs 2025/26 NUoS forecast ($ nominal)

Large & Major Business Tariff	Tariff Structure	Meter	Supply Charge $ p.a.	Peak Usage c/kWh	Off Peak Usage c/kWh	Peak Demand $/kVA/Day	Anytime Demand $/kVA/Day	Anytime Demand Flexible $/kVA/Day
Large LV Business Generation	Supply Charge + Annual Demand	Interval	$3000.01	$-	$-	$0.3009	$0.0630	$-
Large LV Business Generation Flexible	Supply Charge + Annual Demand	Interval	$3000.01	$-	$-	$0.3009	$0.0630	$0.0315
HV Business Generation	Annual Demand	Interval	$-	$-	$-	$0.2324	$0.0849	$-

Large & Major Business Tariff	Tariff Structure	Meter	Supply Charge $ p.a.	Peak Usage c/kWh	Off Peak Usage c/kWh	Peak Demand $/kVA/Day	Anytime Demand $/kVA/Day	Anytime Demand Flexible $/kVA/Day
HV Business Generation Flexible	Annual Demand	Interval	$-	$-	$-	$0.2324	$0.0849	$0.0425
Zone Substation Generation	Annual Demand	Interval	$-	$-	$-	$0.1638	$0.0658	$-
Zone Substation Generation Flexible	Annual Demand	Interval	$-	$-	$-	$0.1638	$0.0658	$0.0329
Sub Transmission Generation	Annual Demand	Interval	$-	$-	$-	$0.1365	$0.0274	$-
Sub Transmission Generation Flexible	Annual Demand	Interval	$-	$-	$-	$0.1365	$0.0274	$0.0137

8.4 Tariff assignment

In the 2025-30 RCP SA Power Networks is continuing its cost reflective tariff assignment policy established in the 2020-25 RCP. If a customer has an interval meter they will be assigned to a ToU tariff with no opportunity to opt out. With the accelerated interval meter deployment recommended by the AEMC in 2025-30 it is expected that most customers will be assigned to a cost reflective ToU tariff by the end of the 2025-30 RCP.

Outlined below in Figure 30 to Figure 35 are the tariff assignment policies for the five tariff classes. For simplicity, SA Power Networks has grouped together all generation tariffs and their assignment criteria, across different tariff classes in Figure 36.

As a result of the introduction of the sub tariff class in Small Business, customers will be reassigned based on their annual consumption and demand profile. The demand threshold of 120kVA will continue and a customer who may be assigned to Small Business Time of Use because of their annual consumption will be reassigned to Medium Business Time of Use Demand if their demand is greater than 120kVA. Small and Medium Business customers with demand greater than 120kVA do not have the option to opt out of demand charges. This is a continuation of the tariff assignment policy in the 2020-25 RCP.

Further detail on export tariffs is contained in Section 11.

Figure 30: Residential tariffs and assignment criteria

Residential | 0-30kW Export Capacity

	ACCUMULATION METER	INTERVAL METER
Default	Single Rate | **RSR**	Time of Use | **RTOU**
Customer Choice		Time of Use Electrify | **RESELE**
	Off Peak Controlled Load | **OPCL**	Time of Use Controlled Load | **CL**

Residential | >30kW Export Capacity

	ACCUMULATION METER	INTERVAL METER
Default	Single Rate | **RSRNE**	Time of Use | **RTOUNE**
Customer Choice		Time of Use Electrify | **RESELENE**
	Off Peak Controlled Load | **OPCL**	Time of Use Controlled Load | **CL**

Figure 31: Small Business tariffs and assignment criteria

Small Business 0-40MWh p.a. | 0-30kW Export Capacity

	ACCUMULATION	INTERVAL
Default	Single Rate | **BSR**	Time of Use <120kVA | **SBTOU**
	Two Rate | **B2R**	Time of Use Demand if >120kVA | **MBTOUD**
Customer Choice		Time of Use Demand if <120kVA | **MBTOUD**
		Time of Use Electrify if <120kVA | **SBELE**

Small Business 0-40MWh p.a. | >30kW Export Capacity

<table>
<tr><th></th><th>ACCUMULATION</th><th>INTERVAL</th></tr>
<tr><td rowspan="2">Default</td><td>Single Rate Non Export | BSRNE</td><td>Time of Use <120kVA | SBTOUNE</td></tr>
<tr><td>Two Rate Non Export | B2RNE</td><td>Time of Use Demand if >120kVA | MBTOUDNE</td></tr>
<tr><td rowspan="2">Customer Choice</td><td rowspan="2"></td><td>Time of Use Demand if <120kVA | MBTOUDNE</td></tr>
<tr><td>Time of Use Electrify if <120kVA | SBELENE</td></tr>
</table>

Figure 32: Medium Business tariffs and assignment criteria

Medium Business 40-160MWh p.a. | 0-30kW Export Capacity

<table>
<tr><th></th><th>ACCUMULATION</th><th>INTERVAL</th></tr>
<tr><td rowspan="2">Default</td><td>Single Rate | BSR</td><td rowspan="2">Time of Use Demand | MBTOUD</td></tr>
<tr><td>Two Rate | B2R</td></tr>
<tr><td rowspan="2">Customer Choice</td><td rowspan="2"></td><td>Time of Use if <120kVA | SBTOU</td></tr>
<tr><td>Time of Use Electrify if <120kVA | SBELE</td></tr>
</table>

Medium Business 40-160MWh p.a. | >30kW Export Capacity

<table>
<tr><th></th><th>ACCUMULATION</th><th>INTERVAL</th></tr>
<tr><td rowspan="2">Default</td><td>Single Rate | BSRNE</td><td rowspan="2">Time of Use Demand | MBTOUDNE</td></tr>
<tr><td>Two Rate | B2RNE</td></tr>
<tr><td rowspan="2">Customer Choice</td><td rowspan="2"></td><td>Time of Use if <120kVA | SBTOUNE</td></tr>
<tr><td>Time of Use Electrify if <120kVA | SBELENE</td></tr>
</table>

Figure 33: Large Low Voltage Business tariffs and assignment criteria

Large Low Voltage Business > 160 MWh p.a.

	INTERVAL METER
Default	Time of Use Annual Demand | **LBAD**
Customer Choice	Time of Use Monthly Demand | **LBMD**
	Time of Use Agreed Demand Flexible | **LBADF**

Figure 34: High Voltage Business tariffs and assignment criteria

High Voltage Business > 160 MWh p.a.

	INTERVAL METER
Default	Time of Use Annual Demand | **HVAD**
Customer Choice	Time of Use Monthly Demand | **HVMD**
	Time of Use Annual Demand <500KVA | **HVAD500**
	Time of Use Agreed Demand Flexible | **HVADF**

Figure 35: Major Business tariffs and assignment criteria

Major Business Zone Substation + Sub Transmission

	INTERVAL METER
Default	Single Rate Agreed Demand | **ZSS** | **STR**
Customer Choice	Single Rate Agreed Demand Flexible | **ZSSF** | **STRF**

Figure 36: Large Business Generation tariffs and assignment criteria

Generation

	INTERVAL METER
Default	Single Rate Agreed Demand | **LBG** | **HVBG** | **ZSSG** | **STRG**
Customer Choice	Single Rate Agreed Demand Flexible | **LBGF** | **HVBGF** | **ZSSGF** | **STRGF**

8.5 Closed tariffs

In the 2025-30 RCP we are proposing to close several tariffs which will simplify and streamline SA Power Networks' TSS.

Residential Prosumer

This tariff was introduced in the 2020-25 RCP as a customer choice tariff option. We have seen limited take up of this tariff, in large part due to the demand charging component. Stakeholder feedback indicates that demand is a difficult concept for customers to understand and so whilst demand pricing provides a cost reflective pricing signal, the adoption has been limited. This has led to the creation of our Residential Electrify tariff which, as a trial tariff, has had greater customer response than our Residential Prosumer tariff approved in the 2020-25 TSS.

Small Business Time of Use Demand

This tariff has been relabeled Medium Business Time of Use Demand due to the introduction of the tariff sub classes within Small Business: 0-40 MWh p.a. and 40-160MWh p.a. Therefore this tariff will be closed in the 2025-30 RCP.

Small Business Actual Monthly Demand | Large LV Business Actual Monthly Demand | HV Business Actual Monthly Demand

In our 2020-25 TSS these tariffs became transition tariffs, with no new customers being able to access them. Customers on these tariffs had a five year window to transition to more cost reflective tariffs within their tariff class. To incentivise transition, there was an annual fixed supply charge increase of $1,000 and an annual increase of 1c/kWh for usage. Despite what we considered to be strong pricing signals, customers did not transition from these tariffs, despite other available tariffs offering lower bill impacts.

In 2021/22 SA Power Networks contacted all customers on the transitional tariffs via a mail out to encourage them to transition to other available tariffs. Each customer letter included individual customer impact analysis to outline how much they could save in distribution charges by transitioning to an alternative tariff in their tariff class. Analysis was based on their most recent 12 months of billing data. We also engaged directly with retailers to encourage them to reassign their customers. This proactive engagement has had an impact, however it is clear from our experience that price signals alone do not encourage tariff transition, even when the customer will positively benefit.

Large Low Voltage Business Single Rate | Large Low Voltage Business Two Rate

Large Low Voltage Business customers with legacy metering arrangements were assigned to this tariff in the 2020-25 RCP. All customers on these tariffs have now upgraded their metering arrangements and have been assigned a ToU tariff or their usage has fallen below the tariff class threshold of 160MWh p.a.

Overnight Unmetered

This is a legacy tariff which has the same pricing structure and prices as 24 Hour Unmetered. There is no need to have two identical tariff structures and prices.

8.6 Reassignment of existing customers

We will reassign customers on closed tariffs to the default tariff within their tariff class, as summarised in Table 10.

Table 10: Tariff reassignment 2025-30 RCP

Tariff Assignment 2020-25 RCP	Tariff Assignment 2025-30 RCP
Residential Prosumer	Residential Time of Use
Electrify/Electrify Two-way	Residential Electrify
Small Business Time of Use Demand	Depending on customer usage profile: Small Business Time of Use • 0-40MWh p.a. and Demand <120kVA Medium Business Time of Use Demand • 0-40MWh p.a. and Demand >120kVA • 40-160MWh p.a.
Small Business Actual Monthly Demand	Depending on customer usage profile: Small Business Time of Use • 0-40MWh p.a. and Demand <120kVA Medium Business Time of Use Demand • 0-40MWh p.a. and Demand >120kVA • 40-160MWh p.a.
Large Low Voltage Business Actual Monthly Demand	Large Low Voltage Business Annual Demand
High Voltage Business Actual Monthly Demand	High Voltage Business Annual Demand
Large Low Voltage Business Single Rate	No existing customers at 30 June 2025 to reassign.
Large Low Voltage Business Two Rate	No existing customers at 30 June 2025 to reassign.
Overnight Unmetered	24 Hour Unmetered

9 Customer impact analysis

Based on our proposed tariff structures we have completed analysis to illustrate the network bill impacts using 2025/26 indicative network prices (NUoS and legacy metering services unless otherwise stated). The analysis is based on 2022/23 consumption data and excludes the impact of proposed export tariffs. Export tariff bill impacts are addressed in Section 11. The key findings from our sample analysis are provided in Table 11 for Residential and Table 12 for Small and Medium Business customers. The key findings in this section are explained using tariff codes as detailed in Section 8.4.

Table 11: Residential key findings

Number	Key findings
1	The proposed new RTOU structure and relativities for 2025-30 RCP deliver similar outcomes on average to the 2020-25 RTOU structure and relativities.
2	Analysis supports RTOU as the default tariff for interval meter customers.
3	RTOU vs RSR for solar customers is marginally higher than for non-solar customers.
4	Analysis supports RESELE as a customer choice tariff to incentivise behaviour change.
5	Retailers benefit by reducing controlled load usage in the peak time window.
6	The default tariff, RTOU, does not disadvantage those customers experiencing vulnerability.

Table 12: Small and Medium Business key findings

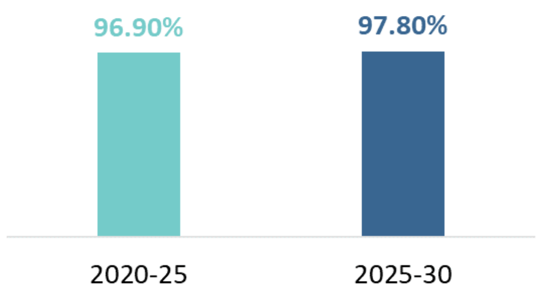
Number	Key findings
1	New SBTOU pricing differential benefits Small Business 0-40MWh p.a. customers.
2	Analysis supports SBTOU as the default interval meter tariff for Small Business 0-40MWh p.a. customers.
3	Analysis supports MBTOUD as the default interval meter tariff for Medium Business 40-160MWh p.a. customers.
4	120 kVA threshold for Small and Medium business continues to be appropriate.
5	Businesses who can avoid the Peak window or have the flexibility to shift load benefit by being on the customer choice tariff, SBELE.

9.1 Residential

Key Finding 1: The proposed new RTOU structure and relativities for 2025-30 RCP deliver similar outcomes on average to the 2020-25 RTOU structure and relativities.

The time windows and pricing relativities are proposed to change for the RTOU tariff in the 2025-30 RCP in response to stakeholder feedback. It is imperative that the proposed structure and relativities for RTOU deliver similar outcomes on average for customers compared to being on the flat tariff, RSR. The RTOU relativities to RSR for the current RCP (2020-25) and the new RCP (2025-30) are shown in Figure 37.

Figure 37: RTOU vs RSR relativity



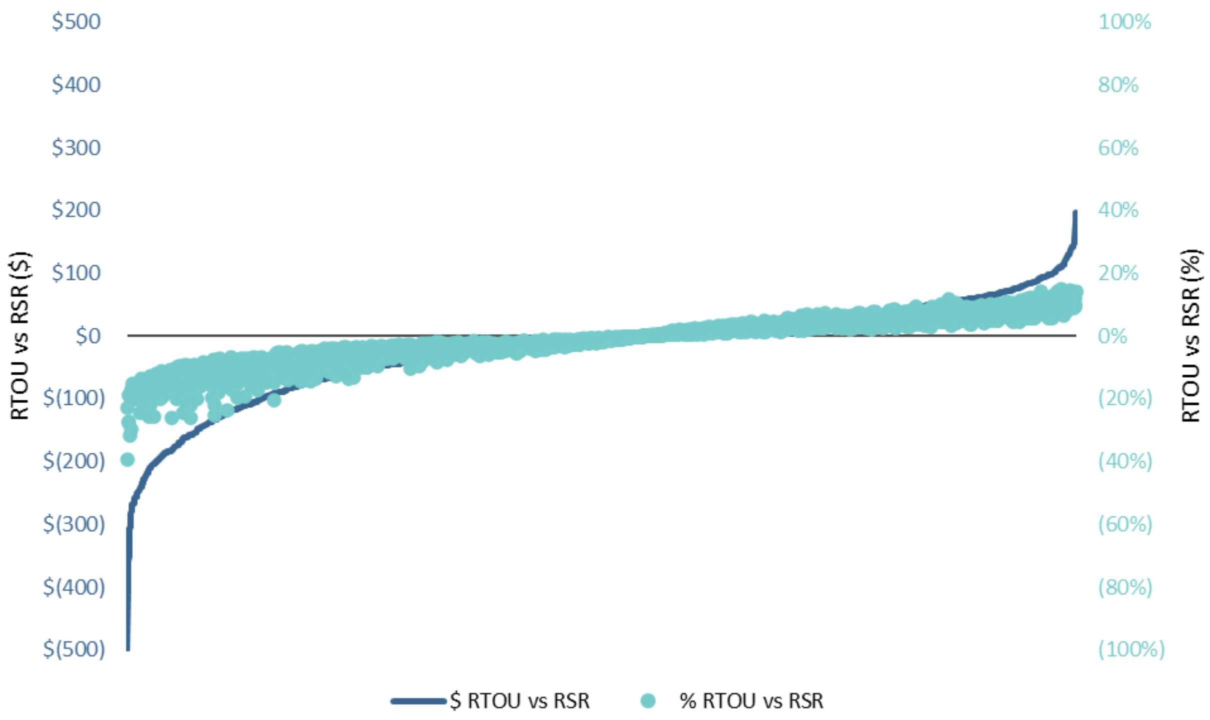
Source: SA Power Networks analysis (Sample: 2,000 Residential NMIs) excluding legacy metering services

A value of 100 percent means that the customer bill outcome will be the same regardless of the tariff. As per Figure 37, the RTOU relativity to RSR, 97.8 percent for the 2025-30 RCP compared to 96.9 percent for the 2020-25 RCP, indicates that customers will have similar bill outcomes under the proposed RTOU tariff structure, assuming the same usage profile.

Key Finding 2: Analysis supports RTOU as the default tariff for interval meter customers.

In a continuation of the 2020-25 RCP, we propose the RTOU tariff as the default tariff for interval meter Residential customers in the 2025-30 RCP. The comparison between RTOU and RSR bill outcomes for a sample of customers including those with solar is shown in Figure 38.

Figure 38: Annual customer bill impact RTOU vs RSR ($ nominal)



Source: SA Power Networks analysis (Sample: 2,000 Residential NMIs)

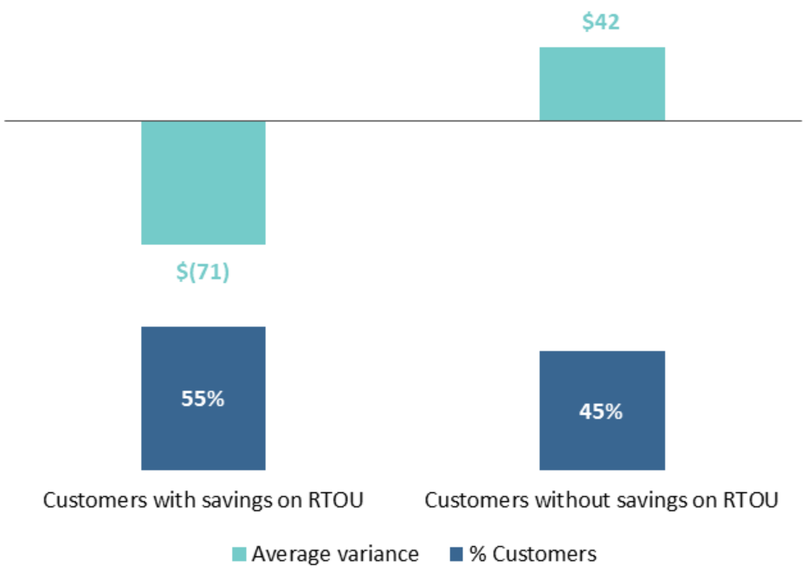
Figure 38 maps two parameters for each customer:

- The blue line represents the bill impact $ outcomes for each customer, sorted in ascending order of annual bill impact; and
- A corresponding green dot for each customer represents the percentage change in the customer's bill.

The analysis shows 55 percent of customers will be better off on RTOU with no behavioural change, compared to RSR. The average reduction for the sample is $20 p.a.

Analysis of those who will be better off against those who will pay more as separate cohorts, as shown in Figure 39, highlights that those customers who can make savings on RTOU are saving a larger amount on average compared to those who are paying more.

Figure 39: Average RTOU customer bill impact ($ nominal)



Source: SA Power Networks analysis (Sample: 2,000 Residential NMIs)

The results support the RTOU tariff design as the default tariff, which rewards customers with the ability to shift load while not significantly penalising those unable to. The favourable risk-reward profile is a fundamental design principle for a default ToU tariff to ensure the tariff continues to support pricing reforms while considering the impact on customers with various degrees of flexibility to shift load. This is consistent with the "carrot" rather than "stick" approach, which underpins the ToU default tariff design in 2020-25 RCP and will be continued in the 2025-30 RCP.

Key Finding 3: RTOU vs RSR for solar customers is marginally higher than for non-solar customers

The results of RTOU to RSR relativity for solar and non-solar customers are shown in Table 13.

Solar customers have a lower average annual usage compared to non-solar customers and therefore, a lower average annual network bill. However, when comparing this outcome based on tariff structure, RTOU has a marginally more unfavourable outcome. As solar customers may self-consume their own generation during the Solar Sponge, most of a solar customer's energy is drawn from the grid during the peak period (4:00pm – 12:00am) which is the highest priced time window of the RTOU tariff. This drives a higher average bill compared to RSR. With consideration to the relativity being less than 2 percent unfavourable on average, SA Power Networks considers its default tariff structure is appropriate for all Residential customers.

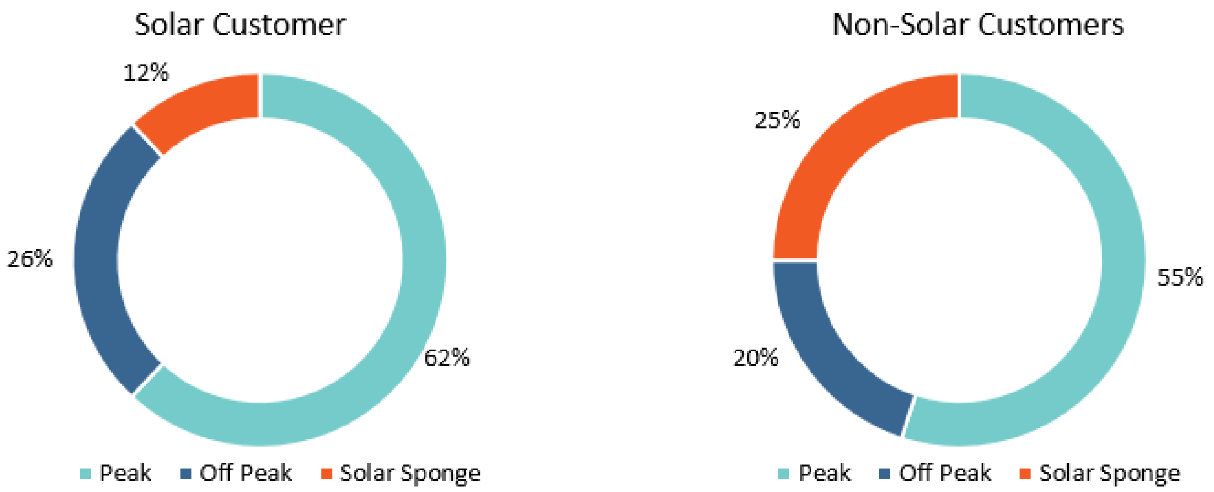
Table 13: Average Residential network bill ($ nominal)

	Average annual usage kWh	Annual RTOU $	Annual RSR $	Variance to RSR	% Relativity to RSR
Solar	4,095	$ 875	$ 863	$ 11	101.3%
Non-Solar	4,592	$ 889	$ 940	$ (50)	94.5%

Source: SA Power Networks analysis (Sample: 2,000 Residential NMIs)
Note: Totals may not add due to rounding

The average daily usage profiles of solar and non-solar customers by time windows are provided in Figure 40.

Figure 40: Usage profiles of solar and non-solar customers



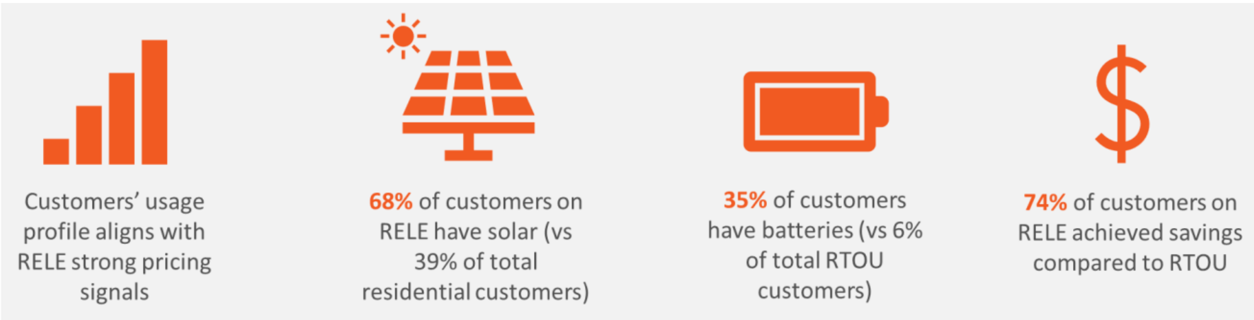
Source: SA Power Networks analysis (Sample: 2,000 Residential NMIs)

Key Finding 4: Analysis supports RESELE as a customer choice tariff to incentivise behaviour change.

RESELE tariff is a customer choice tariff catered to customers with above average energy consumption who predominantly meet their energy needs through electricity and have flexibility in their energy usage. RESELE tariff provides stronger pricing signals than RTOU tariff to promote change in customer behaviour and shift electricity consumption outside peak distribution network times to access cheaper pricing. It is proposed to be the new prosumer tariff.

RESELE is an evolution from the Electrify (**RELE**) trial tariff which has been in place in different structures since 2021/22. The insights from the RELE trial tariff are provided in Figure 41.

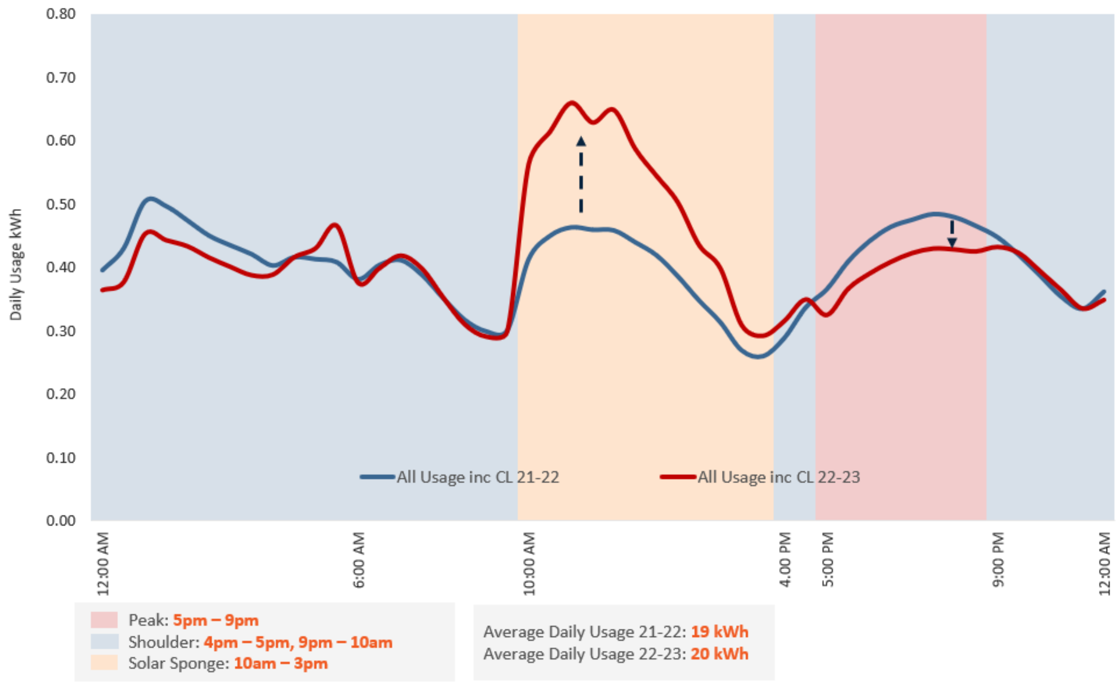
Figure 41: Insights from RELE trial tariff



Source: SA Power Networks analysis (Sample: 141 RELE NMIs)

The average daily usage profiles of RELE trial tariff customers for 2022/23 and 2021/22 are provided in Figure 42.

Figure 42: Average daily load profiles for RELE customers for 2021/22 and 2022/23

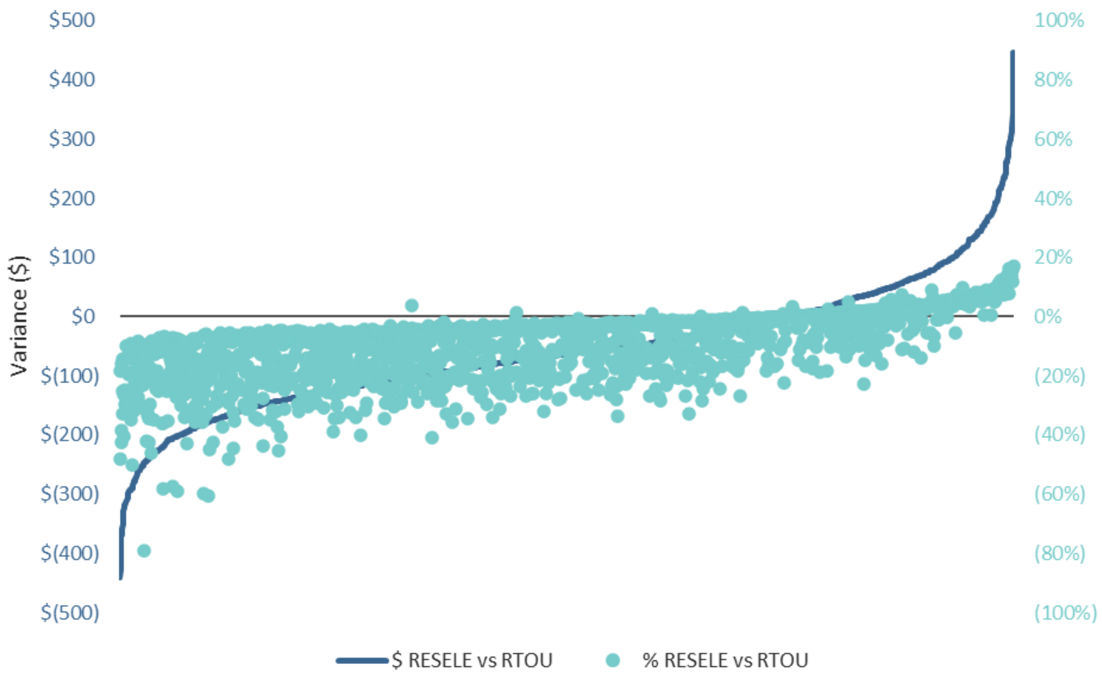


Source: SA Power Networks analysis (Sample: 97 RELE NMIs)

Figure 42 shows a change in the average daily usage profile from 2021/22 to 2022/23, with customers shifting a portion of their usage from the Peak time window (5:00pm to 9:00pm) to the Solar Sponge time window (10:00am to 4:00pm). The results support the objective of having stronger pricing signals in the RESELE tariff compared to RTOU which are likely to promote behavioural change. Furthermore, having pricing signals in kWh instead of kVA increases the ability of the customer to understand and respond to the tariff.

Figure 43 illustrates the network bill impact for customers on RESELE compared to RTOU.

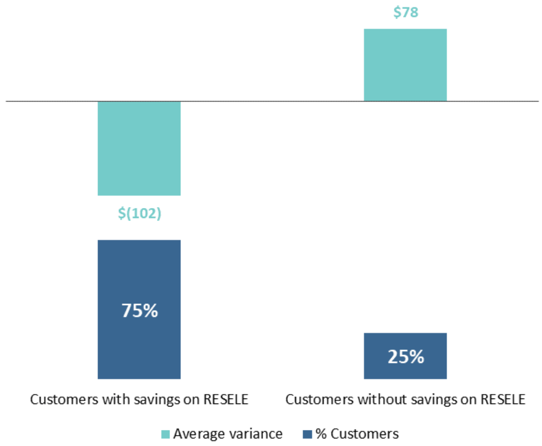
Figure 43: Customer bill impact RESELE vs RTOU ($ nominal)



Source: SA Power Networks analysis (Sample: 2,000 Residential NMIs)

Most customers, 75 percent, achieve average savings of $102 by being on the RESELE tariff compared to the RTOU tariff without any behaviour change. The RESELE tariff is a customer choice tariff and so customers who pay more on the RESELE tariff (25 percent) than the RTOU tariff should not choose this tariff. Additional analysis was conducted to understand the pricing impact of shifting 10 percent[9] of load outside the peak window. A network bill could further reduce by 4 percent with this behavioural change.

Figure 44: Average RESELE customer bill impact ($ nominal)



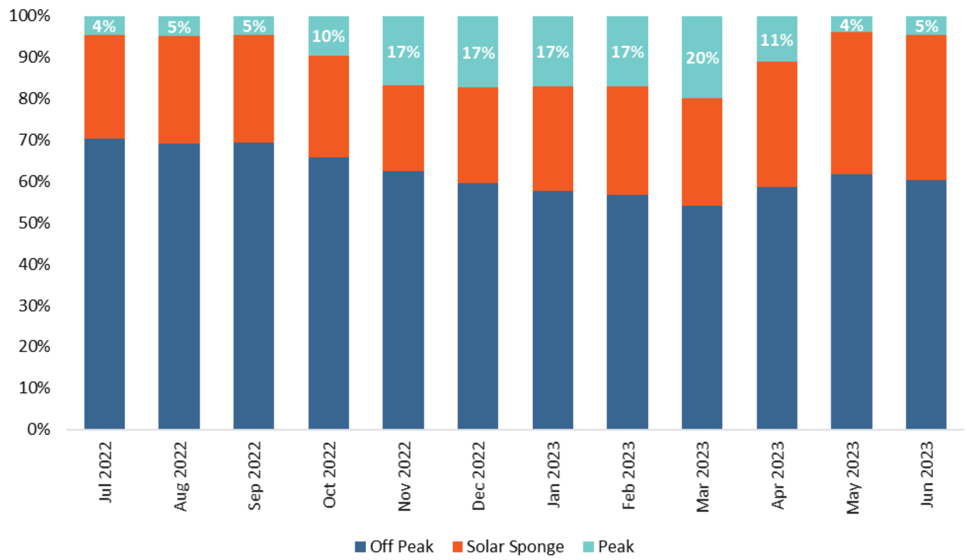
Source: SA Power Networks analysis (Sample: 2,000 Residential NMIs)

The results from the trial tariff and the bill impact sample analysis demonstrate that RESELE's strong pricing signals and simple structure provide opportunities to customers throughout the day to access lower-cost electricity outside of the network peak periods and promote load shifting from peak periods.

Key Finding 5: Retailers benefit by reducing controlled load usage in the peak time window.

In South Australia, Retailers are responsible for the control of the interval-metered Controlled Load which enables them to respond to our pricing signals. Figure 45 shows the monthly usage data by tariff time windows in 2022/23 for the Controlled Load ToU tariff which is in ACST all year round.

Figure 45: Monthly control load usage 2022/23



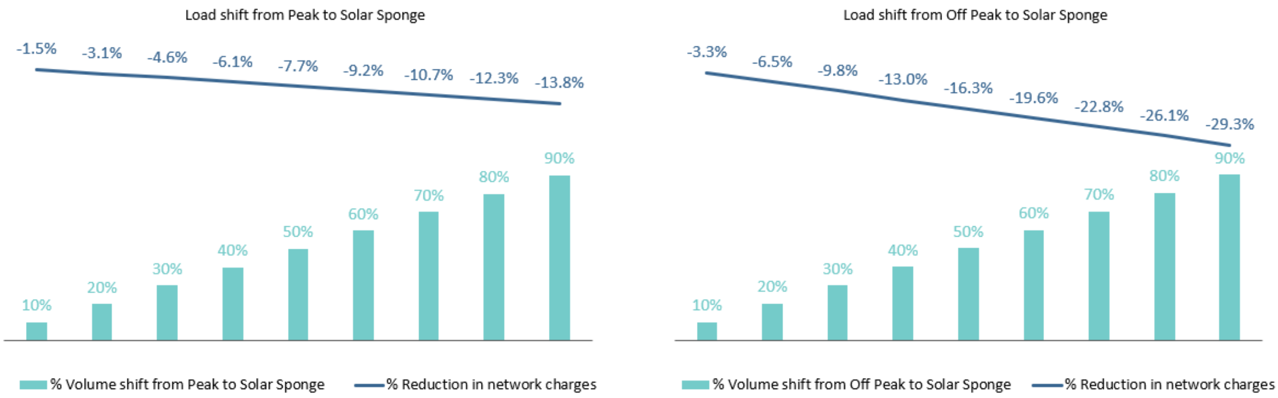
Source: SA Power Networks analysis

[9] The 10 percent load shift is estimated based on SA Power Networks' review of household appliances. For our load shift scenarios, it is assumed that 10 percent of annual energy consumption will shift from Peak to non-peak periods: 5 percent to Shoulder and 5 percent to Solar Sponge time windows.

The analysis shows that there is increased Peak usage in daylight savings months, indicating that Retailers are changing their meter times to ACDT for the controlled load circuit despite the tariff being ACST. As outlined in Section 4 we proposed to change the tariff to local time (ACST/ACDT) to address the issue however this was not supported.

Figure 46 illustrates the NUoS savings which could be made by Retailers if they shifted controlled load usage and responded to the ToU pricing signals. Reducing peak volumes by 50 percent would result in a 7.7 percent reduction in network charges, whilst shifting 50 percent of Off Peak to Solar Sponge would result in reduction of 16.3 percent of network charges. SA Power Networks encourages Retailers to optimise the tariff to reduce network charges and will continue to engage with them to promote our ToU pricing signals.

Figure 46: Reductions in NUoS 2025/26 from load shifting



Source: SA Power Networks analysis

Key Finding 6: The default tariff, RTOU, does not disadvantage those customers experiencing vulnerability.

In designing RTOU as the default tariff for interval meter customers, it is important that the tariff does not materially disadvantage customers compared to the single rate if they cannot change their consumption behaviour. To understand the impact of RTOU on those customers experiencing vulnerability, SA Power Networks analysed their usage profile and network bill impact. A list of the most disadvantaged suburbs and towns in South Australia was identified via the "Dropping of the Edge"[10] report. A sample of Residential customers from the identified disadvantaged suburbs and towns was used to form the vulnerable customer sample.

To also understand the characteristics of the wider population we compared all Residential customers in South Australia to all Residential customers in the most disadvantaged suburbs and towns of the state. This enabled key metrics to be compared: interval meter, solar and battery penetration as outlined in Table 14.

Table 14: Comparison of customers between disadvantaged suburbs and state

	Disadvantaged suburbs/towns	South Australia
Interval meter	40%	41%
Solar	35%	39%
Average solar system size	4.6kW	4.9kW
Battery	3%	3%

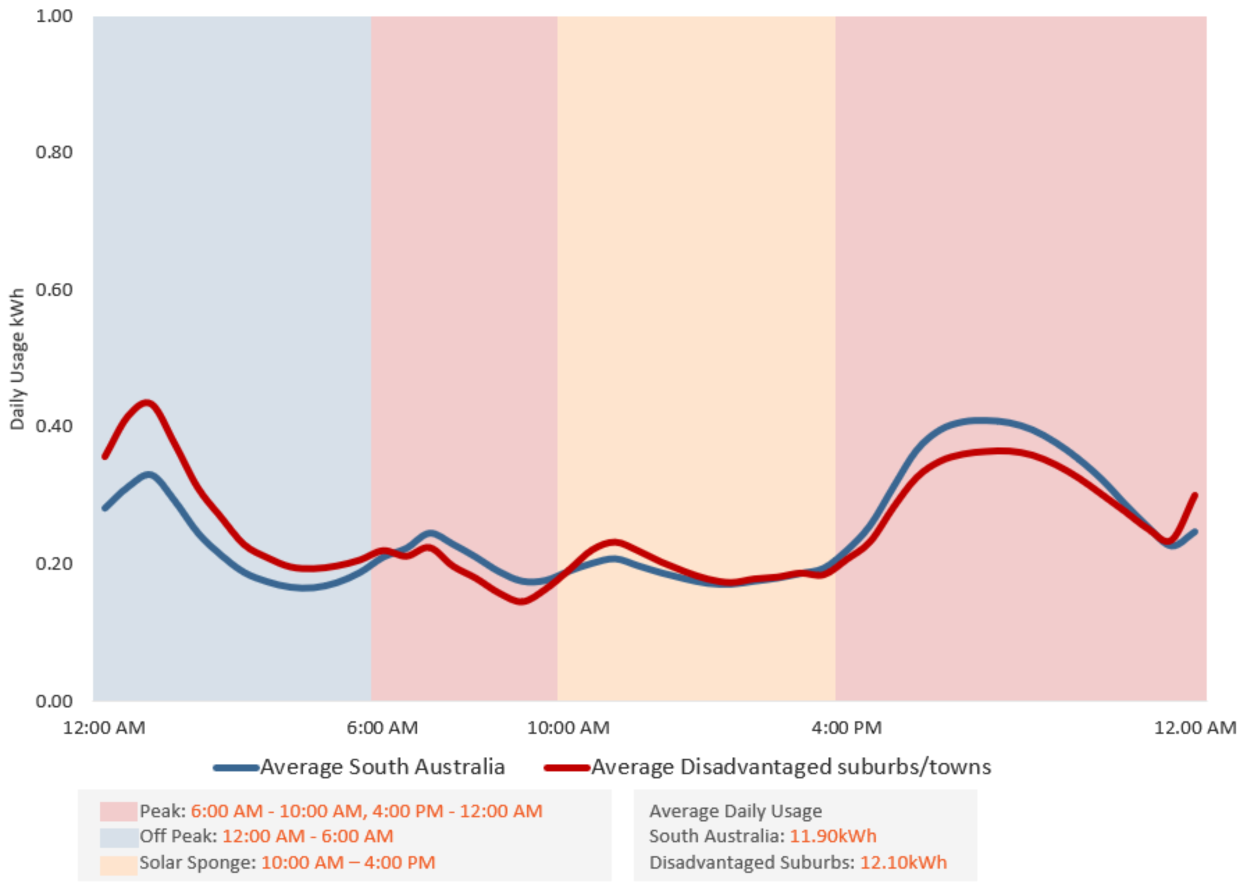
Source: SA Power Networks analysis

The data showed no significant difference between customers from these disadvantaged suburbs and towns, and the total state.

[10] Dropping of the Edge Report: https://www.dote.org.au/south-australia.

The average daily usage profiles for these two sample groups are compared, as shown in Figure 47.

Figure 47: Average daily usage profile comparison between disadvantaged suburbs/towns and South Australia

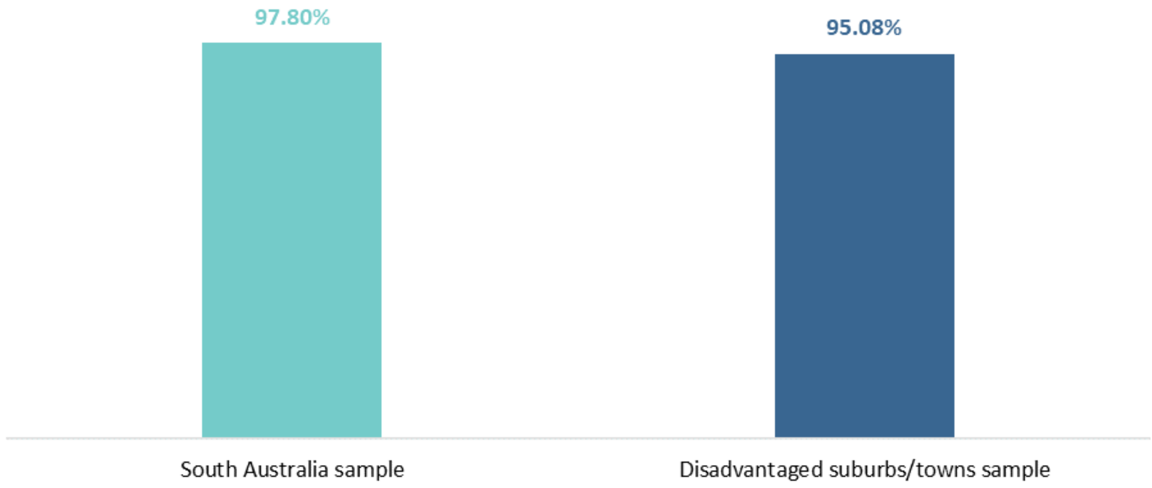


Source: SA Power Networks analysis (Sample: 2,000 Residential NMIs from South Australia and 2,000 Residential NMIs from South Australian disadvantaged suburbs/towns)

The results demonstrate that the average daily load profiles for both sample groups are similar. In addition, the graph also shows that the average customer from the disadvantaged suburbs/towns sample has a lower energy consumption during the Peak time window compared to the average customer from the state sample.

Figure 48 outlines the RTOU relativity to RSR for both sample groups.

Figure 48: RTOU vs RSR comparison between disadvantaged suburbs/towns and South Australia



Source: SA Power Networks analysis (Sample: 2,000 Residential NMIs from South Australia and 2,000 Residential NMIs from South Australian disadvantaged suburbs/towns)

Figure 48 shows that customers within the disadvantaged suburbs and towns are paying 95.08 percent on average of the single rate price compared to the statewide sample average of 97.80 percent. The results indicate that customers who experience disadvantage or vulnerability are likely on average to save more by being on the RTOU tariff than the average customer in South Australia. The results illustrate that on average our proposed RTOU structure does not disadvantage those customers experiencing vulnerability and therefore it remains appropriate that the tariff assignment policy is continued in 2025-30 RCP with all interval metered customers being assigned to a ToU tariff with no option to choose a singe rate tariff.

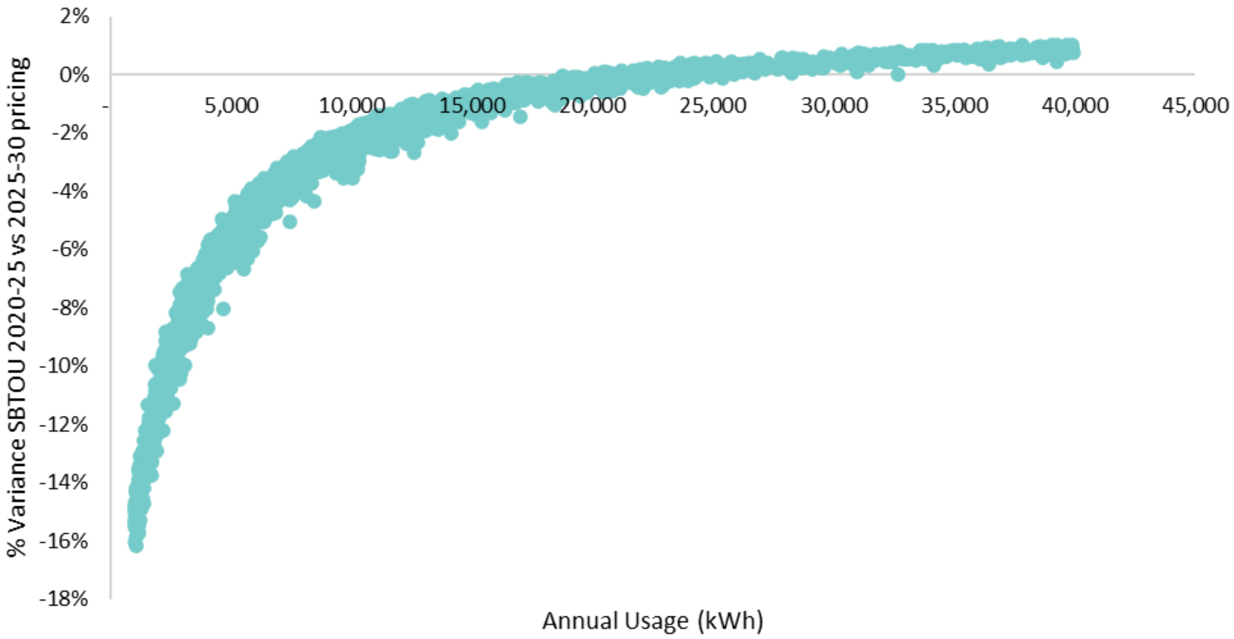
The proposed accelerated interval meter deployment recommended by the AEMC in 2025-30 will enable more vulnerable customers to access the RTOU tariff and make savings on their energy usage.

9.2 Small and Medium Business

Key Finding 1: New SBTOU pricing differential benefits Small Business 0-40MWh p.a. customers.

The creation of the sub class within the Small Business tariff class was designed to create a pricing differential between Small and Medium Business. Analysis outlined in Figure 49 shows that 82 percent of customers with usage up to approximately 20MWh p.a. will have reduced network charges under the new SBTOU pricing structure in 2025-30 RCP.

Figure 49: Comparison between SBTOU 2020-25 and SBTOU 2025-30 pricing

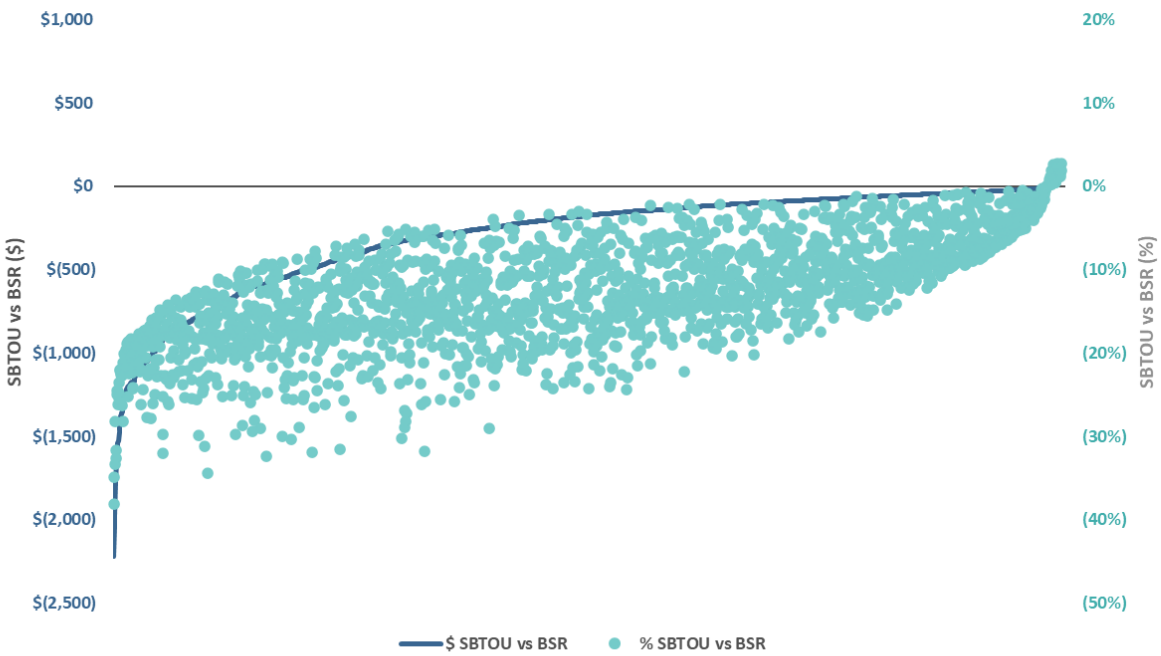


Source: SA Power Networks analysis (Sample: 1,993 Small Business NMIs) excluding legacy metering services

Key Finding 2: Analysis supports SBTOU as the default interval meter tariff for Small Business 0-40MWh p.a. customers.

We propose the SBTOU tariff as the default tariff for Small Business interval meter customers with consumption of 0-40MWh p.a. Figure 50 compares the bill impact of SBTOU tariff to the BSR tariff for Small Business customers.

Figure 50: Comparison between SBTOU and BSR tariffs ($ nominal)



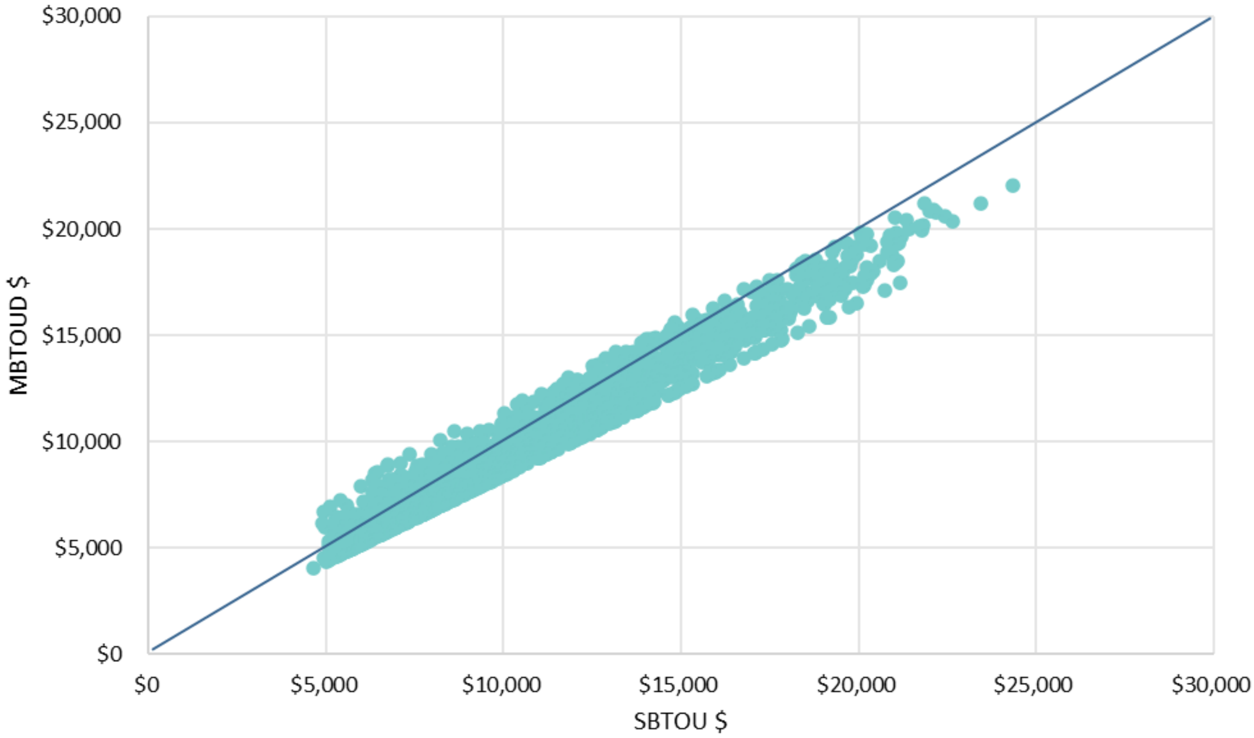
Source: SA Power Networks analysis (Sample: 1,993 Small Business NMIs)

The chart shows that most customers, 98 percent, have savings on the SBTOU tariff compared to the BSR tariff. Therefore, customers moving to the SBTOU tariff from the BSR tariff are likely to have savings without any behavioural change. The analysis supports the SBTOU tariff as the default interval meter tariff for Small Business 0-40MWh p.a. customers.

Key Finding 3: Analysis supports MBTOUD as the default interval meter tariff for Medium Business 40-160MWh p.a. customers.

Figure 51 demonstrates the bill impact for Medium Business customers on the MBTOUD tariff with consumption of 40-160MWh p.a. compared to the SBTOU tariff. The analysis only includes those customers with less than 120kVA as those customers with demand greater than 120kVA are not able to access SBTOU under our proposed tariff assignment policy for 2025-30 RCP.

Figure 51: Bill outcome comparison between MBTOUD and SBTOU ($ nominal)



Source: SA Power Networks analysis (Sample: 1,914 Medium Business NMIs)

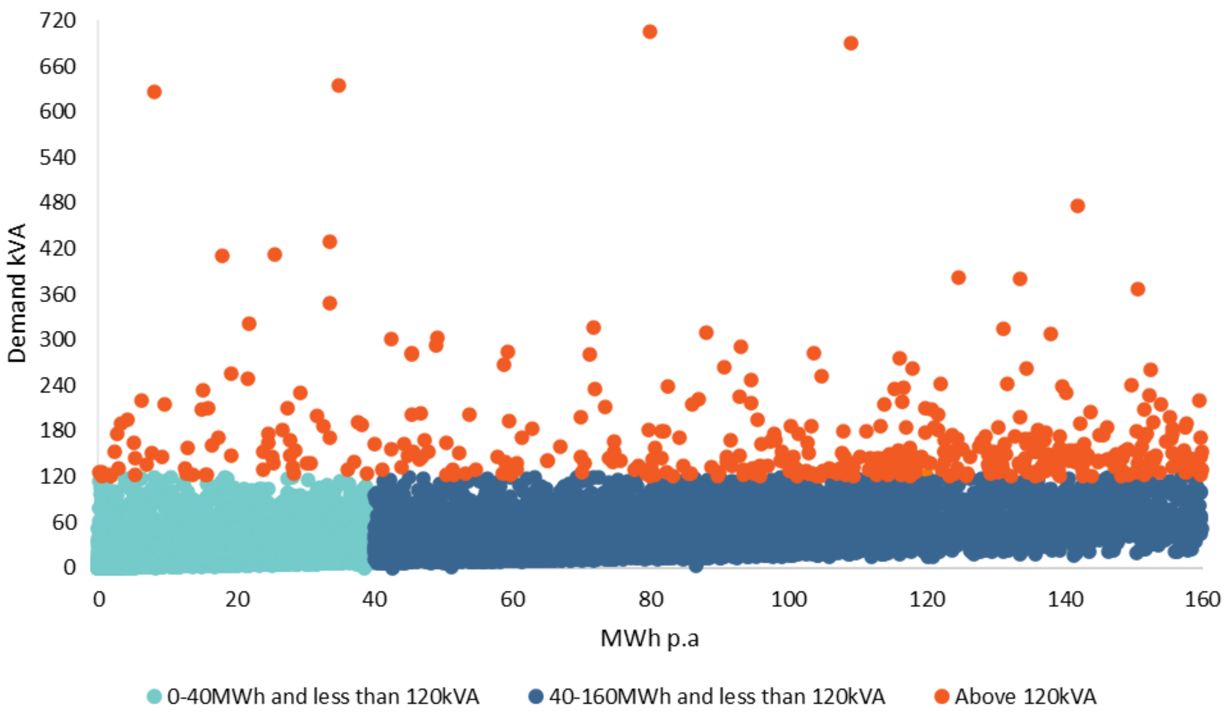
The majority of customers, 76 percent, will pay more on SBTOU compared to MBTOUD which supports the default interval meter tariff assignment for Medium Business customers. Those customers who would pay more are able to elect to be reassigned to SBTOU as they have less than 120kVA demand.

The pricing of the MBTOUD tariff, which has a higher supply rate and a lower usage rate than the SBTOU tariff, is suitable for customers with larger usage. This analysis supports the creation of the Small Business tariff sub class of Small and Medium Business.

Key Finding 4: 120 kVA threshold for Small and Medium business continues to be appropriate.

All businesses in the Small Business tariff class will be subject to demand charges via MBTOUD if they have demand more than 120kVA. Figure 52 shows that the majority of businesses have demand at 120kVA or below, as illustrated by the concentration of data points. Above this threshold there is greater diversity in demand and usage. The continuation of the 120kVA threshold is considered appropriate as a customer at these levels and above can dominate the demand on local distribution network assets and therefore it is important to provide a price signal for this utilisation. This is a continuation of the 2020-25 RCP demand thresholds and tariff assignment policy.

Figure 52: Small Business Anytime demand kVA



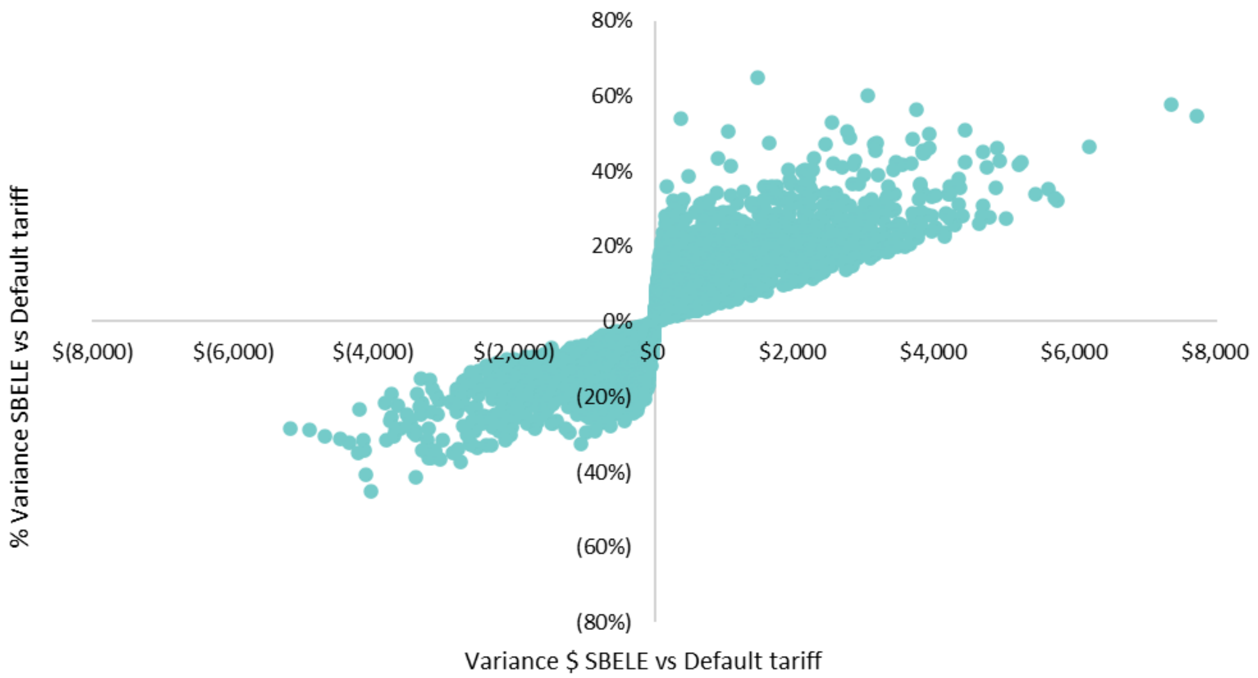
Source: SA Power Networks analysis

Key Finding 5: Businesses who can avoid the Peak window or have the flexibility to shift load benefit by being on the customer choice tariff, SBELE.

The SBELE tariff is an extension of our RESELE tariff. Based on stakeholder feedback, the SBELE tariff is proposed to encourage customers to shift load to the middle of the day.

Figure 53 compares the network bill outcome for customers on the SBELE tariff to their respective default tariff (SBTOU or MBTOUD) based on our tariff assignment policies.

Figure 53: Comparison between the SBELE tariff vs default tariff (SBTOU or MBTOUD)



Source: SA Power Networks Analysis (Sample: 3,907 Business NMIs with annual usage between 0-160 MWh and less than 120 kVA)

The quadrant analysis shows that with no behavioural change, 40 percent of businesses have savings on the SBELE tariff compared to their default tariff, as indicated by the bottom left quadrant. These savings reflect the businesses operations are predominantly outside the Peak window. Those businesses in the top right quadrant who can exercise a degree of flexibility in their usage could move into the bottom quadrant and maximise their savings. The SBELE tariff is a customer choice tariff and so customers who are in the top right quadrant who cannot exercise any flexibility should not choose this tariff.

9.3 Large Business

If Large Business customers can be flexible in when they use the distribution network the tariff design rewards this efficient use. This flexibility aims to avoid or defer distribution network augmentation. Table 15 and Table 16 illustrate the savings that can be achieved comparative to the default tariff for the tariff class when customers elect to be flexible.

Table 15: Savings for Large LV customer who can be flexible

	Supply Days	Peak Usage kWh	Off Peak Usage kWh	Peak Demand kVA	Anytime Demand kVA	Anytime Demand Flex kVA	Total ($)
LBAD	365	981,120	1,471,680	1,400	2,000	-	-
LBADF	365	981,120	1,471,680	700	1,500	500	-
LBAD	$3,000	$71,072	$66,667	$149,570	$45,990	$-	$336,299
LBADF	$3,000	$71,072	$66,667	$74,785	$34,493	$5,749	$255,766
Flexible savings	**$-**	**$-**	**$-**	**($74,785)**	**($11,498)**	**$5,749**	**($80,534)**

Source: SA Power Networks analysis

Table 16: Savings for HV customer who can be flexible

	Supply Days	Peak Usage kWh	Off Peak Usage kWh	Peak Demand kVA	Anytime Demand kVA	Anytime Demand Flex kVA	Total ($)
HVAD	365	1,471,680	2,207,520	2,100	3,000	-	-
HVADF	365	1,471,680	2,207,520	420	2,400	600	-
HVAD	$16,000	$82,120	$77,042	$178,135	$92,966	$-	$446,262
HVADF	$16,000	$82,120	$77,042	$35,627	$74,372	$9,308	$294,469
Flexible savings	**$-**	**$-**	**$-**	**($142,508)**	**($18,593)**	**$9,308**	**($151,793)**

Source: SA Power Networks analysis

In these examples, the customer has agreed on an amount to which they can reduce their Peak Demand on days above 38 degrees and, in turn, they don't pay Peak Demand prices for the demand that they would ordinarily use in the 5:00pm to 9:00pm window on all other days when the temperature is below 38 degrees between November and March. This demand is instead charged at the Anytime Demand price. Additionally, the customer has committed to the minimum amount of flexibility required to access the tariff – Anytime Demand amount must be at least 500kVA and not less than 20 percent of total Anytime Demand. This flexible demand is charged at 50 percent of the Anytime Demand price and, therefore, reduces network charges. The combination of avoiding extreme temperatures and being flexible can deliver material savings for Large Business.

10 Metering

10.1 Background

The AEMC published its final report on its review into the regulatory framework for metering services on 30 August 2023[11]. The final report has made recommendations to improve the regulatory framework for metering services, enabling consumers to access the benefits of interval meters sooner. The AEMC recommended an accelerated deployment of interval meters, with interval meters to be installed for all 'small customers' including residential and small commercial or business customers by 2030.

To assist distribution networks in preparing their revised regulatory proposals and proposals, the AER released a 'Legacy metering services - guidance note' (**Guidance note**) in November 2023. Noting the AEMC's final decision, the AER considers that it would be more appropriate to reclassify legacy metering services as Standard Control Services (**SCS**) as this would result in the most equitable solution by recovering legacy metering costs across all customers. The AER considered cost recovery for the metering transition across all customers appropriate as all customers will receive the whole-of-system benefits the interval meters will provide. SA Power Networks has developed its proposal in line with the Guidance note.

[11] AEMC Final Report Review of the Regulatory Framework for Metering Services, 30 August 2023.

10.2 SA Power Networks proposal

SA Power Networks proposes to classify legacy metering services as SCS where the costs are recovered across a broader customer base. As SCS, legacy metering services are proposed to operate under a revenue cap form of control. Metering services expenditures are proposed to be treated as a sub-component of the total SCS expenditure, where it is modelled separately with a separate Annual Revenue Requirement (**ARR**) output. This ARR is proposed to be smoothed in the same way as the main SCS ARR. This will maintain the transparency of these costs and assist with any ‘true-ups’ or adjustments (such as cost pass throughs) that may need to occur during the RCP.

SA Power Networks proposes to recover the legacy metering ARR from our Residential, Small Business and Medium Business tariff classes as an additional daily fixed charge component of the distribution network bill. This will be published as a separate Metering price schedule within our Annual Pricing Proposal (**APP**). This schedule will be in addition to the current Distribution Use of System (**DUoS**), Transmission Use of System (**TUoS**) and Jurisdictional Service Obligation (**JSO**) schedules.

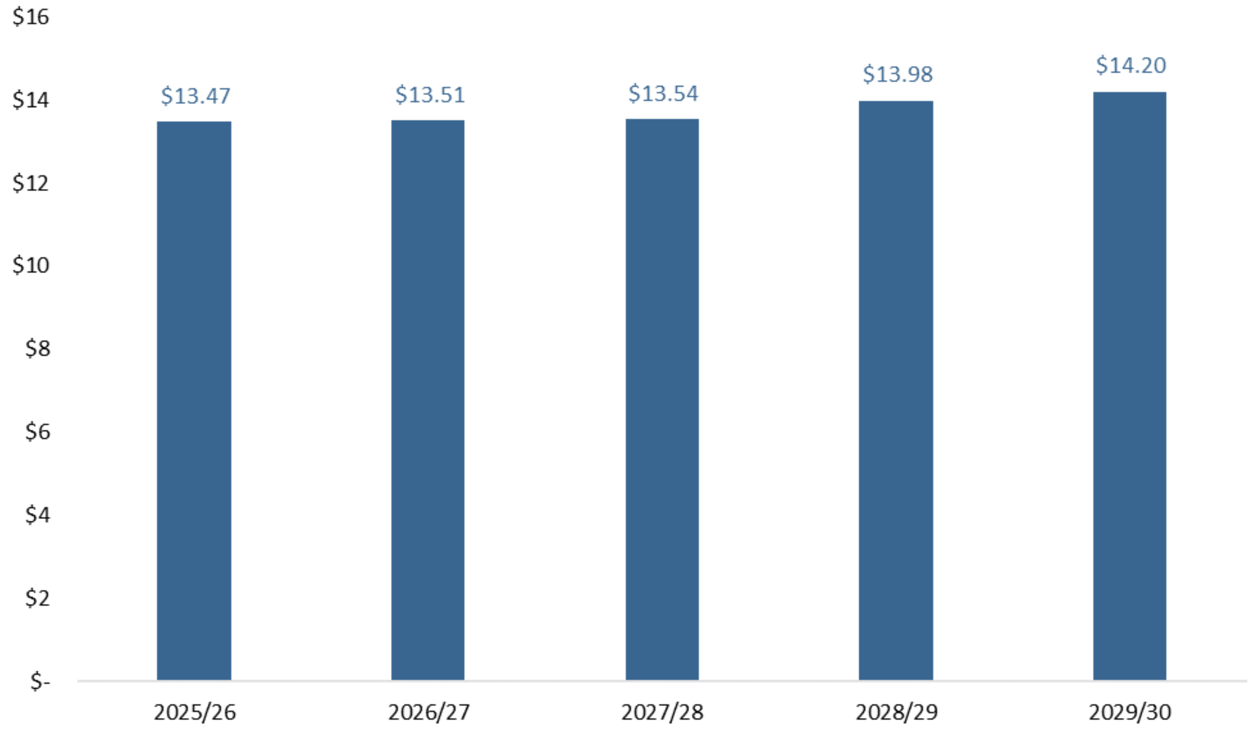
SA Power Networks will maintain a separate under/over recovery account which will be adjusted as part of our APP process. Pricing will be adjusted annually to capture forecast volumes of meter exchanges and forecast expenditure.

10.3 Stakeholder engagement

SA Power Networks consulted with both our TWG and CAB on the proposed change in classification by the AER. Our consultation incorporated our proposed response and the likely impact on SCS pricing over the 2025-30 RCP. This consultation occurred, prior to the AEMC decision and the AER guidance, in August 2023. Additional consultation took place with the TWG in November 2023 which incorporated the final outcomes of the AEMC report.

Our stakeholders provided in principle support for our approach and for the legacy metering costs to be recovered as a separate daily fixed charge from our Residential, Small Business and Medium Business tariff classes.

Figure 54: Proposed indicative annual fixed metering charge per customer ($ nominal)



Source: SA Power Networks analysis

10.4 Alignment to the AER Guidance note

SA Power Networks' metering proposal adopts all except one of the recommendations within the AER's Guidance note. The AER state that they *"consider it optimal to recover these costs over all LV customers where appropriate."* We have considered the customer base within South Australia and instead propose to recover costs only from small customers, defined as those customers whose annual consumption does not exceed 160 MWh p.a.[12]

The classification of small customers includes Residential, Small and Medium Business tariff classes but excludes Large LV Business. Large LV Business is classified as 'large market', and all large market customers have interval meters which do not incur meter reading costs. On this basis SA Power Networks does not consider allocating metering costs to the Large LV Business tariff class appropriate. Such an allocation is considered a backwards step in cost reflectivity for a tariff class which is cost reflective. Furthermore, whilst Large LV Business customers have relatively large consumption, they only represent 0.5 percent, of total LV customers. As this is such a small percentage, their inclusion or exclusion will not materially affect the revenue recovery per customer however by excluding them it keeps the tariff class cost reflective.

[12] National Energy Retail Law (Local Provisions) Regulations 2013 Section 5(2).

11 Export tariffs

11.1 Background

The distribution network was originally designed to deliver electricity 'one-way' to our customers. Whilst the distribution network can support the export of some renewable energy from households and businesses, in some areas of our distribution network this capacity is already diminished due to the increase in export customers.

In 2021, the Australian Energy Market Commission made changes to the Rules that clarify the obligations of electricity distribution networks like SA Power Networks to plan for future levels of exports and invest appropriately in distribution network capacity to meet demand for export services. The rule changes also allow for the cost of this distribution network investment to be recovered via export tariffs whilst also enabling distribution networks to reward customers with export credits when they export at times when it is most needed.

11.2 Justification for export tariffs

In South Australia today, we have the highest ratio of rooftop solar generation to operational consumption of all the NEM regions. In October 2023 almost 350,000 homes and businesses have installed rooftop solar, that is more than one in three premises. Uptake continues to grow as homes and businesses respond to high energy prices, while falling system costs mean that the average system size is also increasing each year. Installed rooftop solar capacity currently stands at 2.5GW, making rooftop solar the largest source of generation in the state.

Rooftop solar output lacks diversity, that is, all rooftop solar systems in the same local area are generally exporting at full power simultaneously in the middle of the day. Based on forecast rates of uptake of rooftop solar and behind-the-meter batteries, our distribution network modelling indicates a progressive increase in the incidence of export constraints in the distribution network in the 2025-30 RCP, that is, periods in which local reverse power flows exceed the capacity of the local distribution network.
SA Power Networks' approach to managing the challenges facing our distribution network as well as providing additional capacity for households and businesses to export energy into the distribution network comprises three key pillars:

Flexible Exports

Development of an industry leading transition away from static export limits for new solar customers to dynamic limits, now known as flexible exports or dynamic operating envelopes. Customers connecting solar in certain congested areas of the distribution network have the option to connect with a flexible export connection, which allows a dynamic export limit of up to 10kW per phase, or to opt for a 1.5kW fixed limit. Currently, flexible export connections are available only in specific areas of the distribution network where solar penetration has already exceeded the intrinsic capacity of the local distribution network, and some level of dynamic management of exports is required, however by the end of 2024 we expect that flexible exports will be the default connection arrangement for new solar customers connecting anywhere on the distribution network.

Enhanced Voltage Management

In 2020, as part of our response to urgent system security risks in South Australia, we undertook a $10 million capital program to implement Enhanced Voltage Management across 140 of our larger zone substations. The primary driver at the time was to develop an emergency voltage raise capability to rapidly shed large amounts of small-scale solar if required to support AEMO during a minimum demand contingency event. The equipment upgrades made through this program also enabled us to activate Line Drop Compensation at these substations, a technology that automatically raises or lowers the voltage setpoint at the substation depending on load. This has the effect of reducing daytime voltage rise due to solar without creating under-voltage conditions at times of peak demand.

Consumption Tariffs

All Residential ToU tariffs, including Controlled Load, are proposed to continue to have a Solar Sponge time window in the 2025-30 RCP. This is the lowest priced time window signalling that the distribution network has the highest available capacity in this window. This time window is proposed to be extended by 1 hour to 4:00pm to further encourage load shifting.

In South Australia, Retailers are responsible for the control of the Controlled Load and to date, we have seen great success with Retailers responding to our price signals. The Controlled Load pricing signals are the same as the default Residential ToU tariff, and Retailers can respond to the Solar Sponge pricing signal. In December 2023, 29 percent of Controlled Load shifted to the Solar Sponge time window and it is expected that this shift will continue to increase.

Encouraging additional load to shift into these low and increasingly negative demand periods of the day via pricing signals plays a role in alleviating congestion in the low voltage distribution network.

Having put in place the foundational capabilities that enable us to maximise utilisation of the capacity that we have, our focus has shifted to planning for the progressive, prudent and efficient addition of export capacity to the distribution network as required to keep pace with continued growth in demand. This expenditure is proposed to be recovered via export tariffs.

In the 2025-30 RCP SA Power Networks proposes to invest in new capacity in the low voltage distribution network to relieve solar-related congestion and enable more export into the distribution network. This expenditure would largely benefit small embedded generation customers, who can export less than 30kW. Today, these are predominantly customers with solar and/or batteries and in the future would include customers with EVs with 'Vehicle to Grid' (**V2G**) capability.

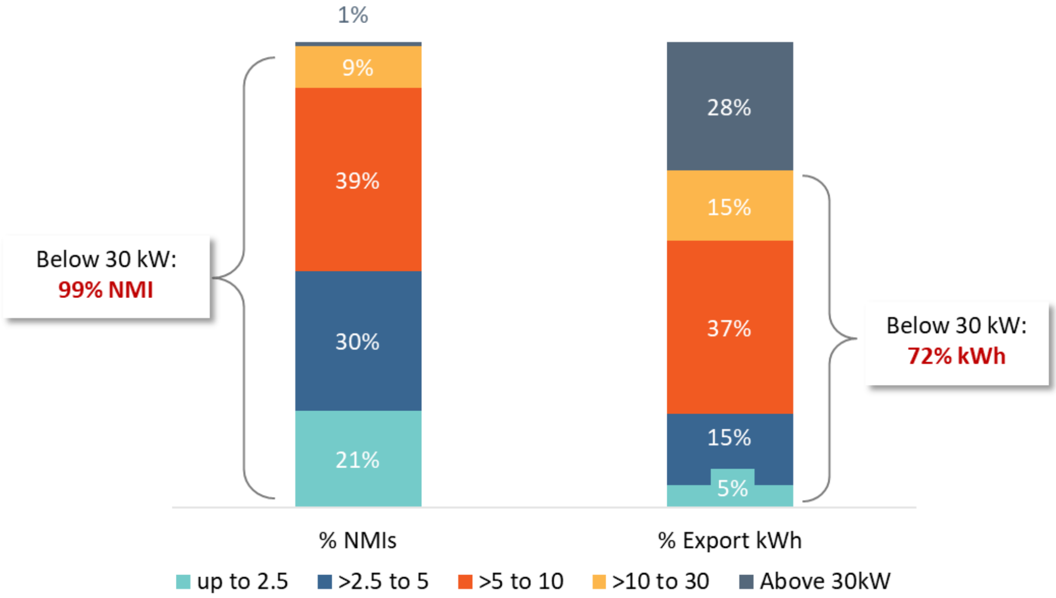
We consider the introduction of export tariffs to align with our pricing principles:

- Empower the Customer: Export charges can encourage behavioural change and reward flexibility
- Fairness and Equity: Export charges can create a fairer outcome
- Compliance: Export charges create more efficient outcomes
- Simplicity: Proposed structures build upon existing consumption tariff structures

11.3 Development of export tariffs

In South Australia, 99 percent of solar systems connected to the distribution network were less than 30kW in capacity and were responsible for 72 percent of exported energy in 2022/23. 50 percent of these solar exports were metered by an accumulation meter. Figure 55 details the sizes of solar systems connected to the distribution network.

Figure 55: Energy exported by solar systems connected to the distribution network



Source: SA Power Networks analysis

The proposed CER integration expenditure is focused on the low-voltage distribution network, as this is the main source of solar congestion. Therefore, export tariffs have been developed for Residential and Small Business export customers with both interval and accumulation meters.

Customers with greater than 30kW embedded generation

Export tariff structures were also considered for customers with embedded generation system capacity of greater than 30kW and less than 100kW connected to the low voltage distribution network. These tariffs were to recover the expenditure of enabling export capacity in the low voltage distribution network where these customers are connected. The 100kW threshold was a new threshold that was considered as part of the low voltage modelling of expenditure.

Feedback from stakeholders was that the creation of a new threshold which didn't align with the embedded generation connection process was adding unnecessary complexity for SA Power Networks, customers, and the solar industry.

Embedded generation thresholds are defined as:

- Medium Embedded Generation greater than 30kW and up to 500kW
- Large Embedded Generation greater than 500kW and up to 5MW

Based on this feedback, expenditure in the 2025-30 RCP to relieve solar congestion on our low voltage distribution network is proposed to be entirely recovered from customers with systems less than 30kW in capacity. Whilst customers with greater than 30kW systems will not be subject to export tariffs they will face pricing signals via the distribution network connections process as their impact on the distribution network is more clearly defined.

11.4 Stakeholder engagement

As outlined in Section 4, our proposed export tariff structures in the 2025-30 RCP are the result of extensive stakeholder engagement.

We held a series of five export tariff Focused Conversation workshops which stepped stakeholders through:

- The change in Rules and the newly developed AER Export Tariff Guideline;
- How CER was impacting our distribution network;
- The development and impact of export tariff structures on CER customers; and
- Developing options of when transition to two way charging should take place.

As export tariffs are a new concept, we considered it appropriate for an equal number of workshops to be held (as consumption tariffs) to recognise the importance of this change for stakeholders and the industry at large.

In addition to the Focused Conversation workshops, our People's Panel, a more representative group of 50 South Australian customers were asked to deliberate on when export customers should be transitioned to export tariffs. We posed the following questions to the People's Panel:

Regulation requires SA Power Networks to consider export tariffs that reflect the cost of providing this service. How can the transition be phased in to maximise fairness and equity for all?

- *Option 1 — All Export Customers (New* and Existing) assigned to export tariffs from July 2025*
- *Option 2 — No export tariffs introduced until July 2030*
- *Option 3 — All New Export Customers* assigned to export tariffs from July 2025 and all Existing Export Customers assigned from July 2030*

**For the purposes of consultation, we defined a new Export Customer as a customer with CER installed on or after 1 July 2023.*

Option 1 was recommended as the preferred option by the Focused Conversation participants as it was considered the most equitable option and allowed for clear, simple communications to all customers. While the People's Panel deliberations discounted Option 3 quickly, they did not reach consensus on a preferred option. Half the Panel supported Option 1 while half the Panel did not support any export tariffs being introduced for the 2025-30 RCP.

Given this, and noting that the introduction of export tariffs could be considered to have a stronger alignment with the AER's Pricing Principles, SA Power Networks has decided to adopt the recommendation from the Focused Conversations workshops and proposes to introduce new export tariffs for all existing and new small generation customers from 1 July 2025. This approach is also strongly supported by our CAB.

Outside of the formal Focused Conversation workshops we held additional information sessions as requested by stakeholders to ensure they felt supported in developing their tariff knowledge and confident to participate in the workshops actively.

Retailer engagement was also key in the development of export tariffs. SA Power Networks formally engaged with retailers via workshops in 2022 and 2023. We also held individual sessions with retailers to allow them to raise questions or provide comments, recognising that they may not have wanted to actively engage in a group forum.

In 2023/24, we introduced an export tariff within the trial tariff, Electrify Two Way RELE2W. This trial tariff has both the consumption and the credit components. As of December 2023, we have 2,334 customers on this trial tariff, making it the most successful trial tariff from the customers' uptake perspective. The learnings from the trial tariff have been incorporated into our TSS to ensure the successful implementation of the proposed export tariff. Whilst all stakeholder feedback was considered, not all stakeholder viewpoints could be incorporated into the final tariff structures. Table 17 summarises how our tariff structures have been influenced by stakeholder engagement.

Table 17: Stakeholder feedback and SA Power Networks proposed response

Tariff Structure	Stakeholder Feedback	SA Power Networks Proposed Response
Export Tariffs structure	Tariff structure needs to be understood by a wide range of stakeholders including customers, retailers and the solar industry. Simplicity over complexity.	Export tariff structures proposed align time windows with Residential and Small Business consumption tariffs and charge/credit on a kWh basis. The interval meter basic export level is simple to calculate and the rollover of unused free export maximises the benefit for the customer. Export charge is fixed for the entirety of the RCP.
Export Tariffs and **Small Business**	Businesses should not have to pay export tariffs.	Allowing businesses with 0-30kW export capacity to opt out of export tariffs would create an inequitable outcome within the 0-30kW segment of customers.
Export Tariffs credit	An export credit should be meaningful and not only available for a demand tariff with a small number of customers.	An export credit component was developed to be partnered with the prosumer tariff options: Residential Electrify and Small Business Time of Use Electrify. Residential Prosumer tariff with demand is proposed to close.
Export Tariffs >30kW	Any proposed tariff needs to be simple and easily understood. New application thresholds should be avoided.	No export tariff for customers with >30kW generation. Pricing signal for customers with >30kW systems is provided via the connections process in accordance with our Connections Policy. There is no distribution network congestion forecast, and consequently no distribution network expenditure forecast. Therefore, no export tariffs are proposed for >30kW generation systems.
Transition to **Export Tariffs**	All export customers should be considered as one cohort and not be classified based on when they purchased their solar systems.	The People's Panel did not reach a consensus on the transition timeframe however they did determine that all export customers should be considered as one cohort. Failure to reach consensus on the transition timeframe meant that the Focused Conversation recommendation is what is being proposed: transition to an export tariff for all export customers from 1 July 2025. This approach is also strongly supported by our CAB.
Export Tariffs communications	Must provide comprehensive guidance for customers, retailers, government, and other market participants well in advance of implementation.	In the lead up to 1 July 2025 (and beyond) we will develop communications utilising a variety of media to ensure all stakeholders can develop an understanding and make informed decisions about the value and cost of their exports.

11.5 Export tariff structure

11.5.1 Basic Export Level

All proposed export tariffs have a defined basic export level, that is, the amount of capacity that the distribution network already has for customers to export. Export up to the basic export level is proposed to be free in line with the Rules[13]. There is inherent export capacity in the distribution network because these distribution network assets are constructed to supply load but can also support some reverse power flow, resulting from customer exports. Modelling undertaken by SA Power Networks suggests that our distribution network has a basic export level in the order of 1.5kW per customer. If every customer on the distribution network had a solar system installed, and each of those systems wanted to export back to the distribution network, highly congested parts of the distribution network could only support 1.5kW of exports from each of those customers.

Whilst the basic export level has been determined in power capacity (kW) terms we are proposing to incorporate it into export tariffs in energy volume (kWh) terms.

In applying the basic export level to the interval meter tariff structure, we have converted the 1.5kW to kWh: 1.5kW x 6 hours (Solar Sponge 10:00am – 4:00pm) = 9kWh.

In applying the basic export level to the accumulation meter tariff structure, we have converted the 1.5kW to kWh: 11kWh.

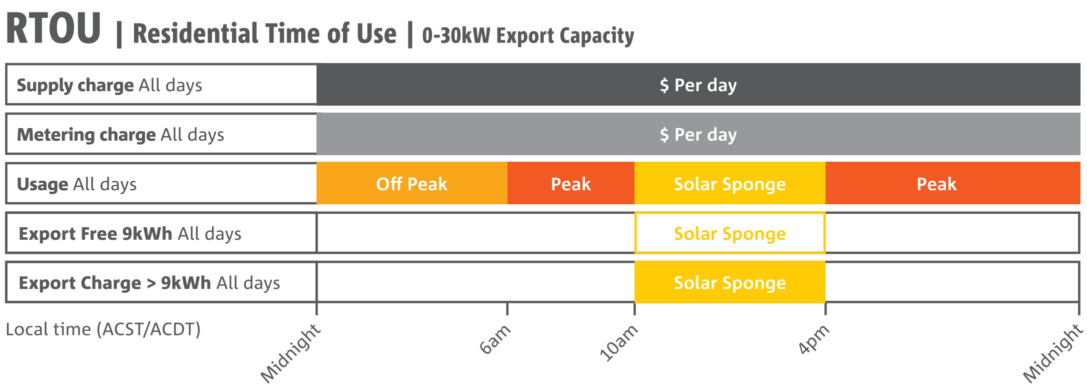
The basic export level for accumulation meters is designed so that on average, a customer is neither advantaged nor disadvantaged because of their meter type. This level was determined based on the analysis of solar customers with accumulation meters which determined that the allowance needed to be greater than 9kWh to recognise that some export could occur before 10:00am and after 4:00pm which would not be subject to an export tariff if the export was recorded on an interval meter.

No customer with the ability to export up to 30kW will have a zero basic export level.

We consider volumetric pricing signals in kWh basis to be better understood by customers and more likely to be incorporated by Retailers. This also aligns with our overarching Residential consumption tariff strategy where we have moved away from demand based charges.

11.5.2 Interval meter export tariff structure

Figure 56: Residential default export tariff

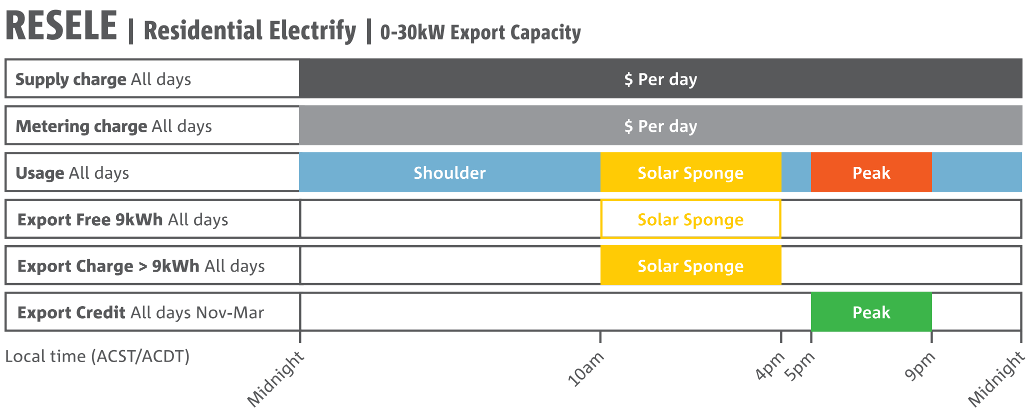


[13] National Electricity Rules clause 11.141.12.

The RTOU tariff is our proposed default export tariff for Residential customers with interval meters. We propose all Residential interval meter customers would be able to export up to 9kWh per day between 10:00am – 4:00pm free of charge. If exports between 10:00am – 4:00pm are less than 9kWh, the remainder of the free export allowance would roll over to the next day, within a single billing period. For example, a billing period of 30 days would include 270kWh of free export between 10:00am – 4:00pm. All additional export between 10:00am – 4:00pm would incur a charge. All export outside 10:00am – 4:00pm would be free.

The tariff is structured to only have a charge on the amount of export above the free basic export level, there is no daily supply charge component.

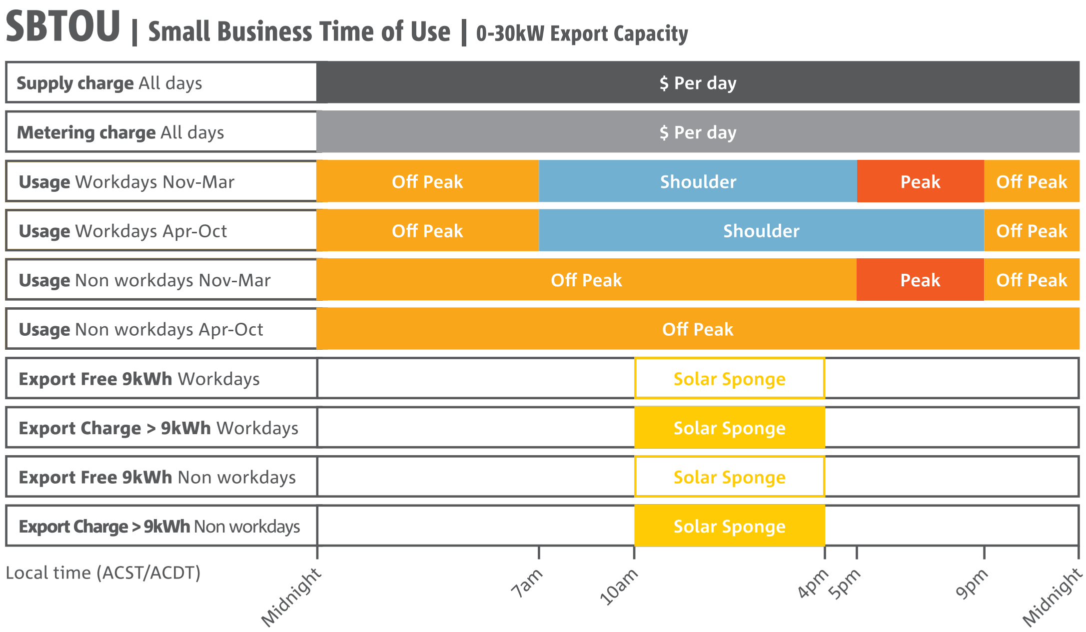
Figure 57: Residential customer choice export tariff

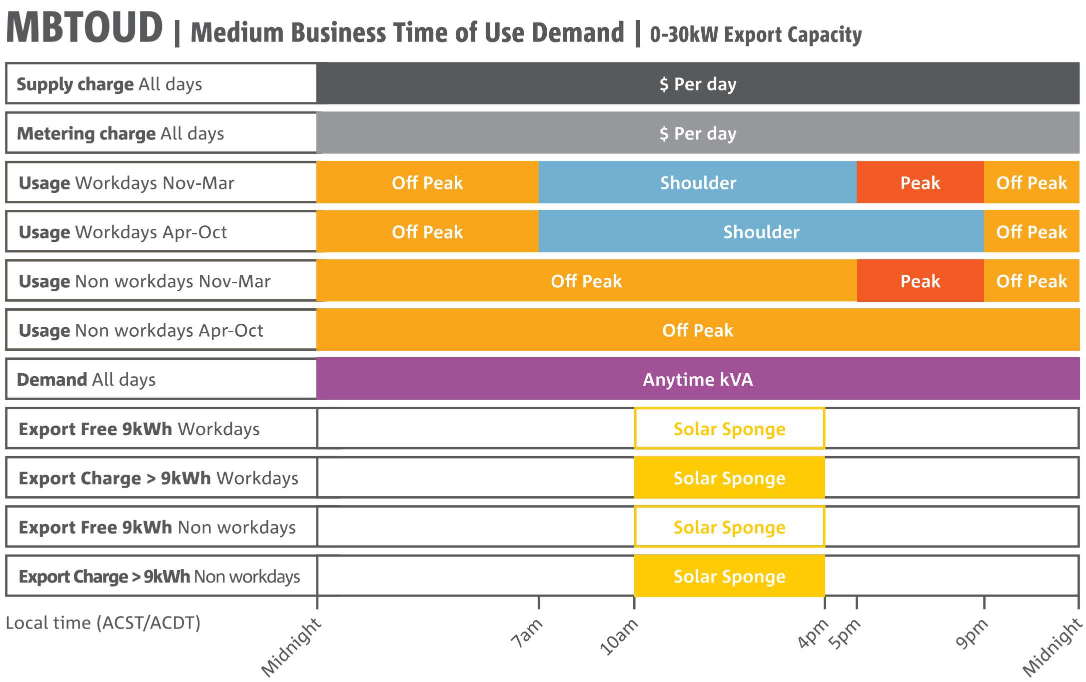


We propose a customer choice RESELE tariff for those customers who have the ability to export into the distribution network during the summer peak of November to March. This tariff has the same free export allowance and charging parameters as RTOU default export tariff for 10:00am – 4:00pm. In addition, if a RESELE customer can export to the distribution network between 5:00pm – 9:00pm November to March then they would be rewarded with a credit for each kWh exported during this time.

This tariff structure is currently a trial tariff in 2023/24 and will be proposed for 2024/25.

Figure 58: Small and Medium Business default export tariffs





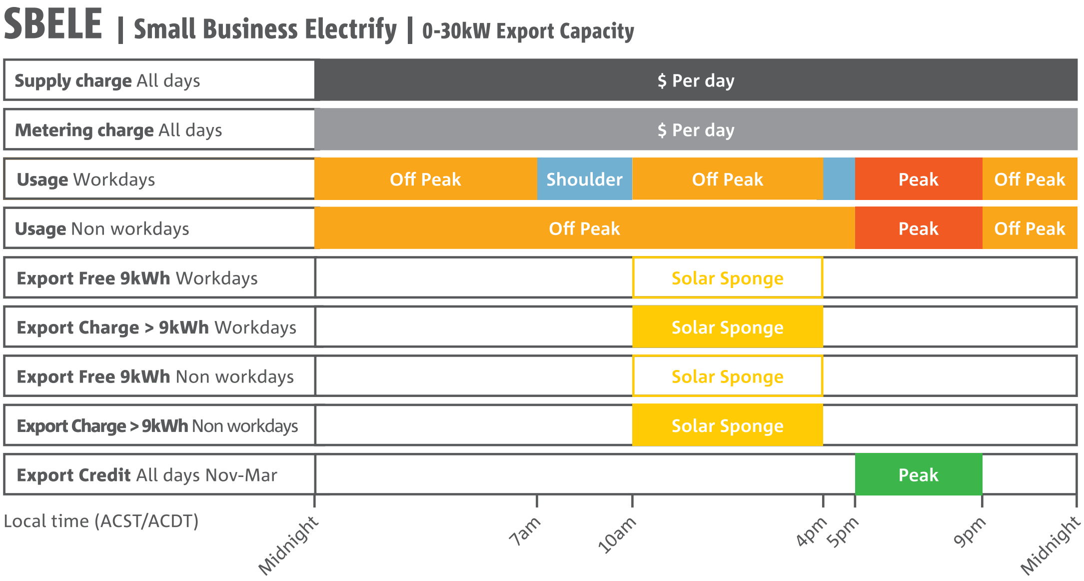
The SBTOU and MBTOUD tariffs are our proposed default export tariff for small and medium business customers with interval meters. We propose all Small and Medium Business interval meter customers would be able to export up to 9kWh per day between 10:00am – 4:00pm free of charge. If exports between 10:00am – 4:00pm are less than 9kWh, the remainder of the free allowance would roll over, within a single billing period.

Small and Medium Business interval meter consumption tariff structures categorise days of the week by Workdays and Non workdays. Workdays are Monday – Friday and Non workdays are Saturday, Sunday and Public Holidays. Unused free export on a Workday can only be rolled over to another Workday. Unused free export on a Non workday can only be rolled over to another Non workday.

For example, a billing period of 30 days with 5 weekends would include 180kWh of Workday and 90kWh of Non workday free export between 10:00am – 4:00pm. All additional export between 10:00am – 4:00pm incurs a charge. All export outside 10:00am – 4:00pm is free.

The tariff is structured to only have a charge on the amount of export above the free basic export level, there is no daily supply charge component.

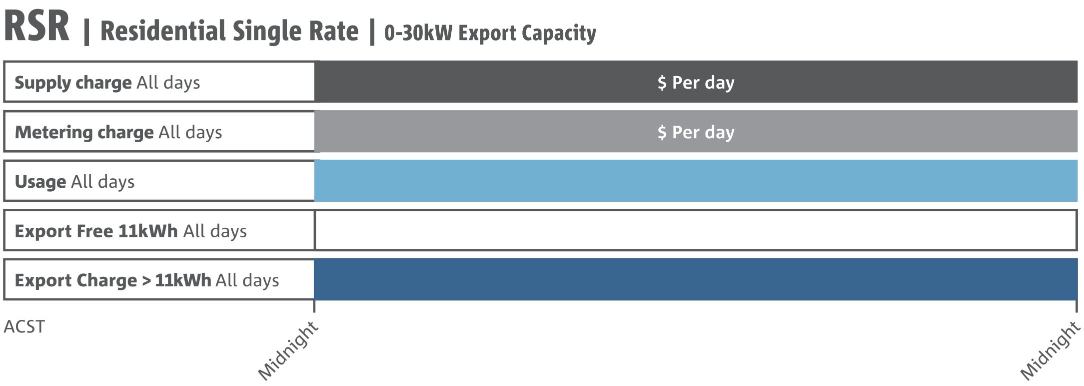
Figure 59: Small Business customer choice export tariff



We propose a customer choice SBELE tariff for those Small and Medium Business customers who have the ability to export into the distribution network during the summer peak of November to March. This tariff has the same free export allowance and charging parameters as SBTOU and MBTOUD default export tariffs for 10:00am – 4:00pm. In addition, if a SBELE customer can export to the distribution network between 5:00pm – 9:00pm November to March then they would be rewarded with a credit for each kWh exported during this time.

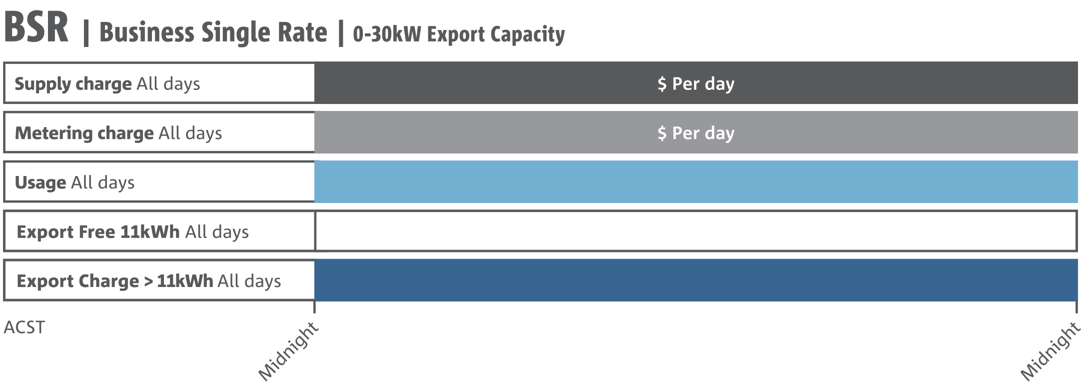
11.5.3 Accumulation meter export tariff structure

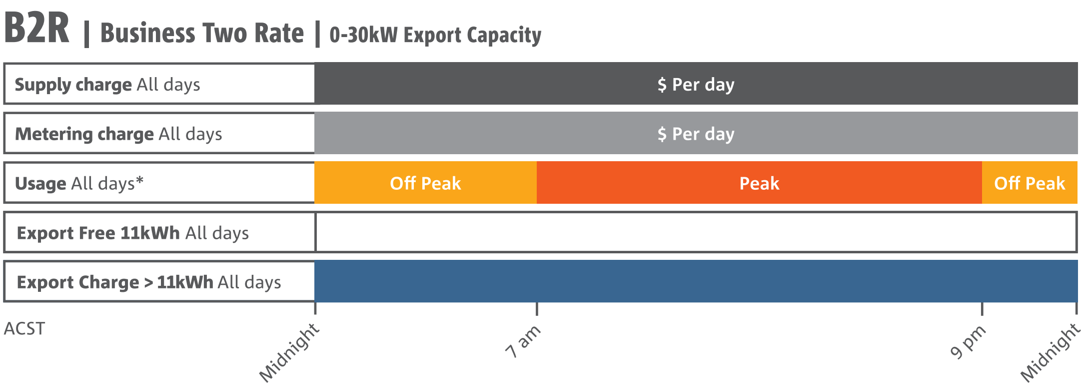
Figure 60: Residential default export tariff



The RSR tariff is our proposed default export tariff for Residential customers with accumulation meters. We propose all Residential accumulation meter customers would be able to export up to 11kWh per day free of charge. If daily exports are less than 11kWh, the remainder of the free allowance rolls over to the next day, within a single billing period. For example, a billing period of 90 days would include 990kWh of free export. All additional export incurs a charge.

Figure 61: Small Business default export tariffs





*Time clock is managed by SA Power Networks. Peak supply usage is typically Monday to Friday but can be all days between 7am and 9pm

The BSR and B2R tariffs are our proposed default export tariffs for Small and Medium Business customers with accumulation meters. We propose all Small and Medium Business accumulation meter customers would be able to export up to 11kWh per day free of charge. If daily exports are less than 11kWh, the remainder of the free allowance rolls over to the next day, within a single billing period. For example, a billing period of 90 days would include 990kWh of free export. All additional export incurs a charge.

11.6 Transition to export tariffs

Based on stakeholder support including from the People's Panel, we are proposing that all customers with the ability to export into the distribution network would be assigned an export tariff from 1 July 2025. There is no distinction regarding when customers installed their CER.

Customers would not be able to opt in or opt out of export tariffs. This approach has been informed by our experience with opt in/out consumption tariff options and through consultation with our stakeholders who reiterated the need for simplicity in messaging and application.

We recognise, and customers and stakeholders reinforced, that customer awareness and education are critical to the successful implementation of export tariffs. In the lead up to 1 July 2025 (and beyond) SA Power Networks will develop communications utilising a variety of media to ensure all customers and stakeholders can develop an understanding and make informed decisions about the value and cost of their exports.

11.6.1 Export cost recovery start date

SA Power Networks is proposing to recover expenditure relating to the enablement of export on the distribution network incurred from 1 July 2025, the first day of our new RCP.

The proposed expenditure includes the following:

- Ongoing maintenance and support for the systems that enable our Flexible Exports capability;
- Improvements to distribution network voltage management to reduce daytime voltage rise in high solar areas including installation of dynamic voltage control equipment at 48 zone substations and a transformer tapping program to tap down over 740 LV transformers;
- Capacity upgrades to 484 existing LV transformers (including replacement of old fixed-tap transformers) and the installation of 615 additional infill transformers to increase export capacity in areas of congestion;
- Installation of new voltage regulators required to maintain voltage compliance at 11 locations in the regional sub transmission network;
- Upgrades to SCADA to enable measurement of reverse power flows at 82 substations; and
- Continuation of our CER compliance program to improve compliance to inverter technical standards and configuration settings.

11.6.2 Long term strategy

In the 2020-25 RCP, SA Power Networks introduced ToU tariffs with an extra low Solar Sponge rate, becoming the first DNSP to introduce the concept. These tariffs have been effective in rewarding efficient use of the distribution network and progressing our tariff reform. The proposed export tariffs are expected to further drive our tariff reform to ensure CER technologies such as solar, batteries and EVs are integrated into the distribution network as efficiently as possible.

Our export tariffs form part of the SA Power Networks CER Integration Strategy. The investment plan proposed as part of the integration strategy for the 2025-30 RCP is intended to maintain a 95 percent level

of service for 95 percent of customers through to 2030. This target reflects the level of service performance our customers and other stakeholders indicated they want and are willing to pay for.
Our long-term strategy for two-way pricing is centered around three key pillars:

Implementation

We will continue to monitor and assess our export tariffs, including continuous stakeholder engagement to influence the pass-through of our pricing signals within retail offers. SA Power Networks notes that Retailers are not obligated to pass through our pricing signals.

We will evaluate any feedback loops associated with our pricing strategy to understand how customer behaviour evolves during the 2025-30 RCP. This assessment will provide valuable insights on the impact of our proposed export tariffs to better refine our approach for the 2030-35 RCP.

New technologies

It is imperative that we continue to assess our strategy to consider the impact of the continued growth of new CER technologies on distribution network dynamics and load characteristics. We will be reviewing the components and the structures of our tariffs to ensure that they continue to support customers in meeting their energy needs.

High Voltage Network

Our proposed export tariffs for 2025-30 RCP are only for the low voltage distribution network. We will be monitoring the high voltage distribution network to identify any constraints to the distribution network capacity. If expenditure is required and approved for the high voltage distribution network, we will be proposing new tariffs or changes in existing tariff structures to ensure our tariffs continue to be cost reflective.

11.7 Export pricing and Annual Pricing Proposal

In setting our export tariff structure and pricing, we have applied a consistent approach for LV distribution network customers (Residential, Small and Medium business customers). LV distribution network customers have the same export charge, export credit, structure and basic export level threshold. The only difference is the application of the basic export level for Small and Medium Business Interval Meter customers as outlined in 11.5.2.

Export charge

For customers with an interval meter, the proposed export charge above the free threshold of 9kWh is 1c/kWh. Recognising that the accumulation meters cannot measure the time of export, the tariff for accumulation meters has a higher level of free export, 11kWh per day and a lower per unit export charge of 75 percent of the interval meter export charge. These differences are designed to ensure on average, a customer is neither advantaged nor disadvantaged because of their meter type. If a customer exports above the 11kWh threshold, they will be subject to an export charge of 0.75c/kWh.

We propose to maintain this pricing for the entirety of the 2025-30 RCP to provide price certainty whilst enabling clear and simple communication for all stakeholders the lead up to implementation.

Export Credit

The proposed export credit is available with RESELE and SBELE customer choice tariffs. It is limited to these tariffs because it allows us to develop a strong pricing signal to promote optimal outcomes for the distribution network. Our reward aims to encourage three key actions:

- consistent behavioural change,
- more installation of west-facing solar, and
- investment in batteries.

If successful in the long term, future augmentation costs can minimised. We consider that if price signals are not strong and set early, the ability for customers to change behaviour reduces. Limiting export rewards to RESELE and SBELE tariffs only will help us achieve this and encourage the wider adoption of these tariffs.

RESELE and SBELE tariffs have the strongest pricing signal for consumption during the peak time window and lower prices during all other time windows when the distribution network has the greatest capacity. These price signals aim to incentivise reduction in usage and/or load shifting. The addition of a strong export during the peak time window complements and further encourages customers to reduce their usage in the peak time window and reward them for any export to the grid. This approach ensures alignment in pricing objectives between the consumption and export components of the tariff.

As stated in the TSS Part A 5.1 the relativity for interval meter export reward is 62 percent of RESELE consumption peak price for both RESELE and SBELE. Therefore, the export credit will always be lower than the peak consumption price. It is imperative that the export credit component is lower than the corresponding RESELE peak consumption price during the peak demand time window. A higher export credit relative to the peak consumption charge means customers are encouraged to export CER energy during the peak window instead of using the energy for in-house consumption as they will earn more. If customers earn more from export credit than they pay in consumption charges, it could drive over-investment into CER technologies, which will drive inefficient distribution network use and create inequitable outcomes. Therefore, our proposed pricing structure, where the export credit component is lower than the consumption peak charge, aims to prevent the issues of inefficient investment.

RESELE and SBELE tariffs will likely play an essential role in the 2025-30 RCP with the uptake in electrification, smart appliances, batteries, and EVs. If passed through in retail offers, the strong pricing signals of the Electrify tariffs, including export charges and rewards, will incentivise customers to change their behaviour.

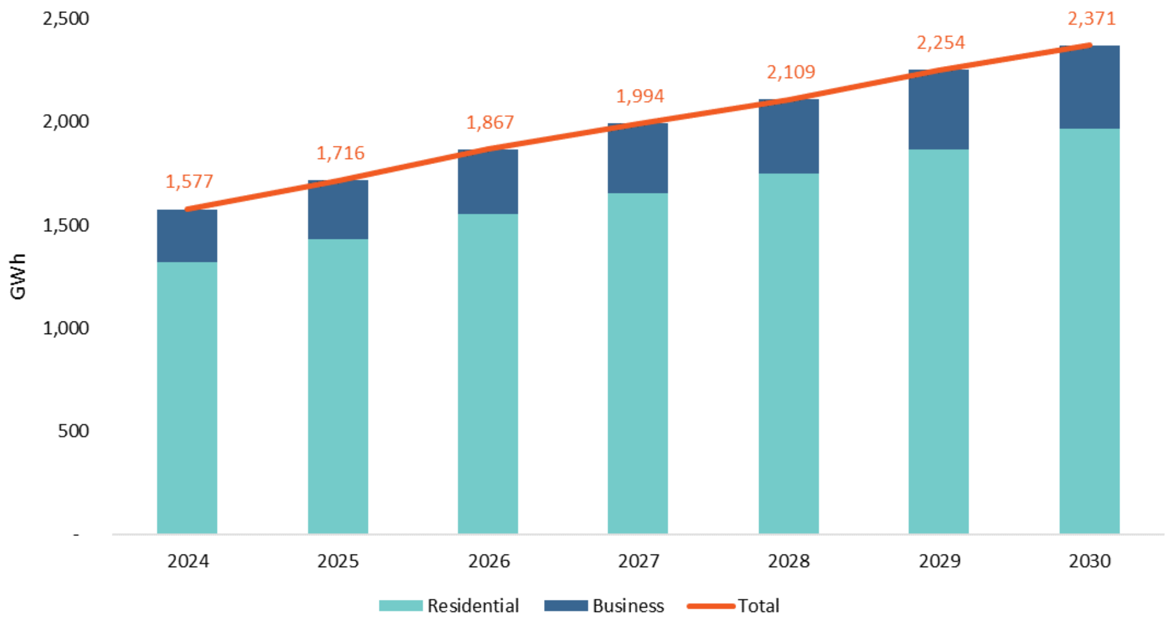
We do not consider a diluted export credit for a default Residential, Small and Medium Business tariffs will elicit a desirable distribution network response.

11.8 Export quantity forecast

We have estimated the export quantity forecast as part of our forecast process for TSS, as shown in Figure 62. The forecast net export from solar systems (0-100 kW) has been derived from the SA Power Networks' LV Planning Engine tool[14], which considers variables such as our long-term forecasts of CER uptake, investment programs, export constraints, hosting capacities and other inputs.

[14] For further details see 5.7.9 - CER Integration Modelling Methodology.

Figure 62: Export volume forecast by customer segment



Source: SA Power Networks analysis

Further adjustments were incorporated using findings from our sample analysis to forecast:

- Export volume from systems below 30kW
- Export volume during Solar Sponge 10:00am – 4:00pm and above the basic free threshold that will be subject to export charges
- Export volume during November to March 5:00pm – 9:00pm that will be subject to export credits

The results of our forecast are shown in Table 18 and Table 19.

Table 18: Quantity forecast for export charge

	2025/2026	2026/2027	2027/2028	2028/2029	2029/2030
Residential (GWh)	322.2	346.5	368.1	391.5	415.1
Business (GWh)	110.9	120.7	128.5	136.5	144.6

Table 19: Quantity forecast for export credit

	2025/2026	2026/2027	2027/2028	2028/2029	2029/2030
RESELE (GWh)	1.1	1.6	2.1	2.5	3.0
SBELE (GWh)	0.3	0.4	0.5	0.7	0.8

11.9 Bill impact analysis

Based on our proposed tariff structures for Residential, Small and Medium Business customers with export capacity less than 30kW we have completed analysis to illustrate the network bill impacts using 2025/26 indicative NUoS. The analysis is based on 2022/23 export data and considers the outcomes for both interval and accumulation meters[15]. Key findings are summarised in Table 20.

[15] SA Power Networks analysis using a sample of 1,774 solar residential NMIs and 1,661 solar small and medium business NMIs.

Table 20: Key findings of bill impact analysis

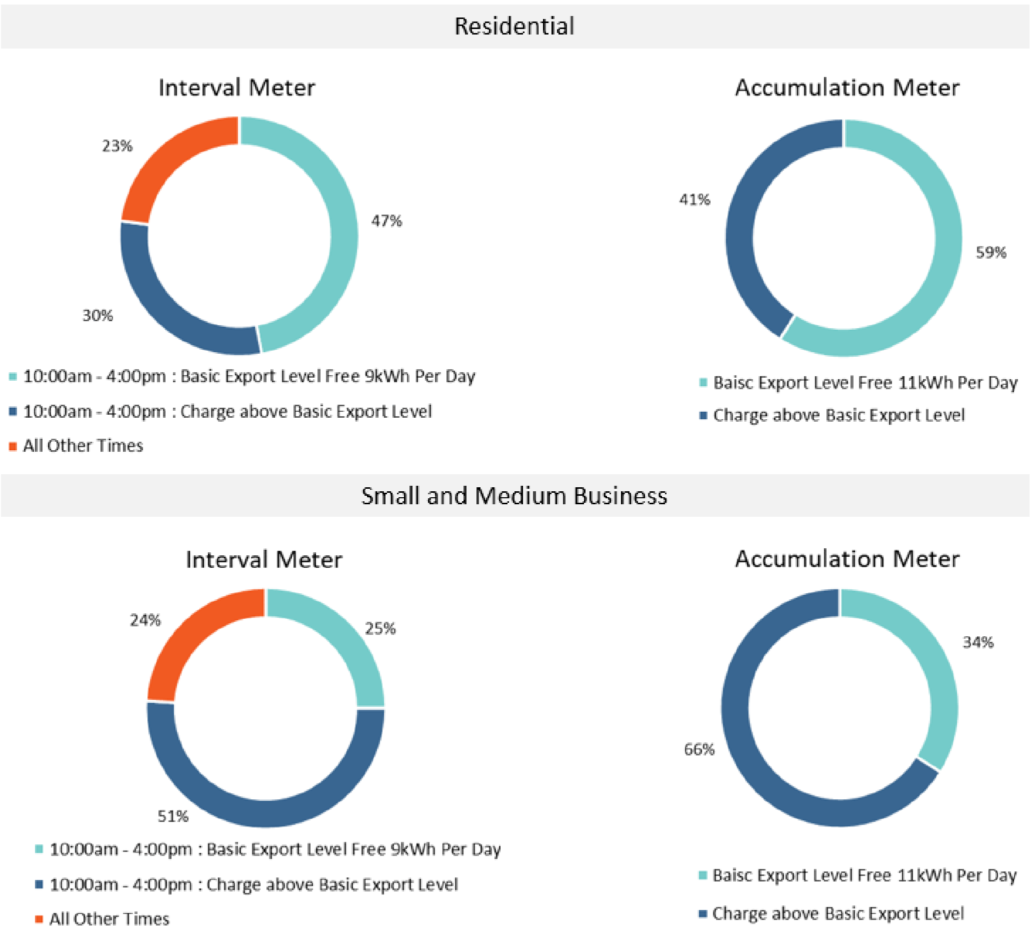
Number	Key findings
1	The proposed export pricing signals are designed only for a portion of customers' export energy.
2	Customers would be neither advantaged nor disadvantaged because of their meter type.
3	The proposed export tariff structure benefits customers who could shift their network usage in response to price signals.
4	The proposed export pricing structure ensures that most customers pay below the average export charge.
5	The average export charge for those customers experiencing vulnerability is lower than the state average.
6	Export charges are cost reflective as customers with larger solar systems will likely pay more.
7	Most customers on the RESELE and SBELE tariffs are likely to have a higher export credit than the export charge.

Key Finding 1: The proposed export pricing signals are designed only for a portion of customers' export energy.

Our analysis in Figure 63 shows that on average the majority of a Residential customer's export does not attract an export charge. Whilst for Small and Medium Business customers, up to 49 percent of export on average does not attract an export charge.

The roll over mechanism of the free basic export level in each of the proposed export tariffs results in customers being able to maximise the benefit of the free threshold as illustrated in the average outcomes for customers.

Figure 63: Export profiles for interval and accumulation meters



Key Finding 2: Customers would be neither advantaged nor disadvantaged because of their meter type.

The average export charges for Residential, Small and Medium Business customers are broadly similar as shown in Table 21. The analysis supports the export pricing relativities established by SA Power Networks of accumulation meter customers paying 0.75c/kWh compared to interval meter customers paying 1c/kWh for each kWh of export above the free threshold. The average outcomes also support the basis for different basic export levels for interval and accumulation meters.

Table 21: Average export charges by meter type

Average export charges	Interval Meter	Accumulation Meter
Residential	$ 14.77	$ 15.14
Small and Medium Business	$ 45.20	$ 44.45

Key Finding 3: The proposed export tariff structure benefits customers who could shift their network usage in response to price signals.

If customers can increase their daytime loads to consume more of their solar generation, they will reduce their export charges. Table 22 shows that if the average customer increased their usage between 10:00am – 4:00pm by 10 percent they could reduce their export charges by up to 20 percent on average. A load shift of this magnitude represents shifting the use of residential appliances like washing machines and dishwashers to the export charge window or for business optimising heating or cooling. Those customers with batteries have an even greater ability to load shift to respond to export charges. Currently, without any change in behaviour, business battery customers would pay up to 51 percent less on average in export charges. With the proposed introduction of export tariffs a customer can further consider how best to utilise their battery to maximise their price response.

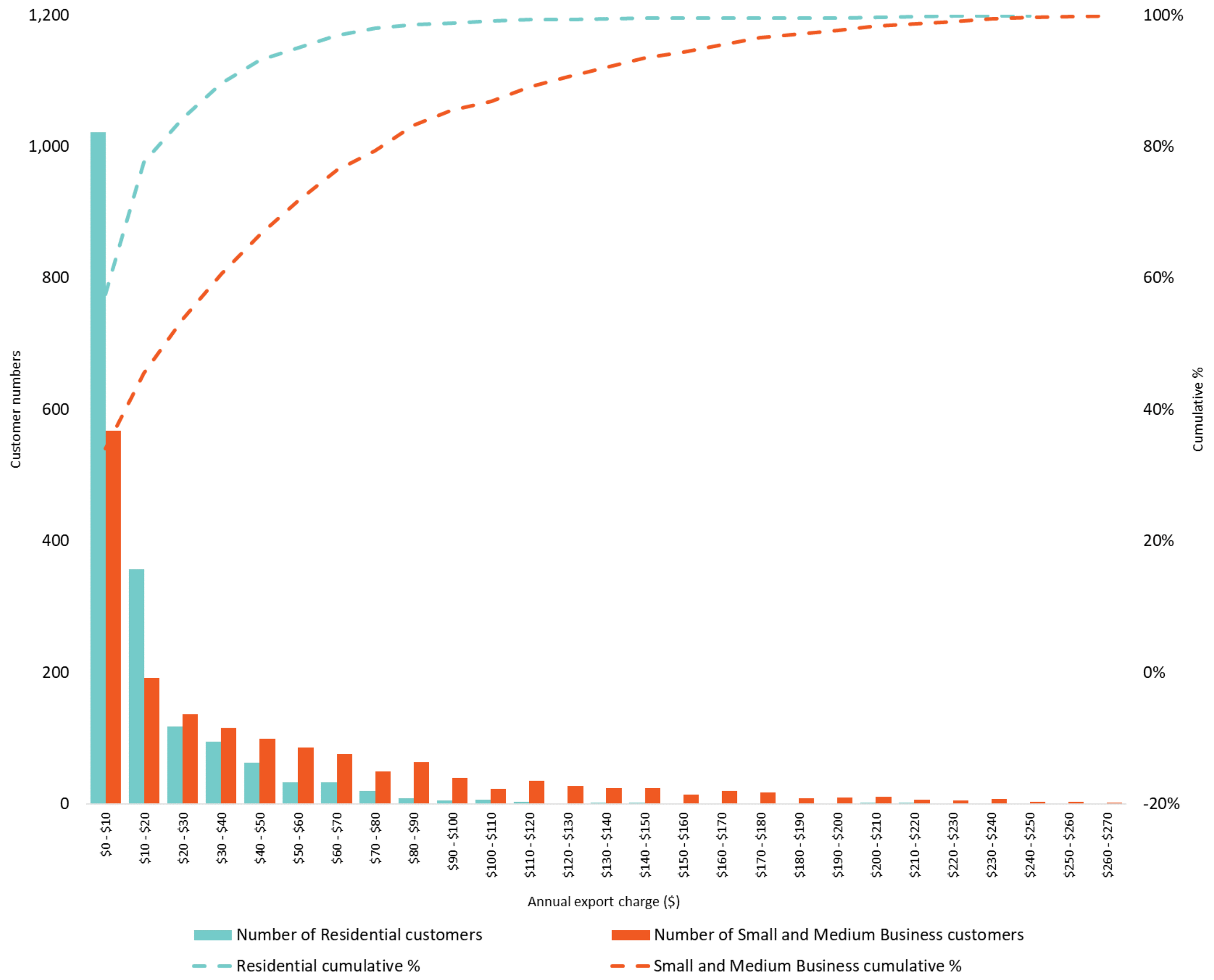
Table 22: Average export charge for customers with load shift flexibility

Average export charges	Interval Meter	10% load shift	Battery customers
Residential	$ 14.77	$ 11.86 (- 20%)	$ 12.12 (- 18%)
Small and Medium Business	$ 45.20	$ 38.94 (- 14%)	$ 22.27 (- 51%)

Key Finding 4: The proposed export pricing structure ensures that most customers pay below the average export charge.

The distribution of export charges for Residential, Small and Medium Business customers is shown in Figure 64. These charges are based on customer export with no behavioural change.

Figure 64: Annual export charges distribution for Residential and Small and Medium Business customers



Our analysis demonstrated that:

- 68 percent of Residential customers will pay less than the average export charge of $14.77, with 58 percent of customers paying less than $10 p.a.
- 64 percent of the Small and Medium Business customers will pay less than the average export charge of $45.20, with 54 percent of customers paying less than $30 p.a.

We observed that the median for both sample groups is lower than the average, indicating some customers are on the tail end of the distribution. For example, within the Residential sample group, one Residential customer would pay $250 p.a. export charges based on their current export profile with a solar system of 32.4kW panels and a 30kW inverter. Within the Small and Medium Business sample group, one customer would pay $269 p.a. based on their current export profile with a solar system of 33kW panels and a 30kW inverter. Export charges of this quantum illustrate that these customers are exporting large amounts into the distribution network and therefore a large contributor to the congestion in the low voltage distribution network. Facing such a pricing signal allows the customer to make a choice as to how they value their export.

Key Finding 5: The average export charge for those customers experiencing vulnerability is lower than the state average.

Further analysis of the average export charge shows that customers from disadvantaged suburbs and towns as identified in the analysis in Section 9.1, have an average export charge lower than the state average, as detailed in Table 23.

Table 23: Average export charge for customers from disadvantaged suburbs/towns compared to Residential customers

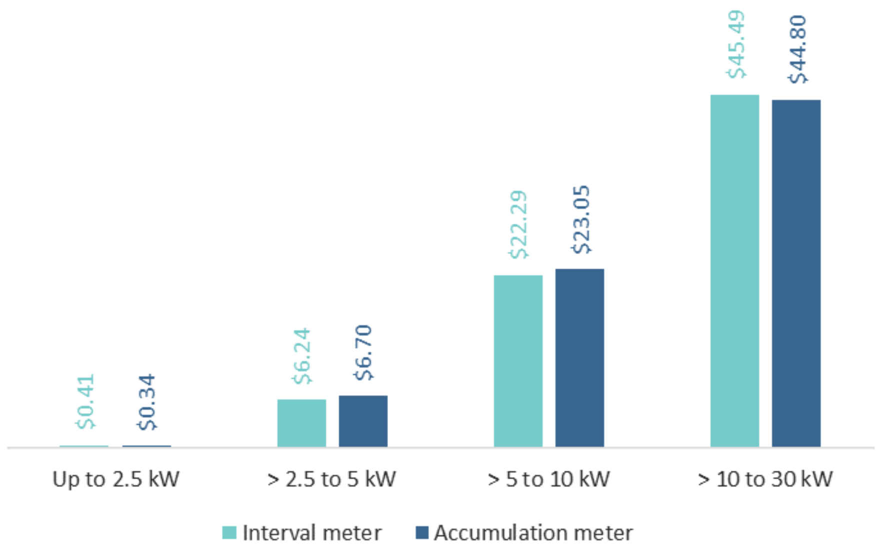
Average export charge	Interval meter
Customers from South Australia	$ 14.77
Customers from disadvantaged suburbs/towns	$ 11.30

The lower average export charge for customers from disadvantaged suburbs and towns can be attributed in part to these customers having an average solar system size that is smaller than the state average as detailed in Table 14.

Key Finding 6: Export charges are cost reflective as customers with larger solar systems will likely pay more.

Figure 65 shows Residential customers' average export charge categorised by solar system size.

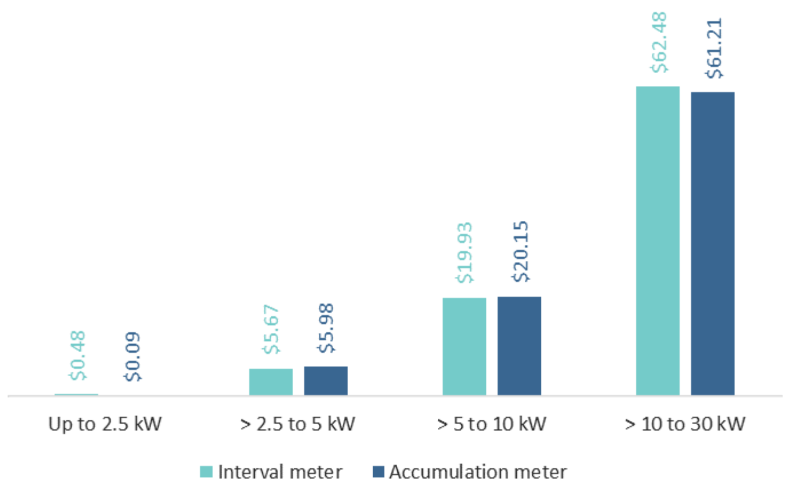
Figure 65: Average annual export charges for Residential interval and accumulation meter customers by solar system size



Residential customers with solar systems of below 2.5kW are, on average, going to pay less than $1 p.a. because their generation is largely self-consumed or if an amount is exported then it is within the free basic export level. As the size of the solar systems increases, the levels of export increase and therefore so do the quantum of export charges.

Figure 66 shows Small and Medium Business customers' average export charge categorised by solar system size.

Figure 66: Average annual export charges for Small and Medium Business interval and accumulation meter customers by solar system size

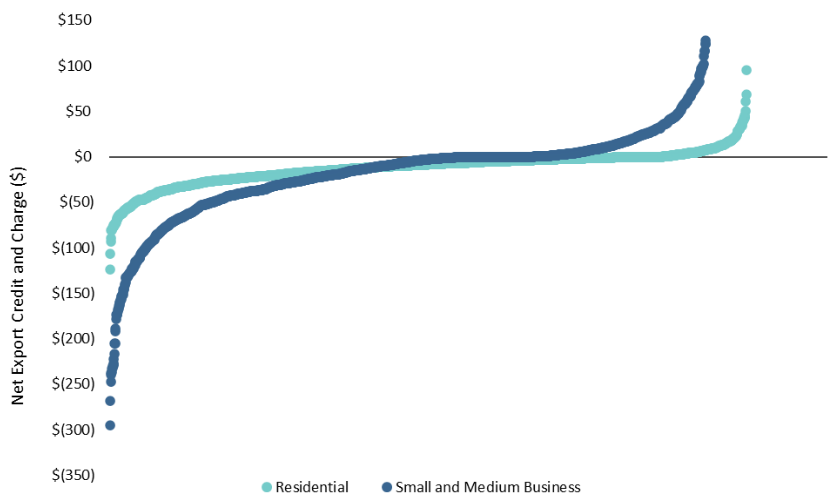


In line with the Residential analysis, Small and Medium Business customers export charges increase relative to the size of the solar system. Customers with solar systems of less than 2.5kW will, on average, pay less than $1 p.a. because their generation is largely self-consumed or if an amount is exported then it is within the free basic export level.

Key Finding 7: Most customers on the RESELE and SBELE tariffs are likely to have a higher export credit than the export charge.

SA Power Networks proposes an export credit component for export between November and March, 5:00pm – 9:00pm, available for the RESELE and SBELE tariffs. The net annual impact of the export charge and credit on the network bill is shown in Figure 67.

Figure 67: Net $ impact from export charge and credit for Residential, Small and Medium Business customers



In Figure 67 each data point represents the net annual export tariff impact, with those data points below the $0 showing customers who will achieve a net export credit based on current export data with no behavioural change. Our analysis shows that 87 percent of solar Residential and 68 percent of solar Small and Medium Business customers have a higher export credit than the export charge by being on RESELE and SBELE tariffs. The difference in data profiles illustrates the differences between Residential and Business export. Residential export is typically more homogeneous in nature resulting in smaller deviations from the average outcome whereas the diversity in business operations means that the outcome of bill impacts is much more varied.

11.10 Export LRMC

As per the Rule 6.18.5(f), our export tariffs must be based on LRMC. LRMC calculates the cost of providing the additional capacity to which the tariff relates. Generally, two methodologies can be used to estimate the cost component of the LRMC which are:

- Perturbation approach
- Average Incremental Cost (**AIC**) approach

In the Perturbation approach, the future planned capital and operating expenditures are recalculated every time the export capacity is increased by a fixed and permanent increment (perturbation). The Perturbation approach is the most aligned methodology to the LRMC theoretical framework compared to other methodologies. The Perturbation approach requires more detailed information, and the application of the methodology is feasible if the constraint is in one localised distribution network area.

We have chosen the AIC approach consistent with our approach in calculating the consumption LRMC. The constraint on the LV distribution network for solar export occurs throughout the distribution network and is not localised to a specific area. In developing our expenditure forecast, we modelled the likelihood of constraints across the distribution network. The resulting costs and the increased export are suited to the AIC approach.

We have estimated export LRMC using the AIC approach and on a $/kWh basis. In our calculation, we use the incremental export energy kWh between 10:00am and 4:00pm since we are required to offer a basic export level without charge. The LRMC is calculated only at the LV distribution network level since our charging parameters for export services are designed for LV customers. The equation for export LRMC is provided below.

$$LRMC\ (AIC) = \frac{Present\ Value\ (Growth\ related\ capex) + Present\ Value\ (Growth\ related\ opex)}{Present\ Value\ (incremental\ export\ between\ 10am - 4pm)}$$

Where:

- *Growth related capex* is annualised capital expenditure to meet the additional export over the forecast period;
- *Growth related opex* is the incremental annual cost of operating and maintaining newly constructed assets over the forecast period;
- *Incremental export between 10:00am to 4:00pm* is the incremental export quantity forecast between 10:00am and 4:00pm used in our calculation; and
- *Present Value* stands for the present value of that calculation.

We have used incremental cost in our export LRMC calculation. Historical costs (costs to provide our distribution network's intrinsic hosting capacity) are not included in our export LRMC calculation nor recovered through export charges. We only considered the additional costs to meet the incremental export between hours of 10:00am – 4:00pm which are the times of greatest utilisation of the export service. The expenditure programs and costs that are included in our export LRMC calculation are further detailed in **supporting document 18.2 - Long Run Marginal Cost Model – Export**. These expenditure programs and relevant cost drivers are further explained in the CER integration business cases. Costs allocated to export services do not overlap with costs allocated to consumption services and costs from 1 July 2025 are included in the export LRMC calculation and recoveries.

The LRMC $/kWh for LV distribution network customers is estimated at $ 0.0163. In establishing the export charge for the 2025-30 RCP, SA Power Networks noted that the export charge $/kWh is lower than the estimated LRMC $/kWh because of the following considerations:

a. Export expenditure is recovered from all LV customers that are exporting above the free threshold therefore a higher number of customers is eligible for the export charge than in the incremental export calculation. Only expenditures related to export services are included in our calculations.
b. In our export LRMC calculation, we use the incremental volume above the basic threshold enabled by the expenditure. In contrast, the export recovery charge is based on the total volume above the free threshold. A higher denominator will result in a lower export charge.
c. In translating the LRMC estimates to charging parameters, no residual costs are included within our export charge, unlike the charging parameters for consumption charges. Therefore, the export charge only recovers the efficient costs for the export customers, resulting in a lower export charge.

11.11 Stakeholder factsheet

SA Power Networks have developed export tariff factsheets to assist stakeholders in their understanding. These factsheets aim to explain:

- why we are proposing export charges and credits;
- the proposed tariff structures;
- who export tariffs will apply to;
- how the free basic export level, export charges and credits are calculated;
- when export pricing is proposed to be implemented; and
- what customers can do to respond to the pricing signals.

We recognise that comprehensive guidance for customers, retailers, government, and other market participants in advance of implementation is critical and commit to developing further material to support and inform all stakeholders.

Figure 68: Residential Two-way pricing customer fact sheet

Residential Two-Way Pricing

Customer fact sheet

SA Power Networks

Empowering South Australia

SA Power Networks is proposing to introduce two-way pricing for Residential customers from 1 July 2025. This fact sheet discusses what is two-way pricing and how it works.

Background

SA Power Networks owns, operates and maintains the electricity distribution network that delivers power to homes and businesses across South Australia.

We bill your Retailer for delivering your electricity, with our charges being around 25% of the retail bill.

Our distribution tariff structures and charges are approved by the Australian Energy Regulator. We design our tariff structures and pricing to encourage more use of our network in non-peak times and less in peak times. This encourages efficient utilisation of the network, helping to reduce future network upgrade costs for customers.

Why two-way pricing?

We are developing systems and approaches to accommodate more renewable energy on the electricity grid at least cost. To date, network investment costs to enable export services for customers who have installed rooftop solar have been paid for by all customers, including those without solar including many customers on government concessions.

To ensure greater equity, national electricity rules have changed, allowing for the cost of export-related network investment to be recovered via export charges. The rule change also enables distribution networks to reward customers with export credits when they export into the electricity grid at times when it is most needed.

Introducing two-way pricing allows us to increase the capacity of the distribution network to host more solar whilst also increasing the ability of others to access the benefits of solar.

Proposed export tariffs from 1 July 2025

Following extensive consultation with customers and stakeholders, SA Power Networks proposes to introduce two-way pricing on 1 July 2025. This pricing will apply to all customers with solar and/or battery systems who can export energy up to 30kW. The two-way pricing structure applicable to export customers will depend on the type of meter: Interval or Accumulation.

An Interval Meter records how much energy is used every 30 minutes. It is read remotely with the energy data being sent each day to the Retailer. A customer will typically receive a bill every month. An Accumulation Meter records total energy data only, it does not record what time of day the energy is used. It is read manually by a person going to the location of the meter approximately every 90 days. A customer will typically receive a bill every quarter.

Proposed changes will see all Accumulation Meters replaced with Interval meters by 2030.

How it will impact retail bills

Export charges and credits will be billed directly to Retailers. A customer may not see these on their electricity bill but will receive a bundled retail offer comprising all the charges and credits associated with the export and delivery of electricity.

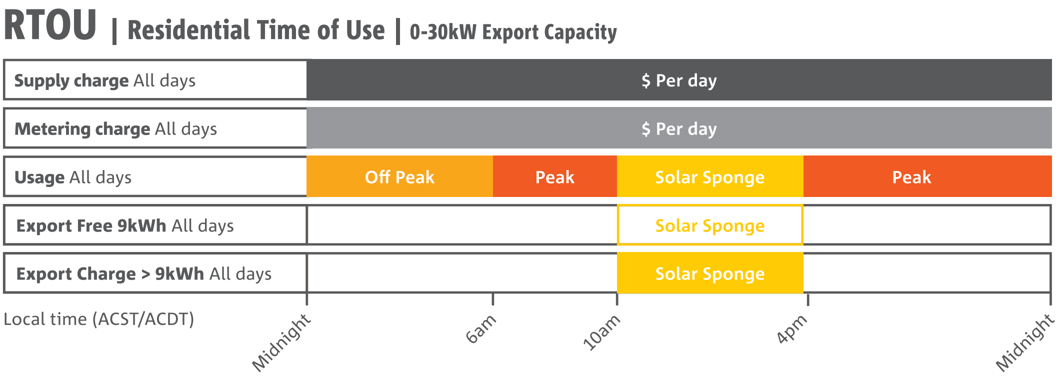
These distribution charges and credits are separate from and in addition to the current feed in tariffs offered by Retailers. Customers will likely to continue to earn rewards on their exports from Retailers as they are higher than the proposed export charges. A customer may also earn additional export credits from the Retailer on top of the distribution credit being proposed.

Customers can choose which Retailer and retail offer is best for their circumstances and we encourage customers to go to the independent Australian Government website **energymadeeasy.gov.au** to help make an informed decision.

Tariff offers and worked examples

Figure 1 outlines the Default two-way tariff for Residential customers who can export up to 30kW with an Interval Meter. A Default tariff is a tariff that the customer is automatically assigned to.

Figure 1: Residential Interval Meter two-way tariff | Default



Under this tariff, there will be no charges for the first 9kWh exported every day between 10am – 4pm. Exports above this threshold will be subject to an export charge of 1c/kWh. All export outside 10am – 4pm would be free.

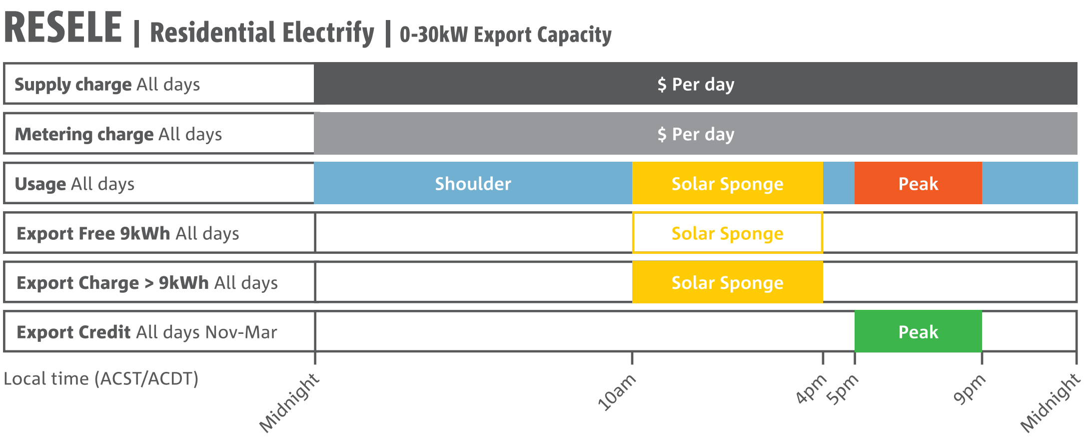
If the free export threshold is not used on the day, for example it is an overcast day, the unused export can be rolled over to the next day within a single billing period. Billing periods are typically 30 days.

The example below illustrates the monthly distribution bill impact on the Default Residential two-way tariff for Interval Meters for a customer exporting 592kWh over a 30 day period with a typical 6kW of solar panels and a 6kW inverter. 449kWh of this export occurs between 10am – 4pm and the remaining 143kWh of export occurs at all other times.

Billing Period Days	**30 Days** 5 November – 4 December inclusive	
Free Export per day 9kWh 10am – 4pm Unused export can be rolled over within the billing period	**270kWh**	30 Days x 9kWh = 270kWh 270kWh x $0.0 = **$0.0**
Export Distribution Charge	**$0.01/kWh**	
Solar Sponge Export 10am – 4pm	**449kWh**	449kWh – 270kWh = 179kWh 179kWh x $0.01 = **$1.79**
Export at All Other Times	**143kWh**	143kWh x $0.0 = **$0.0**
Total Export	**592kWh**	**$1.79 charge**

Figure 2 outlines the Customer Choice two-way tariff for Residential customers who can export up to 30kW with an Interval Meter. A Customer Choice tariff is a tariff which the customer can choose to be on instead of the Default tariff.

Figure 2: Residential Interval Meter Electrify two-way tariff | Customer Choice



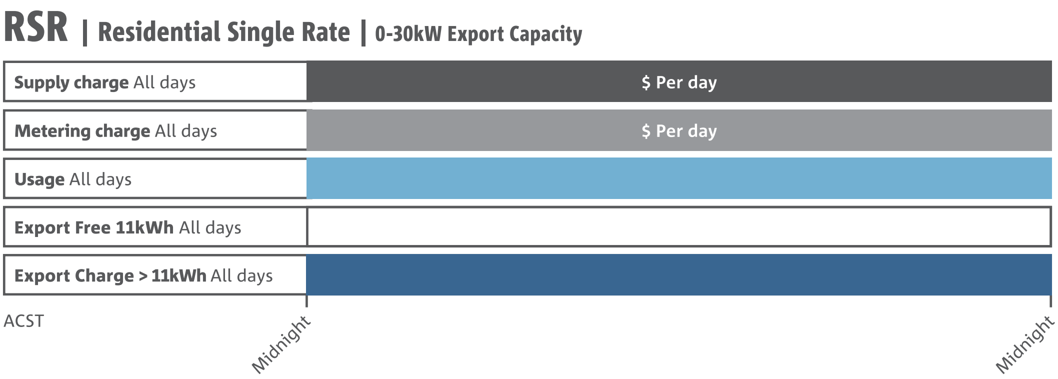
For those customers who have the ability to export into the distribution network via a west facing solar or a battery in the summer peak window of 5pm – 9pm from November to March the Electrify two-way tariff structure may be attractive. While it retains the 9kWh free threshold and has the same export charge window as the Default tariff, it also provides an export credit to customers who export during the 5pm – 9pm window from November to March (which is our peak demand period).

The example below illustrates the monthly distribution bill impact on the Customer Choice Residential two-way tariff for Interval Meters for the same customer exporting 592kWh over a 30 day period with a typical 6kW of solar panels and a 6kW inverter. 449kWh of this export occurs between 10am – 4pm, 126kWh occurs between 5pm – 9pm and the remaining 17kWh of export occurs at all other times.

Billing Period Days	**30 Days** 5 January – 3 February inclusive	
Free Export per day 9kWh 10am – 4pm Unused export can be rolled over within the billing period	**270kWh**	30 Days x 9kWh = 270kWh 270kWh x $0.0 = **$0.0**
Export Distribution Charge	**$0.01/kWh**	
Solar Sponge Export 10am – 4pm	**449kWh**	449kWh – 270kWh = 179kWh 179kWh x $0.01 = **$1.79**
Export Credit 5pm – 9pm November to March	**126kWh**	126kWh x $0.1287 = **$16.22**
Export at All Other Times	**17kWh**	17kWh x $0.00 = **$0.0**
Total Export	**592kWh**	**$14.43 credit**

Figure 3 outlines the Default two-way tariff for Residential customers who can export up to 30kW with an Accumulation Meter.

Figure 3: Residential Accumulation Meter two-way tariff | Default



Recognising Accumulation Meters cannot measure time of export, this tariff has a higher level of free export, 11kWh every day and a lower per unit export charge of 75% of the Interval Meter export charges. These differences are designed to ensure on average a customer is neither advantaged or disadvantaged because of their meter type. If a customer exports above the 11kWh threshold they will be subject to an export charge of 0.75c/kWh.

If the free export threshold is not used on the day, for example it is an overcast day, the unused export can be rolled over to the next day within a single billing period. Billing periods are typically 90 days.

The example below illustrates the quarterly distribution bill impact on the Default Residential two-way tariff for Accumulation Meters for a customer exporting 1,497kWh over a 90 day period with a typical 6kW of solar panels and a 6kW inverter.

Billing Period Days	**90 Days** 5 January – 4 April inclusive	
Free Export per day Unused export can be rolled over within the billing period	**11kWh**	90 Days x 11kWh = 990kWh 990kWh x $0.0 = **$0.0**
Export Distribution Charge	**$0.0075/kWh**	1,497kWh – 990kWh = 507kWh 507kWh x $0.0075 = **$3.80**
Total Export	**1,497kWh**	**$3.80 charge** **($1.27 charge per month average)**

What can I do as a customer?

You should consider what electricity usage in your household is flexible and can be shifted to operate between 10am – 4pm to limit or avoid export charges. For example, washing machines and dishwashers could be programmed to operate during the day. If you work from home during the day and have an electric vehicle (EV), you could charge your EV during the day. Pre heating or cooling your home is another way to self consume your generation and reduce evening consumption. Any household load which can be moved to the daytime will reduce the amount of export to the grid and therefore reduce the export charges incurred over and above the free threshold. Some households may consider investing in a battery to allow for energy to be generated and stored and used later in the evening during peak time.

Figure 69: Small and Medium Business Two-way pricing customer fact sheet

Small and Medium Business Two-Way Pricing

Customer fact sheet

SA Power Networks

Empowering South Australia

SA Power Networks is proposing to introduce two-way pricing for Small and Medium Business customers from 1 July 2025. This fact sheet discusses what is two-way pricing and how it works.

A Small Business is defined as having annual consumption of up to 40MWh. A Medium Business is defined as having annual consumption of between 40 – 160MWh. These businesses are connected to the low voltage distribution network.

Background

SA Power Networks owns, operates and maintains the electricity distribution network that delivers power to homes and businesses across South Australia.

We bill your Retailer for delivering your electricity, with our charges being around 25% of the retail bill.

Our distribution tariff structures and charges are approved by the Australian Energy Regulator. We design our tariff structures and pricing to encourage more use of our network in non-peak times and less in peak times. This encourages efficient utilisation of the network, helping to reduce future network upgrade costs for customers.

Why two-way pricing?

We are developing systems and approaches to accommodate more renewable energy on the electricity grid at least cost. To date, network investment costs to enable export services for customers who have installed rooftop solar have been paid for by all customers, including those without solar including many customers on government concessions.

To ensure greater equity, national electricity rules have changed, allowing for the cost of export-related network investment to be recovered via export charges. The rule change also enables distribution networks to reward customers with export credits when they export into the electricity grid at times when it is most needed.

Introducing two-way pricing allows us to increase the capacity of the distribution network to host more solar whilst also increasing the ability of others to access the benefits of solar.

Proposed export tariffs from 1 July 2025

Following extensive consultation with customers and stakeholders, SA Power Networks proposes to introduce two-way pricing on 1 July 2025. This pricing will apply to all customers with solar and/or battery systems who can export energy up to 30kW. The two-way pricing structure applicable to export customers will depend on the type of meter: Interval or Accumulation.

An Interval Meter records how much energy is used every 30 minutes. It is read remotely with the energy data being sent each day to the Retailer. A customer will typically receive a bill every month. An Accumulation Meter records total energy data only, it does not record what time of day the energy is used. It is read manually by a person going to the location of the meter approximately every 90 days. A customer will typically receive a bill every quarter.

Proposed changes will see all Accumulation Meters replaced with Interval meters by 2030.

How it will impact retail bills

Export charges and credits will be billed directly to Retailers. A customer may not see these on their electricity bill but will receive a bundled retail offer comprising all the charges and credits associated with the export and delivery of electricity.

These distribution charges and credits are separate from and in addition to the current feed in tariffs offered by Retailers. Customers will likely to continue to earn rewards on their exports from Retailers as they are higher than the proposed export charges. A customer may also earn additional export credits from the Retailer on top of the distribution credit being proposed.

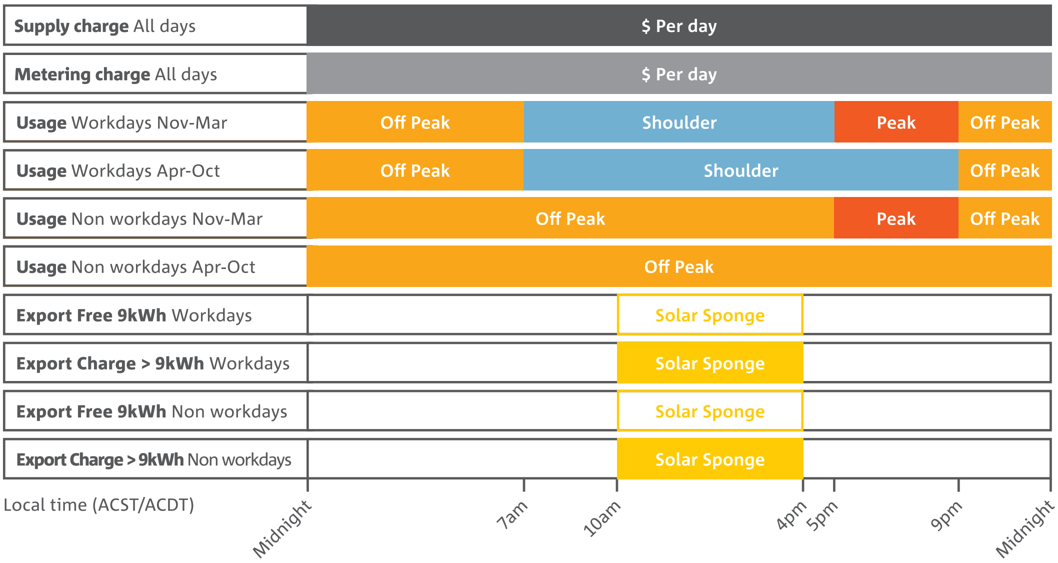
Customers can choose which Retailer and retail offer is best for their circumstances and we encourage customers to go to the independent Australian Government website **energymadeeasy.gov.au** to help make an informed decision.

Tariff offers and worked examples

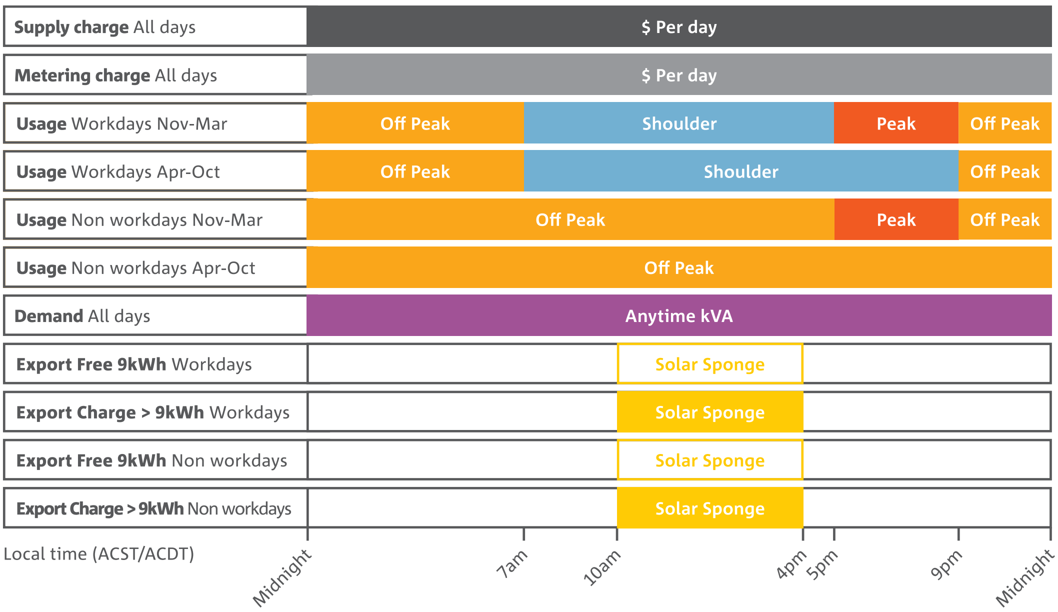
Figure 1 outlines the Default two-way tariff for Small and Medium Business customers who can export up to 30kW with an Interval Meter. A Default tariff is a tariff that the customer is automatically assigned to.

Figure 1: Small and Medium Business Interval Meter two-way tariffs | Default

SBTOU | Small Business Time of Use | 0-30kW Export Capacity



MBTOUD | Medium Business Time of Use Demand | 0-30kW Export Capacity



SA Power Networks

Small and Medium Business Two-Way Pricing Customer Fact Sheet | 2

Under this tariff, there will be no charges for the first 9kWh exported every day between 10am – 4pm. Exports above this threshold will be subject to an export charge of 1c/kWh. All export outside 10am – 4pm would be free.

If the free export threshold is not used on the day, for example it is an overcast day, the unused export can be rolled over to the next day within a single billing period. Billing periods are typically 30 days.

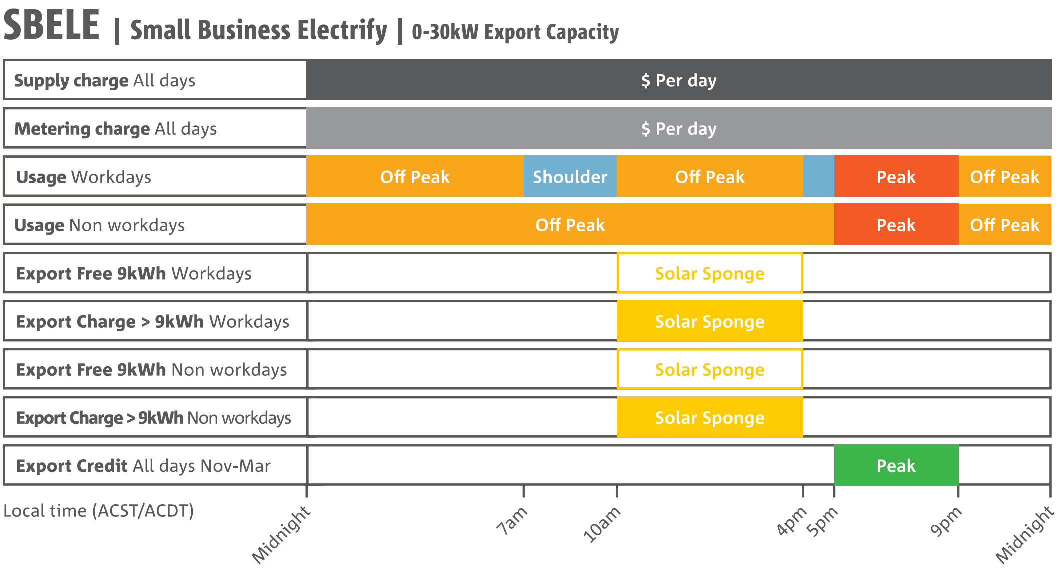
Small and Medium Business Interval Meter consumption tariff structures categorise days of the week by Workdays and Non workdays. Workdays are Monday – Friday and Non workdays are Saturday, Sunday and Public Holidays. Unused free export on a Workday can only be rolled over to another Workday. Unused free export on a Non workday can only be rolled over to another Non workday.

The example below illustrates the monthly distribution bill impact on the Default Small and Medium Business two-way tariff for Interval Meters for a business exporting 1,993kWh over a 30 day period with 19.2 kW of solar panels and 15kW inverter. 1,303kWh of this export occurs between 10am – 4 pm and the remaining 690kWh of export occurs at all other times.

Billing Period Days	**30 Days** 22 Workdays, 8 Non workdays 1 November – 30 November inclusive	
Free Export per day 9kWh 10am – 4pm Unused export can be rolled over within the billing period based on Workdays/Non workdays	**198kWh** Workday	22 Days x 9kWh = 198kWh 198kWh x $0.0 = **$0.0**
	72kWh Non Workday	8 Days x 9kWh = 72kWh 72kWh x $0.0 = **$0.0**
Export Distribution Charge	**$0.01/kWh**	
Solar Sponge Export 10am – 4pm	**954kWh** Workdays	954kWh – 198kWh = 756kWh 756kWh X $0.01 = **7.56**
	349kWh Non workdays	349kWh – 72kWh =277kWh 277kWh X $0.01 = **$2.77**
Export at All Other Times	**690kWh**	690kWh X $0.00 = **$0.0**
Total Export	**1,993kWh**	**$10.33 charge**

Figure 2 outlines the Customer Choice two-way tariff for Small Business customers who can export up to 30kW with an Interval Meter. A Customer Choice tariff is a tariff which the business can choose to be on instead of the Default tariff.

Figure 2: Small Business Interval Meter Electrify two-way tariff | Customer Choice



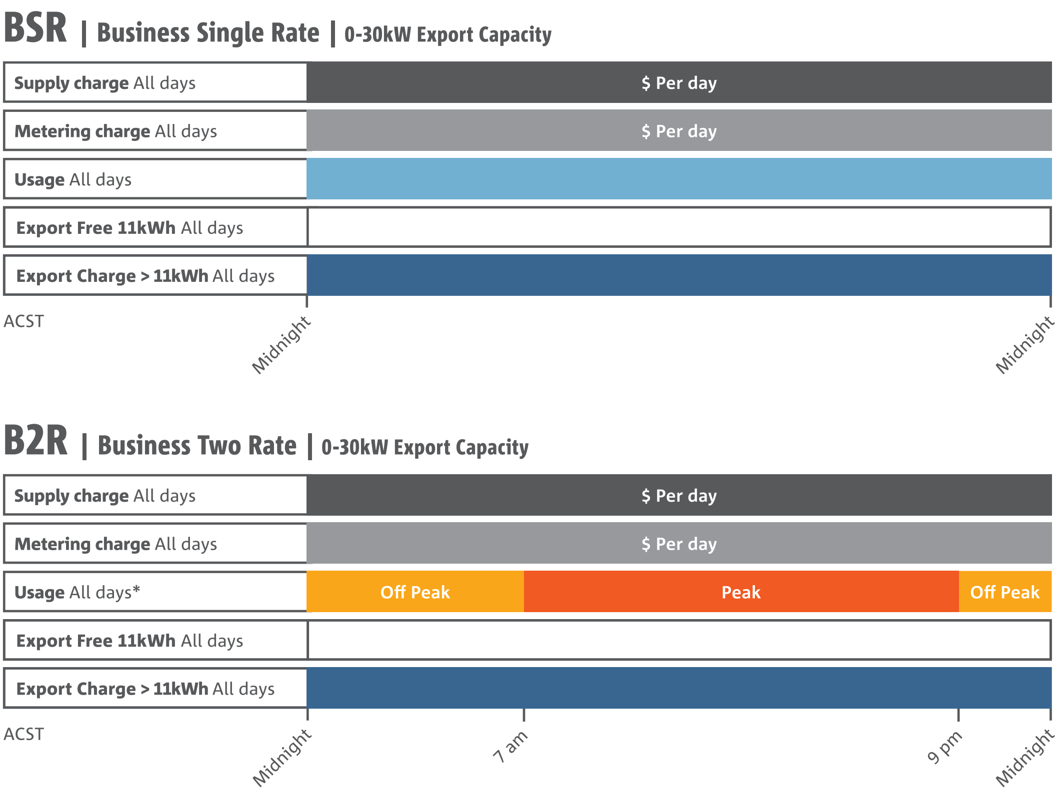
For those businesses who have the ability to export into the distribution network via west facing solar or a battery in the summer peak window of 5pm – 9pm from November to March the Electrify two-way tariff structure may be attractive. While it retains the 9kWh free threshold and has the same export charge window, as the Default tariff, it also provides an export credit to businesses who export during the 5pm – 9pm window from November to March (which is our peak demand period).

The example below illustrates the monthly distribution bill impact on the Customer Choice Small Business two-way tariff for Interval Meters for the same business exporting 1,993kWh over a 30 day period with 19.2kW of solar panels and a 15kW inverter. 1,303kWh of this export occurs between 10am – 4pm, 269kWh occurs between 5pm – 9pm and the remaining 421kWh of export occurs at all other times.

Billing Period Days	**30 Days** 22 Workdays, 8 Non workdays 1 November – 30 November inclusive	
Free Export per day 9kWh 10am – 4pm Unused export can be rolled over within the billing period based on Workdays/Non workdays	**198kWh** Workday	22 Days x 9kWh = 198kWh 198kWh x $0.0 = **$0.0**
	72kWh Non Workday	8 Days x 9kWh = 72kWh 72kWh x $0.0 = **$0.0**
Export Distribution Charge	**$0.01/kWh**	
Solar Sponge Export between 10am – 4pm	**954kWh** Workdays	954kWh – 198kWh = 756kWh 756kWh x $0.01 = **$7.56**
	349kWh Non workdays	349kWh – 72kWh = 277kWh 277kWh X $0.01 = **$2.77**
Export credit 5pm – 9pm November to March	**269kWh**	269kWh X $0.1287 = **$34.62**
Export at All Other Times	**421kWh**	421kWh X $0.00 = **$0.0**
Total Export	**1,993kWh**	**$24.29 Credit**

Figure 3 outlines the Default two-way tariff for Small and Medium Business customers who can export up to 30kW with an Accumulation Meter.

Figure 3: Small and Medium Business Accumulation Meter two-way tariff | Default



*Time clock is managed by SA Power Networks. Peak supply usage is typically Monday to Friday but can be all days between 7am and 9pm

Recognising Accumulation Meters cannot measure time of export, this tariff has a higher level of free export, 11kWh every day and a lower per unit export charge of 75% of the Interval Meter export charges. These differences are designed to ensure on average a business is neither advantaged or disadvantaged because of their meter type. If a customer exports above the 11kWh threshold they will be subject to an export charge of 0.75c/kWh.

If the free export threshold is not used on the day, for example it is an overcast day, the unused export can be rolled over to the next day within a single billing period. Billing periods are typically 90 days.

The example below illustrates the quarterly distribution bill impact on the Default Small and Medium Business two-way tariff for Accumulation Meters for a business exporting 6,677kWh over a 92 day period with 19.2 kW of solar panels and a 15kW inverter.

Billing Period Days	**92 Days** 1 October – 31 December inclusive	
Free Export per day Unused export can be rolled over within the billing period	**11kWh**	92 Days x 11kWh = 1,012kWh 1,012kWh x $0.0 = **$0.0**
Export Distribution Charge	**$0.0075/kWh**	6,677kWh – 1,012kWh = 5,665kWh 5,665kWh x $0.0075 = **$42.49**
Total Export	**6,677kWh**	**$42.49 charge ($14.16 charge per month average)**

What can I do as a business?

You should consider whether any of your business' electricity usage is flexible and can be shifted to operate between 10am – 4pm to limit or avoid export charges. For example, a business could shift heating or cooling of the building to align with the solar window. Consideration may also be given to replacing fleet with electric vehicles which can be charged at the business premises during the day or investing in a battery which may better suit the operations of the business as a way of avoiding peak usage charges. Any business load which can be moved to the daytime will reduce the amount of export to the grid and therefore reduce the export charges incurred over and above the free threshold.

12 Pricing Methodology

12.1 Compliance with Rules

SA Power Networks 2025-30 RCP pricing methodology is consistent with the current 2020-25 RCP, with some key changes as outlined below:

- We have updated the stand alone and avoidable cost model for the new 2025-30 RCP, consistent with the existing revenue recovery model. Our pricing approach did not vary from the update.
- We have updated the consumption LRMC calculation. The updated consumption LRMC model considers the increased expenditure and higher demand due to electrification, resulting in a lower cost than the consumption LRMC calculation for the 2020-25 TSS. We have adjusted the Large Business peak demand prices to reflect the consumption LRMC. Usage prices have been adjusted to recover the balance of the efficient costs.
- We have created a new export LRMC model to calculate the export charges.
- We have elected to continue to use our cost allocation model, which has been updated for the 2025-30 RCP.

This section demonstrates how SA Power Networks' network tariffs for the 2025-30 RCP will comply with the requirements of the Rules and pricing principles. All proposed tariffs in the TSS comply with the Rules and all applicable regulatory instruments.

Rule requirements

The network pricing objective has been specified in Rule 6.18.5(a), which requires that our tariff charges reflect our efficient costs of providing these services to customers. We note that the AER will determine efficient costs in its regulatory determinations.

Clause 6.18.1A(b) of the Rules specifies that SA Power Networks' TSS must comply with the pricing principles for direct control services. The pricing principles set out in clauses 6.18.5(e) - (j) of the Rules are shown below.

Pricing principles

(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 service; 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;
    (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 of the relevant service 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 decisions about usage of services.

(i) The structure of each tariff must be reasonably capable of:

(1) being understood by retail customers that are or may be assigned to that tariff (including in relation to how decisions about usage of services or controls may affect the amounts paid by those customers) or

(2) 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:

(3) the type and nature of those retail customers;

(4) the information provided to, and the consultation undertaken with, those retail customers; and

(5) the information provided by, and consultation undertaken with, retailers and Market Small Generation Aggregators.

(j) A tariff must comply with the Rules and all applicable regulatory instruments.

Clause 6.18.6 Side Constraint

SA Power Networks, under the Rules is limited to the annual movement of revenue recovery between tariff classes. Any tariff class cannot face increases above the permissible percentage as outlined in the Rules. The side constraint applies to the DUoS only and/or the tariff class as a whole, and not to individual tariffs, tariff elements, or individual customer outcomes.

Compliance with this side constraint is addressed in our APP and is not discussed in detail in this TSS. SA Power Networks will ensure that the annual increase of each tariff class, weighted average DUoS price, is not more than the permissible percentage overall.

12.2 Compliance with NER pricing principles

This section demonstrates SA Power Networks' compliance with the pricing principles set out in clause 6.18.5 of the Rules, in particular the pricing principles set out in paragraphs (e) to (j) above.

Clause 6.18.5(e) Stand alone and Avoidable costs

Paragraph (e) of clause 6.18.5 of the Rules requires SA Power Networks to ensure that the revenue recovered for each tariff class lies between:

- an upper bound, representing the stand alone cost of serving the retail customers who belong to that class; and
- a lower bound, representing the avoidable cost of not serving those retail customers.

The stand alone and avoidable cost methodologies are consistent with those used for the 2020-25 TSS. They have been reviewed and updated with the characteristics of our assets and feeders.

These costs are compared with the revenue derived from SA Power Networks' proposed indicative prices and forecast quantities. The tariff revenue recovered for each tariff class lies between the stand alone and avoidable costs. Table 24 outlines the comparison for 2025/26.

Table 24: Stand alone and avoidable costs for 2025/26 ($ nominal)

Tariff Class	Stand alone cost $m	Tariff Revenue $m	Avoidable Cost $m
Major Business	28	12	6
High Voltage Business	51	41	23
Large Low Voltage Business	293	234	122
Small Business	496	174	109
LV Residential	720	490	373
Total Revenue (efficient cost)		952	

Source: SA Power Networks analysis

Clause 6.18.5(f) Long-run marginal costs

Consumption LRMC

The consideration of LRMC applies where price signalling charging parameters (peak period energy and demand-related components) form part of a tariff. SA Power Networks aims to ensure that where price signals are varied, they are moved in such a direction as to improve alignment with the LRMC. Charging components that materially over-recover or under-recover the LRMC would not pass on an efficient pricing signal to customers, representing their cost of utilising the distribution network.

In this TSS, we have applied the AIC approach to determine the distribution network consumption LRMC for our tariff classes, consistent with our previous TSS. The calculation for this approach has been carried out at the following levels:

a. Sub Transmission (33kV and 66kV)
b. Zone Substation (11kV busbar)
c. HV Feeder (11kV system connected)
d. Distribution transformer (LV connected at the substation busbar)
e. LV Feeder (connected to the LV distribution network)

The marginal cost at each level has been determined using the following equation:

$$LRMC\ (AIC) = \frac{Present\ Value\ (Growth\ related\ capex) + Present\ Value\ (Growth\ related\ opex)}{Present\ Value\ (incremental\ demand)}$$

Where:

- *Growth related capex* is annualised capital expenditure to meet the additional demand over the forecast period;
- *Growth related opex* is the incremental annual cost of operating and maintaining newly constructed assets over the forecast period;
- *Incremental demand* is the forecast change in kVA demand compared with the 2024/25 base year; and
- *Present Value* stands for the present value of that calculation.

The calculated AIC values derived are shown in Table 25 these values are derived for each system level.

Table 25: SA Power Networks consumption LRMC $/kVA p.a. (June 2025)

System Level	Δ MW	Δ Cost	ST	HV Bus	HV Net	LV Bus	LV Net	Alloc. Cost	$/kW/year	pf	$/kVA/year
ST	21.2	10.0	0.2					0.2	$10	0.95	$9.9
HV Bus	20.6	25.2	0.2	0.6				0.8	$37	0.90	$33.5
HV Net	51.0	26.4	0.5	1.4	1.5			3.4	$66	0.90	$59.4
LV Bus	234.6	12.6	2.5	6.3	6.8	3.4		18.9	$81	0.90	$72.5
LV Net	632.7	7.8	6.6	16.9	18.2	9.2	7.8	58.8	$93	0.90	$83.6
Totals	960.1	82.0	10.0	25.2	26.4	12.6	7.8	82.0			

Source: SA Power Networks analysis

Where:

Δ MW	refers to the change in MW (demand)
Δ cost	refers to the change in costs
ST	refers to sub transmission lines level
HV Bus	refers to the High Voltage bus at the zone substation
HV Net	refers to the High Voltage feeder
LV Bus	refers to the distribution transformers
LV Net	refers to the Low Voltage distribution network
Alloc cost	refers to the allocated cost
$/kW/year	refers to the demand charge for measured kW each year
Pf	refers to the power factor for the class
$/kVA/year	refers to the demand charge for measured kVA each year

The calculation of the AIC from the forecast kW demand is represented in $/kW p.a. The distribution network is augmented to provide additional capacity represented in kVA for the connection of additional load rather than in kW terms. Accordingly, the consumption LRMC has been converted to $/kVA p.a. using the typical (and compliant) power factor for each voltage level.

The consumption LRMC outcomes of our distribution network ($/kVA p.a.) have been calculated for individual tariff classes for 2025/26 in Table 26.

Table 26: SA Power Networks consumption LRMC $/kVA p.a. (June 2025)[16]

Voltage Step	Tariff Class	Step	Total
ST	Major Business Sub Transmission	$9.92	$9.92
HV Bus	Major Business Zone Substation	$23.59	$33.51
HV Network	HV Business	$25.91	$59.43
LV Bus	Large LV Business	$13.04	$72.46
LV Network	Combined Small Business and Residential	$11.12	$83.58

Source: SA Power Networks analysis

[16] Numbers do not add due to rounding.

Clause 6.18.5(g) – Tariffs reflect total efficient costs

The way in which consumption LRMC and the balance of efficient costs have been taken into account by SA Power Networks in establishing the 2025-30 RCP tariffs has involved the following considerations:

a. **Ensuring the demand price signalling components reasonably signal the consumption LRMC**
For Large Business, our Peak demand DUoS charges reflect the consumption LRMC of the distribution network upstream of the connection voltage. An Anytime demand charge is also applied, which includes the consumption LRMC of connection voltage assets.

b. **Use of price signalling components where practicable**
Where Accumulation meters are in use and demand cannot be effectively signalled, energy rates have been structured to recover efficient costs. However, the metering does not indicate usage during high consumption periods, so we have retained relatively simple tariff structures that recover the efficient costs for the tariff's assigned customers.

c. **Revenue recovery through non-distortionary charging parameters**
For cost reflective tariffs, demand charging parameters recover a proportion of the total revenue reflecting high distribution network utilisation period future costs. The balance of revenue recovery takes place in the least distortionary manner possible, through fixed supply charges for the efficient costs of local assets and customer service with the balance recovered through energy usage rates. Lower rates apply to usage outside of high network utilisation periods for off peak periods (two rate tariffs) and controlled load.

The Export LRMC is detailed in Section 11.

Revenue Cost Allocation

Figure 70 outlines how SA Power Networks allocates direct control revenue across tariff classes to ensure that tariffs reflect efficient costs. Additionally, Figure 70 shows the allocations and methods for recovery of Designated Pricing Proposal Charges (**DPPC**), otherwise known as Transmission and Jurisdictional Scheme Obligations (**JSO**), otherwise known as SA Government schemes, under clauses 6.18.7 and 6.18.7A of the Rules.

SA Power Networks proposes to allocate revenue across tariff classes based on an analysis of each tariff class.

Analysis of each tariff class is based on the following categories:

- The number of customers within the tariff class (NMIs)
- The annual energy usage of the tariff class (GWh at pool exit)
- The diversified Peak demand[17] of the tariff class (MVA)

Each category was combined to show a tariff class's proportion of the distribution network utilisation.

We have then created seven asset categories, reflecting different voltage steps and individual customer driven cost items within the distribution network. These have then been allocated based on the use of the assets as measured by demand, usage, or customer numbers.

[17] In this context the diversified Peak demand is relative to the tariff class, not the distribution network. To allocate based on the coincident demand of the distribution network would lead to a disproportionate recovery from certain tariff classes.

The voltage steps of the distribution network have an allocation of 50 percent demand and 50 percent usage, which we have found to broadly reflect the LRMC of the distribution network. It should be noted that the actual tariffs are priced using the actual LRMC calculation, not the 50 percent cost allocation. The balance of charges within these asset categories is allocated in a non-distortionary manner using energy usage. If we need to consider pricing for a potentially constrained distribution network in the 2025-30 RCP, we will look at other variations to this for those specific locations and consider a Customer Choice tariff/rebate. The variation might have a stronger demand signal reflecting the local LRMC. Customers would retain the right to access state-wide prices despite the constraint.

The Low Voltage lines class has been allocated on an equal basis between demand, usage and NMIs as it reflects both utilisation of the distribution network as well as connection services and needs of individual customers accessing the distribution network. The Customer related Services, Guaranteed Service Level payments (**GSL**s) asset class is allocated 100 percent by NMIs to reflect the drivers of these costs.

Metering revenue is allocated 100 percent by NMIs in accordance with the methodology outlined in the Guidance note.

Tariff classes are only allocated charges for the asset categories they utilise. For example, a High Voltage customer is not allocated to costs in the Low Voltage asset category. Figure 70 outlines how SA Power Networks allocates revenue to tariff classes. This ensures that tariffs reflect the efficient costs incurred in supplying customers using those tariffs.

Figure 70: Cost Allocation across network elements and to tariff classes

ALLOCATION BASIS TO TARIFF CLASS	TARIFF CLASSES				
	Major Business	Large HV business	Large LV Business	Small Business	Residential
Number of Customers (NMIs)	0.0%	0.0%	0.5%	10.0%	89.5%
Diversified Demand (MVA)	4.5%	6.3%	27.3%	17.5%	44.4%
Usage GWh (at Pool Exit)	9.2%	7.8%	32.4%	16.4%	34.2%
Distribution (SA Power Networks)					
Sub Transmission lines	8% of Revenue allocated 50% Demand and 50% Usage				
Zone Substations	17.5% of Revenue allocated 50% Demand and 50% Usage				
High Voltage lines		33.3% of Revenue allocated 50% Demand and 50% Usage			
Distribution transformers			17% of Revenue allocated 50% Demand and 50% Usage		
Low Voltage lines				15% of Revenue allocated 33.3% each to NMI/Demand/Usage	
Services, GSLs				6.2% of Revenue allocated on a per NMI basis	
Customer related	3% of Revenue allocated on a per NMI basis				
Metering				100% of Metering Revenue allocated on a per NMI basis	
Transmission (ElectraNet)					
Transmission exit	6% Locational passthrough	9% Peak Demand allocation			
Transmission locational		26% Peak Demand allocation			
Transmission non-locational		34% Demand		25% Usage	
Transmission common service					
SA Government Schemes (PV FiT recovery)					
PV FiT recovery	37% of charges allocated on DUoS proportion				63%

The cost allocation methodology in Figure 70 provides a robust structure in cost allocation across different tariff classes and provides a framework for our indicative revenue recoveries from each tariff class. The cost allocation methodology is consistent with our 2020-25 RCP approach and has been updated with the latest 2025-30 RCP forecast, leading to an updated allocation. During the 2025-30 RCP, we will set prices based on this model to achieve cost reflective tariffs.

Table 27: Revenue cost allocation to tariff classes for 2025-30 RCP

Tariff Class	Major Business	High Voltage Business	Large Low Voltage Business	Small Business	Residential	Total
Distribution	1%	4%	24%	18%	52%	100%
Transmission	6%	7%	28%	17%	42%	100%
JSO	1%	3%	19%	14%	63%	100%
Total	3%	5%	25%	18%	49%	100%

Source: SA Power Networks analysis

*The JSO PV FiT scheme concludes 30 June 2028

Our cost allocation methodology provides a measured and methodical approach to revenue recovery while considering the impact of annual price changes on customers.

Residual Distribution Cost Recovery

After pricing the LRMC signal in the DUoS demand tariff element for Major Business, High Voltage Business and Large Low Voltage Business, the balance of residual costs are recovered from usage and fixed (supply charge) tariff elements as per the revenue cost allocation model presented in Figure 70. The demand tariffs for Large Low Voltage Business and High Voltage Business include a supply charge reflecting fixed costs associated with the connecting equipment (e.g. the transformer for LV annual demand). The remainder of the recovery for the assigned tariff class is recovered in usage. Refer to Table 28, which shows the proportion of an average customer's distribution charge, recovering either LRMC reflective costs (Peak demand charges) or residual costs (Anytime demand, fixed and usage charges). Note that the Residential and Small Business usage tariffs do not have any significant LRMC demand tariff element.

In the 2020-25 RCP, the Residential and Small Business tariff classes had an increasing annual fixed supply increment to recover a greater proportion of the customer-related distribution network costs, including the service and low voltage wires, which are recovered per-customer basis. This was considered more cost reflective for smaller and medium-sized customers, resulting in lower usage charges. It also promoted a more equitable outcome between those customers with CER and those without.

In 2025-30 RCP, we propose changing the annual fixed supply increment for Residential and Small Business tariff classes. In reviewing our allocation methodology for the 2025-30 RCP SA Power Networks will no longer have a fixed increment for the supply charge as the allocation of local connection assets on a per customer basis has reached the optimal allocation threshold. Instead, the supply charge price for Residential will move in line with the revenue allocation for the Residential tariff class. This price movement will be the same for Small Business as the supply charge is the same as Residential. Medium Business supply charge represents 2.4 times the Residential supply charge and will move in line with the Residential supply charge.

Table 28: Residential cost recovery by tariff elements (DUoS)

Tariff Class	Major Business	High Voltage Business	Large Low Voltage Business	Small Business	Residential
Demand	53.9%	39.5%	32.3%	4.2%	0.0%
Usage	32.8%	53.9%	53.9%	82.7%	64.1%
Fixed (supply)	13.3%	6.6%	13.8%	12.6%	35.3%
Export	0.0%	0.0%	0.0%	0.5%	0.6%

Table 29: Residual cost recovery by tariff elements (NUoS)

Tariff Class	Major Business	High Voltage Business	Large Low Voltage Business	Small Business	Residential
Demand	64.0%	37.9%	33.3%	2.9%	0.0%
Usage	25.7%	58.1%	57.6%	87.3%	73.1%
Fixed (supply)	10.3%	4.0%	9.1%	9.4%	26.5%
Export	0.0%	0.0%	0.0%	0.4%	0.4%

Transmission Recovery

SA Power Networks applies the ElectraNet pricing structure where possible as our basis for allocating and pricing the recovery of DPPC under the Rules clause 6.18.7. Major customers with greater than 10 MVA or 40GWh p.a. have transmission charges individually calculated to ensure the pass through of ElectraNet pricing signals according to their location and demand/energy characteristics. They will receive the same transmission price as though they were directly connected to the transmission network.

Excluding those costs allocated to transmission locational customers, transmission locational prices (relating to the transmission exit and locational charges) are allocated based on each tariff class's diversified demand. Transmission non-locational and common services charges are allocated by customer tariff class as follows:

- Large Low Voltage and High Voltage customers are allocated based on their diversified kW demand, which provides the lower price.
- Small Business and Residential customers are allocated the balance of these charges per MWh basis. This should be at a lower price than the ElectraNet published price adjusted for losses.

This arrangement ensures a reasonable pass through of the ElectraNet price structure and equitable outcomes for all customers.

SA Government schemes (JSO)

SA Government schemes can be imposed at any point during an RCP, and SA Power Networks is required to implement them via the APP. In the 2025-30 RCP, there is one scheme in place, PV FiT, which is a continuation of the scheme from the 2020-25 RCP.

The revenue recovery of the PV FiT scheme remains unchanged from the previous allocation methodology applied in the 2020-25 RCP, as it reflects the primary driver of these costs based on historical PV incentive schemes. This allocation is primarily borne by the Residential tariff class with a 63 percent allocation, whilst the remaining tariff classes receive the balance of charges in line with their allocation of DUoS revenue. Table 30 outlines the indicative prices for the scheme in 2025/26.

Table 30: SA Government schemes indicative prices for 2025/26

Tariff Element	Major Business	High Voltage Business	Large LV Business	Small Business	Small Business/ Unmetered	Residential	Control Load
Fixed Charges $ p.a.	-	-	-	$15.00	-	$15.00	-
Usage charges $/kwh	$0.0006	$0.0032	$0.0050	$0.0066	$0.0043	$0.0114	$0.0057

The JSO PV FiT scheme concludes on 30 June 2028.

System Strength Pricing

Transmission system strength charges are incurred if a distribution connected customer (**Distribution Network User**) elects to pay the transmission network for their system strength services rather than remediating their system strength impact. In accordance with the Rules clause 6.20.3A SA Power Networks must bill the Distribution Network User at system strength connection points on the distribution network to pass through system strength charges.

SA Power Networks is required to bill the Distribution Network User on a passthrough basis so that the amount, structure, and timing of the amount billed by SA Power Networks replicates as far as is reasonably practicable the amount, structure, and timing of the corresponding system strength charge billed to SA Power Networks by the System Strength Service Provider, ElectraNet.

The bill to recover system strength charges from the Distribution Network User will be issued to the relevant Distribution Network User and will identify the system strength connection point and other information required by the Distribution Network User to verify the charge.
SA Power Networks does not currently incur any system strength charges from ElectraNet however will act in accordance with the rules as and when required during the 2025-30 RCP.

Clauses 6.18.5(h) and (i) – Customer impact and understanding of tariffs

Clause 6.18.5(h) of the Rules requires us to consider the impact of annual price changes on customers. This will mainly be an APP matter; however, this clause has some relevance to the TSS. We are required to balance the competing needs of having tariffs that comply with the pricing principles (i.e. are cost reflective), the time necessary for a period of transition to such tariffs, the degree of customer choice available for tariffs and the extent to which customers can mitigate tariff impacts by responding through usage decisions. Clause 6.18.5(i) further requires us to structure our tariffs in a way that can be understood by the customer. As outlined in Section 3 we are guided by the customer impact principles of simplicity, fairness and equity, empowering the customer and compliance. SA Power Networks considers the tariff development process in conjunction with stakeholders has achieved this.

In developing our TSS, we have adopted a measured and methodical approach towards cost reflective tariffs and state-wide pricing. As outlined in this TSS, SA Power Networks’ 2025-30 RCP tariffs have therefore been structured to comply with the pricing principles of clause 6.18.5 of the Rules.

Glossary

Acronym / term	Definition
Accumulation meter	Legacy meter which records the amount (kWh) of energy consumed but not the time of consumption. Sometimes referred to as a 'Type 6' meter.
ACS	Alternative control services
ACDT	Australian Central Daylight Savings Time
ACST	Australian Central Standard Time
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIC	Average Incremental Cost
APP	Annual Pricing Proposal
ARR	Annual Revenue Requirement
B2R	Business Two Rate
B2RNE	Business Two Rate Non Export
B2RT	Business Two Rate Transition
BD	Business Actual Monthly Demand
BEV	Battery electric vehicles
BSR	Business Single Rate
BSRNE	Business Single Rate Non Export
BSRT	Business Single Rate Transition
capex	Capital expenditure
CBD	Central business district
CER	Customer energy resources
CL	Time of Use Controlled Load
Customer choice tariff	Optional tariff available to eligible customers within a tariff class.
DER	Distributed energy resources
Distribution Network	The assets and service which links energy customers to the transmission network.
Distribution Network User	A distribution customer or an embedded generator.
DNSP	Distribution Network Service Provider
DPPC	Designated Pricing Proposal Charges
DUoS	Distribution use of system. The utilisation of the distribution network in the provision of electricity to consumers. A component of NUoS.
ESCoSA	Essential Services Commission of South Australia
ESOO	Electricity Statement of Opportunities
ESS	Energy Storage Systems
EWoSA	Energy and Water Ombudsman of South Australia
Export	Generation energy delivered from customers into the distribution network.
GSL	Guaranteed service level payment.
Guidance Note	AER Legacy metering services – Guidance note November 2023
Guidelines	AER Export Tariff Guidelines May 2022
GW	Giga-watt. A thousand mega-watts.
HBD	HV Business Actual Monthly Demand
HV	High voltage. Equipment or supplies at voltages of 7.6kV or 11kV.

HVAD	High Voltage Business Annual Demand
HVAD500	High Voltage Business Annual Demand less than 500kVA
HVADF	High Voltage Business Annual Demand Flexible
HVBG	High Voltage Business Generation
HVBGF	High Voltage Business Generation Flexible
HVMD	High Voltage Business Monthly Demand
Interval meter	A meter which records both the amount (kWh) of energy consumed as well as the time of consumption. May or may not record demand (kVA) and may or may not have remote communications capability.
JSO	Jurisdictional Service Obligation
kV	A kilo-volt is a unit of measurement for electric potential or voltage (1000 volts).
kVA	Kilo-volt amps are units of apparent total electrical power demand. Usually the peak demand is referenced.
kW	Kilo-watts are units of instantaneous real electrical power demand.
kWh	Kilo-watt hours are units of electrical energy consumption.
Large customer	A customer who has annual consumption greater than 160MWh.
LBAD	Large Low Voltage Business Annual Demand
LBADF	Large Low Voltage Business Annual Demand Flexible
LBG	Large Low Voltage Business Generation
LBGF	Large Low Voltage Business Generation Flexible
LBMD	Large Low Voltage Business Monthly Demand
LRMC	Long run marginal cost
LV	Low voltage. Equipment or supply at a voltage of 230V single phase or 400V, three phase.
LVUU	Overnight unmetered tariff
LVUU24	24 hour unmetered tariff
MBTOUD	Medium Business Time of Use Demand
MBTOUDNE	Medium Business Time of Use Demand Non Export
MVA	Mega-volt amps are units of apparent total electrical power demand. Usually the peak demand is referenced.
MW	Mega-watt. A thousand kilo-watts.
MWh	Mega-watt hours are units of electrical energy consumption. A thousand kilo-watt hours.
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NMI	National Meter Identifier
NPV	Net present value
NSW	New South Wales
NUoS	Network use of system. The utilisation of the total electricity network in the provision of electricity to consumers.
NWD	Non workday. Saturday, Sunday and Public Holidays.
OPCL	Off Peak Controlled Load
opex	Operating expenditure
OTR	Office of the Technical Regulator
PHEV	Plug-in hybrid electric vehicles
PV	Photo-Voltaic
PV FiT	The SA Government solar photo voltaic feed in tariff.

Qld	Queensland
RCP	Regulatory Control Period
RELE	Residential Electrify, a 2020-25 trial tariff proposed to be replaced by RESELE in the 2025-30 RCP.
RELE2W	Residential Electrify two-way, a 2020-25 trial tariff proposed to be replaced by RESELE in the 2025-30 RCP.
RESELE	Residential Electrify
RESELENE	Residential Electrify Non Export
RPRO	Residential Prosumer
RSR	Residential Single Rate
RSRNE	Residential Single Rate Non Export
RTOU	Residential Time of Use
RTOUNE	Residential Time of Use Non Export
SA	South Australia
SBD	Small Business Actual Monthly Demand
SBELE	Small Business Electrify
SBELENE	Small Business Electrify Non Export
SBTOU	Small Business Time of Use
SBTOUNE	Small Business Time of Use Non Export
SBTOUD	Small Business Time of Use Demand
SCS	Standard Control Services
Small customer	A customer consuming less than 160MWh p.a.
STR	Sub Transmission
STRF	Sub Transmission Flexible
STRG	Sub Transmission Generation
STRGF	Sub Transmission Generation Flexible
Sub Transmission	Equipment or supplies at voltage levels of 33kV or 66 kV.
SWER	Single wire earth return
Tas	Tasmania
ToU	Time of Use
Transmission Network	The assets and service that enable generators to transmit their electrical energy to population centres. Operating voltage of equipment is 275kV and 132kV with some at 66kV.
TSS	Tariff Structure Statement
TUoS	Transmission Use of System. The utilisation of the transmission network in the provision of electricity to consumers. A component of NUoS.
TWG	Tariff Working Group
V2G	Vehicle to Grid
Vic	Victoria
WD	Workday. Monday, Tuesday, Wednesday, Thursday, Friday excluding Public Holidays.
ZSS	Zone Substation
ZSSF	Zone Substation Flexible
ZSSG	Zone Substation Generation
ZSSGF	Zone Substation Generation Flexible