# Planning for the future

Essential Energy 2024–29 Revised Tariff Structure
Explanatory Statement

November 2023

# Our Vision, Purpose & Values

empowering
you

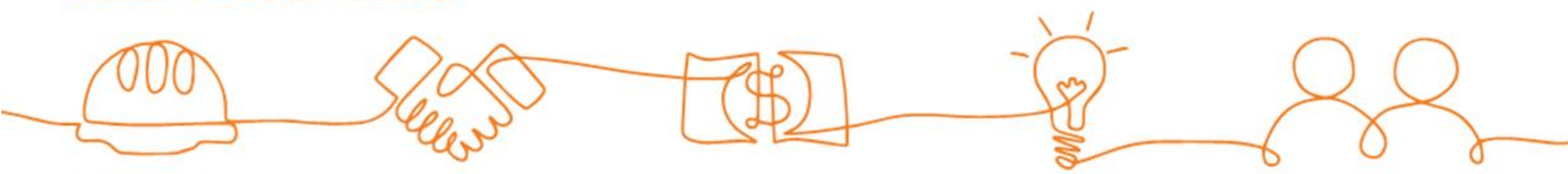

## Our Vision
### What we want to be

Empowering communities to share and use energy for a better tomorrow.

## Our Purpose
### What we stand for

To enable energy solutions that improve life.

## Our Values
### What we care about



Make safety your own

Be easy to do business with

Make every dollar count

Be courageous, Shape the future

Be inclusive, supportive and honest

# Contents

# 01

# Introduction and overview

## What is the Revised Tariff Structure Explanatory Statement?

This Revised Tariff Structure Explanatory Statement (TSES) supports our Revised Tariff Structure Statement (TSS). Together, our Revised TSS and this Revised TSES will inform the Australian Energy Regulator's (AER's) assessment of our compliance with relevant provisions of the National Electricity Rules (NER). In this Revised TSES, we:

> provide important contextual information about our network and customers relevant to tariff setting and clarify why we are starting our transition to two-way pricing
> explain how we have developed and revised our TSS, including through extensive customer and stakeholder engagement
> elaborate on how our TSS complies with the National Electricity Rules (NER) and the new AER Export Tariff Guidelines (guideline).

Once our TSS is approved, we must ensure our annual pricing approval applications within the 2024-29 regulatory period accord with it.

A number of aspects inform our TSS and TSES including:

> the NER and AER guidelines
> our network characteristics
> our future network strategy, our forecast costs and the associated revenue requirement from our 2024–29 Revised Regulatory Proposal (Revised Proposal)
> the AER's draft decision on our January 2023 TSS proposal
> our customer and stakeholder engagement, including our trial tariff development and the associated lessons learned to date, and our engagement since the AER's draft decision see **Attachment 2.01 – Summary of engagement outcomes**
> **January 2023 Proposal Attachment 7.01 – DER Integration Strategy**
> **January 2023 Proposal Attachment 11.01 - Forecasts of customer numbers, energy consumption and demand**
> **January 2023 Proposal Supporting document 10.01.02 – Demand management plan.**

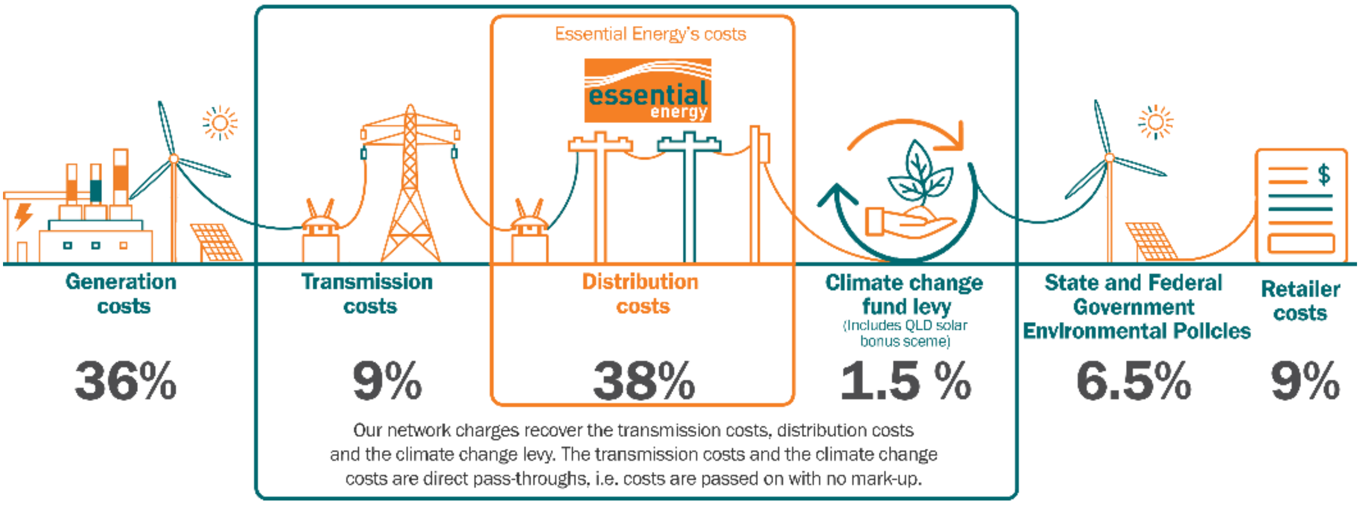
## Our role in the electricity process

As an electricity distributor, our TSS only addresses distribution tariffs, costs and revenues. These are just one part of the total retail bill that our customers pay. Our distribution network tariffs represent our costs to operate and maintain the distribution network and are the subject of the Regulatory Proposal.

On a customer's bill, our charges are bundled with:

> transmission costs, which are regulated by the AER. These costs are passed on by Transgrid and Powerlink, the operators of the transmission networks that are connected to our distribution network
> the NSW Government's Climate Change Fund levy, contributions to the Queensland Government's Solar Bonus Scheme, and contributions to the costs of the NSW Electricity Infrastructure Roadmap (NSW Roadmap).

The costs we recover through our network charges[1]




[1] Based on the 2021–22 forecast, Australian Energy Market Commission, Residential Electricity Price Trends 2021, 25 November 2021 p. 10. Note that energy market conditions may significantly alter these percentages in the future.

# 02

# Designing our proposed distribution charges under the NER

## Chapter summary

- Rule and policy developments
- Drivers for two-way pricing
- Tariff trials
- What efficient pricing involves
- Long-run marginal cost estimation
- Building cost reflective tariffs
- Managing pass-throughs

# Rule and policy developments that have shaped our 2024–29 TSS

## Rule changes

### Export pricing

Following the implementation of the AEMC's final rule for the *Access, pricing and incentive arrangements for DER* rule change (access and pricing rule change)[2], distribution businesses now have clear obligations to support more consumer energy resources connecting to the grid. The change means that we can now provide our customers with services that support the export of energy they generate back into the grid. Importantly, the new rules give our customers clarity around their rights to access export services.

They also affect our planning, expenditure, connection policies and pricing. In terms of pricing, the new rules mean that:

- export pricing is permitted and remains optional for each distribution business
- export pricing can apply to all distribution-level customers
- no mandatory assignment to export pricing can occur until 1 July 2025 for existing customers, and
- a basic export level must be offered to all exporting customers for a 10-year period.

The new rules also require us to develop and include an Export Tariff Transition Strategy (ETTS) in our TSS. The ETTS must describe our plan to phase-in any proposed export pricing over time.

### Storage pricing

The AEMC's final rule for *Integrating Storage in the NEM* rule change also provides useful clarification that batteries will continue to be charged distribution use of system fees.[3] Participants with battery storage who choose to connect to our distribution network will receive an approved TSS tariff or a storage tariff trial option, where offered.

### System strength pricing

The AEMC's final rule for *Efficient management of system strength on the power system* rule change established a new way of charging for system strength.[4] The new approach gives generators and certain large loads a choice to pay to use system strength services offered by transmission networks that are System Strength Service Providers (SSSPs) or to provide their own system strength. Transgrid is the relevant SSSP for our network area.

SSSPs will need to update their transmission annual planning reports (TAPRs) to meet the system strength standard, seek AER cost recovery for their planned activities to meet the standard, and update their pricing methodologies to include system strength pricing.

TNSPs and DNSPs who are not SSSPs (which includes Essential Energy) must implement the system strength charges from the SSSP for their region to connections on their networks who face the system strength charge.

Our pricing proposals from 2023 onwards must explain how we will pass-through Transgrid's system strength charges in a manner that replicates the amount, structure and timing of Transgrid's system strength charge as far as is reasonably practicable.

### Accelerated smart meter roll out

The AEMC's review of the regulatory framework for smart meters completed with its final report in September 2023. New rules will implement an accelerated rollout from 1 July 2025 to 30 June 2030 to achieve 100% deployment of smart meters by 2030.

Retailers will be responsible for smart meter installations. Essential Energy will prepare and seek AER approval of a legacy meter retirement plan (LMRP). Our LMRP will list the meters (by NMI) that must be replaced each year between 2025-2030. Meters will be grouped geographically, e.g. by NMI, post code or substation.

Retailers then have 12 months from each 1 July to replace the meters set out in the LMRP for their customers.

Our 2024-29 TSS period customer number forecasts by meter type now reflect this acceleration decision.

# Policy and customer attitudes to opt in and opt out tariff assignment have evolved

Like many distributors, in our current TSS we took a cautious approach to cost-reflective tariff assignment. We erred on the side of opt-in options for our residential and low voltage (LV) business demand tariffs, while retaining opt-out options for our default time of use (TOU) tariffs.

We have seen relatively low levels of opt-out from our default TOU tariffs. Since 2019, we have had only 1.3 per cent of residential customers and 4.9 per cent of LV business customers opt-in to our anytime tariff.

The opt in take up of our small customer demand tariffs has been better for LV business customers at 13 per cent, but negligible for our residential customers at 0.1 per cent.

This experience has seen the policy views of the AER and ACCC advance. The AER is now clear that distributors can offer customers choice in a cost reflective tariff. However, as we continue on this path, we should no longer offer customers who are on a cost

[2] AEMC, *Access, pricing and incentive arrangements for distributed energy resources*, Rule determination, 12 August 2021.

[3] AEMC, *Integrating energy storage systems into the NEM*, Rule determination, 2 December 2021.

[4] AEMC, *Efficient management of system strength on the power system,* Rule determination, 21 October 2021.

reflective tariff the ability to opt-out to anytime energy network tariffs.[5]

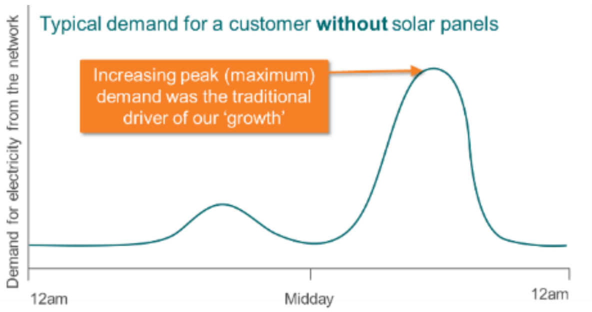
# Drivers for two-way pricing

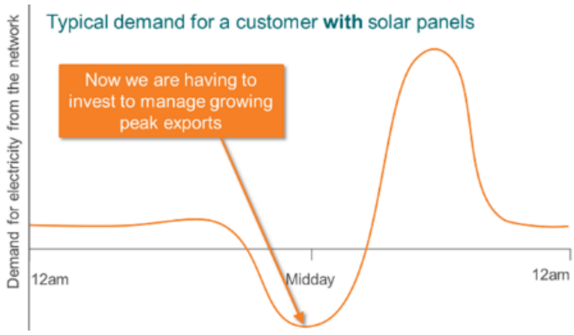
## Responding to changing customer demand

We have assessed our current network capacity, forecast demand for peak energy and peak exports, and options to efficiently meet these. The typical daily profiles of our customers' energy demands are increasingly presenting two distinct cost drivers for us:

- peak demand, which occurs at times when all customers are drawing the most energy from our network
- peak export, which occurs at times when the energy exported by our customers in certain parts of our network exceeds the customer demand to draw that energy from our network in those areas.

How customer demand impacts our costs



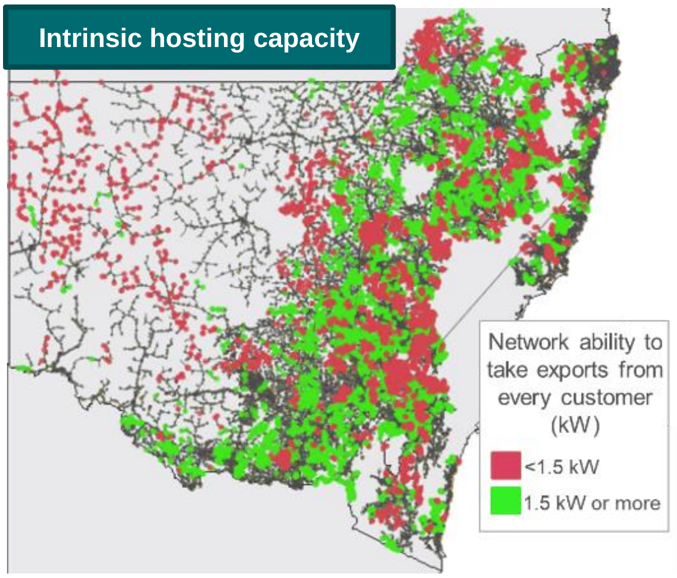

The electricity sector is undergoing significant transformation, driven by customers' increasing requirements around the use of distributed energy resources (DER), or consumer energy resources (CER). As defined by the AER, DER includes solar, batteries, EVs and energy management systems often located on the customer's side of the meter.[6]

Our network has been experiencing strong growth in solar PV connections. However, the network currently has a finite capacity to accept electricity exports and increasing energy demands driven by forecast DER uptake. These forecasts are outlined in the 15-year forecasts of consumption and minimum and maximum demand on our network developed by Frontier Economics.[7]

## What is hosting capacity?

Zepben[8] defines hosting capacity as the ability for the network to accommodate a specific installed capacity of a particular DER technology without adversely impacting power quality such that the network continues to operate within defined operational limits. Hosting capacity varies by location and time and can be impacted by both export and import (demand) for electricity.

Our network's ability to receive exports from every customer




[5] See farrierswier's report - Effectiveness of the TSS process and options for implementing export charges, 11 March 2021, pp.26-27.

[6] AER, DER integration expenditure guidance note, June 2022, pg. 4.

[7] Frontier Economics, Forecasts of customer numbers, energy consumption and demand, May 2022 – see January 2023 Proposal Attachment 11.01

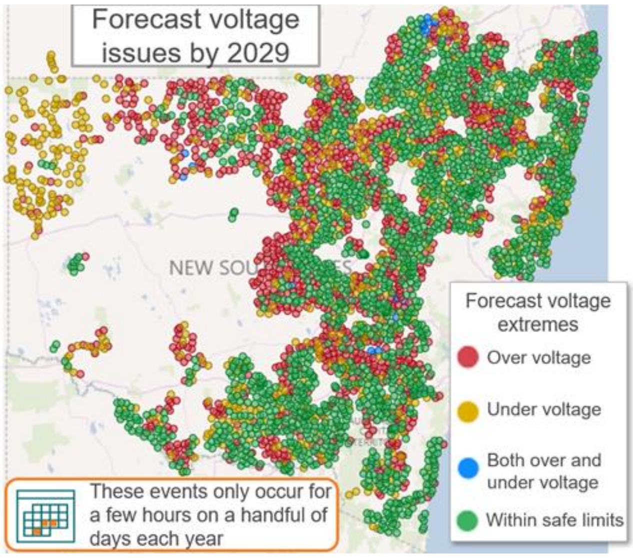
[8] See January 2023 Proposal supporting document 7.01.01 Hosting Capacity Study - Zepben

## What challenges are we facing?

The continuing increase in customer exports means parts of our distribution network are reaching their limits. To maintain network integrity, we must place limits on how much energy customers are allowed to export. Currently, these limits are static (fixed) and are set to ensure integrity in all network conditions, including during peak net export times (representing worst-case scenarios), which occur rarely. Below is the 2029 forecast indicating probable expect voltage issues on our network if we do not undertake investment to manage customers' exports.

Our expert advisors (Zepben) analysed our 15-year demand and DER forecast provided by Frontier Economics and our end-to-end network model, then ran the load flow studies that underpinned the results. These were obtained using the OpenDSS1 electric power distribution system simulator to run millions of individual load flow studies under different DER penetration scenarios.

Forecast voltage issues by 2029




We arrived at the 1.5kW basic export level after considering the Zepben analysis and our customers' preferences for a simple and common basic export limit that could apply on a postage stamp basis.

## How can two-way pricing help?

Our DER integration strategy proposes changes to both our physical system controls and pricing-based incentive elements. Together, these form a complementary approach to efficiently accommodating more customer demand for exports whilst minimising total costs of network services to all our customers.

> Physical responses will enable us to shift from static to dynamic export limits to make better use of our available hosting capacity with real time responsiveness rather than worst case static limits.

> Pricing responses will empower our customers to save money through choosing when to use and export energy, by pairing our export charges with an evening peak export rebate incentive payment and Sun Soaker discounted midday consumption charges.

# Demand forecasts

We must ensure that our distribution network has the capacity to meet our customers' growing and changing needs. To ensure our network is designed appropriately, Frontier Economics helped us develop forecasts for maximum demand, energy consumption, customer numbers and smart meters. These forecasts were described in **Chapter 11 of our January 2023 Regulatory Proposal** and included in **Attachment 11.01** to that Proposal. Customer numbers by meter type have been updated for the AEMC's final decision to accelerate the smart meter deployment. These forecasts helped us to plan our expenditure and to set network pricing plans so that we can:

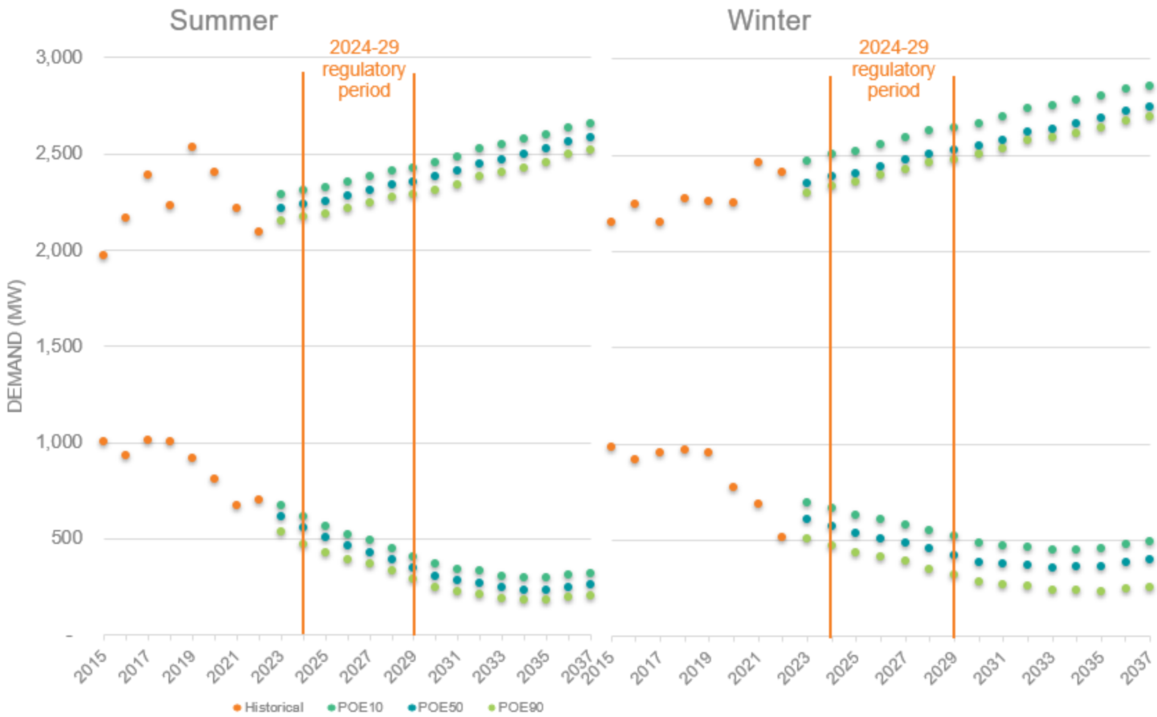
> recover the allowable revenue approved by the AER

> encourage customers who can do so to save money now, and other customers who can do so to save money over time, by shifting their energy consumption and export times away from those times that drive up our costs.

From 2022 to 2037, maximum demand on our network (that is, peak electricity consumption) is forecast to increase to around 2,750 MW, while the minimum demand (peak exports) could head towards zero MW, as shown in the Summer and Winter forecast demand charts below.[9]

[9] These charts reflect the probability of exceedance (POE), for example POE50 reflects that there is a 50 per cent chance that the outcome is higher than these point markers.

Minimum and maximum demand across 2015–21, and projected demand for 2022–37[10]

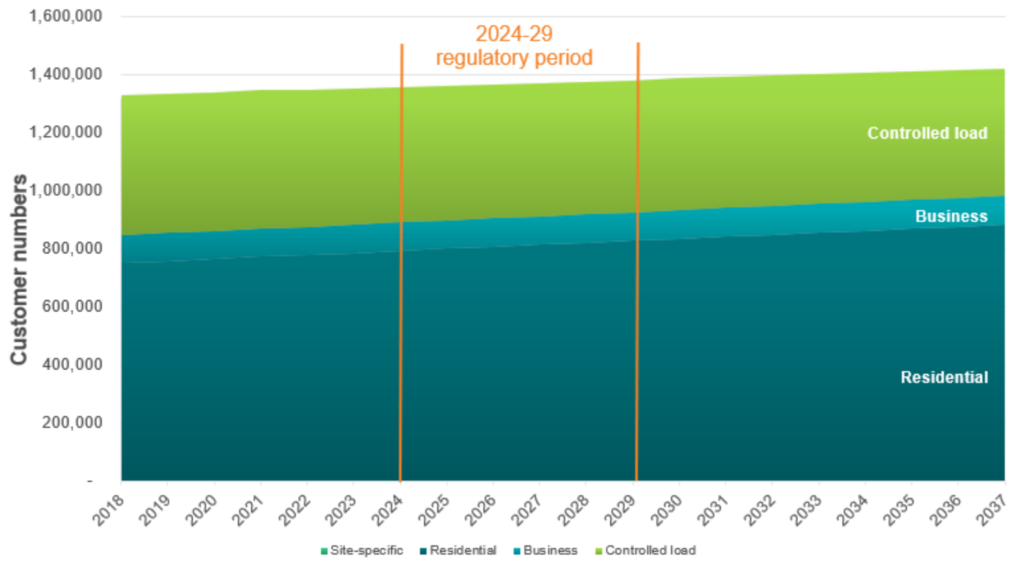



The patterns of usage are also changing across a day. Historically, maximum demand has occurred at around 6 pm in both summer and winter. As rooftop solar capacity and battery uptake increase, the maximum network load is forecast to occur later in the day. By 2037, peak demand is expected to take place between 6 pm and 7 pm in summer and 5 pm and 9 pm in winter.

A similar trend is expected for minimum demand. The expected summer minimum shifts from 10 am in 2022 to 10 am to 12 pm in 2037. The winter minimum demand in 2022 occurs from around 9 am to 1 pm. The expansion of CER will move minimum demand away from the mornings to around 1 pm by 2037.

Customer numbers are also forecast to increase over the next 15 years, consistent with the growth seen in the historical data and the ongoing population growth in our network area. This increase is shown in the chart below.

Customer numbers across 2018–21, and forecast customer numbers for 2022–37[9]




[10] See January 2023 Proposal Attachment 11.01 – Customer number, energy consumption and demand forecasts

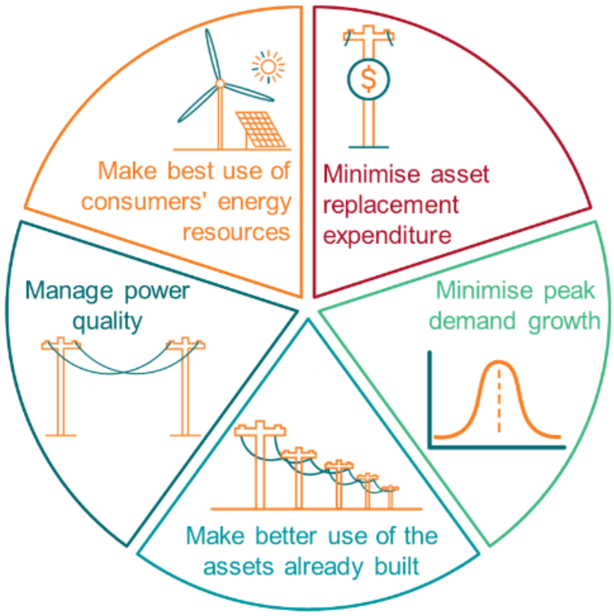
## Using prices to lower costs for all customers

We can use prices to reflect the demands on our network at any time. Using prices to inform customers' electricity usage and export timing decisions is cheaper than increasing our investment in the network. Prices can help solve five challenges that face our network.

Faced with new cost drivers from peak exports, as well as our existing cost driver of peak demand, transitioning to two-way pricing has become increasingly important. It forms a key limb of our transition strategy to efficiently integrate CER into our network and support future customer decisions about their energy consumption and exports. For example, transitioning to two-way pricing and encouraging customers to use more energy in the daily solar peak period will help lessen our overall costs and prices, and ensure customers pay fairly for using our network.

We have worked with our customers through deep dives and our Pricing Collaboration Collective (PCC) to design a plan to transition to two-way pricing.

**Our five network challenges**




This plan provides transparency around our long-term approach to phase in export pricing over time. It is intended to provide our customers, who are considering investing in CER such as roof top solar and batteries, clarity around their ability to access our export services.

Our transition plan has been informed by multiple factors, including the NER and AER guideline, network and customer demand characteristics, our plans to deliver a network fit for the future, customer engagement across a diverse range of stakeholders on two-way pricing and our trial tariff development and trialling lessons to date.

### Our co-designed principles for pricing the network of the future

Working closely with our customers and stakeholders, we have co-designed five principles to inform the development of our new tariff trials and our TSS.

Using feedback gathered through the 'Talking Tariffs' web pages, the five tariff design principles were shared and discussed with participants of our 'Choosing trial tariffs and structures' Round 1 workshops. These principles were also discussed and refined with our customers and key stakeholders as part of our engagement program undertaken across 2021 and 2022. This included our large customer working group for peaky load customers and our Stakeholder Collaboration Collective (SCC).

Subsequently, these principles have been used to guide the assessment of TSS issues and options undertaken with our PCC and in our customer deep dives. They have been key informers of the export tariff transition strategy set out in our TSS.

**Principles for pricing the network of the future**

| Principle | What this means |
|---|---|
| Avoid bill shock | Tariffs minimise the risk of bill shock for customers (especially vulnerable customers) |
| Easy to understand | Tariffs are relatively simple to interpret |
| Fair | Customers pay their fair share of network costs (cost-reflective) |
| Integrate renewables and new technologies | Tariffs accommodate changing technology, energy flows and greener customer choices |
| Effective | Tariffs do the job - they solve network issues and don't create new ones |

In addition to these pricing design principles, we agreed with our PCC a principled approach for having regard to divergent stakeholder feedback on a given topic. This approach was agreed at the October 2022 meeting, and was decided that the starting point is:

- advancing the National Electricity Objective (NEO) in the National Electricity Law (NEL)
- advancing the network pricing objective in the NER
- balancing the pricing principles co-designed with customers shown above
- considering impacts on retailers and other market players who develop products and services for electricity consumers, while not losing the existing focus on consumers' interests.

We have followed this approach in our PCC engagement on matters that had divergent stakeholder views.

## Our approach to continue the adoption of more cost-reflective network charges

During the 2024–29 period, we propose to continue our transition to cost-reflective pricing for our customers. The pace of this transition will be supported by rule reforms requiring retailers to complete their smart meter roll out by 2030.

We are taking a staged approach to the transition to two-way pricing. This approach enables us to adopt cost-reflective export charges based on our long run marginal cost (LRMC) estimates for peak exports by voltage level straight away. It will help us achieve a gradual export transition through:

- default assignments informed by bill impact analysis and customer engagement
- opt-in reassignments for customer and retailer choice
- empowering our customers to save money through choosing when they use and export energy, achieved by pairing our export charges with an evening peak export rebate incentive payment and Sun Soaker discounted midday consumption charges.

## We have been testing future tariff designs and customer views through trials

In our 2019-24 TSS, we committed to undertaking tariff trials to ensure any fundamental changes to tariffs were properly assessed from a customer response and impact perspective. Ahead of the engagement process, we defined the network problems that tariffs may be able to help solve. We then delivered a dedicated engagement program with small customers and stakeholders to co-design acceptable tariffs to trial. The tariff trials will be deployed across three phases as shown below.

**Trial tariff design process**

| Phase 1<br>**Trial Design**<br>1 Jan 2020 - 31 Mar 2021 | Phase 2<br>**Tariff Trials**<br>1 Jan 2021 - 31 Jul 2024 | Phase 3<br>**Input to next reg proposal**<br>From Jul 2022 |
|---|---|---|
| AIM:<br>To design tariffs that are supported by stakeholders & customers. | AIM: To test the tariffs and see whether they:<br>> change how customers use electricity;<br>> help solve our network problems;<br>> improve fairness between customers; and<br>> can be implemented on a broad scale in a cost-effective manner. | AIM:<br>To present data and learnings to gain stakeholder support for any new tariff structures for our next regulatory period, which runs from 1 July 2024 through to 30 June 2029. |

**The network problems that tariffs may help 'solve'**

| | Issue | Potential tariff solution |
|---|---|---|
| 1. | Some areas of our network suffer from voltage and/or thermal constraints (minimise peak demand growth and manage power quality issues) | Pay customers to provide support services to the network to address:<br>> capacity issues<br>> the widening of the voltage envelope; and |
| 2. | The level of replacement capex will cause issues including:<br>> costs to replace ageing assets will push the Regulated Asset Base (RAB) value higher<br>> postage stamp pricing means there is cross-subsidisation between high and low cost-to-serve customers. | > transition uneconomic customers to Stand Alone Power System (SAPS) solutions with efficient SAPS pricing (part of a separate SAPS tariff trials project)<br>> locational tariffs - recognising that our stakeholders are against this proposal consider semi-locational like urban/rural, climatic zones or nodal pricing. |
| 3. | Our network experiences demand peaks and troughs – utilisation is uneven | Reward customers for shifting demand to other times of the day or for reducing demand at peak times |
| 4. | We are not able to make efficient use of customer's Distributed Energy Resources (DER) | > reward DER customers for providing network support<br>> facilitate customers participation in peer-to-peer trading & virtual net metering |

An overview of the status of the tariff trial projects for the 2019–24 regulatory period is shown below. More details on the design of these trials can be found in **Attachment 4.02 – How engagement informed our Proposal** to the January 2023 Proposal.

**Tariff trial projects for the 2019–24 regulatory period**

| Tariff trial project | Objectives | Where we are at |
|---|---|---|
| **1. Residential and small business customers tariff trials project** | In late 2019, we embarked on a tariff trials project for residential and small business customers. The aim of the project is to test whether new tariffs:<br>> change how customers use electricity<br>> help solve our network challenges<br>> improve fairness between the relative prices that different customers pay<br>> can be implemented on a broad scale in a cost-effective manner for the 2024–29 regulatory period.<br>We are also undertaking an education only trial to assess whether this has an impact on how customers use energy in comparison to a control area with a similar climate but without the information provided. | > Four tariffs were scoped to take to trial, then working with retailers these evolved into four tariff trial components:<br>1. Sun Soaker – a new consumption tariff<br>2. Critical Peak Price (CPP) – as an overlay to an existing consumption tariff or the Sun Soaker tariff<br>3. Peak Time Rebate (PTR) – as an overlay to an existing consumption tariff or the Sun Soaker tariff<br>4. Export price – applied to customers with DER who are on either our existing Time of Use tariff or the Sun Soaker tariff.<br>> Form of export charge in our trial was the 'kW Based Capacity Charge' with the additional overlay of the network paying customers for exports into the network during the evening peak period (5pm to 8pm).<br>> The trials went live in a staged approach from August 2022. There are now three retail partners participating.<br>> In August 2023 our trial research partners [UNSW] Provided initial trial insights covering the trial period to 30 June 2023. The next report will be delivered with data up until 31 January 2024<br>> These trials will continue up to 30 June 2024. |
| **2. Large, peaky load customer tariff trials project** | The objective of this project is to:<br>> Consider alternative tariffs that could be applied to large, peaky load customers who often have seasonal loads<br>> Consider whether there are technologies that could assist with making our tariffs easier for these customers to work with<br>> Trial possible solutions<br>> Propose any changes to the rules if required | > A number of discussions and stakeholder meetings were held in relation to the implementation of a trial weekly demand charge.<br>> Following extensive consultation, a number of limitations were identified in billing, metering and load data.<br>> Modelling was undertaken on paper with historical load data for potential trial customers which indicated there were constraints including hours of operation and weather events which may lead to bill shock.<br>> We could not find suitable cohort or retail partner to participate, so we did not proceed further with this trial. |
| **3. Battery tariff trial project** | We have designed grid-scale battery tariffs for new low voltage, high voltage customers and sub-transmission customers connecting a battery whose sole purpose is to operate a commercial scale battery or batteries, with no co-located load behind their meter.<br>The objectives of the trial are to:<br>> seek to minimise the barriers to grid-scale batteries deploying within our network<br>> incentivise operation of these large commercial batteries in a manner that recognises the potential costs and benefits to our network and our customer base<br>> achieve a fair and efficient level of network cost recovery which recognises how grid-scale batteries use and benefit from the distribution and transmission systems. | > The trial tariff adopted the same export price and rebate arrangements as the trial for our small business customers.<br>> When we tested this structure with battery proponents in March 2022 the response was positive, however only 1 trial battery has connected which is on the LV network.<br>> One-on-one engagement with a range of potential battery and hybrid connection applicants has:<br>– Flagged that having energy and demand charges for consumption can affect battery commercials, and incentives for multiple daily battery cycling<br>– Asked why overnight consumption charges are needed?<br>– Asked why are hybrids with co-located batteries and generation treated differently?<br>> We have engaged further with retailers and new tech providers to refine our proposed 2024-29 storage tariffs.<br>> We have changed references from 'battery' tariffs to 'storage' tariffs in recognition that these tariffs are designed to be technology agnostic and can be extended to other forms of storage technology. |

## What do efficient charges look like?

The NER state that our network charges for each customer should reflect our efficient costs of providing these services to that customer. Our services now involve delivering energy to customers and receiving energy from exporting customers – for example, exports from solar PV or discharging batteries. This means the network charge for each of our services must be based on the Long Run Marginal Cost (LRMC) of providing each service to the retail customers assigned to that tariff. The LRMC is our cost of servicing one more unit of demand and we estimate LRMC separately for peak demand and peak exports because the marginal costs involved in providing each of these services are different.

Efficient charges preserve the LRMC on relevant charging parameters while allocating costs that have already been incurred (residual costs) in a way that will provide minimal demand distortion. They signal to customers the future network cost of consuming or exporting the next unit of electricity.

Where there are no network constraints, such as in off-peak times, this cost will be very low. However, if the network is reaching its delivery or hosting capacity at peak demand or peak export times respectively, the cost to the network of consumers using or exporting more energy/demand at that time will grow until we need to augment the network. Under the NER, these additional costs should be reflected in the relevant variable charging component of the tariff.

The metering to enable us to provide pricing structures that better reflect the costs of providing two-way network services to customers will be more readily available in the 2024-29 TSS period.

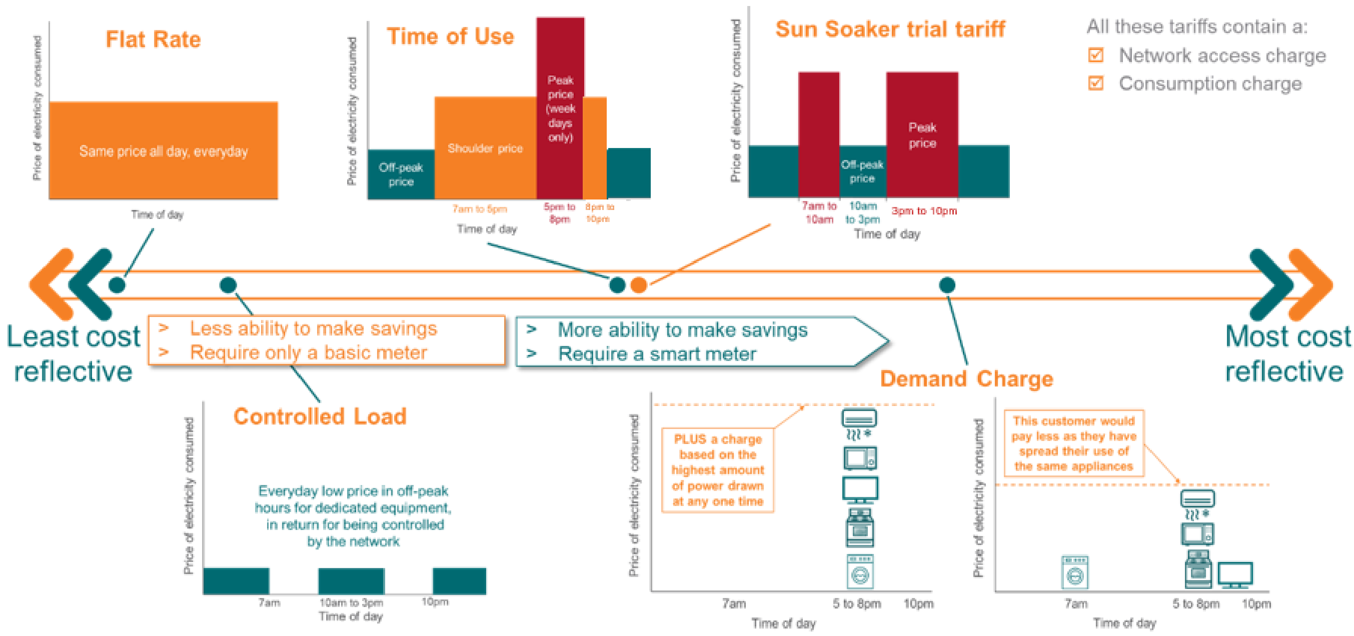
We will continue the transition started in our first TSS that involves moving customers with smart meters onto time of use tariffs. This will enable them, and us, to save money by using energy at times of excess system capacity.

Going forward, we want to maximise how many customers can access our new two-way tariff – the Sun Soaker tariff - to help use up excess renewable solar energy generated during the middle of the day.

### Our current consumption tariffs (including our Sun Soaker trial tariff)

The figure below provides an overview of our current consumption tariffs and our Sun Soaker trial tariff on a scale of cost reflectivity.

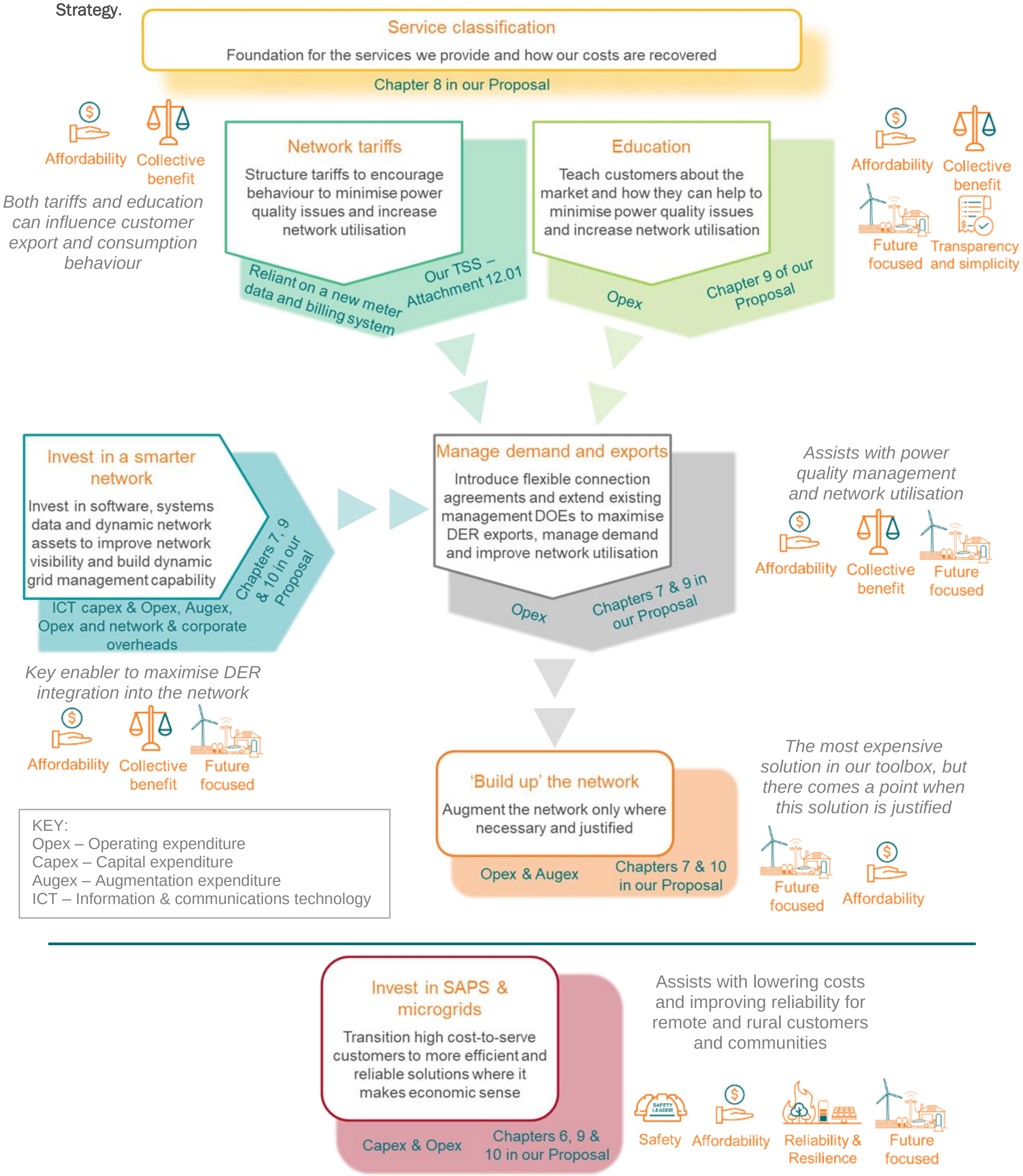
Our current consumption tariffs



## Interrelationship with the other tools we use to address our network challenges

Pricing can play a part in managing how and when customers use our network. However, it is just one tool in a suite of inter-related tools we use to help manage our network challenges and keep our network costs as low as possible. How this suite of tools work together is shown below, along with where the associated costs sit within our Regulatory Proposal and the customer priorities they address.

You can read more about this interrelationship in our **January 2023 Proposal Attachment 7.01 – DER Integration Strategy**.



# Overview of network pricing objective and principles

Clause 6.18.5(f) of the NER states that:

> The *network pricing objective* is that the tariffs that a *Distribution Network Service Provider* charges in respect of its provision of direct control services to a *retail customer* should reflect the *Distribution Network Service Provider's* efficient costs of providing those services to the *retail customer.*

This objective seeks to ensure that network charges recover the efficient costs of providing distribution network services to customers. To achieve this objective, the NER set out network charging principles, which we must comply with when setting our charges.

**NER pricing principles**

| Clause | Principles |
|---|---|
| **6.18.5(e)** | For each tariff class, the revenue expected to be recovered must lie on or between:<br>(1) an upper bound representing the standalone cost of serving the retail customers who belong to that class; and<br>(2) a lower bound representing the avoidable cost of not serving those retail customers. |
| **6.18.5(f)** | Each tariff must be based on the long run marginal cost (LRMC) of providing the service. |
| **6.18.5(g)** | The revenue expected to be recovered from each tariff must reflect the total efficient costs of serving the retail customers, permit recovery of the expected revenue for the relevant services and minimise distortions to the price signals for efficient usage. |
| **6.18.5(h)** | Consideration must be given to the impact on retail customers of changes in tariffs from the previous regulatory year. |
| **6.18.5(i)** | Tariff structures must be reasonably capable of being understood by retail customers or being directly or indirectly incorporated by retailers or Market Small Generation Aggregators in contract terms. |
| **6.18.5(j)** | A tariff must comply with the Rules and all applicable regulatory instruments. |

In applying the above pricing principles, we must also address transitional arrangements in clause 11.141.13 of the NER that accompany the introduction of export pricing. These require that we propose a basic export level that our customers can access without incurring an export charge or a method for determining this. Our approach to meeting this requirement is discussed below.

Our 2024-29 TSS also:

> gives effect to the NSW Government's Green hydrogen electricity concessions for producers which we will administer through site specific tariffs for producers who have been approved by the NSW Government – in accordance with NER clause 6.18.5(j) and the *Electricity Supply (General) Amendment (Green Hydrogen Limitation) Regulation* (network tariff exemptions for approved green hydrogen producers)

> recognises that we are required to pay contributions to the costs of the NSW Roadmap each year once these contributions have been determined by the NSW Government's Scheme Financial Vehicle, though our recovery of these contributions does not fall under the above distribution pricing principles.

## Efficient charging bounds

Revenue for each of our tariff classes lies between avoidable cost and stand-alone cost. This is important because:

> using only an LRMC estimate to set network charges would not allow us to recover all the network costs approved by the AER

> some residual costs are not recovered when our network charges are set to equal marginal cost

> the way we recover these residual costs has efficiency implications.

When recovering our residual costs, we must not charge inefficient levels of cross-subsidy or charge some customers less than the avoidable cost of not servicing them. Clause 6.18.5(e) of the NER limits the residual costs we can recover from any one tariff class by imposing an upper bound (the stand-alone cost) and a lower bound (the avoidable cost).

> The **stand-alone cost** of serving a given group of customers in a tariff class is the total cost of servicing them if we rebuilt the network to meet their specific requirements or met their equivalent energy reliability needs through a stand-alone energy solution. This upper bound ensures that customers in any tariff class do not pay more because we are servicing other customers than if they sourced electricity directly.

> The **avoidable cost** is the cost reduction resulting from any (potentially large) decrease in output associated with no longer servicing that same group of customers. This lower bound ensures that the revenue we recover from a given

charging class exceeds the costs that could be avoided were the network not to supply these customers. The customer charge must be no lower than the costs we would avoid by not supplying them.

Stand-alone and avoidable cost are both important for determining how we recover residual costs associated with our network. Our method for estimating them remains the same as for our previous TSS, with updates to the cost inputs to account for new export service costs incurred after 1 July 2024 under our new two-way service obligations.

## Method for estimating stand-alone and avoidable cost

We have used current expenditure as the basis for estimating stand-alone and avoidable cost. For example, to assess our stand-alone cost for the high voltage charging class, we have identified the existing assets and operating expenditure needed for these customers.

Our framework uses two dimensions to classify each network cost category.

1. Whether costs are direct or indirect
   - Direct: the cost can be attributed to a specific group of users and would not be incurred but for those users.
   - Indirect: the cost is common to multiple groups of customers.

   For example, a service line is directly attributable to an individual customer, but operational expenditure costs are generally indirect. For instance, the cost of raising equity cannot be attributed to specific customers or customer groups.

2. Whether costs are scalable or non-scalable
   - Scalable: the cost tends to increase in proportion to the scale at which the service is provided.
   - Non-scalable: the cost is independent of the scale at which the service is provided.

   For example, maintenance and repair costs are scalable as they usually depend on the physical size of the network. Equity-raising costs will be independent of network characteristics such as the number of customers or maximum demand.

The following explains how we calculate avoidable and stand-alone costs.

- Avoidable cost for each tariff class is the sum of all direct costs for providing traditional distribution services multiplied by a weighting. This represents the proportion of direct costs that are attributable to that tariff class. Added to this is the export LRMC attributable to export-billed customers in this tariff class.
- Stand-alone cost for each tariff class is the sum of avoidable costs, non-scalable indirect costs and scalable indirect costs. This is then multiplied by a set of scaling factors that vary according to the costs in question.

We have escalated our stand-alone and avoidable cost calculations for inflation, to ensure they align with the nominal annual charges and revenues proposed in our TSS.

## Comparison of revenue and charging bounds

In relation to clause 6.18.5(e), our estimates of the standalone and avoidable cost for each customer class are included in our economic costs model.

The table below sets out our comparison of 2024-25 forecast revenue compared with our estimates of stand-alone and avoidable cost for each charging class. The results demonstrate that our proposed network charges satisfy the NER charging bounds.

**How our forecast 2024–25 revenue ($ million, Real 30 June 2024) by customer class complies with the NER**

| Tariff class | Avoidable | Standalone | Proposed | Proposed revenue lies between standalone and avoidable cost? |
|---|---|---|---|---|
| Low-voltage residential and small business customers | 367 | 2,179 | 873 | Yes |
| Low-voltage demand | 68 | 630 | 176 | Yes |
| High-voltage demand | 24 | 240 | 62 | Yes |
| Sub-transmission | 43 | 419 | 111 | Yes |
| Unmetered | 3 | 413 | 7 | Yes |

## Each network charge is based on long run marginal cost

Under the NER, our network charges must be based on the LRMC and, ideally, reflected in the relevant variable component. However, not all network charges have been designed under the current rule framework, so we have accounted for LRMC differently in legacy and new network charges.

- Legacy network charges that were designed before this obligation (e.g. our anytime tariffs for accumulation meter customers) have been tested to ensure they will recover at least the relevant LRMC revenues attributable to customers on that network charge.
- New cost reflective network charges introduced in the previous TSSs are, in this Revised TSS, based on the LRMC for the relevant variable charging parameters. This is regardless of whether it is demand, time of use (TOU) electricity or time of use exports.

## Long run marginal cost of peak demand

In relation to clause 6.18.5(f), we have used the Average Incremental Cost (AIC), which was used to estimate the LRMC values in our previous TSSs.

This approach was agreed with our PCC and is the same as that approved by the AER for our previous TSS. It has been updated to reflect the AER's feedback on replacement expenditure forecasts, our current cost forecasts and a 10-year forecasting horizon.

**How different expenditures contribute to our LRMC of peak demand at each voltage level ($/kVA, Real, 30 June 2024)**

| Voltage level | Connection capital expenditure | Growth capital expenditure | Replacement capital expenditure | Growth operating expenditure | Voltage level component of LRMC | Total LRMC at voltage level |
|---|---|---|---|---|---|---|
| CONSUMPTION | | | | | | |
| Sub-transmission | 37 | 10 | 4 | 2 | 55 | 54 |
| High-voltage | 38 | 50 | 47 | 11 | 145 | 200 |
| Low-voltage | 2 | 8 | 7 | 2 | 19 | 218 |

Numbers may not add up due to rounding

We calculate LRMC at a voltage level for all customers, with an LRMC estimate for low-voltage, high-voltage, and sub-transmission customers. The LRMC estimate is not specific to location or feeder, but an average for all customers connected at the same voltage level within the same customer class.

As these costs are all variable over time, the variable components of our distribution network charges are set to at least reflect our LRMC estimates. This is consistent with our tariff classes having tariffs that are averaged across those classes and with our customers' strong preference for postage stamp pricing.

## Long run marginal cost for peak exports

In preparing this Revised TSES we have calculated the LRMC of peak export services by voltage level, consistent with the AEMC's access and pricing rule change and the AER's subsequent guideline for export tariff setting.

**How different expenditures contribute to our LRMC of peak exports at each voltage level ($/kVA, Real, 30 June 2024)**

| Voltage level | Growth capital expenditure | Replacement capital expenditure | Growth operating expenditure | Voltage level component of LRMC | Total LRMC at voltage level |
|---|---|---|---|---|---|
| EXPORT | | | | | |
| Sub-transmission | 2 | 0 | 0 | 2 | 2 |
| High-voltage | 8 | 0 | 3 | 11 | 13 |
| Low-voltage | 1 | 0 | 1 | 2 | 15 |

Numbers may not add up due to rounding

When calculating the above LRMC estimates, we have considered the basic export level of 1.5 kW that we have identified as our existing intrinsic hosting capacity. We explain how we established our basic export level below.

## How our tariffs compare with our estimates of LRMC

The tables below set out how our proposed network charges for the 2024–25 year (first year of the TSS period) compare with our estimate of the LRMC. The LRMC has been translated to the specific charging component for comparison. However, our proposed charging components for demand-based charges still incorporate both consumption charges and demand charges, which need to be considered together in LRMC comparisons.

### LRMC comparison to proposed network charge components by charging type ($real 2024)

Anytime (block) network charges

| Code | Name | LRMC | Proposed 2024–25 DUOS | |
|---|---|---|---|---|
| | | Charge c/kWh | NAC $/year | Energy c/kWh |
| BLNN2AU | LV Residential Anytime | 2.93 | 387.23 | 9.27 |
| BLNN1AU | LV Business Anytime | 2.93 | 658.35 | 13.36 |

Time of Use network charges

| Code | Name | LRMC | | | Proposed 2024–25 DUOS | | | |
|---|---|---|---|---|---|---|---|---|
| | | Peak c/kWh | Shoulder c/kWh | Off-peak c/kWh | NAC $/year | Peak c/kWh | Shoulder c/kWh | Off-peak c/kWh |
| BLNT3AU | LV Residential TOU | 7.66 | 2.36 | 1.62 | 387.23 | 12.63 | 9.73 | 2.98 |
| BLNT2AU | LV Business TOU | 7.76 | 2.74 | 1.53 | 658.35 | 13.19 | 10.17 | 4.86 |
| BLNT3AL | LV Residential TOU Interval | 13.19 | 1.93 | 1.57 | 387.23 | 13.26 | 9.25 | 2.98 |
| BLNT2AL | LV Business TOU Interval | 10.76 | 2.56 | 1.49 | 658.35 | 13.85 | 9.66 | 4.62 |
| BLNRSS2 | LV Residential Sun Soaker | 7.04 | - | 0.58 | 387.23 | 11.25 | - | 2.98 |
| BLNBSS1 | LV Small Business Sun Soaker | 6.43 | - | 0.83 | 658.35 | 11.75 | - | 4.62 |

Demand network charges

| Code | Name | LRMC | | | Proposed 2024–25 DUOS | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Demand charge $/kVA/M | | | NAC $/year | Energy charge c/kWh | | | Demand charge $/kVA/M | | |
| | | Peak | Shoulder | Off-Peak | | Peak | Shoulder | Off-peak | Peak | Shoulder | Off-Peak |
| BLND1AR | LV Residential Opt-in Demand | 3.77 | 3.62 | 3.21 | 387.23 | 4.12 | 2.19 | 1.19 | 4.55 | - | - |
| BLND1AB | LV Small Business Opt-in Demand | 3.77 | 3.62 | 3.21 | 658.35 | 7.04 | 4.40 | 2.29 | 8.51 | - | - |
| BLND3AO | LV Large Business Demand | 3.77 | 3.62 | 3.21 | 6,617.09 | 0.94 | 0.70 | 0.20 | 10.55 | 9.55 | 2.50 |
| BLNDTRS | LV Transitional Demand | 3.77 | 3.62 | 3.21 | 6,617.09 | 0.94 | 0.70 | 0.20 | 10.55 | 9.55 | 2.50 |
| BHND3AO | HV Business Demand | 3.97 | 3.10 | 3.29 | 8,190.89 | 0.72 | 0.53 | 0.30 | 10.08 | 9.12 | 2.73 |
| BSSD3AO | Subtransmission Demand | 1.56 | 1.21 | 1.29 | 8,130.67 | 0.26 | 0.12 | 0.11 | 3.89 | 2.77 | 1.11 |
| BLND4SB | LV small scale storage | 3.77 | 3.62 | 3.21 | 658.35 | - | - | - | 8.51 | 2.02 | 2.02 |
| BLND4LS | LV Large storage/ hybrid | 3.77 | 3.62 | 3.21 | 6,617.09 | - | - | - | 10.55 | 9.55 | 2.50 |
| BHND4LS | HV storage/ hybrid | 3.97 | 3.10 | 3.29 | 8,190.89 | - | - | - | 10.08 | 9.12 | 2.73 |

Export network charges

| Code | Name | LRMC | Proposed 2024–25 DUOS |
|---|---|---|---|
| | | Charge c/kWh | Exports |
| BLNRSS2 | LV Residential Sun Soaker | 0.74 | 0.74 c/kWh |
| BLNBSS1 | LV Small business Sun Soaker | 0.74 | 0.74 c/kWh |
| BLND4SB | LV small scale storage | 1.12 | 1.12 c/kW/M |
| BLND4LS | LV Large storage/hybrid | 1.12 | 1.12 c/kW/M |
| BHND4LS | HV storage/hybrid | 0.92 | 0.92 c/kW/M |

# Estimating LRMC

## Choice of LRMC method

In our TSS, we have retained the average incremental cost approach for estimating the LRMC of our network services. We have then applied this approach to separately estimate LRMCs for peak export and peak demand.

The average incremental cost approach averages the total cost of supplying new growth in either peak demand or peak exports over that growth in demand or exports. This is done by calculating the average change in projected operating and capital expenditure attributable to future increases in peak demand or peak exports. This involves:

> projecting future operating and capital costs attributable to expected increases in peak demand or peak exports
> forecasting future load and export growth for the relevant network asset (or assets)
> dividing the present value of projected costs by the present value of expected increases in peak demand or peak exports.

We have used the average incremental cost method again for the following reasons, including that it was supported by our PCC for the reasons discussed below.

> It relies on information that is currently available within our business from the 2024–29 revenue determination process and our longer-term asset planning processes.
> It is less data-intensive than the alternative perturbation method, making it easier to apply and to explain during stakeholder engagement.
> It is a cost-effective approach.
> It has been commonly adopted by other distribution networks and approved by the AER during their TSS reviews.

## Addressing AER feedback on our previous TSS

In its final decision on our previous TSS, the AER stated that it wanted to see us refine the treatment of replacement expenditure in our LRMC estimates, in our next TSS.[11] This is because the AER did not agree that our identified replacement expenditure costs were associated with 'incremental demand' for network services.

In response, we have refined our approach for this period and included only relevant elements of our replacement expenditure forecasts that are also meeting incremental demand (that is where the capacity of the replacement assets is greater than that of the assets they are replacing to account for incremental demand growth).

The AER's draft decision on our proposed 2024-29 TSS noted these refinements and approved our approach to estimating LRMC.[12]

## Consultation with our PCC on our LRMC estimation approach

We consulted our Pricing Collaborative Collective on our proposed approach to estimating LRMC for TSS.

We commenced this process by explaining the following:

> to date, we have estimated LRMC by voltage level (ST, HV, LV) using the AIC approach over a 30-year forecasting horizon for peak demand only
> to date, in the DNSP LRMC pricing practices, the AER has observed that: [13]
  – most DNSPs calculate LRMC using AIC
  – a 10-year forecast horizon for inputs to LRMC calculations is the minimum needed
  – there is a general perception that the AIC method is less costly to implement than some other methods (but produces less accurate estimates of LRMC).

[11] AER, *Attachment 18: Tariff structure statement | Final decision – Essential Energy distribution determination 2019-24*, April 2019, pp.18-13 and 18-14.

[12] AER, Attachment 19 - Tariff structure statement | Draft decision - Essential Energy distribution determination 2024–29, Sept 2023, section 19.4.5.

[13] AER, *Network tariffs and long run marginal cost | explanatory note*, Sept 2021. pp2-3

- We now have two primary drivers of long-run costs that have different services attached to them:
  - peak demand associated with the provision of energy delivery services
  - minimum demand associated with the provision of peak energy export services.
- By estimating the LRMC for each of these services (at appropriate levels of voltage disaggregation), we can derive relevant LRMC-based charging parameters in tariffs for different types of customers.

In this context, the PCC supported us separately estimating LRMC for these two services.

We then presented the PCC with options for LRMC estimation and discussed the costs and benefits of adopting more complex methods of LRMC estimation. We also discussed the pre-conditions needed for more complex methods of LRMC estimation to deliver customer benefits. We note that:

- this requires customers to see and respond to those LRMC estimates in their prices
- these LRMC-based price must be material enough to support behavioural change.

We also explained to the PCC that it is difficult to demonstrate that our choice of LRMC estimation method will have any perceptible benefits. This is because:

- the pace of smart meter deployment needed for cost reflective tariffs is much lower than expected in the power of choice reforms
- LRMC-based charges make up the minority of our required revenues
- the materiality of other non-cost reflective elements of customer's network use of system (NUOS) bills can be expected to make the marginal pricing signal impact of different DUOS LRMC estimation methods imperceptible to retail customers
- there is little evidence of retailers passing on the signals.

The table below explores these factors and references evidence of the AEMC and AER recognising their presence and impact on benefits realisation. This table was discussed with the PCC, who supported us taking a 10-year AIC view to determine LRMCs.

A time window of 10 years (relative to the previous 30 year window) for forecasting the new costs associated with peak export services was viewed as preferable on the basis that this is a new service and the future costs of DER hosting and integration may be hard to forecast with certainty at this point in time. It is also the time horizon that the AER has recently adopted for 'long-term' in its updated *Transmission pricing methodology guideline* for system strength pricing.

The AER's draft decision on our proposed 2024-29 TSS approved our approach to estimating LRMC.[14]

**Impediments to benefits realisation from adopting more complex LRMC estimation approaches**

| Impediment | Evidence | Consequence |
|---|---|---|
| Slow pace of smart meter deployment | The AEMC's September 2021 Review of metering services directions paper found that: [15]<br>*Outside of Victoria, the current average level of smart meter penetration is currently around 25%. If the current rate of installation continues, it will take at least another four to five years before a 50 per cent penetration is achieved and full deployment of smart meters may not occur until after 2040.*<br>We currently have 25 per cent smart meter penetration. | In its November 2022 draft report, the AEMC recommended universal uptake of smart meters by 2030, where legacy accumulation and manually read interval meters would be progressively retired by DNSPs under a legacy meter retirement plan, and retailers would replace these.[16]<br>This is only a draft and a rule change process still needs to be administered after the final review report, so confirmation of the final pace of smart meter deployment in the next TSS period remains some time away. |
| Residual DNSP costs swamp long run marginal costs | 76 per cent of our revenues (and therefore 76 per cent of our prices) relate to our residual costs in 2025. | Different LRMC methods would need to have very large differences in their results in order to send a perceptible signal beyond the impact of residual costs. |
| Pass-throughs of jurisdictional schemes and TUoS can swamp LRMC-based DUoS charging parameters | The NSW government's Electricity Infrastructure Roadmap is establishing arrangements to recover the costs of its implementation (including those of the authorised network infrastructure, contracts underwriting generator investment, and the costs of EnergyCo) though NSW DNSPs' jurisdiction scheme pass-throughs. | The forecast costs to be recovered through the scheme financial vehicle are significant.[17] The majority of these costs will relate to investments in the provision of wholesale electricity rather than network costs.<br>Pass-throughs of jurisdictional scheme charges have no pricing principles for how they are recovered from DNSPs' customers.<br>We discuss our approach to recovering pass-throughs below, in the section on *Treatment of pass-through costs*. |

[14] AER, Attachment 19 - Tariff structure statement \| Draft decision - Essential Energy distribution determination 2024–29, Sept 2023, section 19.4.5.

[15] AEMC, *Directions Paper \| Review of metering services*, 16 September 2021, p.i.

[16] AEMC, *Draft report \| Review of the regulatory framework for metering services*, 3 November 2022, p.i.

[17] NSW Consumer Trustee, 2021 *Infrastructure Investment Objectives report*, figures 15 and 16.

| Impediment | Evidence | Consequence |
|---|---|---|
| Retailers are not interested in passing on cost reflective network charges to most customers | In 2020, the AER published a research paper titled '*Understanding the impact of network tariff reform on retail offers*'. This followed AER engagement with retailers and energy service providers of various size and examined data for SA and Queensland (its most recent TSS decisions at the time). It identified that: [18]<br>*Our review of retail performance market update data shows that in Queensland 98.5 per cent of residential and small business customers are on a flat or block retail offer with no time-of-use price signals. The remaining 1.5 per cent of customers are on a time-of-use retail offer. In South Australia, 96.2 per cent of residential and small business customers are on a flat or block retail offer. The remaining 3.8 per cent of customers are on a time-of-use tariff retail offer.*<br>We have struggled to get any of the tier 1 retailers to sign up to trial tariffs. | If customers cannot see tariff signals, then there is no mechanism for the benefits from different levels of precision in those signals to be realised.<br>Absent market scale levels of price signal pass-through, the costs of more complex methods of LRMC would be imprudent to incur, based on the expected level of benefits realisation.<br>This analysis may vary for some customer segments such as C&I customers who do see network charges on their bills, but only where the marginal versus residual cost elements of their bill permit this. |

## Modelling LRMC

Our modelling estimates the LRMC by system voltage level – that is, subtransmission, high-voltage, and low-voltage - for each peak demand and peak exports.

The LRMC estimates include three components:

- growth capital expenditure
- incremental operating and maintenance costs
- the component of replacement capital expenditure (repex) that is capacity-enhancing for peak demand only.

Growth capital expenditure, capacity-enhancing replacement capital expenditure and growth operating expenditure are all directly forecast to 2034.

Peak demand and peak exports at each voltage level have also been forecast to 2034 by Frontier Economics.

For connection and growth capital expenditure, and the component of replacement capital expenditure that is capacity-enhancing, we have estimated an annual cost/charge impact of expenditure. Annual costs are used to remove the requirement to model residual values of each capital expenditure item. The annual costs are then discounted to 2022. We have calculated a 12-year Net Present Value (NPV),[19] and the LRMC is calculated as the discounted costs divided by the discounted change in demand at each voltage level.

Our modelling then transforms the LRMC estimate to network charge component values, considering both the probability that consumption on a particular network charge will occur at the time of the system peak and the quantum of the component that would be billed for a 1kVA demand.

[18] AER, Understanding the impact of network tariff reform on retail offers, 2020, p.2.

[19] The 12 year period covers the last two years of the 2019–24 regulatory period and the next two regulatory periods (which are both assumed to be 5 years in length).

**LRMC transformation examples using low voltage network charges**

- Anytime electricity charge
- Peak period electricity charge
- Controlled load charge
- Demand charge
- Peak export charge

Assume the estimate of the consumption LRMC at low voltage is $300/kVA, and (for simplicity) that all customers have a power fact of 1.0. Assume also that the estimate of the export LRMC at low voltage is $15/kVA.

**Anytime charge:** In a year, a 1 kVA constant demand on an anytime electricity network charge will use 1 kVA x 1.0 kW/kVA x 365 days per annum x 24 hours per day = 8760kWh. A 1 kVA continuous demand will certainly be using energy at the peak time, because it operates all the time. Therefore, for the anytime electricity network charge, we transform the $300/kVA LRMC into a component value as: 100% * $300kVA / 8760 kWh/KVA = $0.034/kWh = 3.4c/kWh.

**Peak period charge:** If the peak period is 5 pm to 8 pm on summer days (Nov to Mar), there are 3 hours per day x 151 peak period days per annum = 453 peak period hours per annum. An additional 1 kVA of demand would use 453 kWh of peak period electricity. Again, let's assume that it is virtually certain that the peak will occur during the time the network charge is valid. Therefore, for the peak period electricity charge, we transform the $300/kVA LRMC into a component value as: 100% * $300kVA / 453 kWh/kVA = $0.662/kWh = 66.2c/kWh.

**Controlled Load charge:** Assume a Controlled Load network charge provides 8 hours of supply (generally for water heating) at some time between 10pm and 7am, or 10am and 3pm every day. There are 8 hours per day x 365 days = 2920 hours of supply per annum. An additional 1 kVA of demand would use 2920 kWh of controlled load electricity. However, it is virtually certain that the charge will not be active at the time the peak occurs. Therefore, for the controlled load charge, we transform the $300kVA LRMC into a component value as 0% * $300kVA / 2920 kWh/kVA = $0.000/kWh = 0.0c/kWh.

**Monthly demand charge:** The charging parameter is the highest demand in the month. An additional 1kVA demand would generate 1 kVA each month or 12 kVA-months per annum. There will be diversity between customers, so all customers do not peak at the same time or when the system peaks. Charging an anytime maximum demand without accounting for this diversity would over-recover the LRMC. Assume the inter-customer diversity is 60%. For the monthly demand charge, we transform the $300/kVA LRMC into a component value as 60% * $300/kVA / 12 kVA-months = $15 per kVA-month.

**Monthly peak export charge:** Similar to the monthly demand charge, the charging parameter is the highest export in the month during the 10 am to 3 pm period. An additional 1 kW peak export would generate 1 kW each month or 12 kW-months per annum. There will be diversity between customers, so all customers do not peak at the same time or when the system peaks (in terms of exports). As with consumption, charging a maximum export without actually accounting for this diversity would over-recover the LRMC. Assume the inter-customer diversity is 60%. It is also virtually certain that peak exports will occur during the 10am to 3pm busy period as that is when the sun is shining most. For the monthly peak export charge, we transform the $15/kVA export LRMC into a component value as 100% * 60% * $15/kVA * 1.0 power factor / 12 kW-months = $0.75 per kW-month.

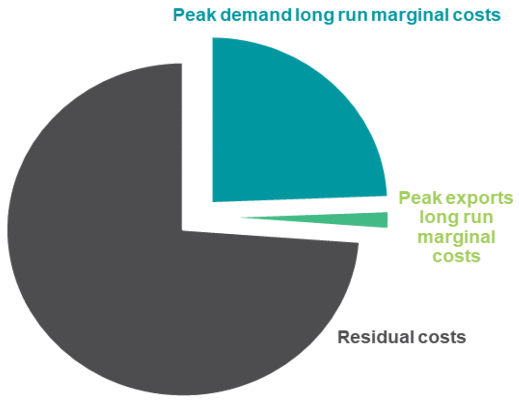
# Building cost reflective tariffs

## Mapping cost concepts to charging parameters

When designing our network charges, we have aligned our cost types to relevant charging parameters and considered how these parameters will influence our customers' electricity usage and export decisions.

The figure below illustrates the shares of our total building block costs that are attributable to growth-related (marginal) costs for peak demand and peak exports, and to largely fixed (residual) costs.

**Aligning costs with charges parameters (2029 year)**




To comply with NER 6.18.5 (g) (1) to (3), we have used our marginal cost estimates when setting demand charges and peak export charges, because demand and peak exports drive our marginal costs.

We have then recovered residual costs from our network access charges and consumption charges. This ensures we recover residual costs in ways that least distort customers' usage decisions.

We have also tested that the revenue from each non-demand-based network charge is greater than the relevant LRMC shown in our LRMC compliance model at **supporting document 9.03**.

## Ensuring network tariffs reflect efficient costs and minimise demand distortions

If we set tariffs based only on our LRMC estimates, we would not recover all of our required revenue. The NER obliges us to consider how to recover the remaining costs (residual costs) in a way that minimises distortions to customer usage and export decisions.

We have weighed our network tariffs to reflect efficient costs and minimise demand distortions against how easy they are for customers to understand, and the impact of any changes on customer bills. We have also considered other applicable regulatory instruments. Our method of balancing these requirements is discussed below.

*Residual cost allocation*

We have sought to allocate residual costs (the difference between LRMC-driven costs and our AER-allowed revenues) in a way that:

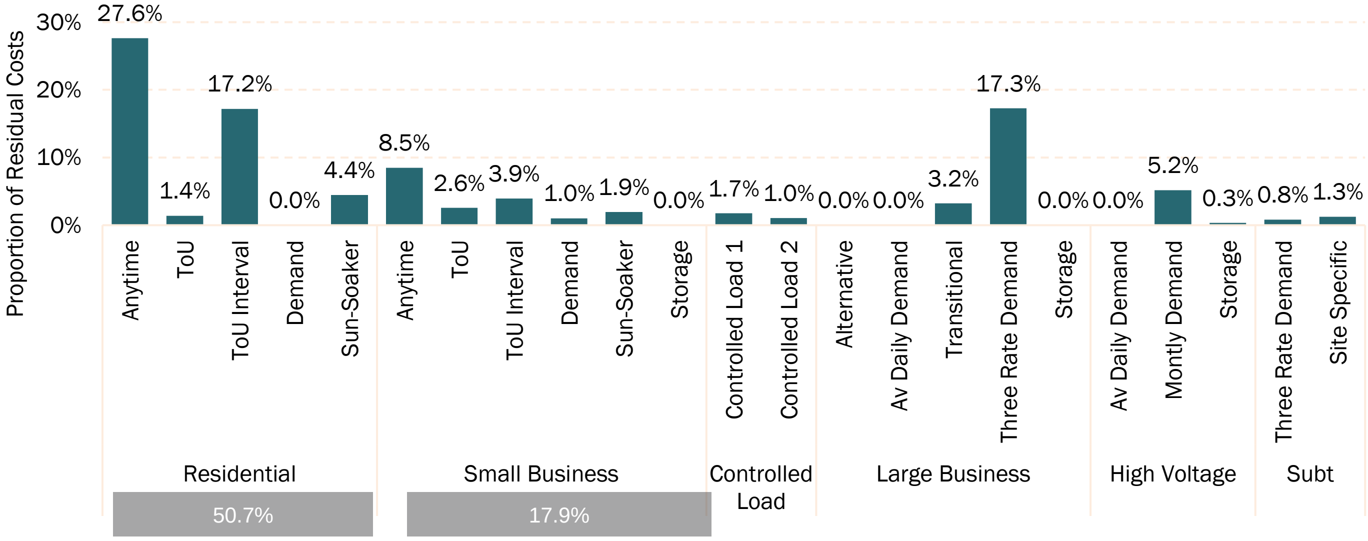
- allows us to create distribution network charges that more accurately reflect the cost of providing network services at different times of the day
- supports cost-reflective tariffs for households and small business customers that are designed for the future state and are technology agnostic, meaning these customers can access the same tariffs and opportunities for savings or rebates irrespective of the new energy technologies they choose to invest in and connect to our grid
- accounts for the fact that a greater share of our customer base will receive a smart meter and be assigned to more efficient distribution network tariffs during the 2024–29 period
- encourages customers to take up and respond to our new Sun Soaker tariff
- provides opportunities for our customers to save money through decisions about when they use energy and when they export energy
- complies with the AER's guidance for recovering legacy metering costs from low voltage customers' fixed charges.[20]

This approach means that:

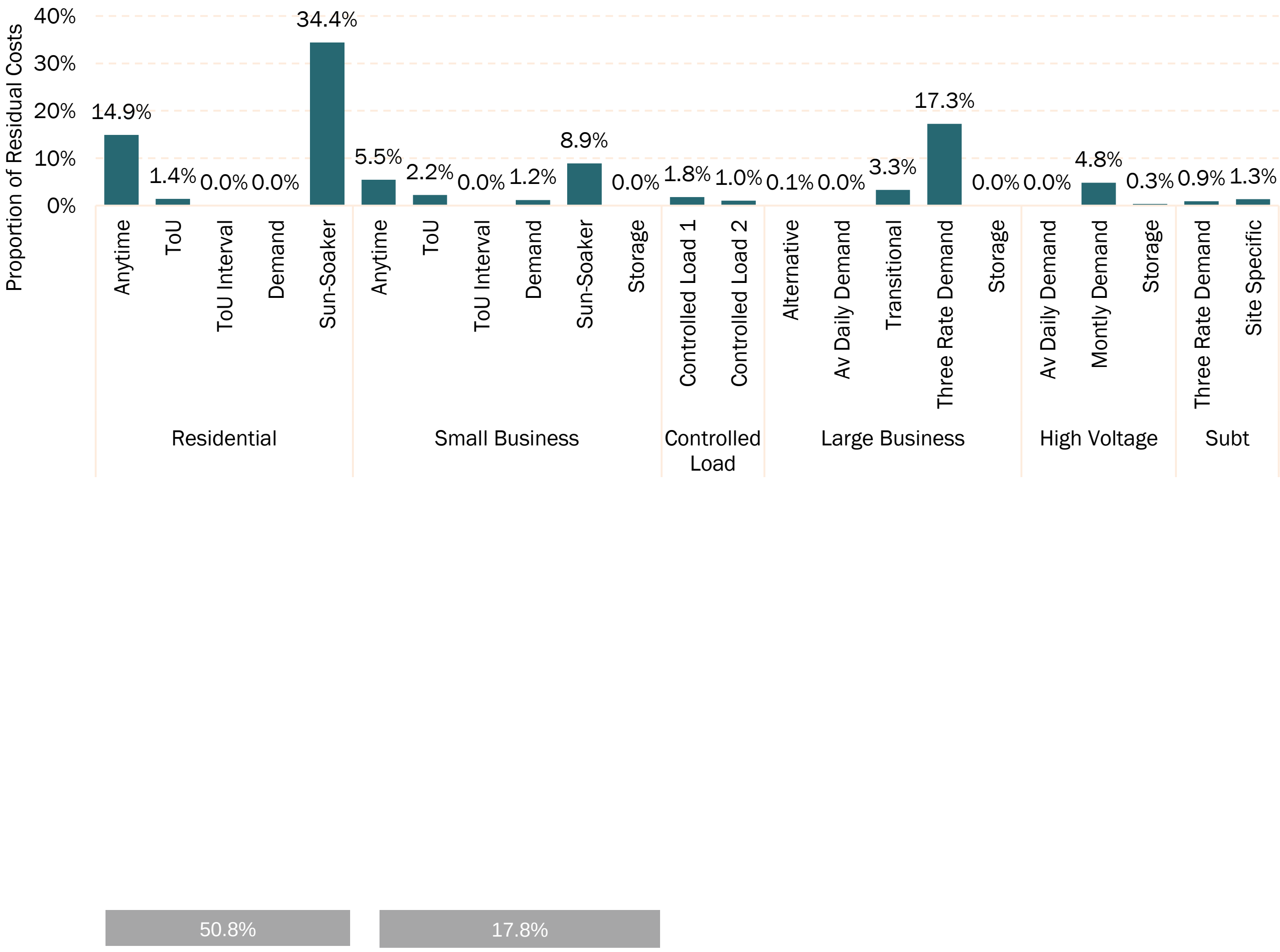
- our most efficient charging types (peak demand and peak exports) closely reflect their associated LRMC estimates
- our relatively more efficient charging types (Time of Use [ToU] charges and rebates) reflect pricing levels that support incentives for efficient use
- our daily network access charges make a stable contribution to our fixed residual costs without distorting energy usage decisions. This enables us to minimise pricing volatility amid the transition of a greater share of our customer base to more efficient tariff structures facilitated through the accelerated deployment of smart meters - specifically, we have aimed to keep fixed charges:
  - equal across all open tariffs by customer type (as we do now, noting we have corrected a historical anomaly to align the LV Small Business Anytime tariff with other small business tariffs)
  - stable by applying the inflation element of our allowed revenue growth to this fixed charge in the first instance, though by no more than 2.5 per cent per annum. Where inflation exceeds 2.5 per cent in any year, the balance will be recovered through consumption charges
- this method of allocating our residual costs across different pricing types is the best way to encourage customers to choose cost-reflective tariffs and also minimise price volatility over time.

[20] AER, Legacy metering services – Guidance note, November 2023, p.4.

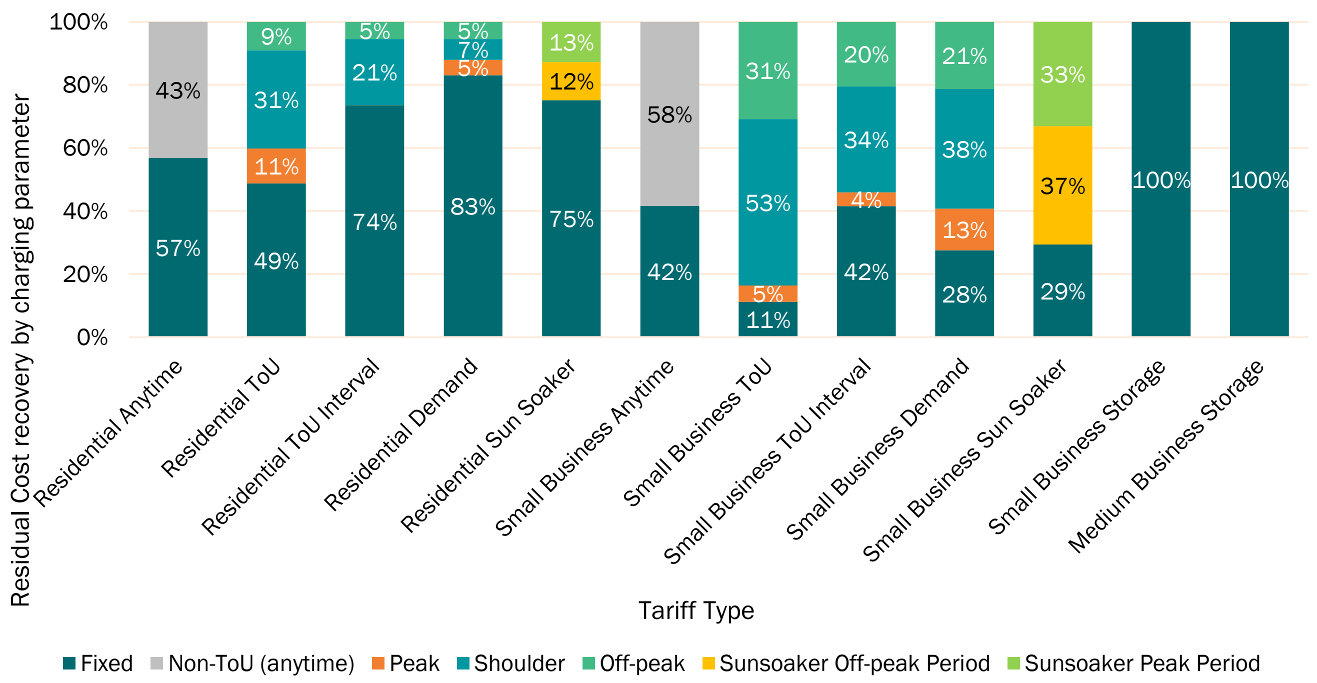
Allocation of residual costs between distribution network charges and customer types – 2025




Allocation of residual costs between distribution network charges and customer types – 2029



Residual Cost recovery by charging parameter (2025)




## Administering site specific tariffs

Our largest customers may be eligible for site specific tariffs which are individually calculated for their circumstances to best comply with the NER pricing principles for those customers.

### Who is eligible?

Customers may apply to us for a site specific tariff where their:

- electricity consumption has been equal to or greater than 40GWh for the year preceding the application, or
- electrical demand is greater than 10MW over the year preceding the application
- the Minister has approved their eligibility for the NSW government's green hydrogen producers concessions scheme.

Essential Energy may also offer a site specific tariff to customers expected to satisfy the above thresholds in the near future and/or customers requiring non-standard connection to our sub-transmission network.

### What do we consider when setting site specific tariffs?

When we apply the NER pricing principles to customers assigned to a site specific tariff, we seek to calculate these tariffs having regard to:

- the structure of the default tariff to which the customer would otherwise be assigned which for our sub-transmission customers is our BSSD3AO sub transmission demand 3 rate tariff that comprises the following charging parameters:
  - network access charge ($/day)
  - peak, shoulder and off-peak energy consumption charges (c/kWh)
  - peak, shoulder and off-peak monthly demand charges (¢/kVA or kW/day)
- the number of NMIs at the customer's connection point
- the need to recover investment associated with stranded or dedicated assets, or other costs incurred by Essential Energy for that connection point, which may otherwise not be recovered under the default tariff assignment
- material connection behaviours that could drive up costs incurred by Essential Energy and which have not otherwise been paid for or avoided by the terms of the customers' connection agreement, including as a result of customer behaviours that can cause:
  - new coincident peak demands (i.e. any increase in demand that contributes to the existing network peak)
  - new non-coincident peak demands (i.e. establishing a localised peak outside of the existing)
  - new coincident minimum demands (i.e. any reduction in demand that contributes to the existing network minimum)

  - new non-coincident minimum demands (i.e. establishing a localised minimum outside of the existing)
  - higher locational TUOS
  - avoided locational TUOS
- our obligations in any relevant jurisdictional schemes (see below for our **Treatment of pass-through costs**).

Tariff structures will be based on the default tariff and adjusted for the above factors. Where there is a risk of behaviours creating non-coincident peak or minimum demands we may propose a critical peak pricing parameter.

Inter-distributor transfer network use of system tariffs are also calculated on a site specific basis and are specifically applied to electricity transferred through our network on behalf of other network service providers.

Applications requesting a new site specific tariff, or a change to an existing site specific tariff, must be submitted by 30 September. Where approved, pricing for a new or varied site specific tariff will take effect on 1 July the following year.

Essential Energy may reassign a default tariff to a connection point, effective from the beginning of the next year, if it is discovered that the connection point no longer satisfies any of the eligibility criteria above.

## Treatment of pass-through costs

Our treatment of pass-through costs has not changed from our previous TSS other than to incorporate the new system strength charges from Transgrid and the NSW Government's Green hydrogen electricity concessions for producers. We also adjust for under-recoveries or over-recoveries made in the previous year.

### Pass-through of jurisdictional scheme costs

When setting network charges, we consider amounts for approved jurisdictional schemes and ensure these costs or exemptions are passed on to customers in accordance with the requirements of these schemes. Currently known schemes include:

- the NSW Government's Climate Change Fund levy, which has a requirement that only 25 per cent of the NSW Climate Change Fund be recovered from residential customers
- contributions to the Queensland Government's Solar Bonus Scheme
- contributions to the costs of the NSW *Electricity Infrastructure Roadmap* (NSW Roadmap).

The manner in which we recover the above jurisdictional scheme costs will also comply with our obligations under the *Electricity Supply (General) Amendment (Green Hydrogen Limitation) Regulation* (network tariff exemptions for approved green hydrogen producers) regarding designated pricing proposal charges.

### Pass-through of transmission costs

The AER allows us to recover our transmission-related costs. These are a significant cost component and are recovered as part of our total network charges. Transmission-related payments are known as TUoS charges, and include:

- transmission-related costs for use of transmission networks owned by TransGrid, Ausgrid and Powerlink
- avoided TUoS payments to embedded generators, calculated in accordance with the NER
- payments for network services to other distributors for inter-distributor transfers.

Transmission charges are not in a form that readily translates into network charging structures. We translate historical energy and kilowatt demand charges from transmission businesses into equivalent peak, shoulder and off-peak energy rates to allocate these charges to the network charges for most customers.

We allocate transmission charges using several principles.

- We allocate the total TUoS to network charges in alignment with our total expected transmission-related payments.
- We align the pass-through of transmission charges and the structure of network charges wherever possible.
- Our site-specific customers are allocated transmission charges in a way that preserves the location and time signals of transmission charging, as per Chapter 6 of the NER. These charges are passed through as closely as possible, reflecting how the charges are levied on us.
- We allocate transmission charges for all other customer classes (that is standard customers) on an average basis. This is due to the difficulties associated with equitably allocating the general and common service fixed charge as a fixed network access charge, and passing through locational charging signals that cannot be preserved when the end charge is applied to many customers within the network.

For large customers with site-specific charges, the individual cost of transmission is directly assigned to the customer. The balance is allocated to standard customer classes.

Direct mapping to network charges for standard customer classes has not been possible. This is due to the large, fixed transmission charges that cannot be directly included in network charging structures for these customers, which typically have a small, fixed charge. More importantly, the customer's metering generally does not readily permit it, as many transmission charges are levied as demand kW charges. Due to these limitations, it is not possible to pass on transmission cost drivers through to all customers in the same format as they are provided to us.

While allocating the large, fixed charge component is reasonably discretionary, we have allocated it between customer classes based on consumption, to balance equity and efficiency. Only the peak and shoulder energy component can be readily passed on to customers through distribution charges.

Transmission charges are allocated on their non-TOU electricity, peak and shoulder consumption and/or demand. They are added to the distribution network charges for each customer class. The intention of this mapping methodology is to preserve the cost drivers inherent in the transmission charge within the customer's network charge, as far as possible.

- Non-TOU charge: The total transmission charge allocation for the class is divided by the total class consumption, and added to the electricity rate for the charge. Average transmission charges would apply to smaller customers.
- TOU charge: The transmission allocation relating to the transmission demand and energy components is divided by the peak, shoulder and off-peak consumption and added to the peak, shoulder, and off-peak electricity rates. The transmission allocation relating to the fixed transmission component is added to the TOU electricity rates.

> Demand TOU charge: The transmission allocation relating to the transmission demand and energy components is divided by the peak, shoulder and off-peak consumption and added to the peak, shoulder, and off-peak electricity rates. The transmission allocation relating to the fixed transmission component is added to the TOU electricity rates.

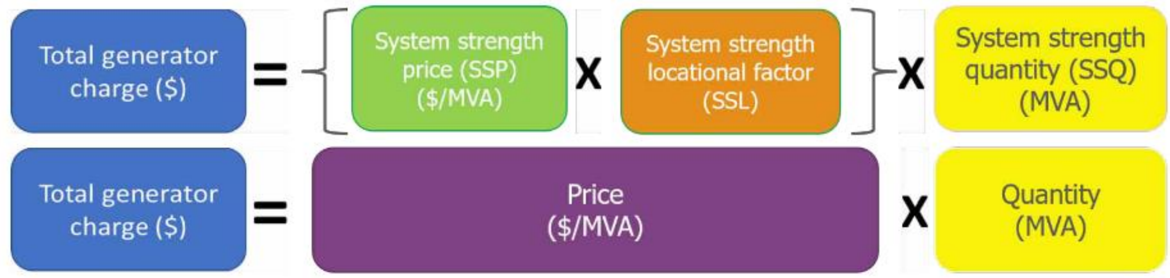
The fixed component of the transmission charge was originally and largely determined from an anytime electricity allocation of costs. This component is apportioned between individual customers and customer classes based on their anytime energy consumption, which balances equity and efficiency. The allocation of the transmission demand charge using peak and shoulder energy is justified on the basis that in the long run, the augmentation of the transmission network – and hence future costs – is related to peak and shoulder use of the network.

## Pass-through of system strength charges

Our pricing proposals from 2023 onwards must explain how we will pass-through Transgrid's system strength charges in a manner that replicates the amount, structure and timing of Transgrid's system strength charge as far as is reasonably practicable.

The final rule prescribed structure of the new system strength charge as shown in the following figure with the charging parameters outlined below. We will seek to replicate Transgrid's system strength charges for those customers on our network who are liable to pay them.

**Prescribed components of the system strength charge**[21]




The prescribed component parts of the system strength charge are:

- system strength unit price (SSUP) in $/MVA for the relevant system strength node is the unit price for system strength procured from a given SSSP
- system strength locational factor (SSL) is the relative electrical distance from the closest system strength node for a newly connecting generator or load, calculated as the ratio of the:
  - additional fault level that would need to be added at the nearest system strength node to restore the available fault level (AFL) at the connection point to the pre-connection level
  - system strength quantity requirement of the connecting party plant.

The SSL will be calculated on a connection-by-connection basis, drawing on AEMO guidance in the system strength impact assessment guidelines (SSIAG).

System strength quantity (SSQ) is the expected consumption of the service (calculated as MVA/MW x MW) by the party connecting to the grid, which will be estimated from:

- the size of the connecting plant in MW
- its short circuit ratio (SCR) as determined by the relevant SCR access standard.

AEMO will provide guidance through the SSIAG, and the relevant NSP will use this guidance to calculate this component on a connection-by-connection basis. The SSQ is fixed at the time of connection unless alterations to the connected plant require an update to the agreed performance standards.

The NER deem all existing fault level nodes to be system strength nodes. AEMO may declare additional system strength nodes from time to time.

## Green hydrogen electricity concessions for producers

Essential Energy will give effect to the *Electricity Supply (General) Amendment (Green Hydrogen Limitation) Regulation* (network tariff exemptions for approved green hydrogen producers) through individually calculated site specific tariffs.

Green hydrogen producers approved under the NSW government's concessions scheme will receive a 90% discount on their charges for standard control services and designated pricing proposal charges. This discount applies for 12 years.

[21] AEMC, *Efficient management of system strength on the power system, Rule determination*, 21 October 2021, figure 2.2, p. 25.

To be eligible for this discount, a customer must use electricity solely for producing green hydrogen (or have separate metering for its hydrogen production), propose to commence production before 1 January 2031, have an annual load of at least 1MW and be approved by the Minister.

The Minister may only approve a green hydrogen producer if:

- its connection will not require any network augmentation
- the customer has agreed to pay for any required network augmentation, or
- the customer has agreed to power transfer limitations or load control arrangements to manage any network constraints.

We will calculate site specific DUOS charges for these customers based on identifying their applicable default tariff assignment, then creating a specific tariff with each charging parameter set at 10% of the equivalent parameter in the default tariff.

We will calculate site specific designated pricing proposal charges set at 10% of the equivalent charge proposed for customers on the default tariff.

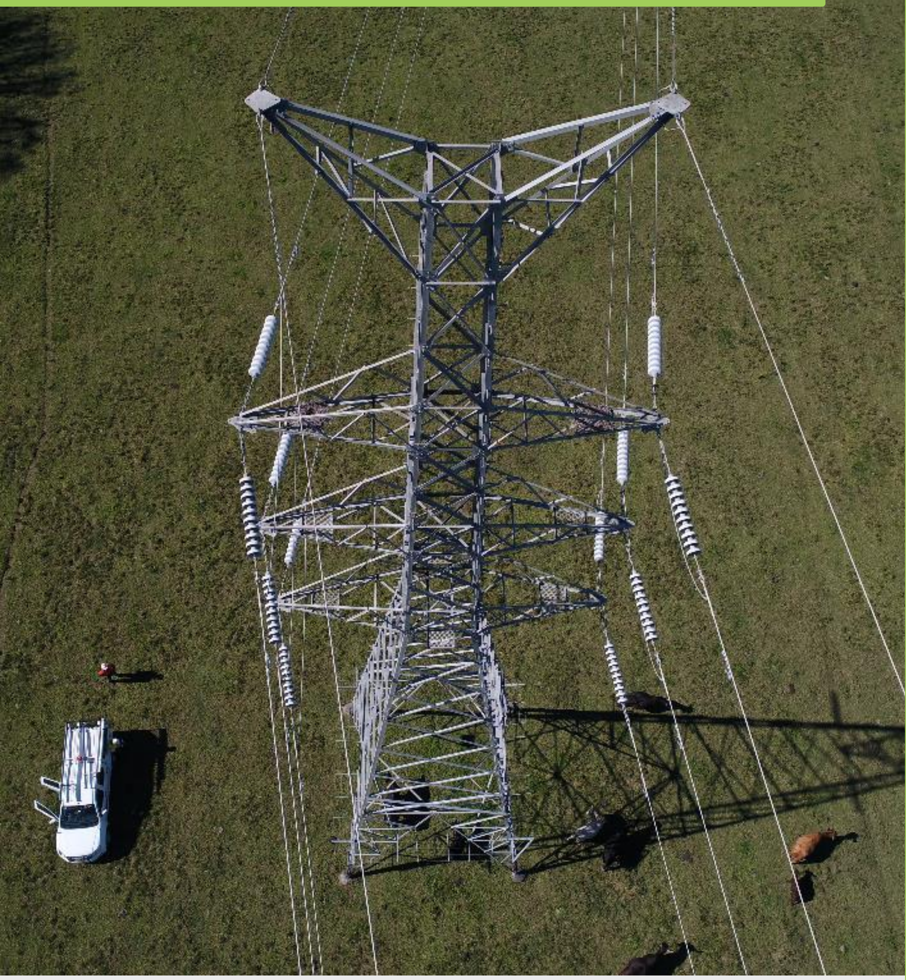
After their 12 year discounting period these customers will be reassigned to the applicable default tariff.

## Alternative control services

Our Alternative control services (public lighting and ancillary network services) are incurred by individual customers. Our approach to determining related charges is detailed in section 7 of our TSS.

03

# Approach to setting tariffs and the basic export level



## Chapter summary

- Peak demand profile
- Peak export profile
- Stakeholder feedback

## Setting our charging windows

TOU charging windows that apply to consumption, demand and export charges are set to provide signals so that, where a customer can do so, they can save money by consuming or exporting at times that impose least cost on our network.

Our TOU charging windows for consumption, demand and export charges are set to different time windows, according to the type of meter a customer has and the tariff they are assigned to.

To support cost-reflective charging, we use charging windows that signal times when the whole network is likely to experience high levels of demand or exports. Charging windows must be:

> wide enough to capture peak demand or peak export periods
> not so narrow that it is easy to shift peak demand by moving the network peak from one time period to another
> wide enough to ensure customers can respond to the charging signal and manage their bills by spreading their load or exports over the relevant period.

We have analysed our historical and forecast demand and export data to determine appropriate cost-reflective charging windows for our network circumstances. We have also taken into consideration the following key factors:

> actual network demand and the profile of network congestion over the day and across the year
> actual network exports and the profile of system minimum demand over the day and across the year
> cost versus benefit of any proposed changes
> stakeholder preferences to not have seasonal tariffs
> managing bill impacts for customers who are assigned to two-way tariffs, including preserving incentives for customers to not opt out of these cost reflective tariffs.

### Network demand profile

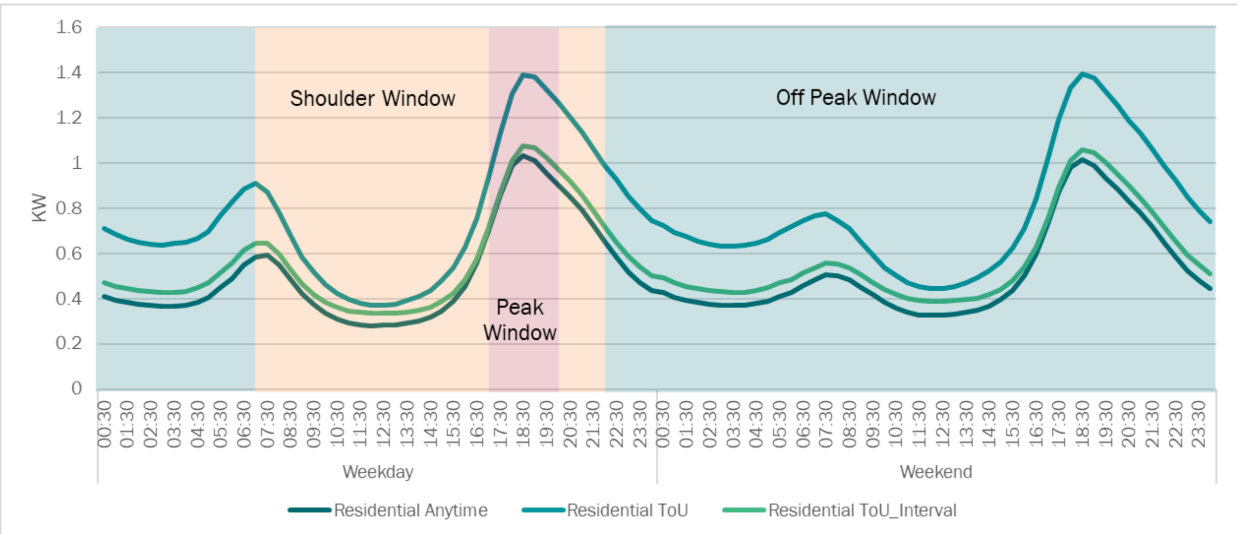
Analysing a range of data in the following figures for respective residential and small business customers, provides a clear picture of network demand. Comparing the peak day network-wide demand and our existing and trial tariff charging windows demonstrates that:

> the peak window lines up with peak use
> weekdays and weekends now have similar shapes
> the Sun Soaker profile provides cheaper prices in the middle of day and aligns with demand trough
> the export rebate window aligns with peak use.

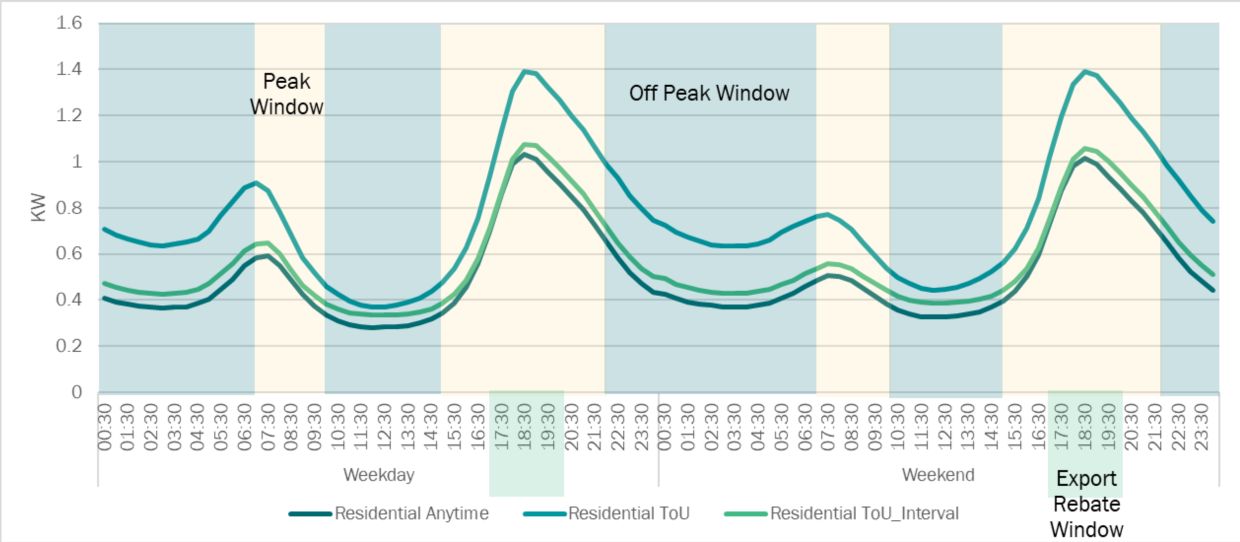
We presented this analysis to our PCC as discussed below under the *Stakeholder feedback* section.

**Comparing residential weekday and weekend TOU data against existing TOU and Sun Soaker charging windows**

**Average Residential Profile with TOU charging windows**

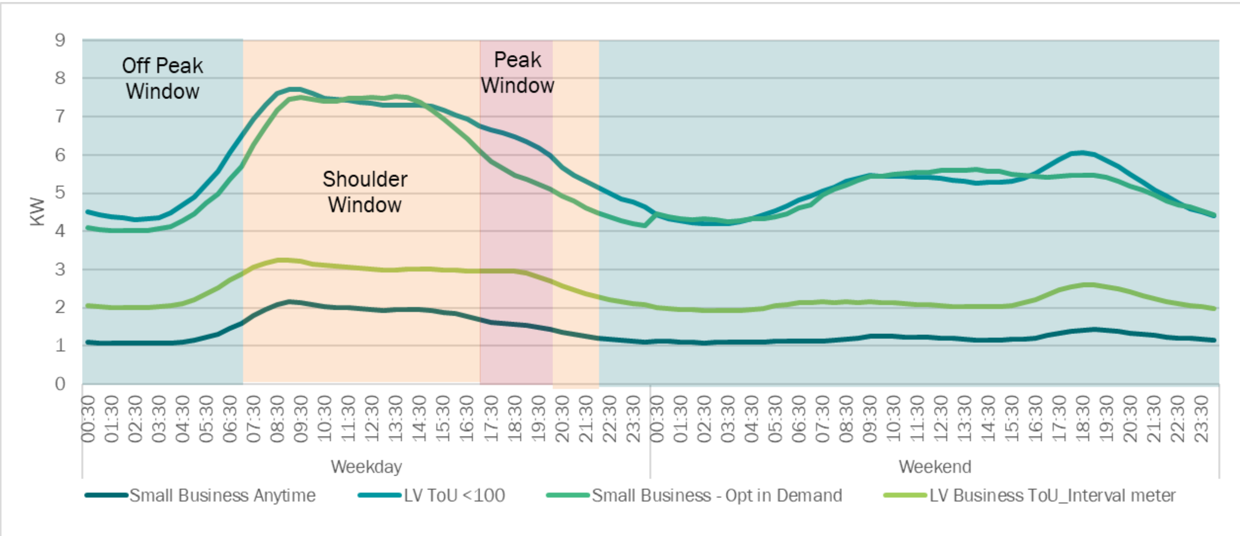


Average Residential Profile with Sun Soaker charging windows

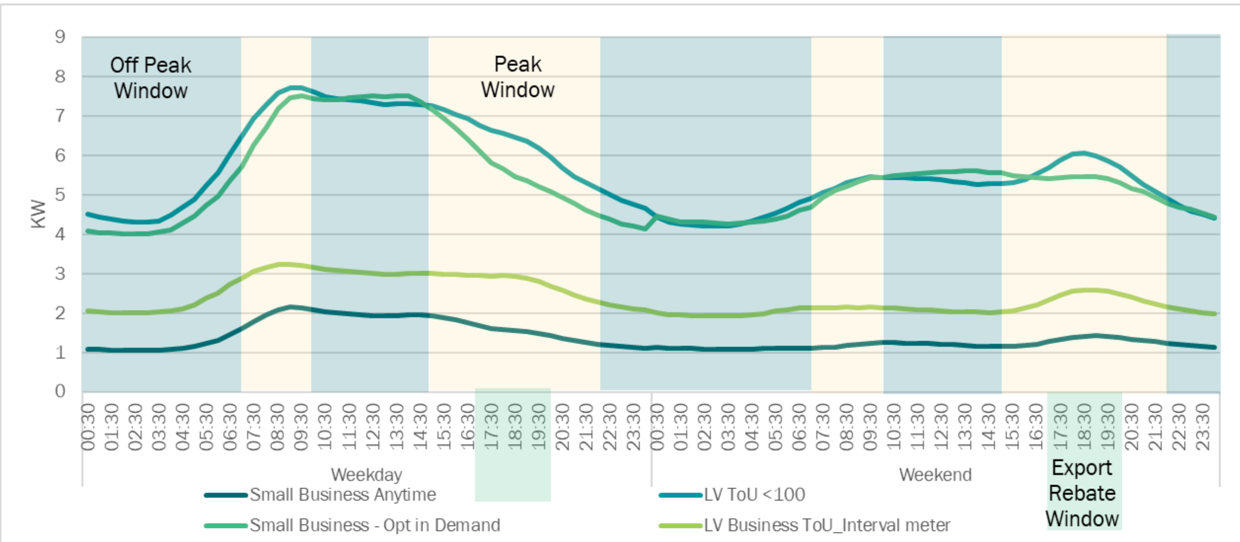



Comparing small business weekday and weekend TOU data against existing TOU and Sun Soaker charging windows

Average Small Business Profile with TOU charging windows



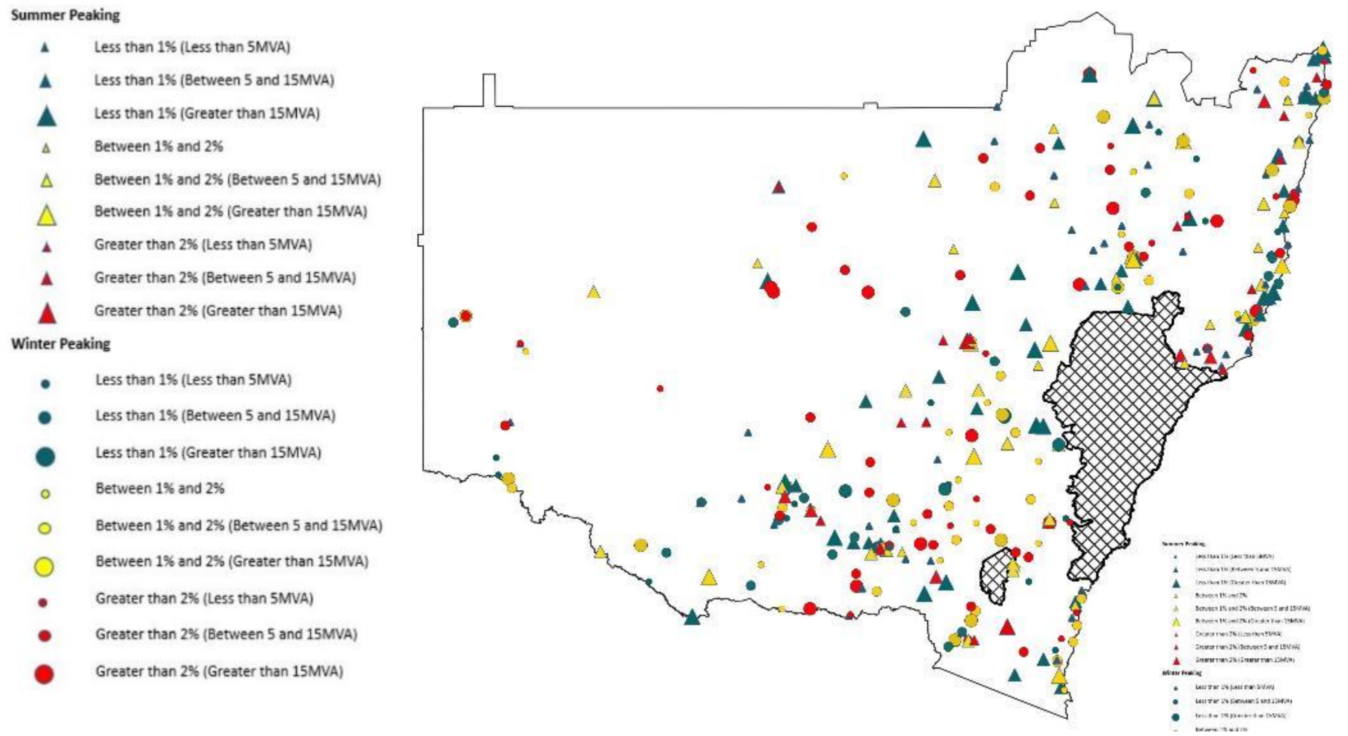

Average Small Business Profile with Sun Soaker charging windows



## Summer and winter peaking network areas

Network demand varies across areas within our network. Some areas exhibit common winter and summer peak periods, while others do not.

The figure below highlights forecast average zone substation pressures across our network from 2022–27 and demonstrates the continued expectation that some areas of our network peak in winter, others peak in summer and some peak in both. The red symbols indicate the zone substations experiencing the greatest demand pressure, through to the green symbols experiencing the least pressure. Triangles represent summer peaking and circles winter peaking. The larger the symbol the larger the capacity of the substation




This demand variation, along with customers' strong preference for network prices that do not vary across the year (62 percent support – see **Appendix A** of our **January 2023 Proposal** and **Attachment 4.02 – How engagement informed our Proposal**) supports our decision to not apply a seasonal aspect to our prices.

## TOU windows for legacy meters

We have approximately 280,400 basic accumulation meters with TOU capability and 528 Type 5 meters spread across our network area. They would all require reprogramming if we were to change the TOU windows for these customers.

Our customers on the *TOU interval tariff* have meters that are uneconomic to reprogram. They will continue to have TOU windows that include the legacy morning peak.

When preparing each of our previous TSS', as well as this Revised TSS, we assessed the costs and benefits of reconfiguring legacy meters so that we could change their charging windows, concluding that the benefits are unlikely to outweigh the costs. This remains the case. It would be cost-prohibitive to reprogram obsolete meters to new charging windows, relative to the likely benefits. Also, if the peak window changed in the future, it would not be feasible to reprogram these meters each time.

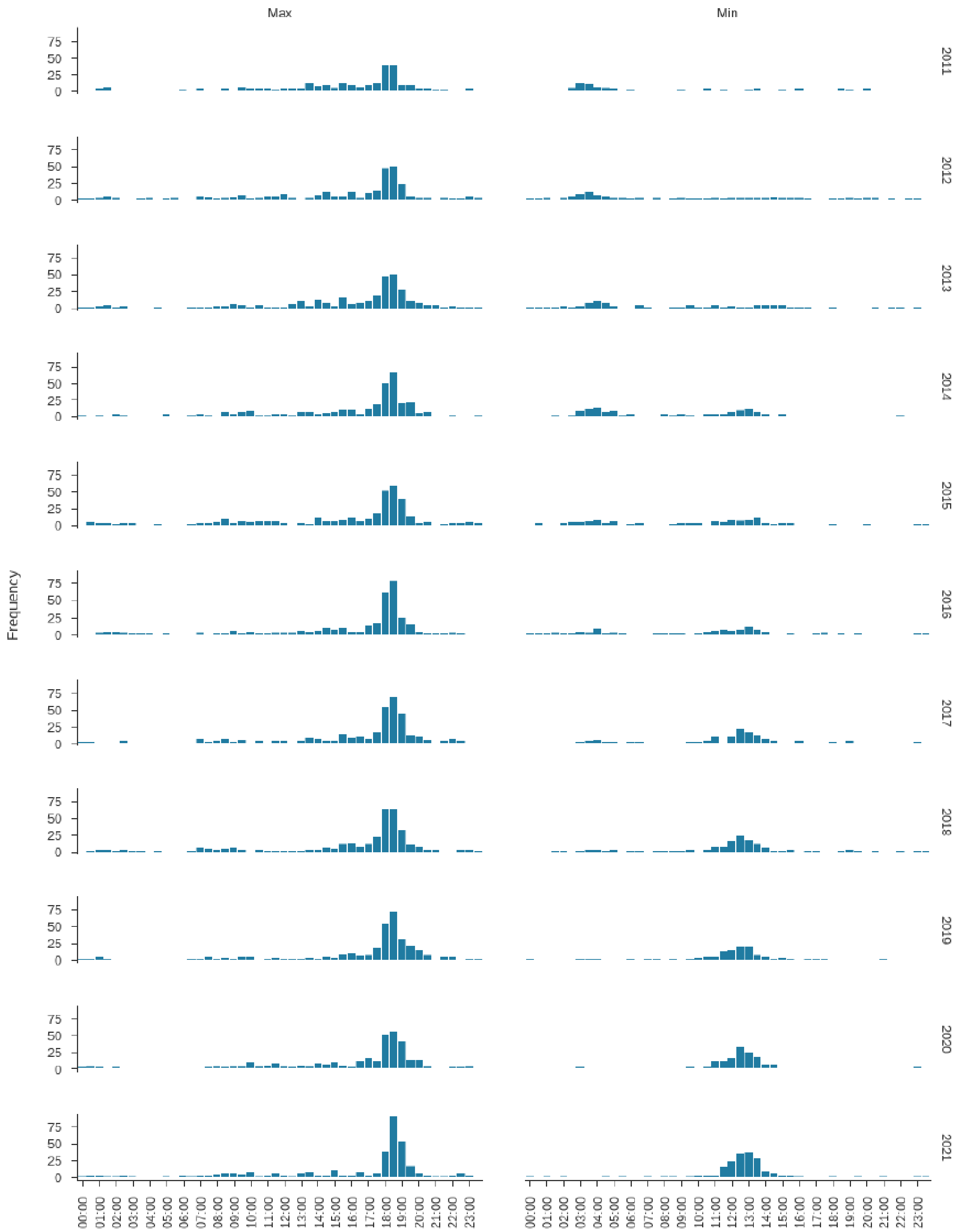
Given that the AEMC plans to expedite the smart meter rollout[22] across this regulatory period, incurring the reprogramming costs would be imprudent as the remaining service life of those meters does not warrant the expense. We do not expect this issue to persist into the next period following competition of the smart meter rollout.

[22] AEMC, *Draft report | Review of the regulatory framework for metering services*, 3 November 2022, p.i.

## Export profile

With Frontier Economics, we examined the timing and trends of system maximum and minimum demand over the last decade. The figure below shows the trends since 2011, and recent data has a discernible and increasing 10 am–3 pm system minimum window emerging as solar penetration on our network grows.

**Timing of local maximum and minimum demand for Essential Energy zone substations by calendar year (AEST)[23]**




[23] Source: Frontier Economics analysis of Essential Energy's zone substation data. Note: 2021 includes data to the end of September. Only zone substations with a unique minimum or unique maximum are shown on this chart – many substations have a non-unique minimum of zero.

## Stakeholder feedback

As part of our engagement program to test tariff trial options, stakeholders and small customers expressed support for the Sun Soaker tariff. Some have considered it may be difficult for certain customers to shift their load to the middle of the day (10 am to 3 pm) to take advantage of a cheaper price. However, other small customers were confident they would be able to take advantage of the charging windows, particularly given the effects of COVID-19 and the shift to working from home.

Regarding export charges, small customers and stakeholders viewed these as potentially risky and unappealing to many customers (particularly solar customers). However, a kW based capacity export charge was seen as the preferred export charge option, especially if combined with an option to be paid a rebate for exporting during the evening peak.

Based on this feedback, we engaged with our PCC to confirm support for retaining our current TOU windows on existing tariffs and not introducing seasonality. The PCC agreed that our charging windows align with daily profiles of demand and exports, and so there is no need to change them. Further, based on our trial tariffs for the Sun Soaker and the trial export price, there was support for the simplicity of only having two TOU consumption periods, and a single export charging period and evening rebate period. Making the discounted midday off-peak consumption window only available on the two-way tariff was seen as a good way to manage bill impacts and incentivise customers to not opt out of the two-way tariff.

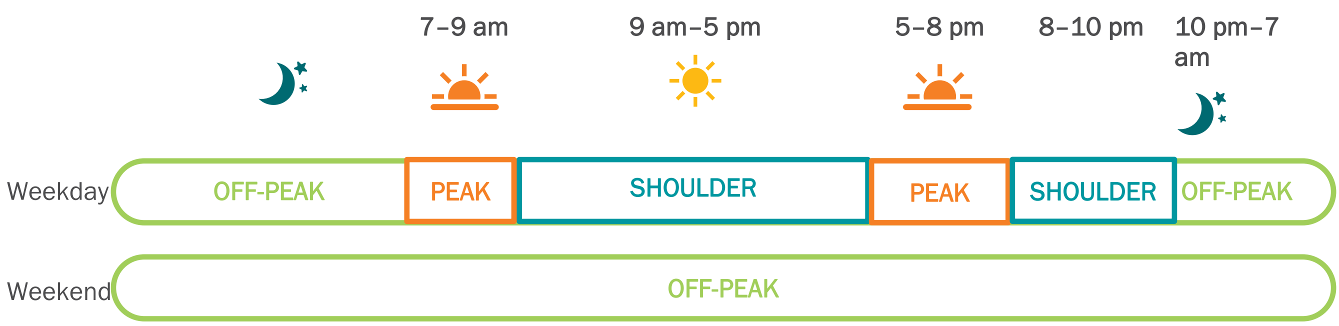
We have therefore maintained our charging windows for existing tariffs and adopted the time windows from our trial tariffs for the Sun Soaker. Under our export tariff transition strategy, we expect all residential and small business customers with a smart meter to be on the new TOU consumption and export windows by the end of this TSS period. This will account for 59 per cent of our customers.

The AER's draft decision on our proposed 2024-29 TSS approved our proposed charging windows as aligning with demand peaks and troughs on our network.[24]

### Our proposed charging windows

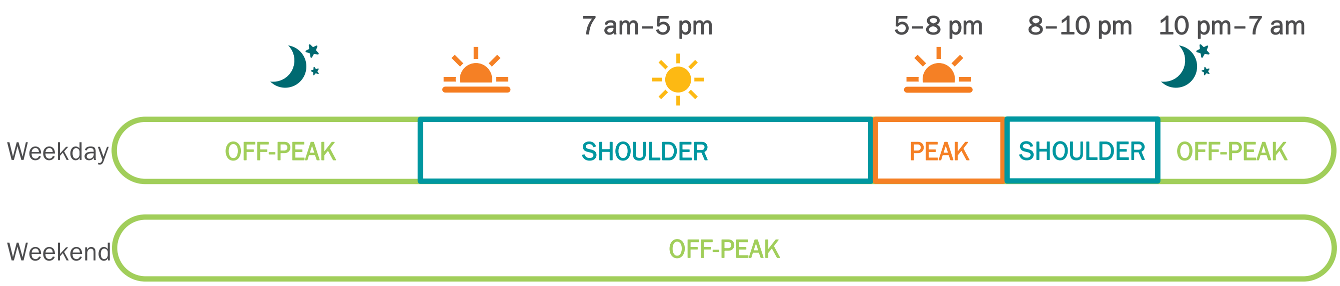
Basic meters with TOU capability and Type 5 meters cannot be cost-effectively reprogrammed, so they still record a morning peak between 7am and 9am on weekdays. This additional peak window also applies to our obsolete charges (historical charges that are not cost-reflective and unavailable to new customers).

### Consumption charging windows for Type 5 meter (our TOU interval tariff)




Smart meters can be remotely reprogrammed. This means we will have two sets of ToU windows depending upon whether a customer is on one of our existing three rate ToU tariffs or on our new simplified Sun Soaker tariff.

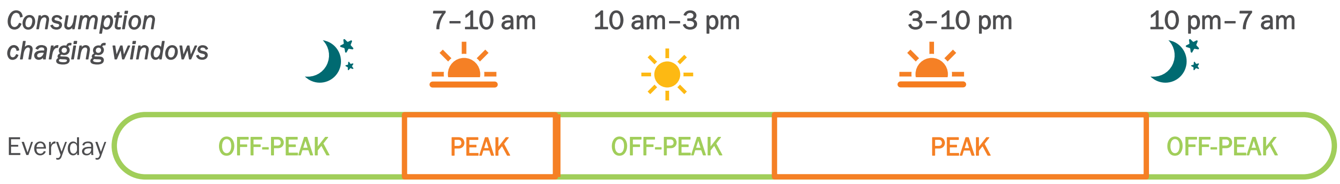
### Consumption and demand charging windows for existing interval/smart meters (our Time of Use three rate tariff)




[24] AER, Attachment 19 - Tariff structure statement | Draft decision - Essential Energy distribution determination 2024–29, Sept 2023, section 19.4.1.2.

Based on our trial experience and PCC feedback, our proposed Sun Soaker tariff TOU charging and rebate windows are shown below. As system minimum demand occurs in line with solar irradiance rather than peak consumption, our Sun Soaker TOU windows do not differ between weekdays and weekends. Their peak rate is charged at a lower peak rate than other three rate TOU tariffs.

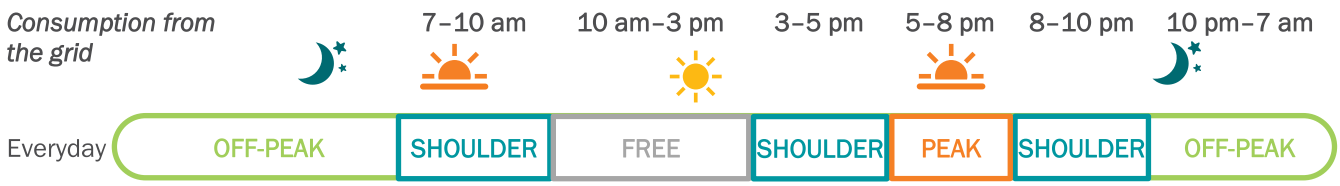
### Consumption charging windows for our Sun Soaker tariffs for interval/smart meters




As consulted on with the PCC and our large user forum during the trial tariff development, our storage tariffs have demand charging windows aligned to the parent tariff charging windows and the export charging and rebate windows aligned to the Sun Soaker tariffs.

These large-scale storage loads have the potential to shift significant loads on a local network scale. It was therefore considered preferable to maintain the same three-rate TOU demand charging windows that apply to other business loads of equivalent size.

### Demand charging windows for our small and large low voltage and high voltage storage tariffs for interval/smart meters

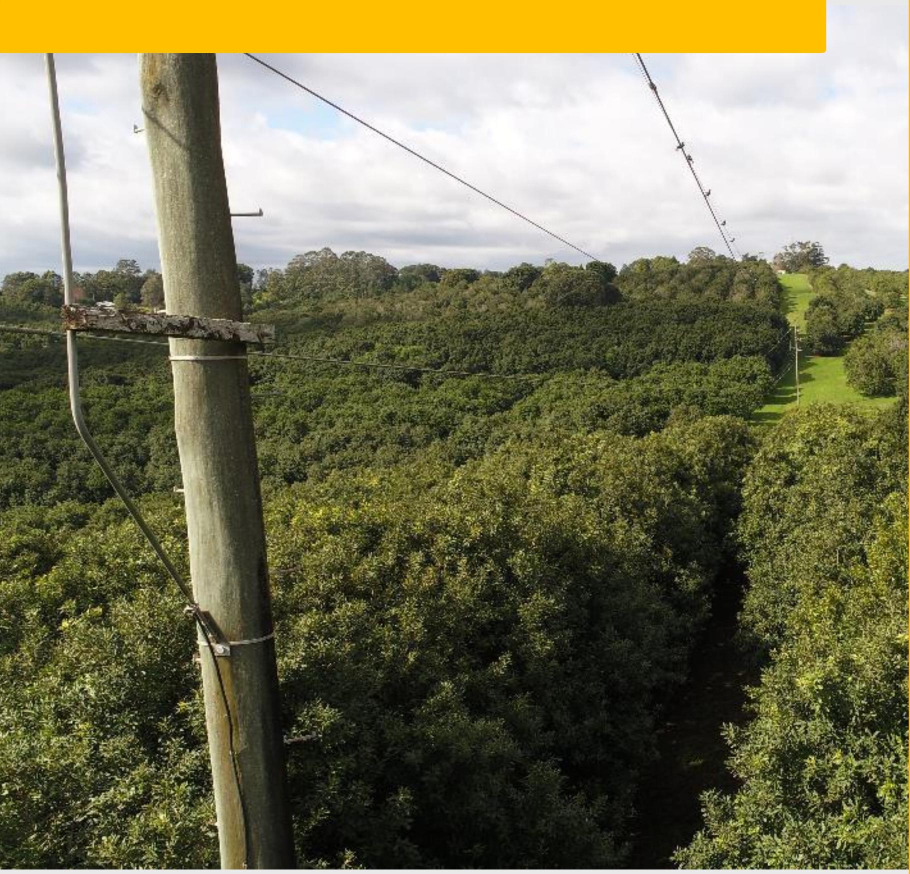



### Export charging and rebate windows for all our two-way tariffs


The same export charging windows are applied to all our two-way tariffs for fairness and due to the undiversified nature of peak exports. Unlike peak demand, system minimum demand shows little diversity between weekdays and weekends. This is because, unlike peak demand, the drivers of peak exports are primarily driven by solar irradiance and not consumption patterns. The sun does not delineate by day of the week. For this reason, our proposed exports windows do not differ between weekdays and weekends. The rebate period only applies to customers connected to our LV network.

04

# Two-way pricing proposals



## Chapter summary

- Why we need two-way pricing
- How we developed our two-way pricing
- How we engaged on two-way pricing
- How we transition to export tariffs
- How we set the basic export limit

## Justification for two-way pricing

As outlined in Chapter 2 (*Drivers for two-way pricing*), our network is changing. We are facing new cost drivers from peak exports as well as our existing cost driver of peak demand.

There are several ways we can manage the challenges facing our network. Examples include new investment, changes to our operations, and through innovative trial tariffs such as two-way prices and dynamic connection agreements. While it will be important for us to use all available levers to efficiently minimise total costs for customers, using prices to inform customers' electricity usage and export timing decisions will be cheaper than increasing our investment in the network.

Analysis on current and forecast network hosting capacity and different constraint and curtailment scenarios found that:

> *For the 2024-2029 period a focus on the efficient management of uncontrolled generation at the consumer level is critical to ensuring Essential Energy can meet technical standards around voltage, safety and performance* ... and
>
> *The forecast scale of DER deployment and its dramatic impact on energy consumer load shapes highlight the importance of focusing on a range of tools and approaches to influencing end consumer demand profiles to shift energy consumption patterns*[25]

By introducing two-way pricing for export services, we can reward customers who own CER for sending power they generate to our network when needed, and charging them for sending power when it is not being demanded by other customers. This will provide significant benefits to all our customers by helping us to lessen our overall costs and prices, and ensure customers pay fairly for using our network.

We have worked with our customers through deep dives and our PCC to design a plan to transition to two-way pricing. Although most customers recognised that two-way pricing would solve some of the issues associated with integrating new technologies and renewables into our network, there was still some concern that export pricing was not consistent with the push to transition to renewable energy. In contrast, many of our other stakeholders, including solar installers, councils and customer advocates, were supportive of the introduction of export pricing.

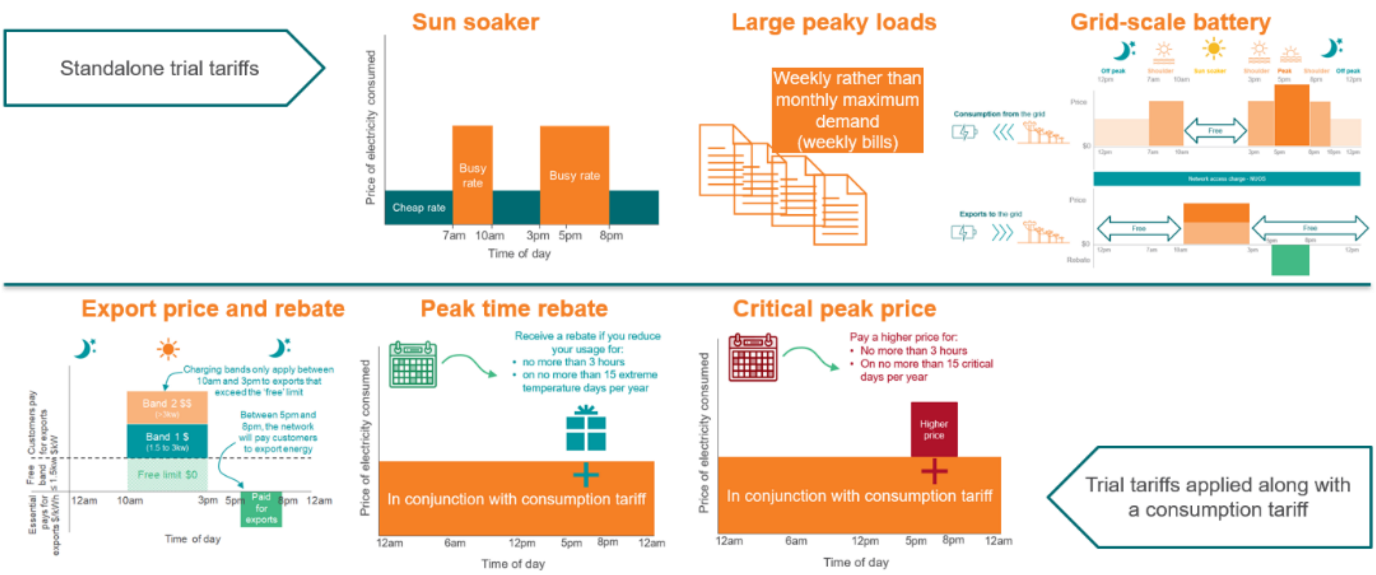
## How we developed our two-way pricing proposal

### January 2023 Proposal export tariff structure

Our tariff trials and customer engagement informed our export pricing proposals. Our PCC encouraged us to adopt an 'end state' tariff structure for our Sun Soaker tariff. Through consultation with our customers, retailers and energy intermediaries, we co-designed a series of tariffs to trial. We then notified the AER of these in our 2021–22, 2022–23 and 2023-34 annual pricing proposals and set about finding retailers and customers to implement those trial tariffs.

We designed and trialled a range of tariffs that could be applied on a standalone basis or in conjunction with our existing consumption tariffs.

**The range of tariffs we designed and are trialling**




[25] Zepben, *Hosting Capacity Study | Network wide HV & LV Scenario based Hosting Capacity Analysis*, 2022, p.10.

Following further engagement with our PCC, deep dive sessions and battery proponent engagement for our new two-way tariffs, we have settled on the 2024–29 export tariff structure included in our Draft Plan and January 2023 TSS proposal. This was to combine the Sun Soaker with the export price and rebate, calling this tariff our Sun Soaker.

**Our initially-proposed 2024–29 export tariff structure for LV residential and small business customers (Sun Soaker)**


Through engagement on our Draft TSS, we were asked:

1. whether large generators who are not residential, small business or grid-scale batteries should be paying for exports
2. whether LV exporters who would face the Sun Soaker tariff should be permitted to opt out of this to avoid the export charge.

We consulted our PCC on these points. This involved circulating a working paper and then discussing the principle, options and impacts for adding export tariffs and rebates to other tariff classes. We asked them the following questions:

> Is it reasonable to not price exports for our ST, HV and large LV business customers?
> Are any tariff assignment requirements needed to stop LV-connected generators on the proposed two-way tariffs opting out of them?

On the first question, it was agreed that, on current evidence, there are sound reasons for not applying export charges to ST and HV connected customers at this stage. This is because:

> we want to preserve competitive neutrality with TransGrid for generators who are big enough to bypass the distribution system and locate on the transmission system. These would generally need to be generators that are 20MW+ that have gone through the registration process with AEMO
> for sub-transmission and HV generators, their expected export costs can be accounted for in the connection process, including through any associated connection charges, operating and maintenance fees, or constraints imposed on their connection capacity (including potentially dynamic export controls).

For these reasons we did not propose to charge our HV and ST customers who are not grid-scale batteries for exports. They would continue to face the default existing tariff that applies to their connection characteristics.

For large business LV customers who consume >160MWh pa, the sample data from actual affected exporters in this tariff class showed the following:

> while intuitively large business LV customers who have a significant co-located load may have more scope for their load to absorb some of their own generation and not drive as much export costs
> we observed that some of these who don't operate their loads on weekends, can still drive export-related costs on those days.

We assessed that 29 per cent (1,367) of customers on the LV large business default tariff (BLND3AO) export energy. Analysing sample of diverse LV large business customers showed they all exported significant shares of their total annual exports in the 10-3 window (an average of 72 per cent of their exports).

Where there are multiple opt-in cost reflective tariffs, there was support that these should all be two-way. Having two cost reflective tariffs with two-way pricing gives you flexibility (for example, where there is a TOU energy version and a TOU demand version). Having a demand and a Sun Soaker variant was seen as supporting future options.

The PCC agreed that export prices should be applied to all LV connected customers, using the same export charge and rebate structure, and common LRMC-based tariffs for exports and a rebate equivalent to the equivalent peak consumption charge for that tariff class.

We therefore proposed that in the pricing year following establishment of our new billing process capabilities (and no later than 1 July 2028), we will add the export charge and rebate to all default and opt-in cost reflective tariffs for LV customers. This will:

- prevent customers opting out of export charges
- allow customers who have already chosen to respond to demand-based tariffs to continue to benefit from their response to such tariff signals for their peak demand, whilst still facing the same export tariff and rebate as other customers.

## Revised Proposal export tariff structure

Following our January 2023 Proposal, three factors have driven us to revise our export tariff structure proposal for some customers:

- lessons from our residential and small business sun soaker and export tariff trials
- feedback from the AER and retailers encouraging us to consider adopting an energy-based kWh export tariff and basic export level and to simplify our export pricing bands[26]
- lessons and feedback from our attempts to find battery tariff trial participants and direct feedback from customers considering connecting batteries and hybrid generation and battery connections to our network.

### Our residential and small business tariff trials

Our small customer trials continue. Early implementation learnings from the first stage report into our trial that were available to inform this Revised TSS found that:

> *there was no discernible impact of the new tariffs on the average daily coincident peak demand, the average coincident minimum demand, the PV export peak (kW) or the average daily PV exports (kWh).*[27]

This data so far does not make a strong case that the complexity of export pricing bands and demand-based (kW) export pricing is warranted for small customers.

**Trial data analysis**

Tariff trial data from our Discover Energy customers and Red Energy customers was analysed as follows:

1. Aggregate analysis across all customers

This assessed the tariff impacts on the average daily coincident peak demand, the average coincident minimum demand, the PV export peak (kW) and the average daily PV exports (kWh). These were all assessed by comparing the change over the 3 months either side of the time that households changed their tariffs with the change over the equivalent period the year before, thus:

- Discover Energy – 1 May to 30 Oct 2022 was compared to the equivalent period a year before
- Red Energy – 1 Aug 2022 to 31 Jan 2023 was compared to the equivalent period a year before.

2. Peak analysis - Demand peaks, PV exports and Minimum demand

This compared the tariff impacts on the 10 highest network peaks, the 10 lowest minimum demand periods, the 10 highest PV export peaks and the average daily exports in summer 2022 to summer 2021.

3. Individual household analysis - Demand peaks, PV exports and Minimum demand

This analysis was identical to the Peak analysis except it was performed at the individual household level.

4. Financial impacts

This was intended to assess changes to the network component of each customer's electricity bills before and after the change in tariff. These outcomes could then be aggregated to assess the impacts on Essential Energy. However, none of the first three types of analysis identified any clear changes in demand in response to the new tariffs. Thus, although the financial impacts on customers, on Essential Energy and on the retailers was determined through the true-up process, there was no point in comparing the financial outcomes between customers.

[26] See *Tariff Structure Statement* pp. 41-42.

[27] UNSW, Essential Energy Trials Using Tariffs and Education to Influence Customer Behaviour - Energy Data Analysis Summary of Outcomes, August 2023, p.5 section 2.1.1.

The social research element of our trial identified that customers with solar are already conscious about and showing evidence of load shifting for self-consumption. It found:

> *The adoption of rooftop solar made households more conscious of when they were using electricity. As such, most participants with solar systems had engaged in some form of load shifting behaviour prior to the trial. In the context of declining feed-in tariffs for solar exports, participants with solar felt that prioritising self-consumption was crucial to getting the most value from their system. Thus, the trial served to reinforce many of the existing practices that these households had already instituted to shift loads such as using timers for dishwashers and washing machines.*[28]

Considering this behavioural feedback and our tariff design suggests that an energy-based (kWh) export price will better reward these behaviours than a monthly demand-based (kW) export charge. This is because with a kW maximum export charge per month, customers only need to miss 1 day of load shifting in a month and they would get no reward for up to 29-30 days of desirable load shifting behaviour.

### AER draft decision on export two-way tariff proposal

The AER's draft decision found that:

> *Essential Energy justified its need for two-way pricing and that its proposed export reward tariff is consistent with the guidance set out in our non-binding Export Tariff Guidelines and complies with the distribution pricing principles as required by the NER.*[29]

It approved:

- our new export reward tariffs for residential and small business customers and large LV businesses
- our introduction of network tariffs for utility scale storage (grid-scale batteries) connected to the LV distribution network.[30]

The AER's draft decision also:

- did not approve rebate amount for grid-scale batteries connected to the HV network citing our intention to look into this further
- asked us to consider expressing our basic export level and export charge in kWh rather than kW in our Revised Proposal[31]
- observed that we were the only network who propose a more complex inclining block pricing band structure above the basic export level.[32]

### Export tariff structures for different customer types

Our Revised Proposal export tariff structures now seek to:

- align export prices with the way customers pay for their energy imports under their existing tariff to support understanding and behavioural response by:
  - only using demand-based kW export prices where customers have a demand charge for their consumption
  - having energy-based kWh export prices for small LV customers who have kWh consumption prices
- recognise differences in storage customers' scale and how this affects their commercial incentives to connect to and cycle on our network by:
  - establishing a new small LV storage tariff
  - removing the rebate from the HV storage tariff in expectation that the scale of energy arbitrage opportunities in the evening peak will likely be sufficient to drive desired battery cycling behaviours without our other customers needed to subsidise those behaviours.

We have also broadened the eligibility for our large LV and HV storage tariffs to include customers who have co-located generating units. This means those hybrid customers would not be charged the default consumption tariff. It responds to proponent feedback and means they and we can benefit from cycling their batteries as intended by the storage tariff.

[28] UNSW, Essential Energy Tariff Trials – Analysis of the Impacts of Novel Tariffs, Social Research Snapshot Report, Aug 2023, p.40.

[29] AER, Draft Decision Essential Energy Electricity Distribution Determination 2024 to 2029 Attachment 19 Tariff structure statement, Sep 2023, p.19.

[30] AER, Draft Decision Essential Energy Electricity Distribution Determination 2024 to 2029 Attachment 19 Tariff structure statement, Sep 2023, p.4.

[31] AER, Draft Decision Essential Energy Electricity Distribution Determination 2024 to 2029 Attachment 19 Tariff structure statement, Sep 2023, p.5.

[32] AER, Draft Decision Essential Energy Electricity Distribution Determination 2024 to 2029 Attachment 19 Tariff structure statement, Sep 2023, p.19.

We note that Origin Energy questioned the basis of our proposed fixed charges in our January 2023 Proposal. It observed that our LV storage tariff was higher than other networks' LV storage tariffs and requested that we consider varying the fixed charge for smaller scale batteries.[33]

We derived all our storage tariffs by reference to the relevant 'parent tariff' being the tariff the customer would have been on previously if not for this new tariff being introduced. Setting the network access charge this was to treat customers of equivalent scale fairly in what they pay to access our network. The proposed grid-scale LV storage had been based on the LV large business customer which is for large customers communing >160MWh per year.

Our Revised Proposal now includes LV small and LV large versions of our storage tariff to support smaller batteries connecting to our network. The fixed charge for the LV small storage tariff is set the same as our small business tariff.

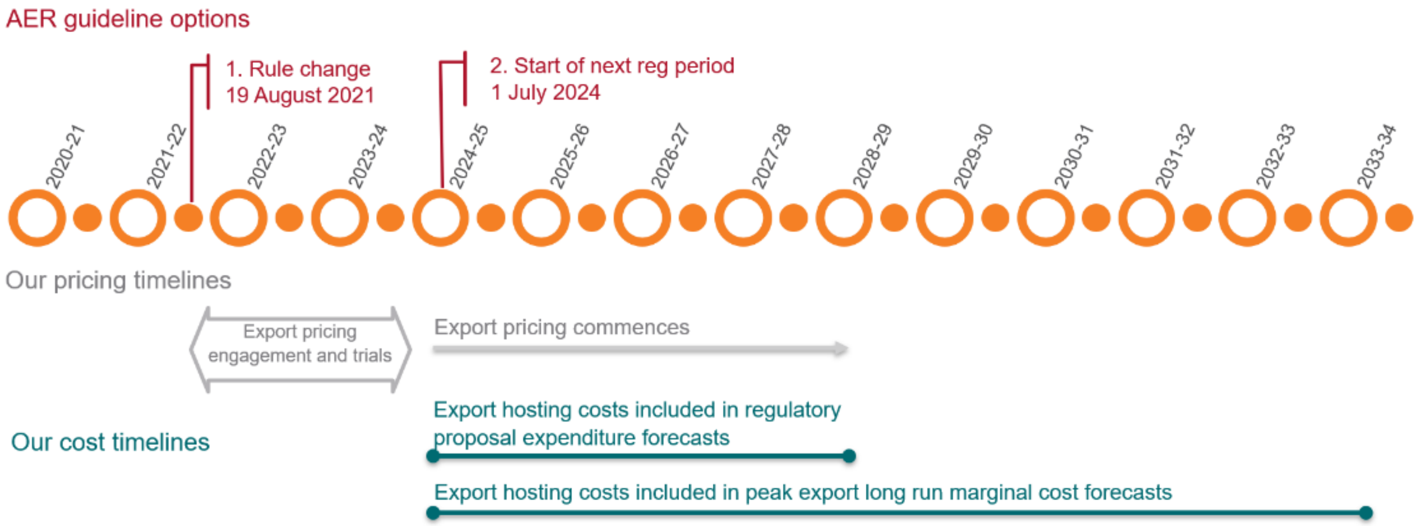
## Export cost recovery start date

We will not be recovering our past costs of providing export hosting in our new export charges. In recent years, we have incurred costs to avoid our customers experiencing power quality issues amid the rapid increase in solar penetration hosted to date. However, in its Export Tariff Guidelines explanatory statement, the AER states it does not support the recovery of historical DER enablement costs through export tariffs.[34] The AER considers:

- consumer DER investments to date have been undertaken without export tariffs
- network DER costs to date are already being recovered through consumption tariffs and it is not appropriate to retrospectively reassign these costs to export charges.

Instead, the AER encouraged us and other networks to consult customers on two possible start dates. These start date options are illustrated below.

**Export pricing cost and pricing timelines**




We presented these options to our PCC who supported[35] our preference to align our export cost recovery with the start of our next regulatory period. This is because it is the first date that we will:

- have an AER approved expenditure allowance that specifically addresses DER integration expenditure
- introduce export prices and rebates.

We have therefore only included relevant costs from 1 July 2024 in estimating our peak export LRMC, which we have relied upon to set our export tariffs.

[33] Origin Energy, Submission - 2024-29 Electricity Determination - NSW and ACT - May 2023, pp 7–8.

[34] AER, Export Tariff Guidelines, May 2022, p.12.

[35] Pricing Collaboration Collective, Meeting 5 – 12 July 2022 minutes.

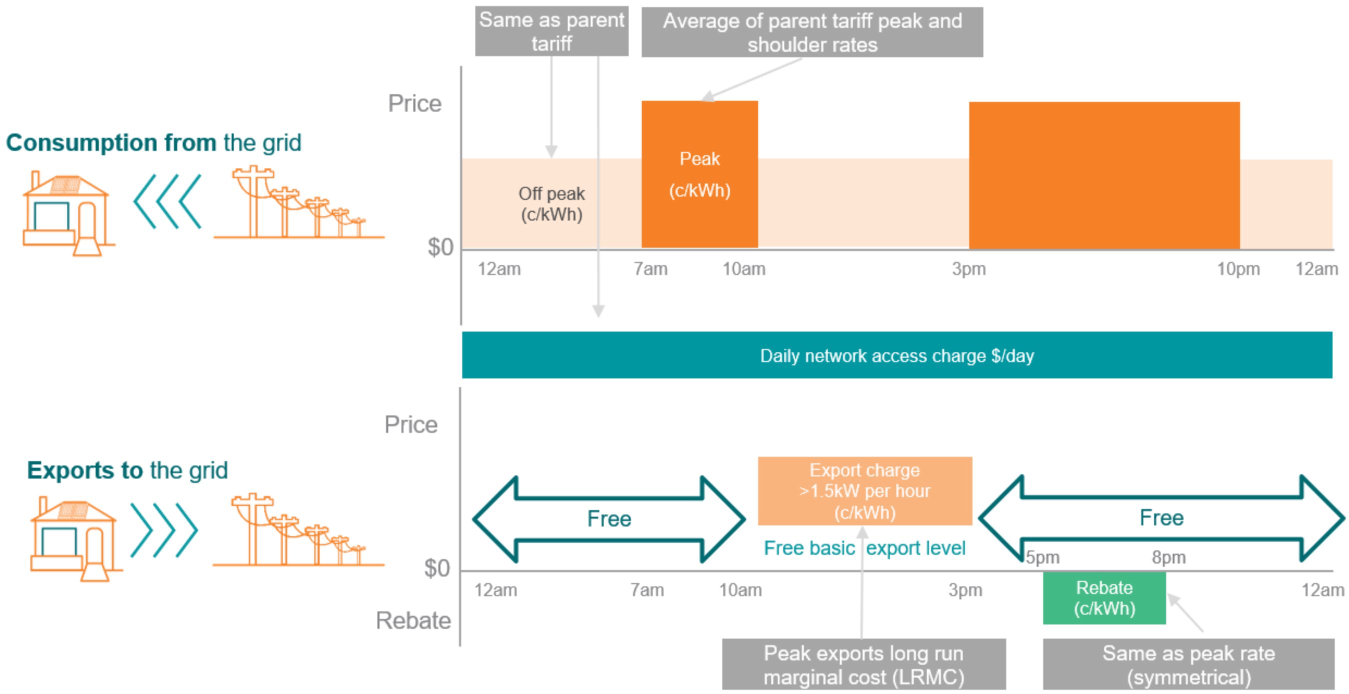
## Sun Soaker tariff levels

After establishing the export tariff structure, we then worked to set the tariff levels (prices for each charging parameter) with the following design considerations:

> where possible, supporting an equitable transition and technology neutrality by setting charges the same as, or by reference to, the relevant 'parent tariff' being the tariff the customer would have been on previously
> addressing network cost drivers arising from peak demand and peak exports by calculating separate LRMC estimates for peak demand and peak exports, and using these to inform our consumption and export charging parameters
> addressing our customers' preference for postage stamp pricing by not including locational pricing and using the same basic export service for all customers, based on our most constrained locations and network hosting capacity
> supporting a fair transition by ensuring that only future peak export costs incurred after 1 July 2024 have been included in our peak export charges, and
> considering customer bill impacts and testing bill outcomes with our PCC and customer deep dives.

The resulting approach to setting our Sun Soaker tariff levels is shown below.

**Our approach to setting our Sun Soaker tariff levels**




### Export tariff level

The export tariffs for all of our tariffs with export charges have been set at our estimate of the LRMC of providing peak export services by voltage level.

### Low voltage export rebate level

The Sun Soaker tariff export rebate has been set symmetrically based on the equivalent peak consumption charge. This tariff design decision was made with regard to:

> our co-designed principles for pricing ensure that prices are *easy to understand*. This is the first time we have applied a rebate, and with the goal of behavioural change, our PCC agreed that a symmetrical tariff was simple to explain and would be perceived as fair
> our customer engagement highlighted the potential controversy that may arise when introducing export charges. Export charges are likely to be met with some resistance by those customers that do not understand the benefits of two-way pricing. It will be important that a reasonable rebate is offered to enable customer acceptance
> our peak charges are calculated based on LRMC of providing distribution services at times of peak demand. While our peak charge on some tariffs includes a contribution to residual costs, we assessed the materiality of the expected rebate and found this to be an immaterial amount relative to the expected benefits of having a simple message of symmetrical reward of peak charge to rebate value to support retailer uptake and residential and small business customer response.

The export rebate for other low voltage customers who will have two-way pricing, including our low voltage small storage tariff and our low voltage large storage and hybrid tariff, has been set at 5 cents per kWh. This tariff design decision was made with regard to:

- the fact that these customers have a demand-based kW charge for their peak consumption and a demand-based export tariff, so they either have no relevant parent tariff peak energy charge or that charge is recovering residual not marginal costs
- assessing the level of rebate that other networks have proposed which shows, based on their January Proposals, that:
  - Ausgrid and Evoenergy's battery tariffs did not include default rebate payments, only critical peak rebates
  - Endeavour Energy was proposing seasonal rebates with these set for 2024-25 at 11.0357 cents per kWh in the high season and -3.3366 cents per kWh in the low season
  - The only non-seasonal rewards were those proposed for small customers' export tariffs and in 2024-25 these ranged from Ausgrid's 2.2569 cents per kWh up to Evoenergy's 4.926 cents per kWh
- a lack of trial data for these customer types to inform our rebate setting.
- the energy arbitrage opportunities available to batteries that we expect will motivate desirable battery cycling behaviours.

We have therefore adopted the higher end of the range of benchmarked non-seasonal export reward tariffs. As we get greater experience with batteries connecting to our low voltage system, we will monitor the cycling behaviours of those batteries and review the adequacy of this reward level in motivating desired behaviours.

## Our stakeholder engagement on two-way pricing

We worked with our customers through deep dives, our PCC and publishing a draft TSS to inform our approach to export pricing for the January 2023 TSS, including our plan to transition to two-way pricing.

### Customer engagement up to our Draft TSS

Our phase 2 engagement focused on understanding our customers' and stakeholders' views on two-way pricing. In particular, we reintroduced the idea of changing pricing structures to accommodate the expected growth in exporting technologies, like batteries, EVs and solar panels. In line with this, we proposed introducing two-way prices. Customers and stakeholders were asked three key questions vital to the development of the export tariff transition strategy:

- do you prefer postage stamp or locational prices?
- what level of exports should be free of charge? (Three options were presented.)
- how should we transition to two-way prices?

We also asked whether customers thought that export prices were fair and would help solve some of our network challenges. From our phase two engagement, we learned that:

- there is a divide in the level of support for two-way prices. Many customers were generally unsupportive of the concept, whilst stakeholders with more knowledge of the sector (including our PCC and solar installers) were more supportive
- the majority of customers and stakeholders believe that two-way pricing will improve fairness and help solve some of the network issues arising from integrating new technologies. However, this has proved a divisive concept. We observed that charging for exports may negate our customers' vision for the future energy system, discourage renewables, and shifting the goal posts for customers who have invested in energy resources
- education was seen as imperative to implementing two-way prices. One stakeholder suggested we partner with retailers to align the introduction of two-way prices with innovative retail offerings, like peer-to-peer trading. This would help alleviate the negative perceptions
- there was a customer preference to apply export prices on a postage stamp basis. Stakeholders also supported this approach
- despite the largely negative reception to two-way prices there was strong support to: offer them on an opt in basis from 1 July 2024 and apply them to all customers from 1 July 2025.

Feedback from our PCC highlighted the need for an in-person deep dive on the topic of export prices, given its divisive nature. Therefore, we decided to undertake a further dedicated session with a smaller number of customers as part of our phase 3 engagement. This in-person deep dive session revisited the export tariff transition strategy in more detail.

As part of this session, we presented our trial export price and two options for a future-proof default tariff — that is, our three part Time of Use tariff and our Sun Soaker tariff, with our trial export price in both instances. We explained indicative bill impacts for different types of customers moving from our Flat Rate Anytime tariff to either of these two tariffs and sought feedback from the group on their preferred two-way tariff.

Participants in this dedicated deep dive session were not put off by two-way pricing and there was minimal perception of solar customers being penalised by two-way pricing. Early adopters were thought to already be financially ahead. The Sun Soaker two-way price was seen as the most favourable default tariff option, though customers still wanted a choice of tariffs to ensure the option of switching.

In terms of the transition to two-way pricing, we also presented three key dates on a timeline:

- 1 July 2024 – the date that customers can choose to opt in to two-way prices under the NER
- 1 July 2025 – the date when we can legally apply export prices to all customers under the NER
- 1 July 2028 – the date that our new billing system will be implemented, which will enable us to move large volumes of customers to two-way prices.

We also showed two customer types (including bill impacts for each) which were those who had invested in energy resources and those who hadn't. We then asked the participants to consider how each should be transitioned to two-way prices.

In the discussion, participants expressed support for a quick transition to minimise potential pain. That is, giving customers the ability to opt in from 1 July 2024 and applying two-way pricing to everyone else from 1 July 2025. These results were identical to the polling from the forums in Phase 2. They also believed education could help avoid negative perceptions.

Finally, we asked customers for their ideas about communicating with other customers about two-way pricing. Customers suggested ways that we could improve and promote a greater understanding of the energy cycle – for example, by providing facts. They ultimately reflected a degree of optimism when discussing the potential solution, highlighting the collective benefit and emphasising a progressive, renewable-focused future.

### Customer engagement on our draft TSS

Our Draft Proposal and Draft TSS were accompanied by our Phase 4 engagement activities, comprising:

- seven face to face forums with residents & small to medium businesses (347 people)
- six in-depths with Aboriginal and Torres Strait Islander customers (ATSI)

- six in-depths with culturally and linguistically diverse customers (CALD)
- group session with new technology providers (4)
- SCC and PCC meetings
- ten submissions (one of which related to public lighting), including from individual customers, PIAC, Red Energy/Lumo and AER staff feedback.

We used our 2 November PCC meeting to review feedback on our two-way pricing. As discussed in the TSS at section 6 on our export tariff transition strategy, that session established:

- principles to consider when balancing divergent feedback
- matters to support a faster pace of two-way tariff transition, including contingent triggers for our billing process capabilities, adaptable TOU charging windows, and removing the one year grace period
- opt-out assignment options only being to two-way tariffs for LV customers.

### Retailers and aggregators discussion and survey

We took a group of retailers and aggregators through our proposed default Sun Soaker tariff and a proposed timeline for the transition to two-way prices. We also provided an update of our current and future trials. We then issued a follow-up survey to attendees.

The following demonstrate the diversity of views from the meeting and subsequent survey responses.

- Some retailers don't support cost-reflective network tariffs, whilst others do.
- Network tariffs that align with wholesale market prices have a greater likelihood of being incorporated by retailers and aggregators.
- Retailers consider our export price complex:
  - They consider the stepped demand charge for exports between 10am and 3pm will be difficult for customers to understand and that customers are unlikely to be able to avoid it through behavioural change. They also said it was confusing because it mixes a demand charge with a cents per kWh (c/kWh) rebate
  - Some consider that the stepped demand charge would be difficult (or impossible) to build in their billing systems. Another considered its billing system could be configured, but the costs and benefits of doing this would depend on the scale of tariff take-up
  - Some consistency in the form of export charge between networks would be preferable, for example, all c/kWh charges even if they have different windows
  - There was a preference for networks to use standardised terms when establishing tariff structures and names.
- At least one retailer would prefer that when customers have a faulty meter replaced (not by choice) that we provide a one-year grace period before moving the customer to a cost-reflective tariff. They are preparing a rule change to this effect. This would enable the customer and their retailer to better understand their consumption and help them select an appropriate retail product.
- One retailer considered that we should recover more of our sunk costs through our fixed charges so that our variable tariff signals can be better seen by customers.
- When surveyed about how likely they are to offer a retail deal that incorporates two-way pricing over the next five years, the respondents said that they were very likely.

### Pricing Collaboration Collective

We conducted seven meetings of our PCC prior to submission of the January 2023 Proposal. A summary of their feedback is provided in **Appendix A - Summary of engagement outcomes** of our January 2023 Proposal, and more detailed findings can be found in **Attachment 4.02 – How engagement informed our Proposal**, where the full minutes are in Appendix C.

### Customer engagement that has informed our revised TSS

Since we submitted our January 2023 TSS, we have continued to engage with customers and stakeholders on our two-way pricing proposals. Further information on our engaged program can be found in **Chapter 2: Our customer engagement** and **Attachments 2.01** and **2.03** of our Revised Proposal. This has included:

- four PCC meetings
- two Essential People's Panel meetings
- one New Technology Providers forum
- more detailed bill impact modelling for large customer samples with our PCC
- further rounds of retailer one on one engagement.

Further information on the issues raised, and how we responded, is outlined in our Revised TSS.

## Implementing two-way pricing

We established our two-way tariff assignment policy based on a combination of:

- the customer and stakeholder feedback discussed above and then further testing of this with our PCC
- our billing system capabilities
- customer bill impact analysis.

### Our billing process capabilities

Our existing billing systems have evolved progressively over their 20+ year lifespan in the company. While they have supported our market compliance up to now, much of the associated processing is overly manual and labour intensive. The current system's operating model is therefore not suitable for ongoing use through the coming TSS period given the introduction of new two-way tariffs and the accelerated migration away from Type 6 metering.

Processing issues and inefficiencies drive the requirement to complete the systems replacement and process improvement prior to large scale transition to two-way tariffs.

The new billing capabilities must:

- provide efficient capability for management of market standing data, customers transfers, B2B transactions, meter data and network billing
- be flexible to support market changes
- enable rapid introduction of new tariffs (for example, dynamic control tariffs, future trial tariffs)
- provide more automation for improved market transaction efficiency
- enable close integration with our Oracle Cloud ERP and the CRM/Portal
- be underpinned by sustainable software platform(s) to operate reliably and securely through the coming decade.

The timing of establishing these new capabilities has informed our two-way tariff assignment and transition strategy.

## Bill impact analysis

We conducted extensive bill impact testing. This impact testing informed our proposed export tariff transition strategy.

The table below shows the estimated bill impacts for different customers who move on to a Sun Soaker tariff from an existing Anytime tariff or our current ToU tariff.

**The estimated effect on bills of moving from one tariff to another (2025–26, $, real 2024)**

| | | Residential | | | Small business | | |
|---|---|---|---|---|---|---|---|
| | **Annual consumption** | 2 MWh | 2 MWh | 5 MWh | 5 MWh | 5 MWh | 20 MWh |
| | **Photovoltaic capacity** | 0 kW | 2.9 kW | 6.5 kW | 0 kW | 7.9 kW | 10 kW |
| | | No solar | Average solar | High solar | No solar | Average solar | High solar |
| **From Anytime** (accumulation meter customers) | $ annual | -50 | -11 | -96 | -290 | -184 | -1,025 |
| | % on retail | -3.0% | -0.7% | -3.4% | -7.8% | -5.0% | -11.4% |
| **From ToU** (interval/smart meter customers) | $ annual | 9 | 48 | 96 | -9 | 139 | 264 |
| | % on retail | 0.6% | 3.1% | 4.2% | -0.3% | 4.9% | 4.7% |

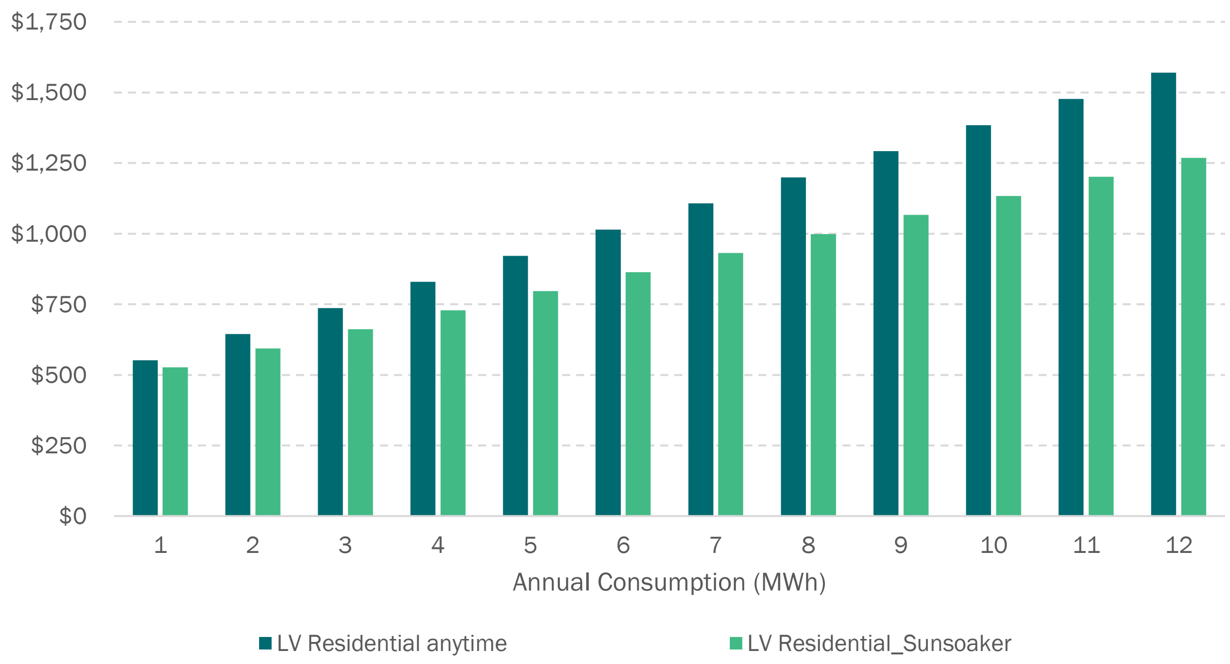
Note: we have assumed that DUoS charges make up 38% of the retail bill.

The following charts illustrate the savings available to customers who receive a smart meter and move from an anytime tariff to a Sun Soaker tariff. These are shown for no solar, average existing solar installations and large solar installations across a range of annual consumption scales for residential and small business customers, and incorporate legacy metering revenue recovered as a standard control service across low voltage tariffs.

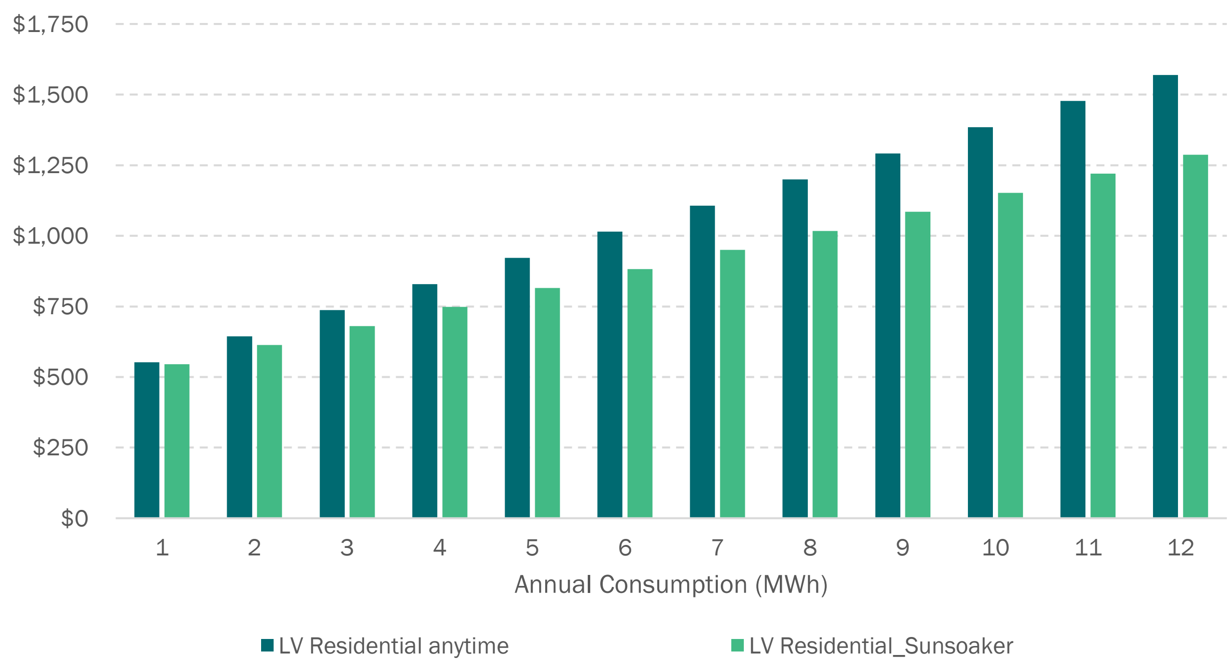
## Residential customer bill impacts ($, real 2024)

*Moving from our anytime flat rate tariff (BLNN2AU) to our Sun Soaker tariff (BLNRSS2), 2025-26 year*

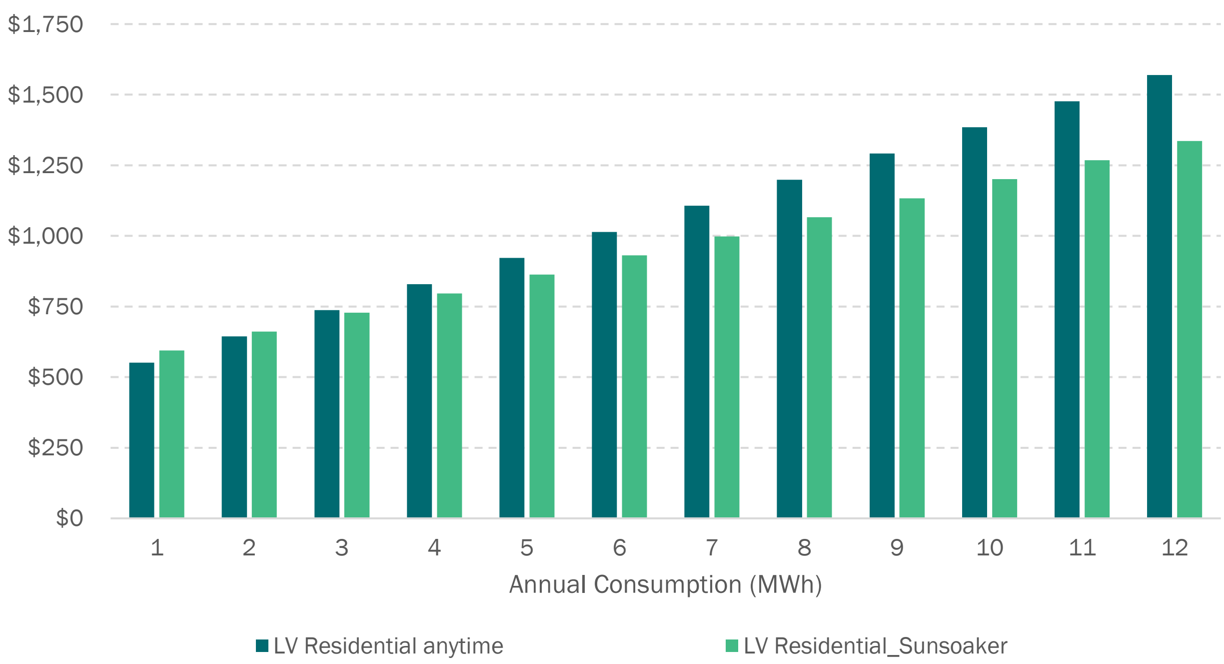
### Residential customer with no solar




### Residential customer with an average size solar system (2.9kW)



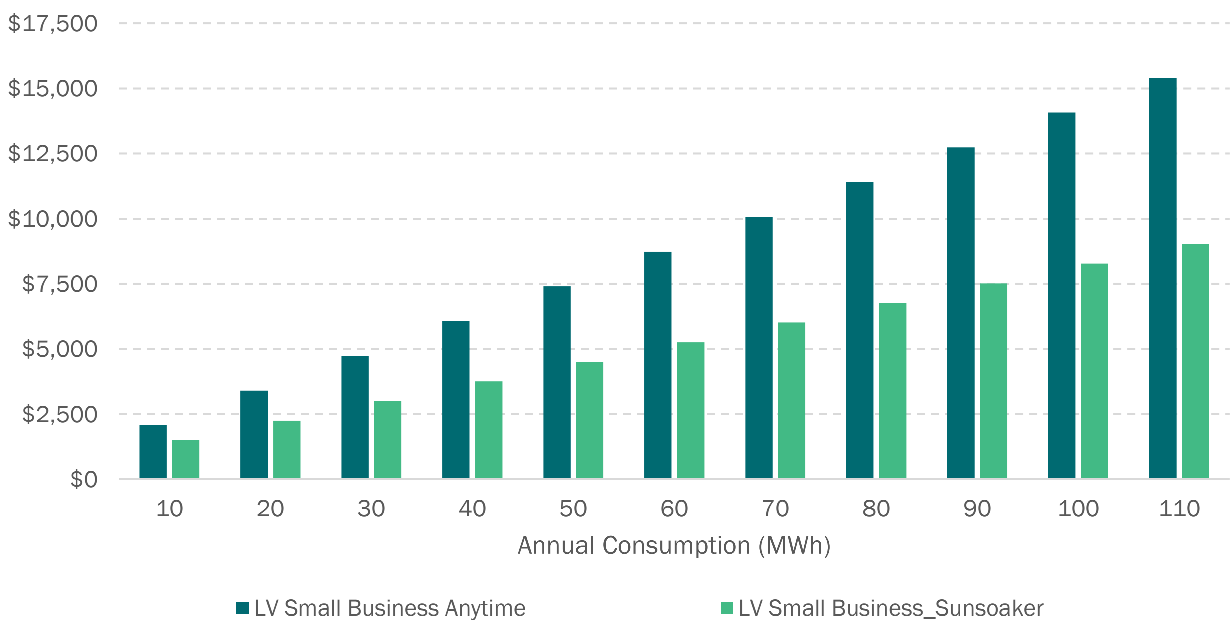
### Residential customer with a large solar system (6.5kW)



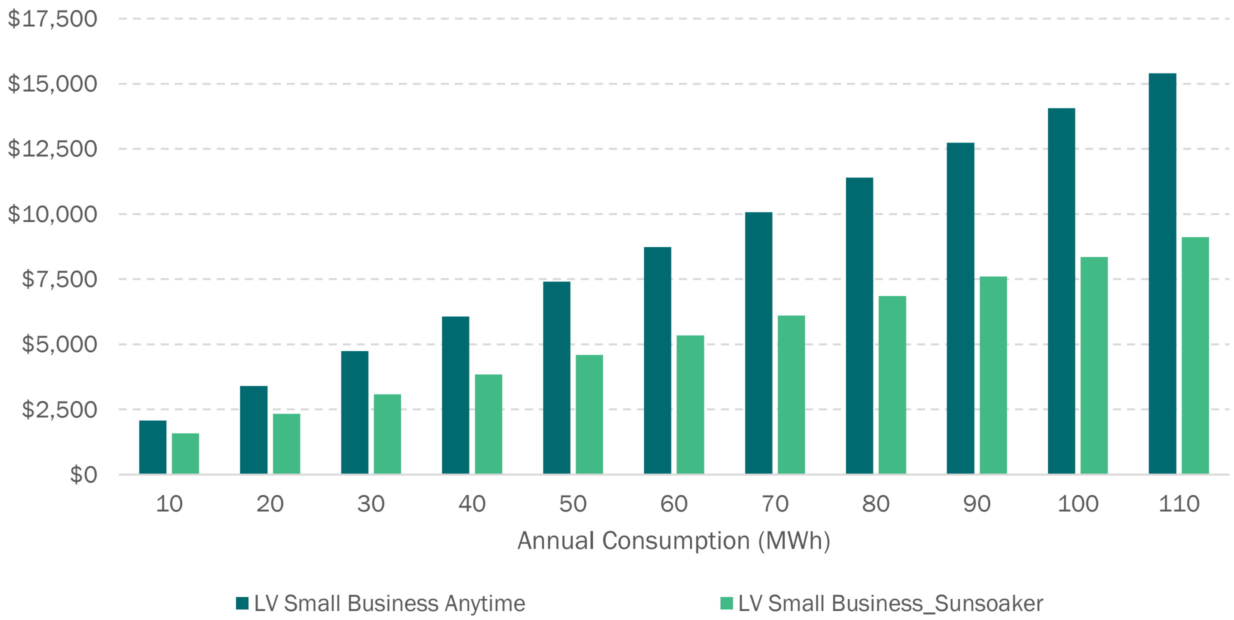

## Small business customer bill impacts (real June 2024)

*Moving from our anytime flat rate tariff (BLNN1AU) to our Sun Soaker tariff (BLTTSS1)*

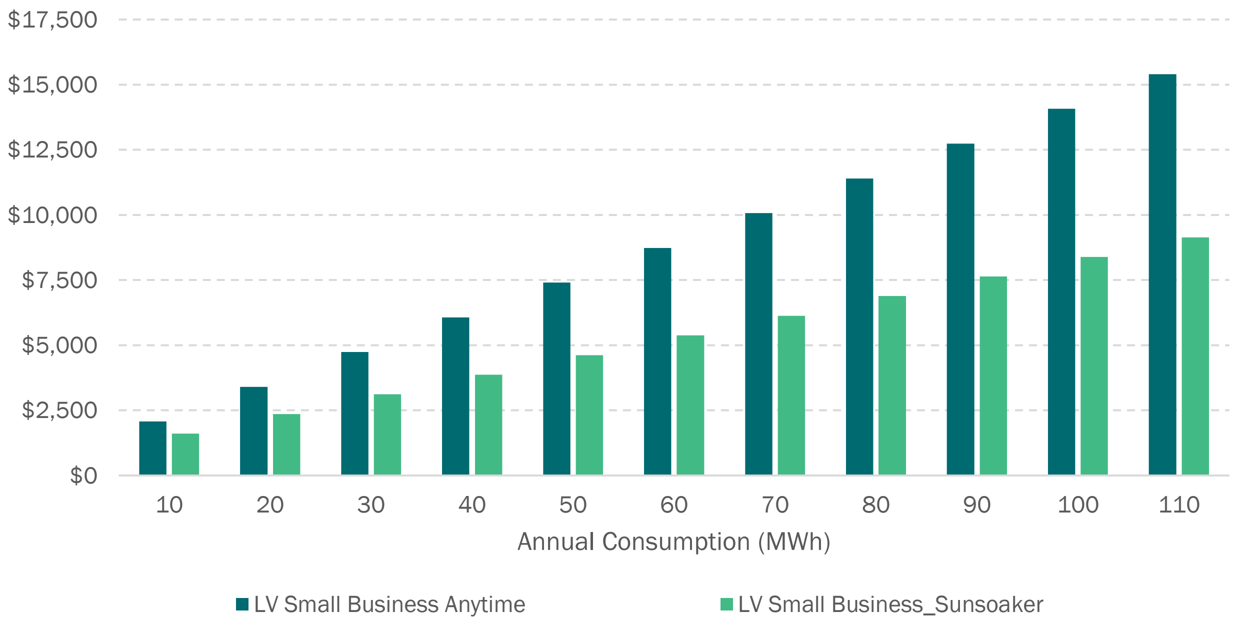
### Small business customer with no solar



Small business customer with an average size solar system *(7.9kW)*



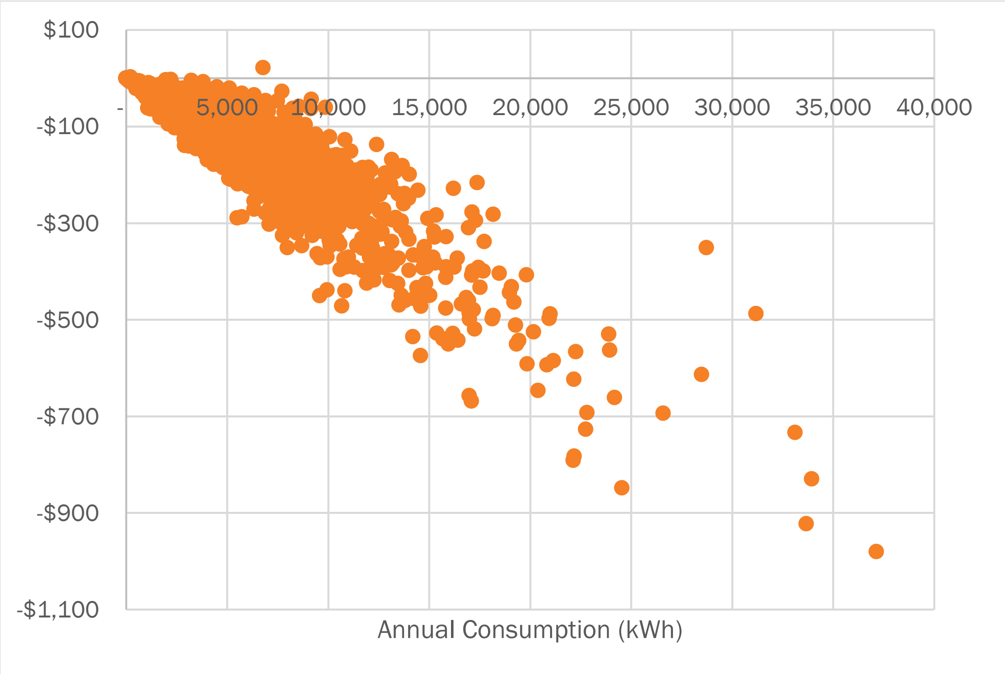

Small business customer with a large solar *system (10.0kW)*



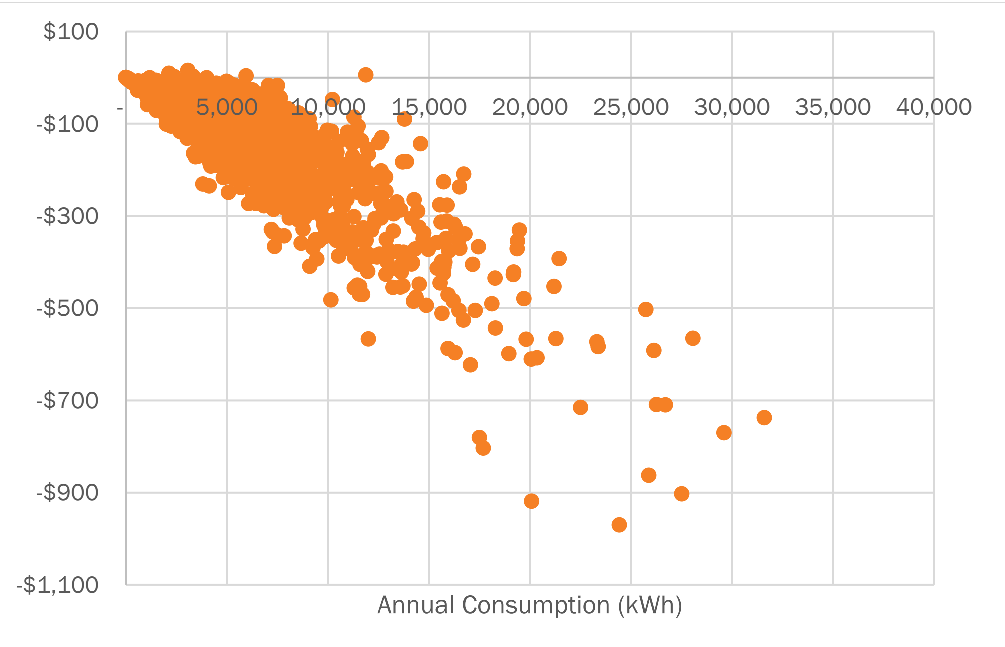
## Customer sample bill impact analysis

We have analysed the consumption profile of approximately 4,000 randomly selected customers with smart meter data. The consumption was taken from 2021-22 and modelled under different tariffs to establish customer impacts. The consumption profiles are historical actual so any customer behaviour is based on the tariff assigned at the time and does not include any changes in customer behaviour due to updates in tariff structures.

**Residential customer without Solar moving from Anytime to Sun Soaker tariff**

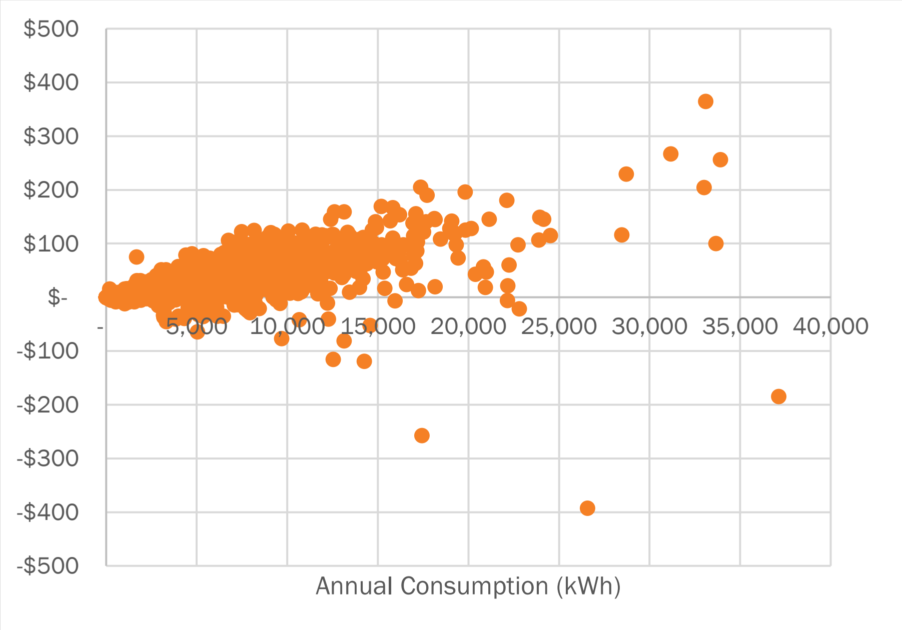



**Residential customer with Solar moving from Anytime to Sun Soaker tariff**

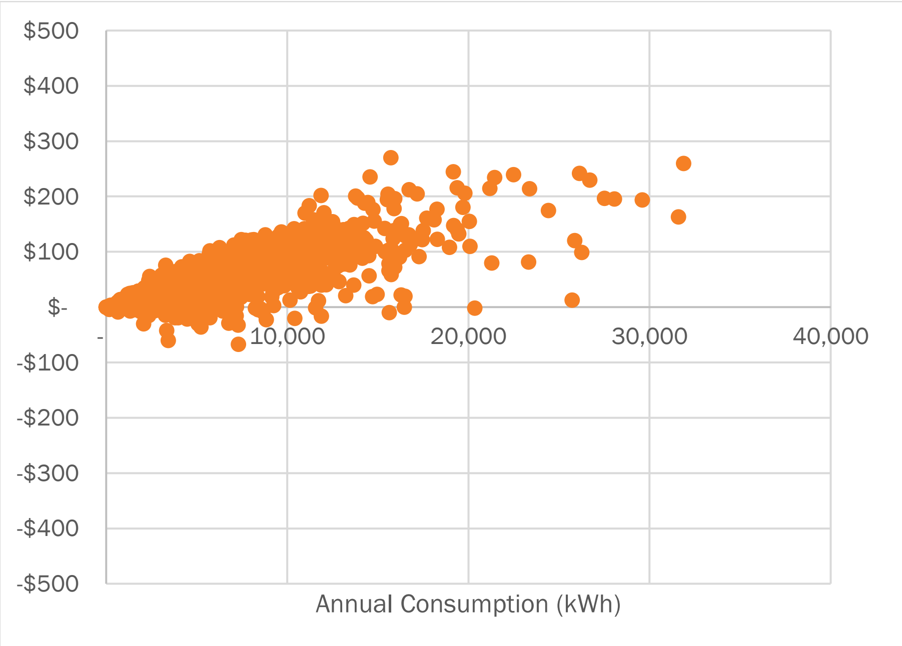



| Residential Customers | Sample Size | Proportion of customers with bill decrease | Proportion of customers with bill increase | $ Average DUOS Impact | % Average DUOS Impact | % Average Retail Bill Impact |
|---|---|---|---|---|---|---|
| Anytime to Sun Soaker without solar | 1,731 | 99.8% | 0.2% | -$141.48 | -11.7% | -4.5% |
| Anytime to Sun Soaker with solar | 1,973 | 99.6% | 0.4% | -$128.48 | -11.5% | -4.4% |

Residential customer without Solar moving from TOU to Sun Soaker tariff

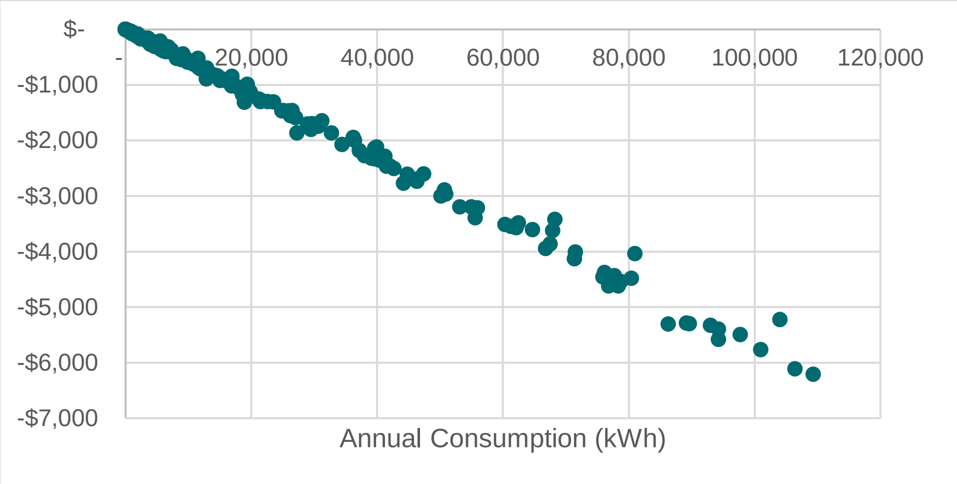



Residential customer with Solar moving from TOU to Sun Soaker tariff

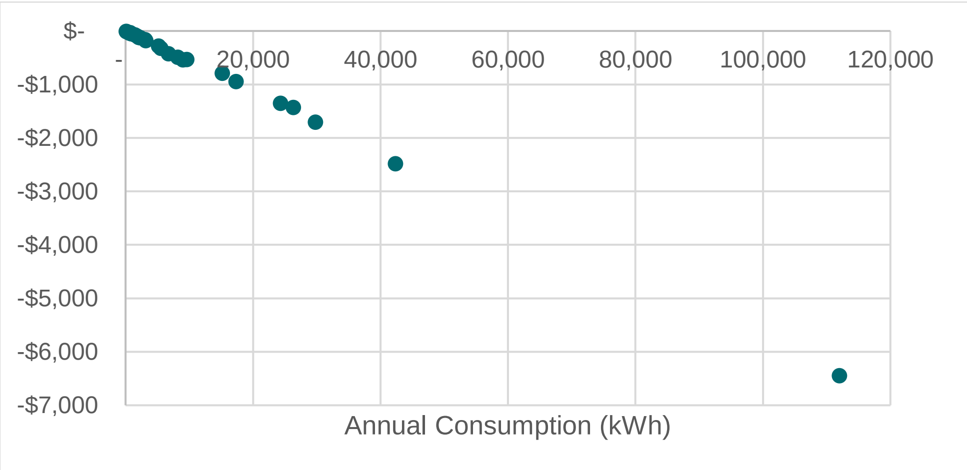



| Residential Customers | Sample Size | Proportion of customers with bill decrease | Proportion of customers with bill increase | $ Average DUOS Impact | % Average DUOS Impact | % Average Retail Bill Impact |
|---|---|---|---|---|---|---|
| TOU to Sun Soaker without solar | 1,731 | 6.3% | 93.7% | $33.64 | 3.5% | 1.3% |
| TOU to Sun Soaker with solar | 1,973 | 3.7% | 96.3% | $45.99 | 5.2% | 2.0% |

Small Business customer without Solar moving from Anytime to Sun Soaker tariff

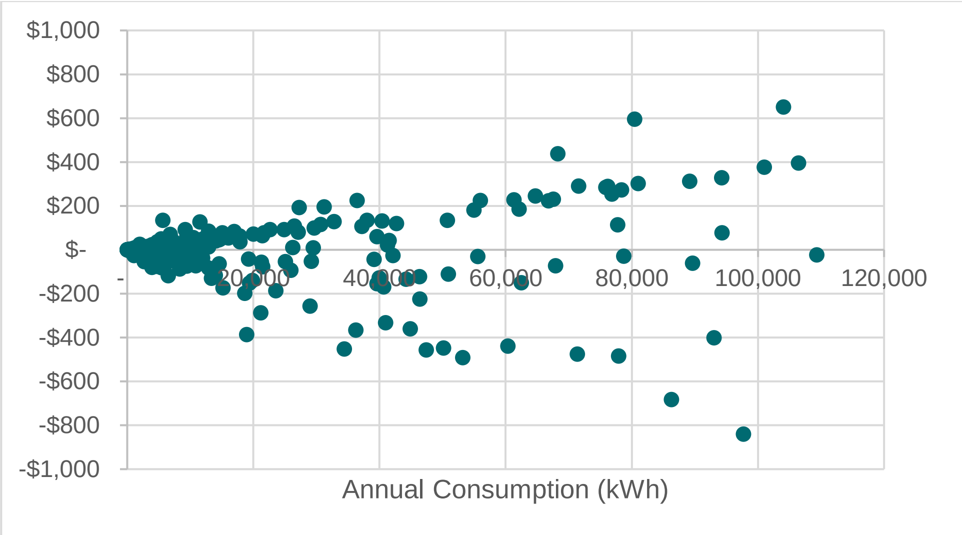



Small Business customer with Solar moving from Anytime to Sun Soaker tariff

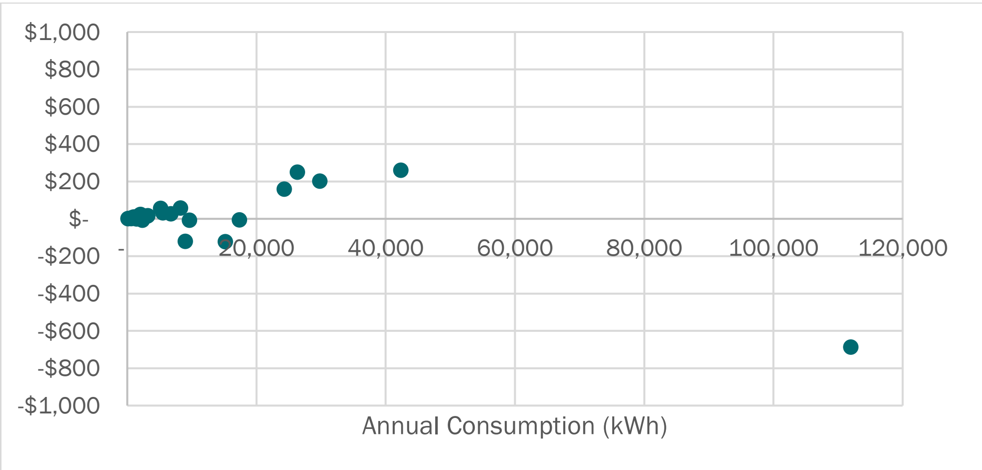



| Small Business Customers | Sample Size | Proportion of customers with bill decrease | Proportion of customers with bill increase | $ Average DUOS Impact | % Average DUOS Impact | % Average Retail Bill Impact |
|---|---|---|---|---|---|---|
| Anytime to Sun Soaker without solar | 247 | 98% | 2% | -$1,388 | -24.3% | -9.2% |
| Anytime to Sun Soaker with solar | 26 | 100% | 0% | -$722 | -18.7% | -7.1% |

Small Business customer without Solar moving from TOU to Sun Soaker

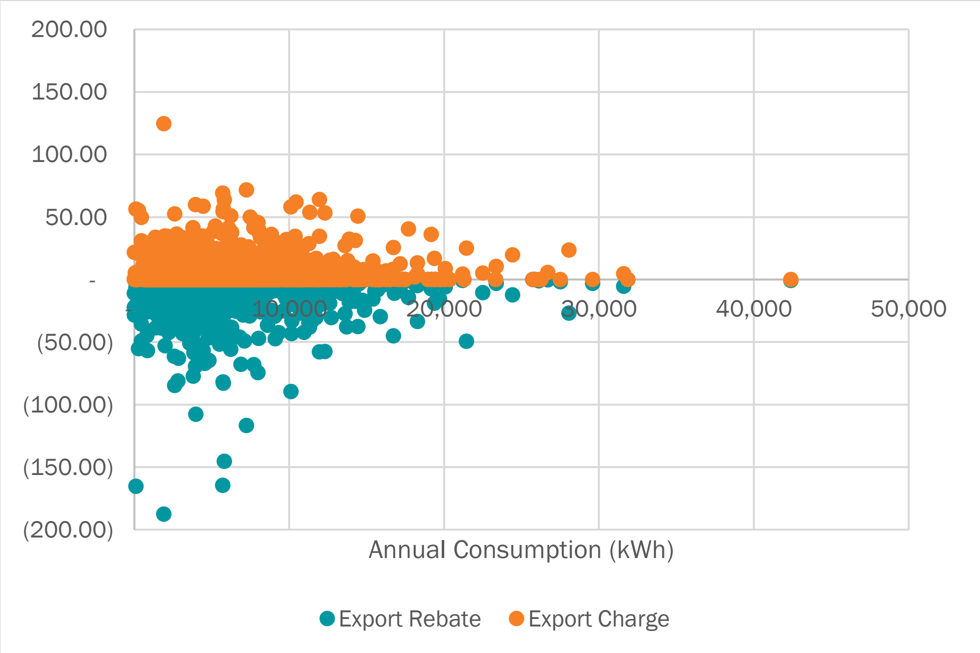



Small Business customer with Solar moving from TOU to Sun Soaker




| Small Business Customers | Sample Size | Proportion of customers with bill decrease | Proportion of customers with bill increase | $ Average DUOS Impact | % Average DUOS Impact | % Average Retail Bill Impact |
|---|---|---|---|---|---|---|
| TOU to Sun Soaker without solar | 247 | 40.5% | 59.5% | $4.05 | -0.1% | -0.1% |
| TOU to Sun Soaker with solar | 26 | 26.7% | 73.1% | $7.05 | 1.3% | 0.5% |

**Residential customer with Solar impacts of Export price**




The average export charge for the sample in the above chart was $4.10 per annum and the average export rebate was $7.11 per annum.

## Case Study: bill impact analysis

As part of the engagement undertaken with customers and stakeholders case studies were presented for two different customers and how the different options presented would impact their bill outcomes.

The two customers can be described by the following characteristics:

Customer 1

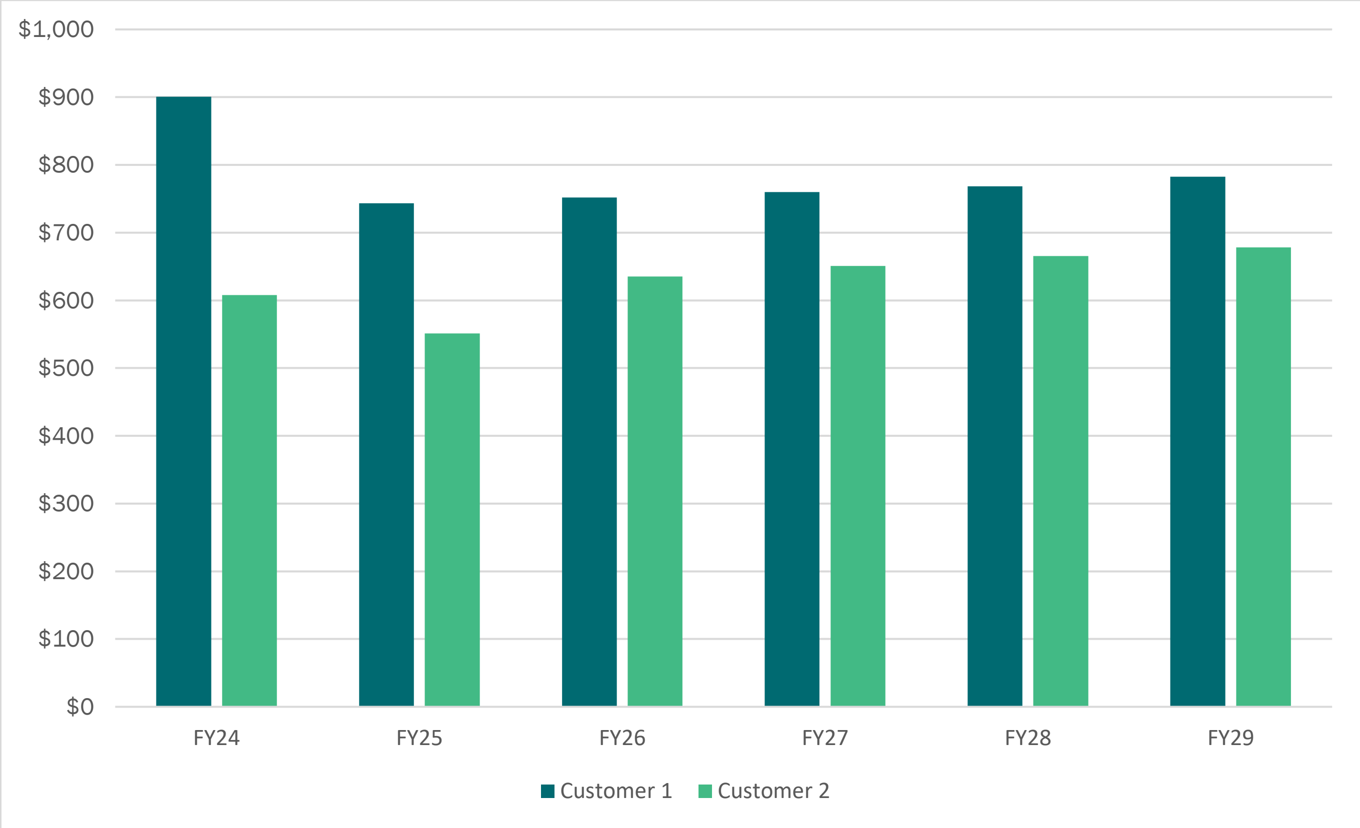
- single person living in a small home
- uses electric heating and cooling
- does not have a solar system
- relies on the network during the day
- uses the network during peak hours

Customer 2

- family of 4 living in a large home with solar
- uses electric heating and cooling
- have a 7kW solar system, of which they use 2kW during the day
- uses the network during peak hours
- excess energy is exported to the network

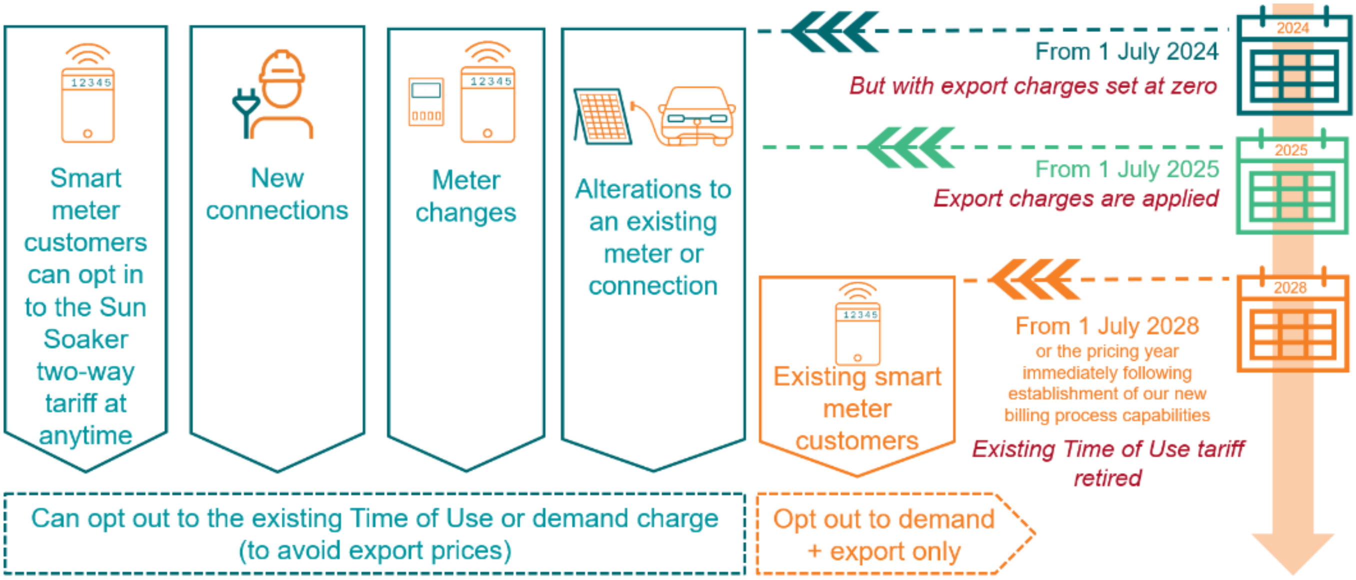
From a network perspective, both customers use the network in busy times, but Customer 2 also contributes to power quality issues.

The graph below shows bill impacts over the regulatory period with both customers moving to the Sun Soaker tariff. As we move through the regulatory period, the bills are becoming more aligned with Customer 2 contributing more towards the power quality issues caused by exports to the grid.


$1,000
$900
$800
$700
$600
$500
$400
$300
$200
$100
$0
FY24
FY25
FY26
FY27
FY28
FY29
Customer 1
Customer 2

## Two-way tariff assignment policies

In light of the above considerations and engagement outcomes, we propose to use assignment for a phased transition having regard to customer bill impacts. Our proposed export tariff transition strategy assignment policies are illustrated and described below.




Export tariff assignment policy

| Stage | Year | Two-way tariff assignment timeframes | Bill impact analysis |
|---|---|---|---|
| Year 1 | 2024-25 | New customers default assignment to Sun Soaker<br><br>New smart meters default assignment to Sun Soaker<br><br>Customers with a smart meter can opt in | Moving from Anytime to Sun Soaker has net bill savings for most customer sizes<br><br>No bill impact due to greenfield connection<br><br>Bill impact considered by individual customers or their retailers when making the choice to opt in<br><br>Note that the export tariff and rebate on the Sun Soaker will be set to zero in 2024-25 |
| Year 5^ | 2028-29 | All existing low voltage customers with a smart meter:<br>• who are on an Anytime or Time of Use tariff will be transferred to the new Sun Soaker tariff<br>• who are on a demand tariff will have an export tariff and rebate added to their tariff | Customers have a least five years notice of transition. This allows for prior solar investments to be recovered on the network tariff settings in place when customers made these investments. Bill impact analysis shows savings, though these are smaller than for customers who move over from the Anytime tariff who have not already been benefiting from TOU tariff signals. |

^From 1 July 2028, or the pricing year immediately following establishment of our new billing process capabilities.

As shown above, existing customers can choose to opt in to get the benefit of Sun Soaker and export charges/rebates. However, this is only likely to occur if retailers have aligned tariff offerings that empower customers to benefit from the TOU consumption, and export charging and rebate windows.

Customers assigned to a Sun Soaker tariff will have the ability to opt out to another cost reflective tariff – either the TOU tariff (prior to its abolition by 1 July 2028) or the three-rate demand (which will also be a two-way tariff by 1 July 2028).

As noted in the AER's draft decision, we have simplified our export tariff assignment policy for residential and small business customers, which the AER supports.[36]

This simplification involves setting the Sun Soaker export tariff and rebate to zero in 2024-25. This allows

[36] AER, Draft Decision Essential Energy Electricity Distribution Determination 2024 to 2029 Attachment 19 Tariff structure statement, Sep 2023, p.14.

us to assign current DER customers to the Sun Soaker tariff without an export charge (complying with transitional rule 11.141.11) as well as minimising change in tariffs. Retailers told us they were concerned about complexity with multiple assignments.

Our consultation about this simplification with our PCC and retailers identified the following benefits:

> customers only have to learn one consumption tariff in the period
> customers receive immediate benefit from the change to the Sun Soaker TOU consumption prices, which aligns with retailers' preference
> if retailers pass on export billing data, customers (and retailers) can learn about their export data during 2024-25 before pricing commences the next year (though only 1 retailer is doing this so far)
> it is simpler to communicate.

Our Essential People's Panel also supported this simplification, concluding that it would deliver a better outcome for customers.

### Treatment of EV fast chargers

Given the potential for EV charging to ramp up over the 2024–29 period and drive network constraints, in late November 2022 AER staff indicated an expectation that DNSPs will include a reassignment trigger to move customers to a cost reflective network tariff following installation of an electric vehicle (EV) fast charger.[37]

We consider that our proposed default cost reflective two-way tariff assignment policy is as robust to meeting the intent of this request as is within our control.

As requested by our PCC, we have developed the default Sun Soaker tariffs to be cost-reflective tariffs for a future state and be technology agnostic. This means customers can access the same tariffs and opportunities for savings or rebates irrespective of the new energy technologies that they choose to invest in and connect to our grid whilst still facing a tariff that efficiently reflects our costs to service them.

Consequently, any customer that connects an EV fast charger who has a smart meter or receives one under the AEMC's accelerated deployment will be assigned to our default cost reflective tariff.

We do not have visibility of instances where an existing three phase accumulation meter customer adds an EV fast charger to be able to apply the reassignment trigger requested above. We do not think this creates a material problem because:

> these circumstances would be for a limited time before being corrected within the period of the AEMC's accelerated smart meter deployment
> given the favourable bill savings opportunities available to customers who get a smart meter or seek to be on a TOU retail offer, we would expect engaged customers that invest in fast EV charging will be more likely to request a smart meter replacement from their retailer in order to access favourable retail offers.

The AER's draft decision asked that we include more information in this Revised TSS around how controlled load tariffs could target flexible load such as EVs.

How our controlled load tariffs work is:

> controlled load tariffs are secondary tariffs meaning they can be paired with other network tariffs for any controlled load circuit
> multiple load types (maximum of 3) are permissible on the one relay, with no restrictions on the type of load which may be controlled by a controlled load relay
> the load types connected shall not exceed more than 25 Amps resistive, as this will exceed the rating of the load control device
> we have two LV controlled load tariffs:
  – Controlled Load One is generally available for 5 to 9 hours on weekdays and extra on weekends except where the load is controlled by a time clock
  – Controlled Load Two is available for 10 to 19 hours per day on weekdays and extra on weekends.

This means single phase EV chargers would be eligible for our existing controlled load tariffs if connected by a controlled load relay.

It is questionable if the customer experience of controlled load would work for EV charging because present technology does not permit customer over-ride.

We expect the accelerated deployment of smart meters to change how controlled load tariffs are administered. This is because retailers will manage the load controls and would need to permit us to provide this service.

We will monitor this change and review our controlled load tariffs at the next TSS.

## Determining the basic export level

We determined a universal basic export level for customers on our network due to our customers' overwhelming preference that we provide a postage stamped approach to pricing.

Our resulting universal 1.5 kW or kW per hour basic export level reflects a balance of the following factors required by the AER's guidance:

> *efficiency* | no customer will be receiving a basic export level that is above our avoidable cost of

[37] Email dated 28 November 2022.

providing export services, as we have set this level at the maximum we can currently provide to all customers without incurring additional costs

- *complexity and understandability* | having a common basic export level was also seen as preferable for our ability to communicate the tariff and have it be capable of implementation in retailer systems and reflected in retail tariffs
- *fairness and equity* | a common basic export level meets the direction we heard in our engagement that customers strongly support postage stamping as a key means of achieving fairness and equity across our diverse customer base

We set about identifying the universal basic export level by considering:

- the export capacity of our distribution network to the extent it requires minimal or no further investment – the network's intrinsic hosting capacity for the most constrained sections in our network
- expected demand for export services in the distribution network
- our customer and stakeholder engagement outcomes.

**Engagement outcomes for the basic export level**

In our phase two engagement with customers and stakeholders, we did not receive a clear level of support from either customers or stakeholders in relation to the free export limit. For example:

- customer advocates thought the free export limit should be at the lower end of the scale – 1.5kW, and perhaps even lower, to ensure all customers realise the benefits of two-way pricing
- solar installers desired a higher level of free exports on the basis that they considered renewable generation benefits everyone, so the additional network investment costs should be levied across all consumers
- at a Stakeholder Collaboration Collective meeting on this topic, it was suggested that we use the inherent hosting capacity being derived as part of the future network business case to inform the free export level. We could then ask customers whether they are happy with this level or whether they want a higher level along with the associated cost. [38]

Our future network business case indicates that our network can accommodate 1.5 kilowatts (kW) of exports from each customer across our network on a postage stamp basis and this was incorporated into our Draft Proposal and draft TSS for feedback. We received no feedback on this element of our draft plans.

## Current intrinsic hosting capacity

### Approach

Understanding the network's intrinsic capacity to host DER export is crucial in enhancing our ability to provide two-way service.

For this work, intrinsic hosting capacity is defined as the ability of the network to support customer energy exports while remaining within technical limits. This aligns with work underway outside this project, such as the early definition used by the AER: the baseline ability of a network to support reverse power flow without additional investment.[39]

The intrinsic hosting capacity of our network was calculated using the electrical modelling of the network and assessing the maximum net export per customer that remains within the network's defined voltage and thermal limits.

The intrinsic hosting capacity is explicitly focused on understanding the inherent spare capacity available to host exports as a by-product of a network built to supply customer consumption.

Utilising a full model of the network produced for the hosting capacity study performed by Zepben (Supporting document 7.01.01 to our January 2023 Proposal), and setting the underlying demand to zero to estimate the impact of export without consideration for self-consumption, and incrementally increasing the export capacity for each customer until a violation of network performance was achieved. At that point, the export capacity for that section of network was set.

Network limits were defined as:

- customer Supply Voltage: 216V <> 253V
- thermal rating - normal asset rating defined as name plate transformer ratings overhead line ratings at standard design temperature.

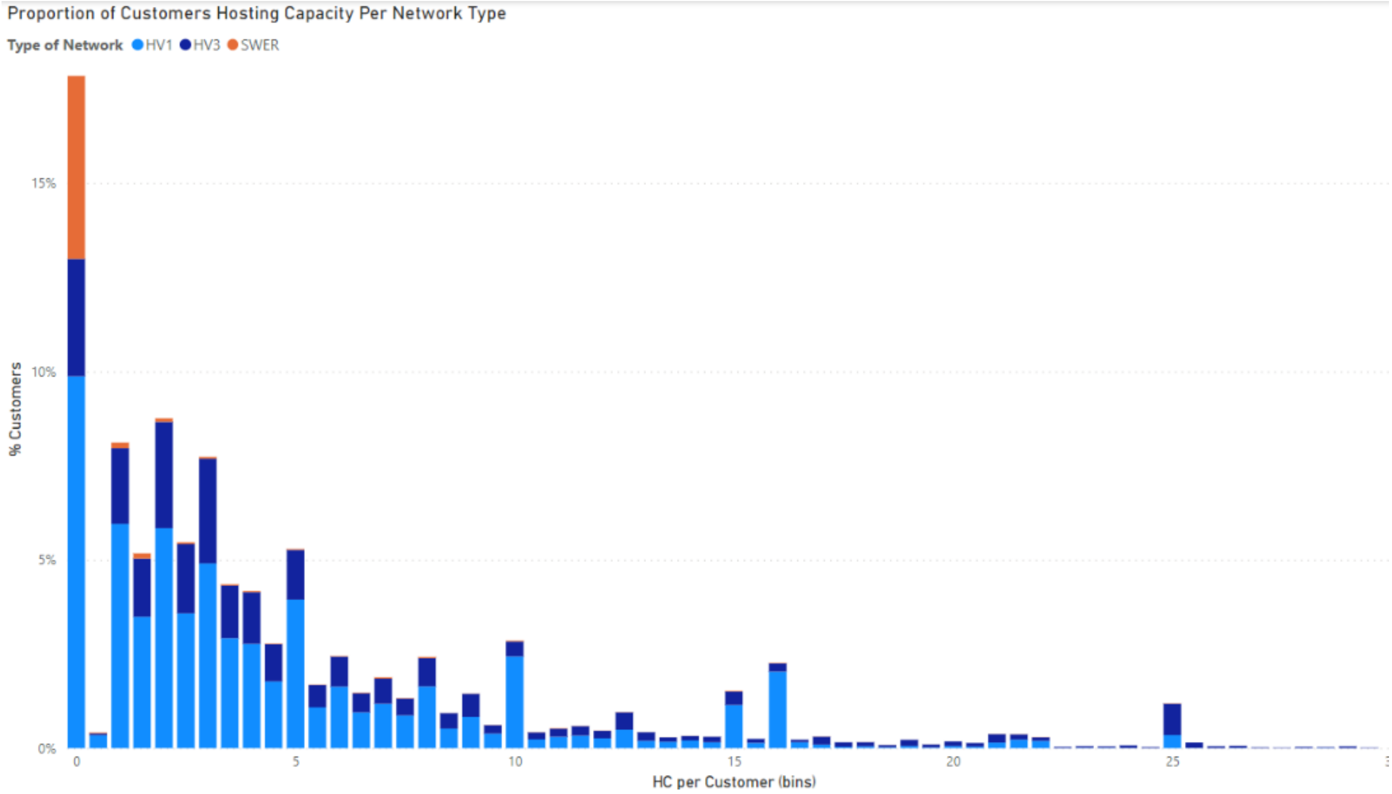
### Results

The figures below show the calculated intrinsic hosting capacity per customer. It shows a large proportion of customers (17 per cent) have zero export capacity, indicating the network would operate outside limits prior to any export. Customers on SWER network are over-represented in this category. The figure also shows circa 70 per cent of customers have hosting capacity of 5 kW or less, and 30 per cent of customers have a constraint of 1.5 kW or less.

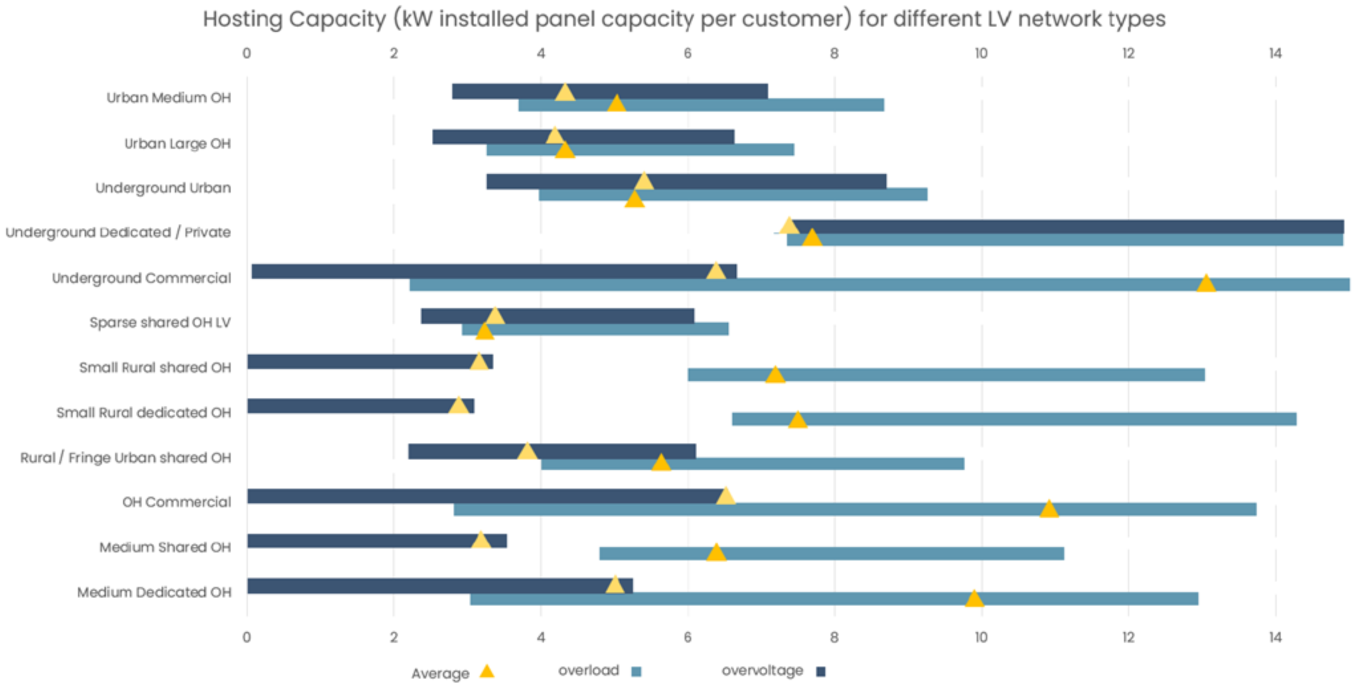
[38] Attachment 4.2 – How engagement informed our Draft Proposal 2024–29, pp. 49.

[39] AER Export Tariff Guidelines May 2022

Percentage of customers with intrinsic hosting capacity levels.




Solar hosting capacity performance by network type

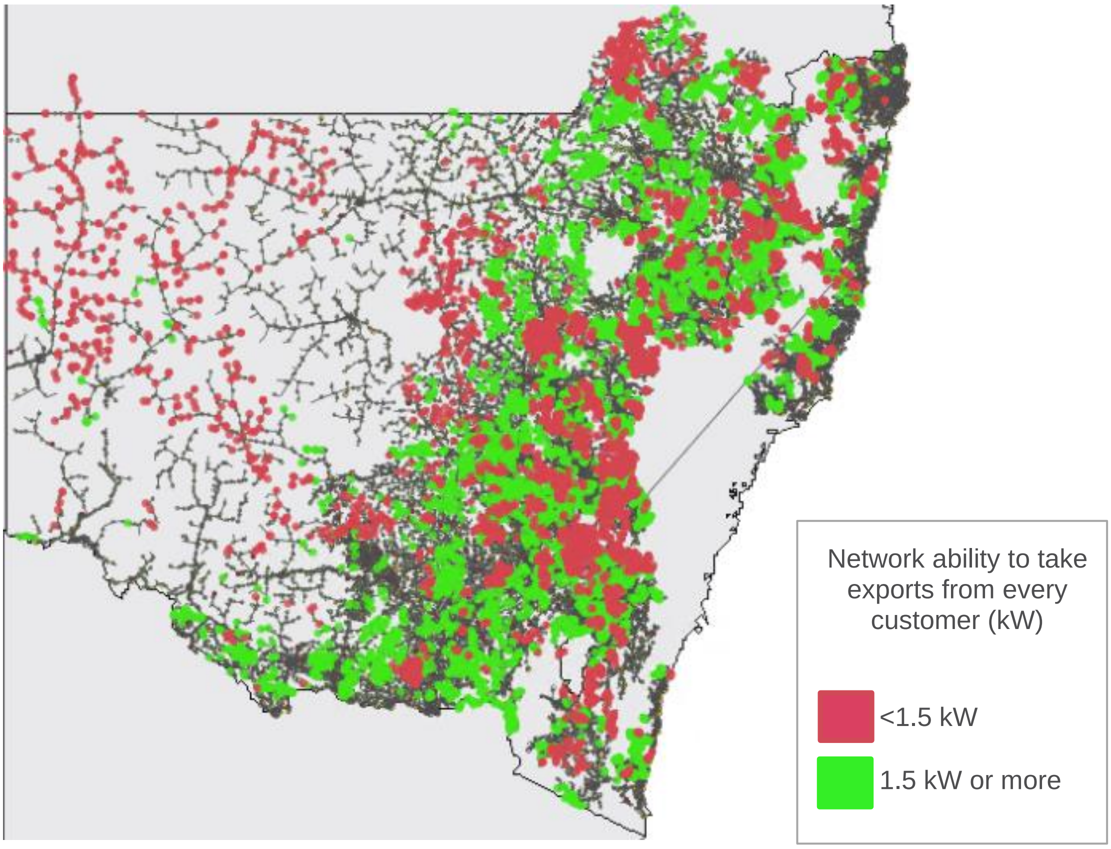


## Expected demand for export services

Our expert advisors (Zepben) took our 15-year demand and DER forecast provided by Frontier Economics and our end-to-end network model. They ran the load flow studies that underpinned the results. These were obtained using the OpenDSS1 electric power distribution system simulator to run millions of individual load flow studies under different DER penetration scenarios.

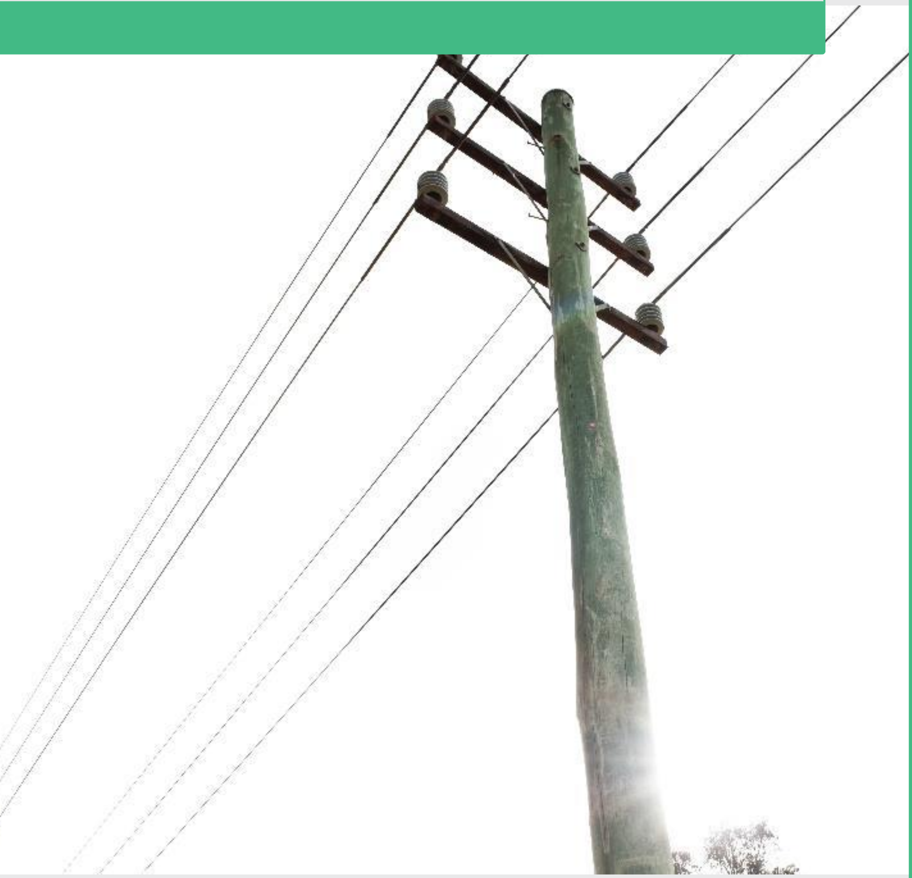
After considering the Zepben analysis and our customers' preferences for a simple and common basic export limit that could apply on a postage stamp basis, we arrived at the 1.5kW basic export limit.

**Our network's ability to receive exports from every customer**



# 05

# Summary of compliance



## Chapter summary

- How our TSS and TSES meet the NER requirements

## Our compliance with the network pricing objective and pricing principles

We have developed our network charges in accordance with the objective and principles set out in clause 6.18.5 of the NER. The table below outlines our compliance.

**How we have addressed the NER network pricing objective and pricing principles**

| | Network pricing objective | How we have addressed the objective |
|---|---|---|
| | The network charge for direct control services for each of our customers should reflect the efficient costs of providing those services to those customers. | The variable component of our charges is at or above the relevant LRMC for each one.<br>Residual costs are being allocated in a way that minimises impact on customer usage and export decisions, and supports bill stability as more customers transition to cost reflective two-way tariffs. |
| | **Pricing principles** | **How we have addressed the principle** |
| 1. | Revenue to be recovered must lie between the stand-alone costs of serving customers and the avoidable costs of not serving those customers. | This has been demonstrated in our economic cost model at Attachment 12.01.01.<br>In addition, each year our annual pricing proposal will demonstrate that the revenue we expect to recover from customers for each network charging class lies between the stand-alone costs of serving customers who belong to that class and the avoidable costs of not serving those customers.<br>Our expected revenue for each class is estimated to lie between our estimates of stand-alone and avoidable cost. |
| 2. | Each network charge is to be based on LRMC. | The variable component for each network charge is at or above the relevant LRMC.<br>The best approach to suit our available inputs and the expected benefits realisation from LRMC-based pricing in current market conditions is the average incremental cost approach. |
| 3. | The revenue to be recovered from each network charge must reflect the total efficient costs of providing services to the customers assigned to that charge, in a manner that minimises distortions to use of the network. | Our proposed charges and export tariff transition strategy mean that over this TSS period, more customers' tariff will align more closely to our estimates of the relevant LRMC than in prior TSSs.<br>Residual costs are allocated in a way that minimises customer impact and improves revenue stability. |
| 4. | Consideration is to be given to the impact on customers of changes in network charges. | Our proposed tariffs and export tariff transition strategy have been informed through extensive bill impact testing. |
| 5 | Charges must be readily understood or incorporated into retail tariff offers. | We have ensured simplicity and transparency, and that our tariff structures can be readily understood through:<br>> testing charging components and windows in our customer engagement program<br>> tariff trials<br>> testing with and surveying retailers and aggregators. |
| 5. | Network charges must comply with any jurisdictional pricing obligations imposed by state or territory governments. | Our proposed charges consider adjustments associated with the recovery of jurisdictional scheme costs – see the *Treatment of pass-through costs* section. |

# Future charging structures or changes

## Changes to the 2024-29 TSS

A further means for us to manage customer impacts within the regulatory period is by amending our TSS. We can seek amendments to an existing approved TSS for events that occur beyond our reasonable control and that could not have reasonably been foreseen at the time of writing it. Such changes would be subject to consultation with our customers and stakeholders and would require AER approval.

### Contingent triggers in the 2024-29 TSS

The 2024-29 TSS includes two contingent triggers that we consulted our PCC on following feedback from AER staff about the use of such triggers amid energy system transformation. The proposed triggers relate to the following:

> *the pace of two-way transition* | a contingent trigger for early establishment of our new billing process capabilities. If we establish our new billing capability ahead of schedule, it will trigger the mass smart meter reassignments to Sun Soaker and the addition of export tariff and rebate to our LV demand-based cost reflective tariffs (BLND3AO, BLND3TO, BLND1AR and BLND1AB) in the next pricing year. We will publish notice of this early trigger six months before the pricing year that these two-way pricing changes will apply

> *maintaining peak period alignment* | a contingent trigger for adapting the TOU charging windows. This will be used if:
  - data shows that this is required to maintain the alignment of our peak TOU windows with the observed system peak demand in the 12 months preceding the date of lodging the annual pricing proposal
  - that peak demand outcome was not caused by what we consider to be an anomalous event.

  If triggered, the number of hours in the peak TOU windows would not change, just the timing for when it commences and finishes.

  This trigger does not apply to controlled load tariffs which already operate dynamically to efficiently maximise the amount of discounted controlled consumption time.

## Annual charging proposal

We also submit an annual pricing proposal to the AER for assessment and approval. It explains:

> how we propose to vary charging levels from the start of the next financial year (1 July)

> any material differences between the charges proposed and the information on charges and charging structures in our TSS

> reasons for any material differences between the proposal and the indicative charging schedule in our TSS.

# Compliance check list

Rule 6.18 of the NER sets out the requirements for preparing and submitting a TSS to the AER. The table below sets out these requirements and where we have complied with them. Our TSS also followed the AER's guidance for recovering legacy metering costs from low voltage customers fixed charges[40] and its Export Tariff Guidelines.

**How to find where we have addressed the NER's TSS requirements**

| Clause | Relevant requirement | Addressed in |
|---|---|---|
| 6.8.2 (a) | A Distribution Network Service Provider must, whenever required to do so under paragraph (b), submit to the AER a regulatory proposal and a proposed tariff structure statement related to the distribution services provided by means of, or in connection with, the Distribution Network Service Provider's distribution system. | Revised Proposed TSS and Attachments 9.01 to 9.06 |
| 6.8.2 (d1) | The proposed tariff structure statement must be accompanied by an indicative pricing schedule. | Attachment 9.04 NUOS/DUOS Pricing Schedule<br>Attachment 9.05 Public Lighting (SLUOS) Pricing Schedule<br>Attachment 9.06 ANS Pricing Schedule |
| 6.8.2 (d2) | The proposed tariff structure statement must comply with the pricing principles for direct control services. | Revised Proposed TSS, TSES (Attachment 9.02) and Attachments 9.303 to 9.06 |

[40] AER, Legacy metering services – Guidance note, November 2023, p.4.

| Clause | Relevant requirement | Addressed in |
|---|---|---|
| 6.8.2 (e) and (f) | If more than one distribution system is owned, controlled or operated by a Distribution Network Service Provider, then, unless the AER otherwise determines, a separate regulatory proposal and a separate tariff structure statement are to be submitted for each distribution system.<br>If, at the commencement of this Section, different parts of the same distribution system were separately regulated, then, unless the AER otherwise determines, a separate regulatory proposal and a separate tariff structure statement are to be submitted for each part as if it were a separate distribution system. | Not applicable |
| 6.18.1A (a)<br><br>6.18.1A (a)(1) | A tariff structure statement of a Distribution Network Service Provider must include the following elements:<br>(1) The tariff classes into which retail customers for direct control services will be divided during the relevant regulatory control period; | Chapter 2 – *List of tariff classes and allocations* in the Revised Proposed TSS |
| 6.18.1A (a)(2) | (2) The policies and procedures the Distribution Network Service Provider will apply for assigning retail customers to tariffs or reassigning retail customers from one tariff to another (including any applicable restrictions); | Chapter 5 – *Tariff assignment procedures and policies* in the Revised Proposed TSS |
| 6.18.1A(a)(2A) | (2A) A description of the strategy or strategies the Distribution Network Service Provider has adopted, taking into account the pricing principle in clause 6.18.5(h), for the introduction of export tariffs including where relevant the period of transition (export tariff transition strategy); | Chapter 6 – *Export tariff transition strategy* in the Revised Proposed TSS |
| 6.18.1A (a)(3) | (3) The structures for each proposed tariff; | Chapter 4 – *Explanation of tariff structures, charging parameters and classes* in the Revised Proposed TSS |
| 6.18.1A (a)(4) | (4) The charging parameters for each proposed tariff; and | |
| 6.18.1A (a)(5) | A description of the approach that the Distribution Network Service Provider will take in setting each tariff in each pricing proposal of the Distribution Network Service Provider during the relevant regulatory control period in accordance with clause 6.18.5. | Chapter 3 – *Approach to setting tariffs and the basic export level* in the Revised Proposed TSS |
| 6.18.1A (b) | A tariff structure statement must comply with the pricing principles for direct control services. | Chapter 3 – *Approach to setting tariffs and the basic export level* in the Revised Proposed TSS |
| 6.18.1A (e) | A tariff structure statement must be accompanied by an indicative pricing schedule which sets out, for each tariff for each regulatory year of the regulatory control period, the indicative price levels determined in accordance with the tariff structure statement. | Attachment 9.04 NUOS/DUOS Pricing Schedule<br>Attachment 9.05 Public Lighting (SLUOS) Pricing Schedule<br>Attachment 9.06 ANS Pricing Schedule |
| 6.18.3 (b) | Each retail customer for direct control services must be a member of 1 or more tariff classes. | Chapter 2 – *List of tariff classes and allocations* in the Revised Proposed TSS |
| 6.18.3 (c) | Separate tariff classes must be constituted for retail customers to whom standard control services are supplied and retail customers to whom alternative control services are supplied (but a retail customer for both standard control services and alternative control services may be a member of 2 or more tariff classes). | |
| 6.18.3 (d) (1) to (2) | A tariff class must be constituted with regard to:<br>(1) the need to group retail customers together on an economically efficient basis; and<br>(2) the need to avoid unnecessary transaction costs. | |
| 6.18.4 (a) | In formulating provisions of a distribution determination governing the assignment of retail customers to tariff classes or the reassignment of retail customers from one tariff class to another, the AER must have regard to the following principles:<br>(1) Retail customers should be assigned to tariff classes on the basis of one or more of the following factors:<br>(i) The nature and extent of their usage or intended usage of distribution services;<br>(ii) The nature of their connection to the network; | Chapter 3 – *Approach to setting tariffs and the basic export level* in the Revised Proposed TSS |

| Clause | Relevant requirement | Addressed in |
|---|---|---|
| | (iii) Whether remotely-read interval metering or other similar metering technology has been installed at the retail customer's premises as a result of a regulatory obligation or requirement;<br>(2) Retail customers with a similar connection and distribution service usage profile should be treated on an equal basis;<br>(3) DELETED<br>(4) A Distribution Network Service Provider's decision to assign a customer to a particular tariff class or to re-assign a customer from one tariff class to another should be subject to an effective system of assessment and review. | |
| 6.18.4 (b) | If the charging parameters for a particular tariff result in a basis of charge that varies according to the usage or load profile of the customer, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which a customer is charged. | |
| 6.18.5 (a) | The network pricing objective is that the tariffs that a Distribution Network Service Provider charges in respect of its provision of direct control services to a retail customer should reflect the Distribution Network Service Provider's efficient costs of providing those services to the retail customer. | Chapter 3 – *Approach to setting tariffs and the basic export level* in the Revised Proposed TSS |
| 6.18.5 (b) | Subject to paragraph (c), a Distribution Network Service Provider's tariffs must comply with the pricing principles set out in paragraphs (e) to (j). | |
| 6.18.5 (c) (1) to (2) | A Distribution Network Service Provider's tariffs may vary from tariffs which would result from complying with the pricing principles set out in paragraphs (e) to (g) only:<br>(1) To the extent permitted under paragraph (h); and<br>(2) To the extent necessary to give effect to the pricing principles set out in paragraphs (i) to (j). | |
| 6.18.5 (d) | A Distribution Network Service Provider must comply with paragraph (b) in a manner that will contribute to the achievement of the network pricing objective. | |
| 6.18.5 (e) (1) to (2) | For each tariff class, the revenue expected to be recovered must lie on or between:<br>(1) An upper bound representing the stand-alone cost of serving the retail customers who belong to that class; and<br>(2) A lower bound representing the avoidable cost of not serving those retail customers. | Chapter 3 – *Approach to setting tariffs and the basic export level* in the Revised Proposed TSS |
| 6.18.5 (f) (1) to (3) | 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:<br>(1) The costs and benefits associated with calculating, implementing and applying that method as proposed;<br>(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<br>(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 | |
| 6.18.5 (g) (1) to (3) | The revenue expected to be recovered from each tariff must:<br>(1) Reflect the Distribution Network Service Provider's total efficient costs of serving the retail customers that are assigned to that tariff;<br>(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<br>(3) Comply with subparagraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (f). | |
| 6.18.5 (h) (1) to (3) | 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 I to (g) to the extent the | |

| Clause | Relevant requirement | Addressed in |
|---|---|---|
| | Distribution Network Service Provider considers reasonably necessary having regard to:<br>(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);<br>(2) The extent to which retail customers can choose the tariff to which they are assigned; and<br>(3) The extent to which retail customers are able to mitigate the impact of changes in tariffs through their decisions about usage of services. | |
| 6.18.5 (i) (1) to (5) | The structure of each tariff must be reasonably capable of:<br>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<br>being directly or indirectly incorporated by retailers or Market Small Generation Aggregators in contract terms offered to those customers,<br>having regard to information available to the Distribution Network Service Provider, which may include<br>(3) the type and nature of those retail customers;<br>(4) the information provided to, and the consultation undertaken with, those retail customers; and<br>(5) the information provided by, and consultation undertaken with, retailers and Market Small Generation Aggregators. | Chapter 4 – *Explanation of tariff structures, charging parameters and classes* in our Revised Proposed TSS |
| 6.18.5 (j) | A tariff must comply with the Rules and all applicable regulatory instruments. | Chapter 3 – *Approach to setting tariffs and the basic export level* in the Revised Proposed TSS |
| 6.18.6 (a) | This clause applies only to tariff classes related to the provision of standard control services. | Demonstrated through our Annual Pricing Proposals |
| 6.18.6 (b) | The expected weighted average revenue to be raised from a tariff class for a particular regulatory year of a regulatory control period must not exceed the corresponding expected weighted average revenue for the preceding regulatory year in that regulatory control period by more than the permissible percentage. | |
| 6.18.6 (c) (1) to (2) | The permissible percentage is the greater of the following:<br>(1) The CPI-X limitation on any increase in the Distribution Network Service Provider's expected weighted average revenue between the two regulatory years plus 2%;<br>Note: The calculation is of the form (1 + CPI)(1 – X)(1 + 2%)<br>(2) CPI plus 2%.<br>Note: The calculation is of the form (1 + CPI)(1 + 2%) | Demonstrated through our Annual Pricing Proposals |
| 6.18.6 (d) (1) to (3) | In deciding whether the permissible percentage has been exceeded in a particular regulatory year, the following are to be disregarded:<br>(1) The recovery of revenue to accommodate a variation to the distribution determination under rule 6.6 or 6.13;<br>(2) The recovery of revenue to accommodate pass-through of designated pricing proposal charges to retail customers;<br>(3) The recovery of revenue to accommodate pass-through of jurisdictional scheme amounts for approved jurisdictional schemes. | Demonstrated through our Annual Pricing Proposals |
| 6.18.7 (a) | A pricing proposal must provide for tariffs designed to pass on to retail customers the designated pricing proposal charges to be incurred by the Distribution Network Service Provider. | |
| 6.18.7 (b) | The amount to be passed on to retail customers for a particular regulatory year must not exceed the estimated amount of the designated pricing proposal charges adjusted for over or under recovery in accordance with paragraph (c). | |
| 6.18.7 (c) (1) to (3) | The over and under recovery amount must be calculated in a way that:<br>(1) Subject to subparagraphs (2) and (3) below, is consistent with the method determined by the AER in the relevant distribution determination for the Distribution Network Service Provider; | |

| Clause | Relevant requirement | Addressed in |
|---|---|---|
| | (2) Ensures a Distribution Network Service Provider is able to recover from retail customers no more and no less than the designated pricing proposal charges it incurs; and<br>(3) Adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year. | |
| **6.18.7 (d) (1) to (3)** | Notwithstanding anything else in this clause 6.18.7, a Distribution Network Service Provider may not recover charges under this clause to the extent these are:<br>(1) Recovered through the Distribution Network Service Provider's annual revenue requirement;<br>(2) Recovered under clause 6.18.7A; or<br>(3) Recovered from another Distribution Network Service Provider. | Demonstrated through our Annual Pricing Proposals |
| **6.18.7A (a)** | A pricing proposal must provide for tariffs designed to pass on to customers a Distribution Network Service Provider's jurisdictional scheme amounts for approved jurisdictional schemes. | |
| **6.18.7A (b)** | The amount to be passed on to customers for a particular regulatory year must not exceed the estimated amount of jurisdictional scheme amounts for a Distribution Network Service Provider's approved jurisdictional schemes adjusted for over or under recovery in accordance with paragraph (c). | |
| **6.18.7A (c) (1) to (3)** | The over and under recovery amount must be calculated in a way that:<br>(1) Subject to subparagraphs (2) and (3) below, is consistent with the method determined by the AER for jurisdictional scheme amounts in the relevant distribution determination for the Distribution Network Service Provider, or where no such method has been determined, with the method determined by the AER in the relevant distribution determination in respect of designated pricing proposal charges;<br>(2) Ensures a Distribution Network Service Provider is able to recover from customers no more and no less than the jurisdictional scheme amounts it incurs; and<br>(3) Adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year. | |
| **6.18.7A (d) (1) to (2)** | A scheme is a jurisdictional scheme if:<br>(1) The scheme is specified in paragraph (e); or<br>(2) The AER has determined under clause paragraph (l) that the scheme is a jurisdictional scheme,<br>and the AER has not determined under paragraph (u) that the scheme has ceased to be a jurisdictional scheme. | |
| **6.18.7A (e) (1) to (3)** | For the purposes of paragraph (d)(1), the following schemes are jurisdictional schemes:<br>(1) Schemes established under the following laws of participating jurisdictions:<br>(i) Electricity Feed-in (Renewable Energy Premium) Act 2008 (ACT);<br>(ii) Division 3AB of the Electricity Act 1996 (SA);<br>(iii) Section 44A of the Electricity Act 1994 (Qld);<br>(iv) Electricity Industry Amendment (Premium Solar Feed-in Tariff) Act 2009 (Vic);<br>(2) The Solar Bonus Scheme established under the Electricity Supply Act 1995 (NSW); and<br>(3) The Climate Change Fund established under the Energy and Utilities Administration Act 1987 (NSW). | N/A |
| **6.19.2 (a)** | Subject to the NEL and the Rules, all information about a Service Applicant or Distribution Network User used by Distribution Network Service Providers for the purposes of distribution service pricing is confidential information. | Requirement adhered to throughout entire Revised TSS |
| **6.19.2 (b)** | No requirement in this Chapter 6 to publish information about a tariff class is to be construed as requiring publication of information about an individual retail customer. | |

| Clause | Relevant requirement | Addressed in |
| --- | --- | --- |
| **No applicable Rule** | Essential should make claims for confidentiality in accordance with the AER's Confidentiality Guideline. | |

# 06

# Glossary

## Chapter summary

– Explanation of acronyms and terms used throughout this document

| TERM | MEANING |
| --- | --- |
| 2024–29 regulatory period | The regulatory control period beginning 1 July 2024 and ending 30 June 2029 |
| ACS | Alternative control services – specific user-requested services: public lighting; Type 5 and Type 6 metering (generally residential and small business customer meters); and ancillary network services |
| AIC | Average Incremental Cost |
| AER | Australian Energy Regulator – the economic regulator for our distribution business |
| CER | Consumer energy resources – decentralised small-scale local energy generation, located 'behind the meter' of a customer |
| charging parameters | The specific charging characteristics of a component within the pricing structure |
| CPI | Consumer Price Index – a measure of inflation |
| customer class | A group of customers who have common characteristics that allow them to be grouped together to ensure similar customers pay similar charges |
| demand charge | The charge based on the maximum amount of electricity a customer uses at any one time, measured in kW |
| DER | Distributed energy resources – decentralised local energy generation, a broad term that encompasses:<br>> generation often located 'behind the meter' of a customer – which we are now referring to as consumer energy resources (CER)<br>> large scale generation such as solar farms and grid-scale batteries<br>> our non-network solutions such as regulated SAPS and microgrids |
| Direct Control Services | Services regulated by the Australian Energy Regulator under the National Electricity Rules, comprising Standard Control Services and Alternative Control Services |
| DNSP | Distribution Network Service Provider |
| DUoS | Distribution Use of System – a charge for using the distribution network |
| HV | High voltage |
| IDT | Inter-distributor transfer – payments to other network distribution businesses |
| kVA | Kilovolt ampere |
| kW | Kilowatt |
| kWh | Kilowatt hour |
| LMRP | Legacy meter retirement plan |
| LRMC | Long run marginal cost – the cost of adding one more unit of demand to the network |
| LV | Low voltage |
| MWh | Megawatt hour – unit of energy equivalent to 1,000 kilowatt hours |
| NAC | Network access charge |
| NEL | National Electricity Law |
| NER | The National Electricity Rules that govern the operation of the National Electricity Market |
| NPV | Net Present Value |
| NSW | New South Wales |
| NUoS | Network Use of System – the charge for using our distribution network, as well as transmission-related pass-through costs and jurisdictional scheme costs such as the Climate Change Fund |
| parent tariff | The tariff a customer would have been assigned to prior to being eligible for a new tariff that has been introduced in this TSS period |
| PCC | Pricing Collaboration Collective – our group of engaged and diverse stakeholders who represent the interests of our customers with whom we engaged closely on pricing related matters |
| peak demand/peak load | The maximum electricity demand customers place on the electricity network |
| prices/pricing | The charges to network customers for providing cost-efficient network services – commonly referred to as a 'tariff' |
| pricing components | The combination of elements – including network access, and consumption and demand charges – that reflect the efficient costs of providing network services to customers |

| TERM | MEANING |
| --- | --- |
| pricing schedule | An annually published list of prices and pricing structures for each network charge – also referred to as the ‘Network Price List and Explanatory Notes’ |
| pricing structure | The combination of pricing components that make up the network charge |
| Proposal | Our Regulatory Proposal for the 2024–29 regulatory control period, submitted under clause 6.8 of the National Electricity Rules |
| real | Dollars before factoring in inflation, for example ‘real $2023-24’ means dollars in equivalent terms before inflation is added – when added it is ‘nominal’ |
| repex | Replacement capital expenditure |
| residual | Those costs recovered annually that are above our Long Run Marginal Cost |
| SCS | Standard control services – our core activities for enabling customers to access our network and for supplying them with electricity |
| SSSP | System strength service provider |
| smart meter | A digital device that measures and records a customer’s electricity usage and their maximum demand every half-hour and transmits the data to their electricity provider (type 1-4) |
| tariff | See ‘prices/pricing’ |
| tariff class | A group of customers who have similar characteristics and who pay similar prices |
| ToU | Time of Use – a meter or charging parameter that varies according to whether electricity is consumed in a peak, shoulder or off-peak period |
| TNSP | Transmission Network Service Provider |
| TSS | Tariff Structure Statement |
| TUoS | Transmission Use of System – charges for using the transmission network that are a component of NUoS charges (see NUoS) |