Explanatory Statement

In support of the Regulatory Determination Proposal 2025-30

January 2024

2025 Regulatory Determination Project

Ergon Energy Network

Part of Energy Queensland

Contact details

Manager Network Pricing & Tariffs

PO Box 1090, Townsville QLD 4810
Level 6, 420 Flinders Street, Townsville QLD 4810
www.energyq.com.au

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1 OVERVIEW

1.1 Purpose of the Tariff Structure Explanatory Statement

This Explanatory Statement provides further information to support our 2025-30 Tariff Structure Statement (TSS) submission to the Australian Energy Regulator (AER).

Our TSS provides necessary information regarding the tariffs and assignment arrangements that will apply from 1 July 2025 and how they comply with the National Electricity Rules (the Rules).

Our Explanatory Statement provides addition information on how we arrived at our network tariff structures and charges for the 2025-30 regulatory control period. This includes the outcome of changes that applied in the current period, key influences of further reform and change and how we have incorporated customer preferences and choice in our final designs.

1.2 The role of tariffs in delivering better outcomes for customers

Our revenues are capped, meaning that changing our assignment arrangements, tariffs and pricing components can only be set in a way that recovers forecast allowed revenues. However, we are expected to ensure our tariffs are set efficiently and reflect the efficient costs of providing services to each class of customer.

More efficient prices encourage more efficient use of networks which can help reduce the need for additional investment over time. As all customers ultimately pay for these network upgrades, improved pricing arrangements that encourage more efficient use of the network can lead to lower network costs for all customers.

Any structural change will result in changes to individual prices and inevitably positive and negative impacts to different customers. Network tariffs are expected to be capable of being reasonably understood and promote efficient usage.

Changes implemented in 2020 represented a significant but transitionary step towards more efficient tariff structures and assignment arrangements. This is particularly the case for residential and small non-residential customers. All customers within this group with capable meters are now assigned to network tariffs that reflect lower prices during most of the day and higher prices in the afternoon and evening (where triggers for network investment are strongest). As a result of these changes, over a third of our customers are currently assigned to some form of cost-reflective network tariff structure.

We see further opportunities to build on reforms already introduced. Our aim is to improve the efficiency of our network tariffs so that customers can use and source energy in response to prices that are more closely aligned to the impact of customer decisions on our future network costs. Customers looking to save on their bill can therefore make decisions on how they use the network in a way that reduces the need for future network augmentation.

1.3 Overview of our Tariff Structure Explanatory Statement

Section	Title	Purpose
1	Overview	Overview of this Statement
2	Our customers	Our role in supply energy to customers and the areas of supply
3	The Impact of Change on Our Network and Tariff Strategy	Outlining the changes to our operating environment
4	Addressing Opportunities and Challenges from change	Our response to changes in our operating environment
5	Engaging with customers	Demonstrating our commitment to customer engagement
6	Consultation outcomes: proposed changes in 2025	What we heard from our customers
7	Outcomes for Customers	Overview of our approach to customer impact analysis
8	Compliance with Pricing Principles	Demonstrate compliance with the Pricing Principles

1.4 Summary of key changes to our Assignment Rules and Tariffs in 2025

Our proposed changes continue a trend nationally toward more efficient network tariff structures aimed at ensuring more efficient outcomes for all customers in relation to the use of electricity networks.

Table 1 below summarises the changes to our Tariff Structure Statement from 1 July 2025 following our pre-lodgement customer engagement.

Table 1 - Summary of key changes in our TSS

Key Change	Description
Time of Use Windows	We will continue our transition away from anytime energy charges towards time variant charges. As such, our Time of Use (ToU) windows will change from 1 July 2025. For residential customers we are targeting zero distribution charges for energy used between 11am-4pm daily. A peak rate will continue to apply to the 4pm-9pm peak window. Volume rates will apply at other times. For our small business customers, we are targeting a zero distribution charges for energy used 11am-1pm daily. A peak rate will apply to a new window of 5pm-8pm weekdays only with shoulder rates applying at other times. Large businesses will move to a default tariff structure aligning to the same windows as small business customers. The majority of high voltage customers will also have the option to move to network tariffs with these windows from 1 July 2025.
Tariff Streamlining	We will withdraw a number of tariffs that have either been closed for some time, have few customers assigned to them or that no longer feature in our future network tariff direction.

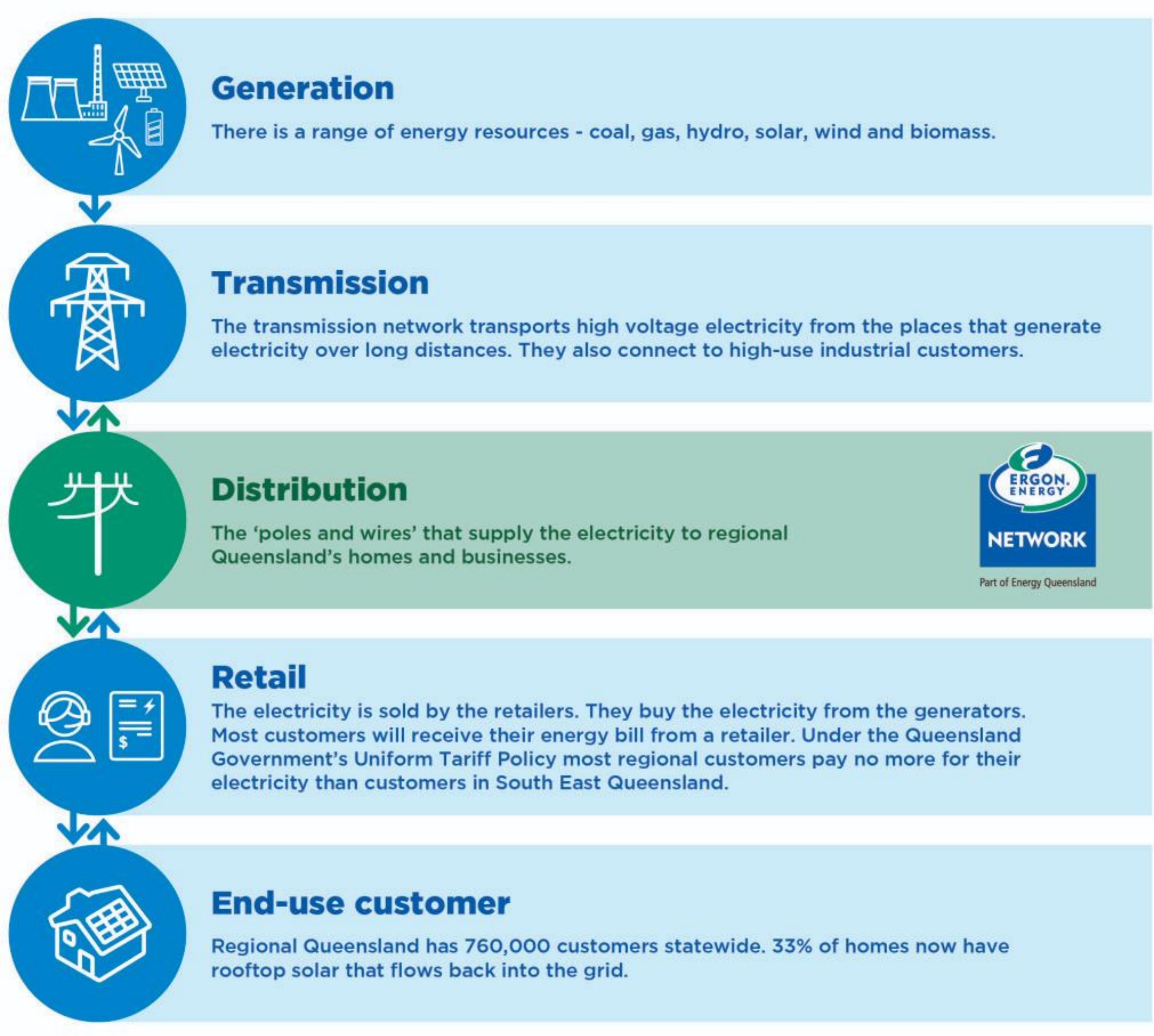
Key Change	Description
Two-Way Tariffs	From 1 July 2026 we will introduce two-way tariffs for new customers with exports below 30kW capacity (optional for existing customers). From 1 July 2028, all customers with exports below 30kW capacity will be assigned to these tariffs. Customers with a dynamic connection may choose to not have two-way tariffs apply depending on their preferences around access to export charge and reward (further detail available via Section 6.2).
Load Control	Load Control tariffs provide customers choice when responding to impacts cost reflective tariffs. For our business, load control provides us flexibility to manage system wide and localised issues in a way that defers or avoids traditional network investment. We will expand options for customers to access load control tariffs. Flexible Load Tariffs will be introduced from 1 July 2025 allowing customers to access cheaper rates for controlled appliances, while also maximising the benefit of using their appliances on a primary tariff with behind the meter solar PV and storage technologies.
Strengthening of peak price signal	As we continue our progression towards cost reflective tariffs, we have revised our approach to Long Run Marginal Cost (LRMC) underpinning our peak prices. Under this revised approach, customers will have greater incentives to move energy use from peak periods to off-peak periods. Responding to these signals will benefit the customer but also reduce the pressure on investment to support import and export services over time – benefiting all customers in the long term.

2 OUR CUSTOMERS

2.1 Our role in supplying energy to our customers

Our distribution network of 'poles and wires' are at the centre of the supply chain connecting homes and businesses. Electricity is provided across Queensland through different organisations that generate energy, transmit the energy, distribute energy and provide energy related retail services to end-use customers, some of whom also self-generate additional energy through solar panels.

Figure 1 - The electricity supply chain



The costs of our services are recovered from retailers based on each customer's usage and the distribution network tariff the customer has been assigned to. The network tariff relates to the combination of charges which, when applied to a customer's usage will determine how much we bill a retailer.

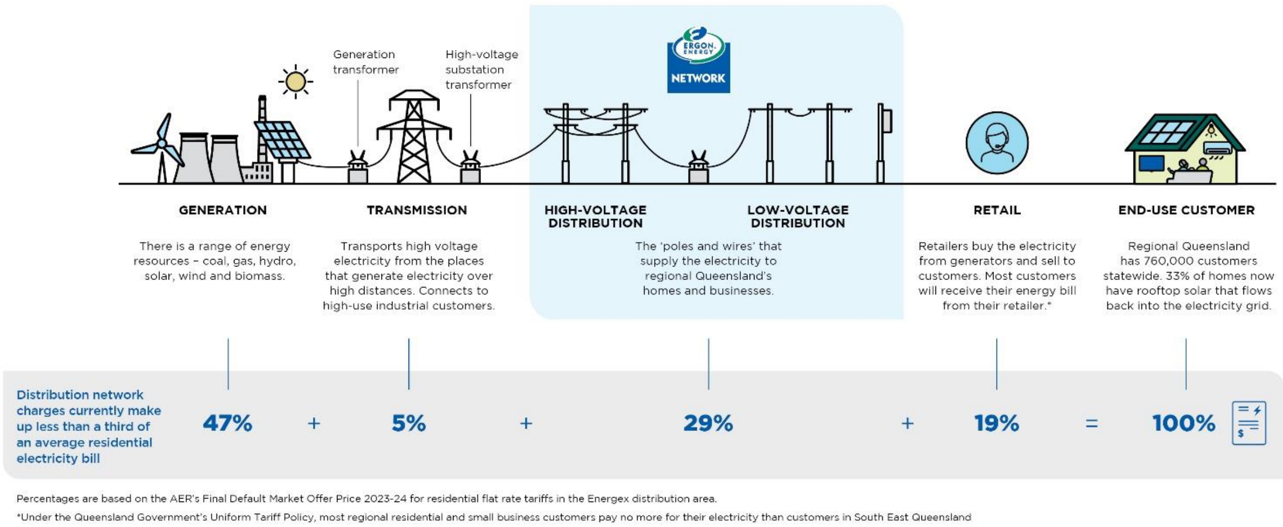
We have a number of tariffs that we assign customers to. Both the rules for assigning customers and the charging components are approved by the Australian Energy Regulator.

There are different types of charges that make up network tariffs:

- Fixed daily rates (measured in dollars per day) are common to most of our tariffs.
- Volume rates are applied to the amount of energy used over a period (measured in dollars per kilowatt hour).
- Demand charges (measured in dollars per kilowatt or dollars per kilovolt amps) are common for large business tariffs, and recently have been included in network tariffs for many residential and small business customers.

The proportion of a customer's bill representing distribution costs will differ depending on the tariff the customer is on, and how much energy the customer uses energy. For some tariffs the end bill will depend on the times that the customer uses energy. Figure 2 shows the breakdown of an average residential customer's energy bill based on information provided by the AER.[1]

Figure 2 - Proportion of typical residential energy bill



Retailers recover network charges through the bill they send to customers but are not obliged to pass on our network tariff *structures* to customers, as our charges comprise only a portion of the total bill. This can mean that the tariff structures we apply are not always passed through to the end customer.

2.1.1 Retail arrangements in regional Queensland

The Queensland Government applies special arrangements aimed at ensuring most customers in regional Queensland face lower electricity bills relative to the cost of supply. Notified Retail prices for small customers set by the Queensland Competition Authority based on the cost of supply in

[1] AER Default market offer prices 2023–24: Final determination, Final Default Market Offer Price 2023-24 for residential flat tariffs in Ergon Network distribution area.

South East Queensland for those customers choosing Ergon Retail as their energy retailer. Retail prices for many large customers are based on the Ergon Energy Network East pricing region with the lowest cost of supply. This impacts how our network tariffs are passed through to the end use customer.

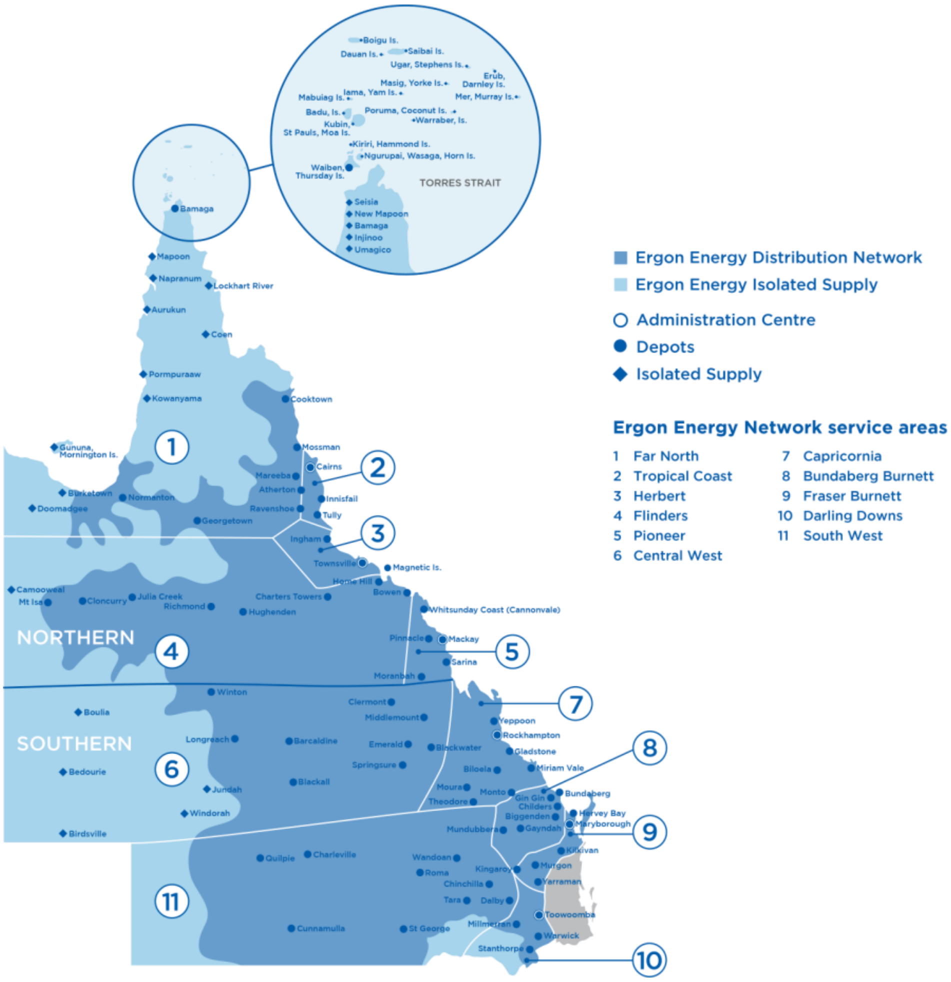
Customers in regional Queensland supplied by Ergon Energy Retail are assigned to a default regulated retail tariff that does not necessarily reflect the underlying network tariff structure we apply to the retailer. However, customers with smart meters have the option to move to different regulated retail structures that are more closely aligned to our network tariff structures.

Our Draft Plan proposed that several small business transitional tariffs be withdrawn on 30 June 2025. However, following feedback from Queensland Government, we will now defer the withdrawal of these tariffs until 30 June 2026. Several gazetted transitional retail tariffs mirror the structure of the tariffs we propose to withdraw. Extending the tariff a further 12 months will assist with the administrative process for setting notified prices in regional Queensland. Further details are available in Section 6.6.

2.2 Who We Supply

Ergon Energy Network is a subsidiary company of Energy Queensland Limited (Energy Queensland), a Queensland Government-owned corporation, and is the electricity distribution network service provider for regional Queensland. We own, operate, and maintain the ‘poles and wires’ that deliver power to 760,000 homes and businesses from the State’s expanding coastal and rural population centres to the remote communities of outback Queensland and the Torres Strait.

Figure 3 - Our Service Area



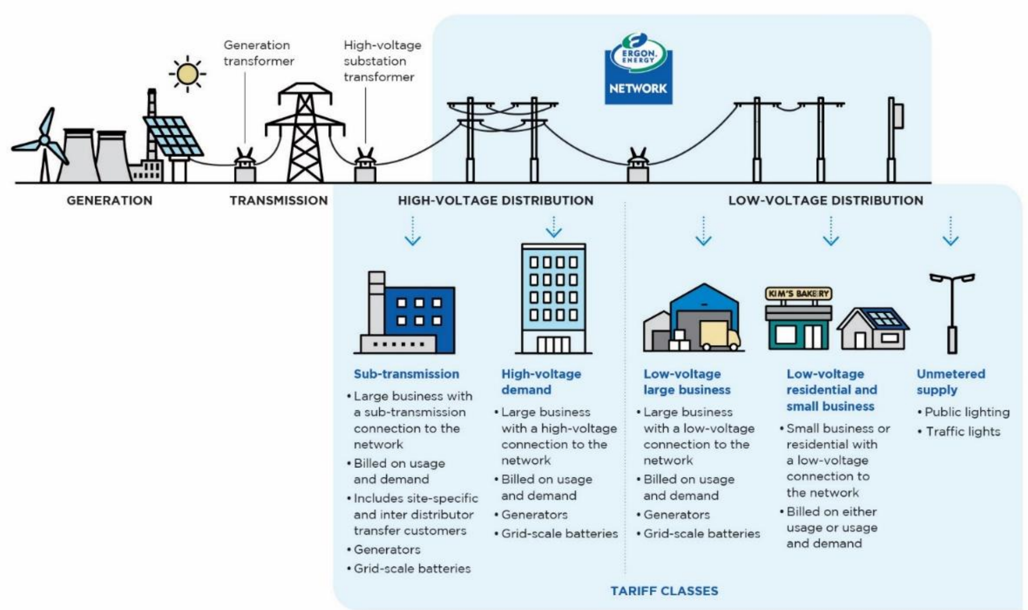
We have a wide diversity of customers who use the network for different purposes. We classify customers according to their connection type, connection attributes and usage characteristics. The majority of our customers are residential customers who, with other small and larger non-residential customers connect to our low voltage network.

Figure 4 - Our Customers according to class

Tariff class	Eligibility criteria	Network tariffs
Standard Asset Customers (SAC)	Customers connected at Low Voltage are classified as SAC. Customers may further be categorised as Small or Large	Tariff choice depends on customer type (i.e. residential vs business), annual consumption and meter type SAC Large are customers over 100MWh/annum
Connection Asset Customers (CAC)	Customers with a network coupled to the Network Voltage from 11kV who are not allocated to the ICC tariff class are allocated to the CAC tariff class	Mix of site-specific & standard tariffs Tariff choice depends on connection characteristics i.e. voltage level, line vs bus connection
Individually Calculated Customers (ICC)	Customers are allocated to the ICC tariff class if they are coupled to the network at 33kV or above	Site-specific distribution and transmission tariffs depending on connection assets, location and capacity requirements

Our annual network tariff rates are set based on a revenue allocation to each Tariff Class. This revenue allocation is based upon the underpinning requirements to service that tariff class. In our engagement, some customers have observed that the relativity between our tariff class revenues may not be reflective to the contributions made to the larger Queensland economy. For example, small business accounts for over 97% of businesses statewide[2], however account for a relatively small amount of our annual revenue.

Figure 5 - Breakdown of customer class



The way our network is managed and built is strongly driven by the expectations and needs of rural and regional residents, businesses, and communities. The vast size of Ergon Energy Network's distribution area and the geographically dispersed nature of the population means that our network needs to cover long distances and be sufficiently resilient to safely and reliably support our customers' domestic, commercial, and industrial needs and preferences - now and into the future.

[2] Small businesses in Queensland | Business Queensland

3 THE IMPACT OF CHANGE ON OUR NETWORK AND TARIFF STRATEGY

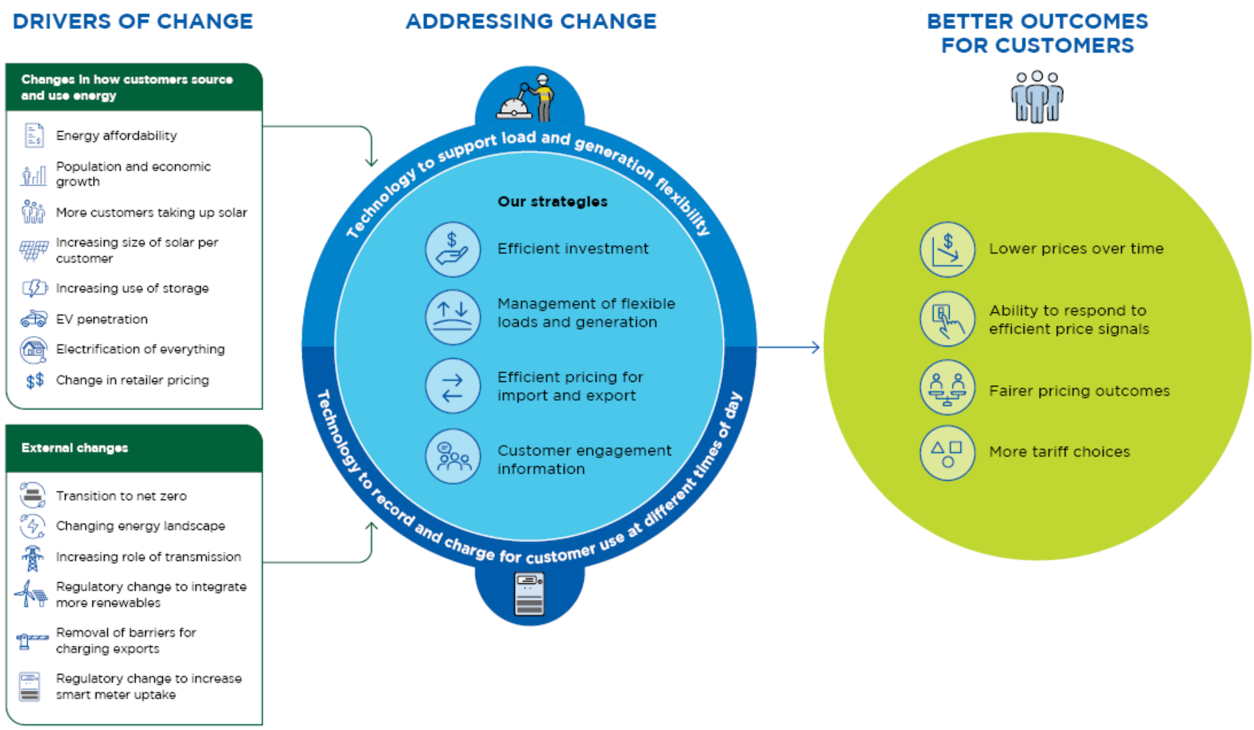
Our engagement with customers has centred on the significant change in the way customers are using energy, as well as transformational change in the energy sector itself. These changes have been a strong driver for changes in our network tariff arrangements.

During the next 5 years, our network will pivot to a new phase in electricity pricing, where the proportion of customers who will be able to receive and respond to more efficient pricing structures (through rollout of smart meters) will move from the minority to the majority. This change removes a key barrier that has slowed the pace of network tariff reforms needed to keep up with customer and energy market driven changes.

Given the unprecedented change in the sector, the widespread rollout of technology enabling us to provide more efficient pricing signals has come at an important time. Along with other technology advances, and efficient investment strategies, efficient pricing arrangements will help us and our customers navigate the changes impacting how we operate, manage and invest in the network.

The link between change factors, impacts on our network and our technology and pricing strategies to enable better outcomes for customers is outlined in Figure 6 below:

Figure 6 - Strategies to address drivers of change



This section outlines key drivers of change that are influencing our tariff strategy. This includes growth in customers and output, but also forecast trends in customer energy resources and changing expectations regarding affordability as cost of living pressures rise. We outline other factors influencing change including the energy sector transformation, regulatory changes, greater penetration of smart meters and retailer response to our tariff structures.

In Section 4 we cover how these changes impact our operation of the network and considerations in tariff structure.

3.1 Changing Customer Needs

With increased customer uptake of renewables and other technologies, people are rapidly changing both how they use the electricity network and what they expect from it. This requires a rethink about the best way to plan and charge for electricity in a way that is fair for everyone and meets different customer expectations.

How we invest in our network in regional Queensland is also being influenced by a range of challenges, including:

- rising electricity prices and cost of living pressures
- increased uptake of distributed energy resources, such as rooftop solar systems, batteries and electric vehicles (EVs), as well as large-scale renewable energy generation and storage
- strong economic growth and development throughout the region
- increasingly harsh climate conditions and more intense and frequent natural disasters, including cyclones, flooding, and bushfires.

3.2 A growing economy and population

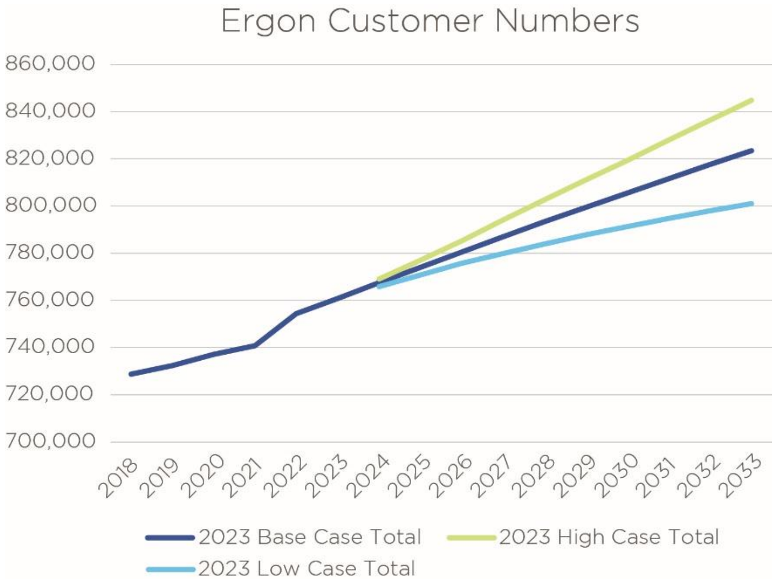
Economic growth projections have factored in short term domestic and international supply constraints as well as likely slowing of consumption growth in response to higher interest rates. While the global economy faces increased uncertainty and volatility, our forecasts assume growth forecasts reflecting the unwinding of supply constraints, a moderation in inflation levels and continued strong employment growth.

The COVID-19 Pandemic impacted Queensland population growth trends, predominantly interstate and international migration. However, overall population growth rebounded quickly due to strong interstate migration.

Adverse COVID-19 impacts, compounded by the slowing construction of housing and apartments resulted in a slowing of new customer connections in 2022-23. As COVID-19 impacts diminish, we expect new connections are expected to recuperate in 2023-24 and stabilise over the subsequent years to 2032-33. The increase will be driven by continued buoyant overseas immigration, the upward housing market and growth in GSP.

Figure 7 below shows the assumed increase in customer connections over the period.

Figure 7 – Forecast Customer Numbers



3.3 Continued growth in distributed energy resources

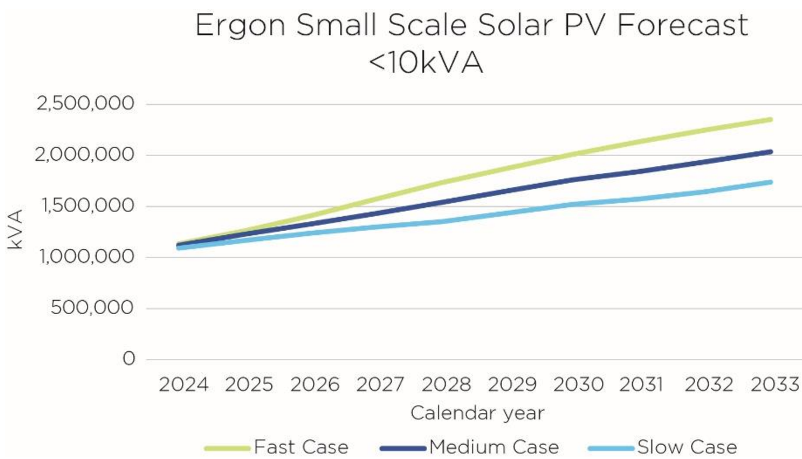
The volume of distributed energy resources, like solar systems, battery storage and EVs, connecting to our network is expected to grow significantly over the next five to 10 years.

3.3.1 Solar PV

Queenslanders lead the world in solar penetration. Around 33% of residential and small business customers have solar PV systems. This trend is likely to continue. Historical data from recent years showed strong signs of growth across all customer categories.

The forecasts in the figure below include all solar capacities from systems installed by residential, business, and industrial customers.

Figure 8 – Solar PV Forecast



3.3.2 Energy storage

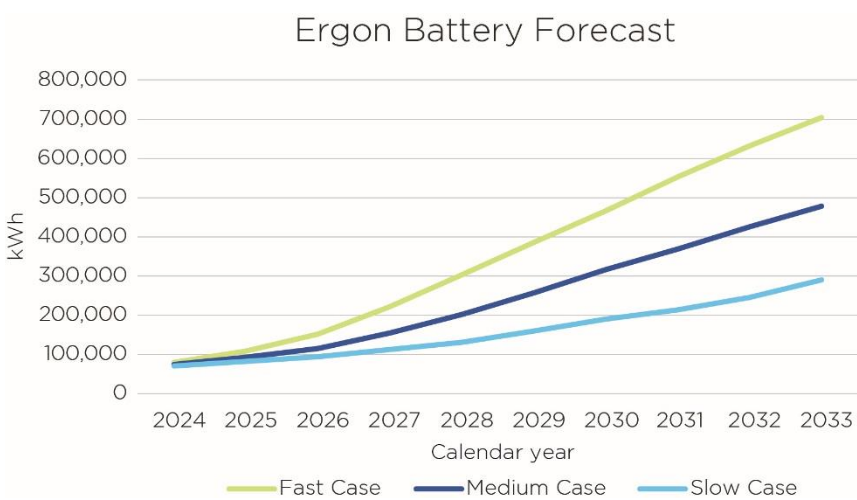
We expect energy storage will be a technology that more and more customers will invest in over the next decade.

With an expected decline in battery costs over time, the installation of varying sized batteries in Queensland homes and businesses will likely increase. Customers will be able to use the stored energy and avoid paying higher prices for network supply during peak periods. Customers may also consider exporting the stored energy to the grid during a peak period.

Electric vehicles also present a future opportunity for customers with the added advantage of mobile storage, with vehicle-to-grid charging having the potential for customers to store energy at one location and use energy at another. Another key driver for the increase in the capacity of storage systems, especially from 2028 onwards, is the addition of capacities from repurposed EVs.

Figure 9 provides the expected increase in behind the meter battery capacity over the next 10 years.

Figure 9 - Battery Forecast



3.4 Electrification of everything

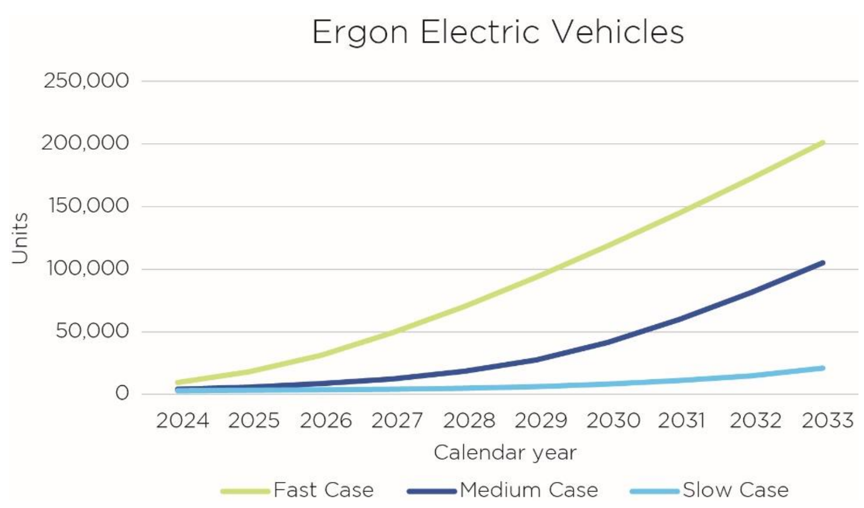
'Electrification of everything' is a critical component in the strategy to reach net zero emissions, and represents a range of difficult-to-forecast, customer driven responses to climate change that will impact future energy demand and volumes.

3.4.1 Electric Vehicles

The most commonly known response is the expected uptake of electric vehicles that has already commenced. Currently, the uptake rate of EVs has not been high due to a combination of factors including the high initial cost and low availability of various vehicle types. However, it is anticipated that EV uptake is likely to have a significant increase through time as a greater variety of vehicle types are on offer in the market and the cost of EV move closer to price parity with its Internal Combustible Engine (ICE) counterpart.

EVs will account for 50 per cent of all new vehicle sales once price parity is achieved. After price parity, EV sales will continue to grow in market share as uptake progresses along the technology adoption curve and the number of ICE vehicles available on the market decreases. While difficult to forecast, our forecasts build in the expected transition to electrified transport. This includes the transition of public transport and commercial fleets as well as privately owned vehicles.

Figure 10 - Electric Vehicles



Conversion from gas to electricity has the potential to change the electricity network load profile with higher demand in the winter (given gas is generally used to heat buildings in the winter). For example we expect to see electric hot water systems having a greater share of the market, as customers switch from gas to electric appliances.

A growing number of business and industrial customers are also setting net zero commitments, alongside state and national targets. Within this context, the progressive shift of many sectors towards electrification is expected to contribute to electricity's growing share of total energy consumption.

Our suite of network tariffs is responding to the uncertain but inevitable uptake in EVs by ensuring our structures incentivise the EV charging in periods that can deliver system benefits. This involves providing low off-peak (typically day-time) and shoulder rates to promote load shift alongside introduction across all tariff classes alongside new flexible load tariffs to provide customer choice between self-control or network control.

In the short term we see day-time EV charging as providing significant network benefits, but as EV technology advances to support two-way energy, the have the potential to reduce future expenditure should they choose to export into the network in the evening peak period. This contribution towards flattening the load curve and associated network expenditure reductions is explore more generally in attached Network Tariffs and Dynamic Controls report that explores long term network bill impacts.

3.5 Cost of living pressures

Queensland has experienced unprecedented challenges associated with the global COVID-19 pandemic and is now facing rising cost of living pressures. Customers have told us they are concerned with cost of living remaining high for some time. They want the energy transition to be affordable and fair, with greater choice that will allow them to reduce their energy bills.

However, customers do not want to place the burden to pay onto the next generation of customers because we have not acted today. We also need to consider the impact of the energy transition on energy inclusion, and advocate for outcomes that deliver for all our customers and communities.

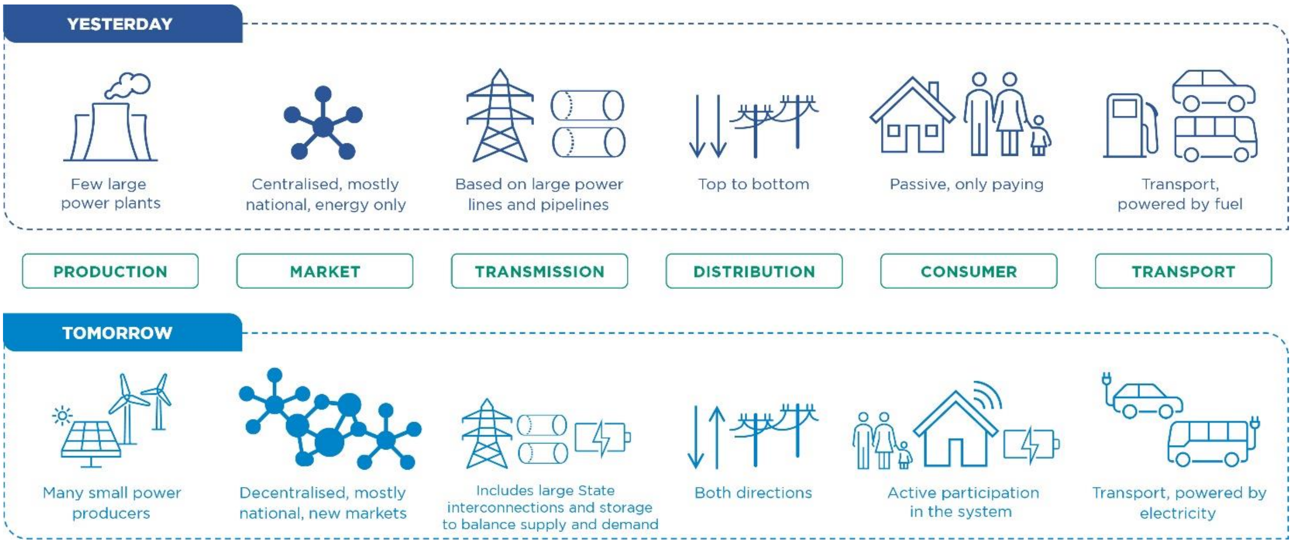
3.6 Other changes influencing network tariffs

3.6.1 A shift to a renewable energy future

Supplying energy to a home or business involves several different functions. Traditionally the energy supply chain has involved generating large amounts of energy from centralised locations (typically from gas or coal), transmitting the energy over long distances and then distributing to residential and business customers over smaller poles and wires. Much of Australia's supply energy infrastructure was built from the 1950s and onwards, meaning our traditional generation resources are rapidly approaching the end of their 50-year technical and economic life.

Almost two-thirds of the generation fleet in the National Electricity Market will retire by 2040 – with the majority of this fleet replaced by wind and solar generation backed up by storage and supported by rooftop solar. The decentralisation of large-scale and residential renewable generation is changing how the power system is managed and operated. The Queensland Energy and Jobs Plan as well as the Queensland Climate Transition Strategy represent plans to manage the transition from traditional sources of supply to renewables.

Figure 11 – The Energy Transformation



Renewable Energy Zones and CopperString

The Queensland Government Renewable Energy Zone (REZ) vision is centred around fostering a thriving clean energy economy, creating job opportunities across the state and reaching our renewable energy targets through coordinated energy infrastructure planning and investment.

REZ delivery will support Queensland industries to decarbonise and energise regional areas by ensuring benefits flow back to local communities. Through coordinated, transparent and collaborative development processes we will deliver on the broader vision of clean, reliable and affordable energy providing power for generations as outlined in the Queensland Energy and Jobs Plan.

Following announcements made by the Queensland Government, CopperString 2032 includes 1,100 km high-voltage electricity line from Townsville to Mount Isa that will connect Queensland's North West Minerals Province to the national electricity grid.

Reforms aimed at integrating distributed solar and storage

Over the last ten years the number of people taking advantage of the benefits of investing in rooftop solar has been so successful, that in some areas there was not enough available capacity to allow new solar connections to export back to the grid. These constraints made it less attractive for many customers to take up solar.

On 12 August 2021, the Australian Energy Market Commission (AEMC) made a final determination on updates to Chapter 6 of the National Electricity Rules (NER) and National Energy Retail Rules (NERR) to integrate distributed energy resources (DER) such as small-scale solar and batteries more efficiently into the electricity grid.

This included clear obligations on networks to support energy flowing in both directions and clarification that export services are a core distribution service. Networks must now plan for the provision and efficient pricing of export services now that the prohibition on export pricing has been removed.

Export Rewards Tariffs

The above changes have resulted in the need for us to develop and consult on strategies for transitioning to export tariffs and include the outcomes of this engagement in our TSS. We have obligations to explain our approach to transitioning toward export pricing over time. Following the rule change, the AER released Export Tariff Guidelines and explanatory statement in May 2022. The Guidelines provide information and guidance on the process for the development and approval of export tariffs.

3.6.2 Increasing smart meter population

A significant barrier to ensuring pricing structures can adapt to the pace of change in the sector has been limitations in measuring energy use for residential and small business customers. The majority of the customers still require network charges to be based on the total amount of electricity consumed over a specified period (flat volume tariffs). These customers have metering devices that have limited capability and are read manually at the customer's premises usually every quarter.

From 1 December 2017, with the commencement of the *Power of Choice* reforms, new customer connections will automatically have a smart meter installed through their retailer.

Smart meters allow us to record and charge for customer usage at different times of the day. This allows us to explore options for charging higher rates at times when we need to invest more and lower rates at other times. In 2020 we commenced tariff reforms for customers with smart meters, and this has resulted in more efficient network prices being sent to retailers for over a third of our customers. From 2025, we aim to build on the reforms already introduced, with improved pricing signals for peak and off-peak times of energy use, combined with more options for customers looking to reduce their bill.

During the next 5 years, our network will pivot to a new phase in electricity pricing, where the proportion of customers who will be able to receive and respond to more efficient pricing structures (through rollout of smart meters) will move from the minority to the majority. This change removes a key barrier that has slowed the pace of network tariff reforms needed to keep up with customer and energy market driven changes.

The current take up and mix of smart meters in our network is shown in Figure 12 and Figure 13 below:

Figure 12 - Customer Count by Tariff Type

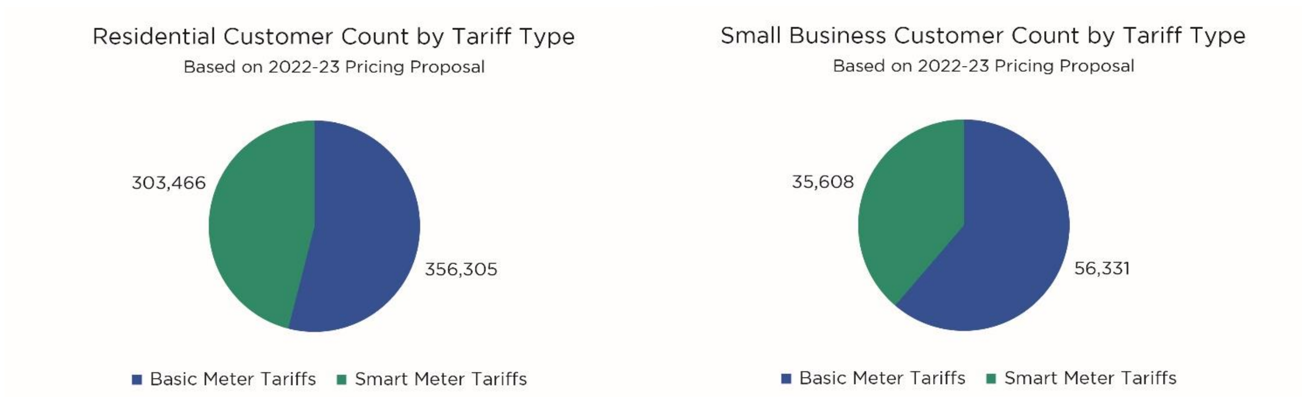
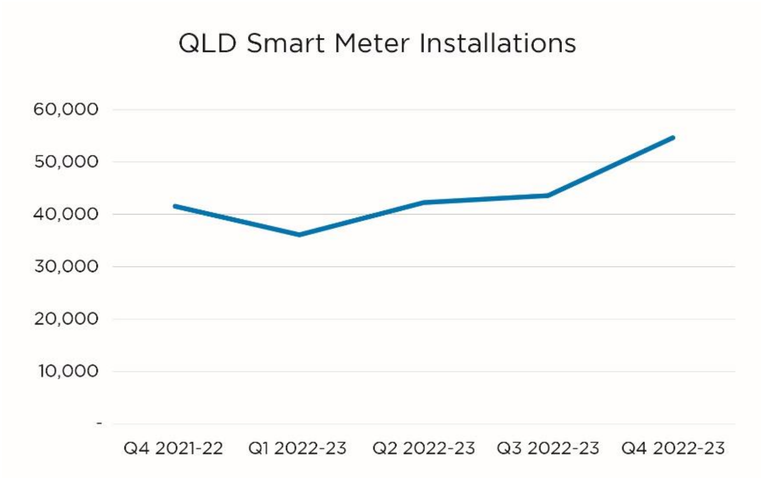


Figure 13 – Smart Meter Installations



Source – AER Quarter 4 2022-23 retail performance data

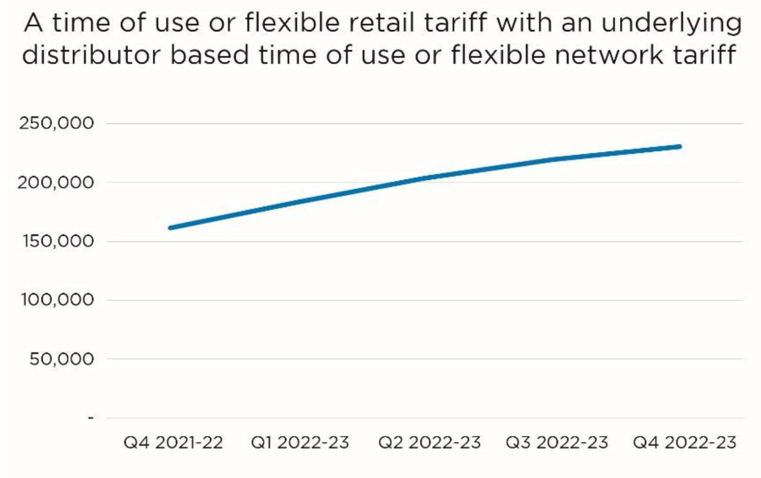
3.6.3 Retailer pass through of network tariff reforms in 2020-25

A customer's most regular interaction with the energy supply chain is usually through the payment of their energy bill to a retailer. A retailer's bill includes all costs associated with providing energy to the home or business, which includes Ergon Energy Network costs.

Customers in regional Queensland supplied by Ergon Energy Retail are assigned to a default regulated retail tariff that does not necessarily reflect the underlying network tariff structure we apply to the retailer. However, customers with smart meters have the option to move to different regulated retail structures that are more closely aligned to our network tariff structures.

Reporting provided by the AER in Figure 14 demonstrates an increasing number of customers in south-east Queensland are now seeing elements of the network tariff in their final retail tariff offering. While the Default Market Offer published by the AER continues to offer a traditional flat energy only retail structure, we see the increasing uptake of more cost reflective tariff offerings as Retailer support for our network tariff reform.

Figure 14 - QLD Retail Energy Market



Source – AER Quarter 4 2022-23 retail performance data

The proportion of customers in regional Queensland seeing the price signals of more efficient tariffs is much lower. This is because current arrangements allow customers to opt in to any changes which reflect the underlying network tariff structure. This means the vast majority of customers remain on the same tariff that they would have had with a basic meter.

3.6.4 Retailer take up of optional tariffs

Throughout the period, the bulk of our residential and small business customers are either assigned to our default time of use demand tariff or are assigned to a flat energy retail tariff if they have a basic meter. While retailers have assigned a small number of customers to the optional time use energy structure, we expect the majority of customers will remain on existing structures.

We will seek to further expand the customer benefits our time of use demand and energy tariff, and will continue to offer time of use energy tariffs through the 2025-30 Tariff Structure Statement.

The lack of transition to more cost-reflective retail tariffs in regional Queensland means that options which allow customers to save on electricity bills through load flexibility become important tools for managing future peaks and troughs in the network (particularly in the absence of direct price signals).

We further introduced new Primary Load Control Tariffs in 2020 which have seen promising uptake, primarily across agricultural customers in regional Queensland. We seek to continue with these tariffs as emerging technology becoming available expanding the value proposition for customers.

3.7 Emerging impacts and contingent triggers

We note throughout our Explanatory Statement the rapidly evolving nature of our energy landscape. With a lack of clarity on future environment, we have made a series of assumptions to underpin the formation of our TSS. The TSS outlines contingent triggers for change should changing assumptions prompt a larger impact on the equitable application of our TSS.

A contingent tariff adjustment relates to a change to a tariff or tariff parameter if a predefined event is triggered during the period occurs and warrants change to the tariff or parameter. Under a contingent tariff adjustment, changes would be made through the annual pricing proposal process and approved subject to the AER's approval of the trigger event and the change.

The following contingent triggers will apply in the 2025-30 period:

- Defer assignment of new customers to secondary two-way tariff from 1 July 2026.
    - Will be triggered if, as a result of technical or operational delays, residential and small business customers are generally unable to access dynamic connections across the network[3].
    - Annual pricing proposal will be amended so that assignment will commence in the pricing year following the availability of dynamic connections on the network.
- Defer assignment of existing customers to secondary two-way tariff from 1 July 2028.
    - Will be triggered if, as a result of technical or operational delays, residential and small business customers are not able to access dynamic connections in any part of the network[3].
    - Annual pricing proposal will be amended so that assignment will commence in the pricing year following the availability of dynamic connections on the network.
- Bring forward introduction of residential and small business demand tariffs to 1 July 2027.:
    - Will be triggered if, as a result of significant uptake of EVSE charging resulting in more dynamic and variable evening and weekend demand[4].
    - Annual pricing proposal will be amended so tariff is available earlier in the period.
- Withdrawal of network tariffs with limited take up throughout the period.
    - Will be triggered if, as a result of smart meter roll out, there is significant migration away from basic and retired network tariffs, for example, Wide Inclining Fixed Tariff (WIFT)
    - For the WIFT, we may seek to align band rates to support transitional arrangements.
    - Re-assignment to the relevant default tariff

4 ADDRESSING OPPORTUNITIES AND CHALLENGES FROM CHANGE

4.1 Impacts of change

A key role in delivering distribution network services to our customers is to ensure there is enough capacity to supply every household and business on the days when electricity demand is at its maximum, no matter where they are located across our distribution area. In more recent years we have been focussed on ensuring we have enough capacity to accept the growing distributed solar energy that our customers export each day.

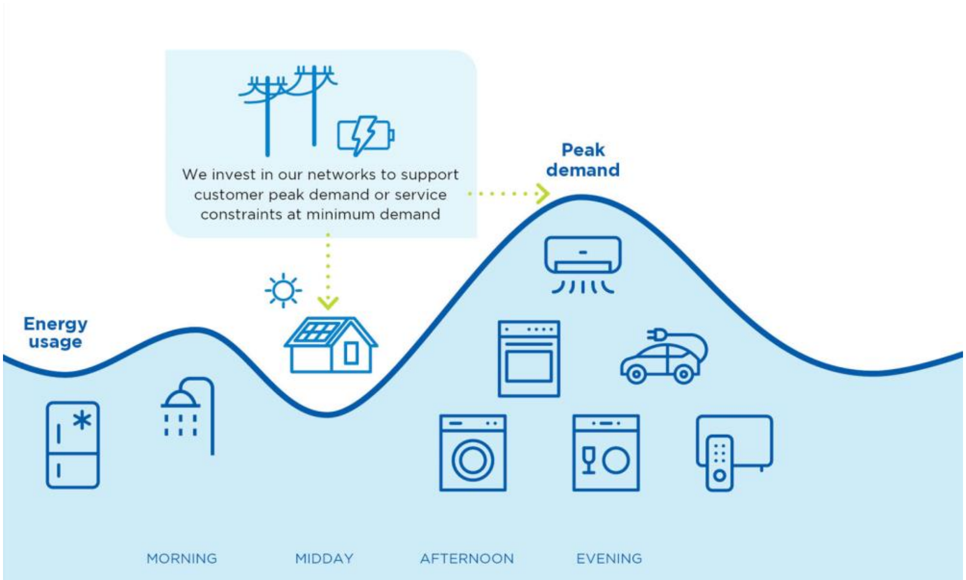
A common feature of all networks is the fact that usage of the network (either to export or to import) occurs are different times of the day. Common periods of high use can differ by location. The common 'peak periods' often define times of likely future investment. As more and more customers connect to our network and more appliances are used in the peak demand window, the

[3] We expect that there may be some parts of the network where dynamic connections are not available – the trigger would only occur where there is no availability of a dynamic connection to residential or small business customers due to technical or operational reasons.

likelihood that we will need to invest in additional network infrastructure to support growth in this period also increases.

Figure 15 provides an example of a residential usage load profile.

Figure 15 – Usage Load Profile



4.1.1 Forecast Peak Demand

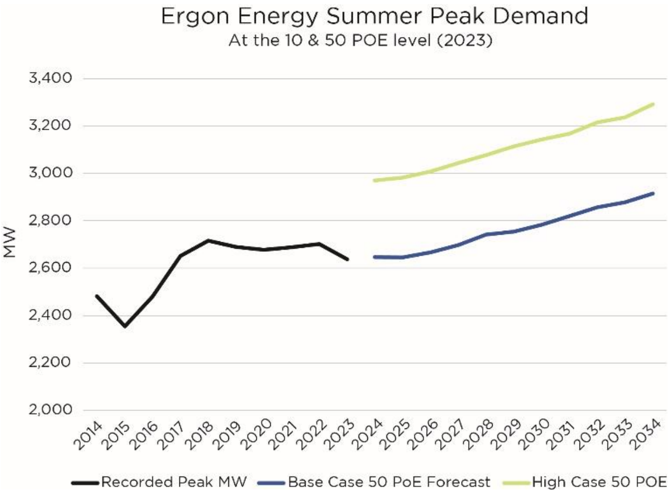
System maximum demand is a measure of the overall growth of load on the network. Maximum demand at a system level provides a useful indication for trends in peak demand across our network. Historically, temperature was the major variable on peak demand (after systematic factors such as time of day and day of year). However, the increasing scale of solar PV generation means that this variable has a strong influence on network peaks.

While the growth of solar PV generation has reduced the midday network load, the peak is relatively unimpacted as it occurs close to sundown. Cloud cover can also create variations in generation output (and net system load) greater than what would otherwise be seen from temperature changes.

Looking forward, system maximum demands are expected to occur outside of the solar PV generation times and, as a result the continued growth of solar PV, will not have any real effect on the annual peaks in future years.

The Ergon Energy Network System Peak Demand measurements and forecast is in the figure below:

Figure 16 - Forecast Demand

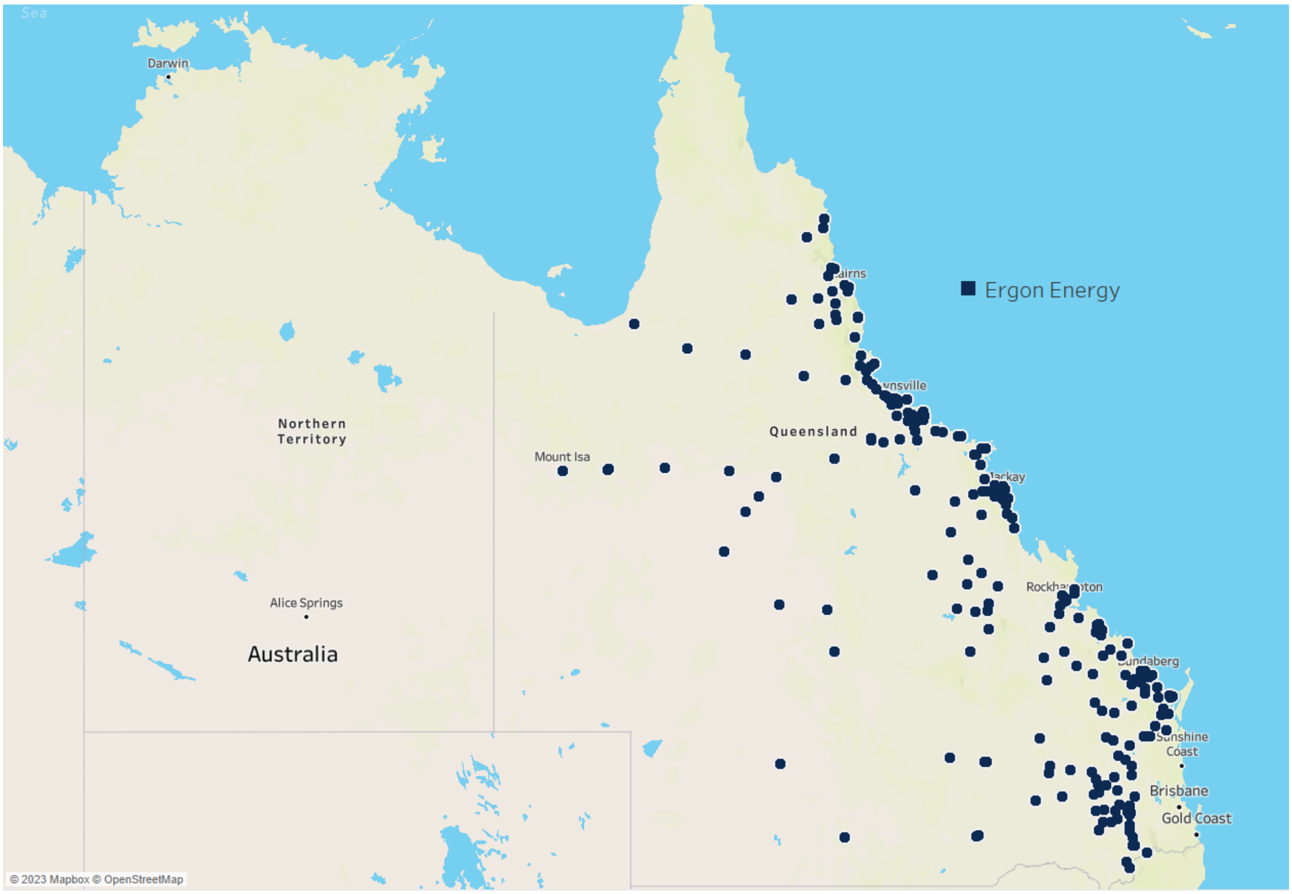


Ergon Energy Network's summer system maximum of 2,637 MW occurred between 6:30 pm and 7:00 pm on the 13th of February 2023.

There are significant challenges associated with setting time of use windows for a distribution network. Network costs are driven by investment in individual assets in different parts of the network, and at different voltage levels. While system peak demand can be informative of overall trends, zone substation and Feeder Maximum Demand forecasts are more commonly used to identify emerging network limitations in the sub transmission and distribution networks.

We analysed the timing of peak demands at all 293 zone substations in Ergon's area.

Figure 17 - Zone Substations



Demand peaks in different parts of the network are not necessarily coincident. They can vary by location and customer mix (industrial and residential). Setting a single time of use window for an entire distribution network area necessitates trade-offs and can only ever be approximate.

Our primary focus was on the evolution of historical intra-day demand profiles to inform the likely timing of peak and minimum network demands for the 2025-2030 financial years. This involved historical and forward-looking analysis. Based on this analysis we found:

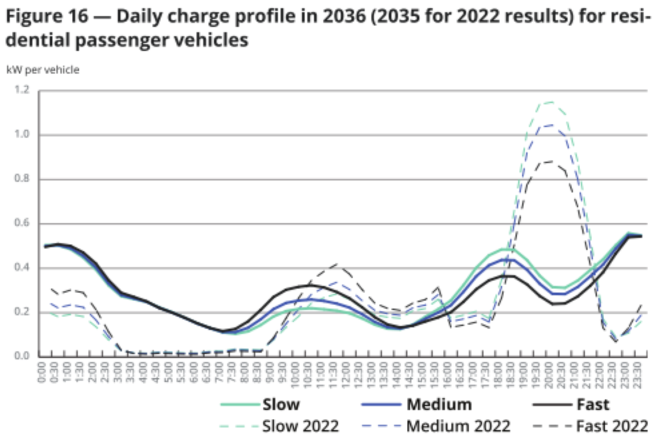
- Historical peak demands across substations have become more concentrated over the past 10 years, typically occurring around 7 pm.
- Future peak demands are projected to occur slightly later, typically occurring around 7:30 pm over the period 2025-30.

Overall, the evidence suggests the current timing of the peak and off-peak windows are broadly appropriate for 2025-2030. Projected peak demands are likely to be concentrated in the peak window. However, the case for change toward a narrower peak window was tested with different customer groups against customer impacts and preference with outcomes based on customer preferences against different trade-offs.

Electric Vehicle impact on peak demand

Mainstream adoption of EVs has the potential to increase energy and demand forecasts in the future. The impact factored into the forecasts is low initially but increases over time with the growing population of vehicles. EVs are not expected to provide much offset for minimum demand due to the differences in timing between vehicle charging and peak solar PV generation.

Figure 18 - Daily Charge Profile



While EV take up today is low, it is growing significantly each year, with many homes expected to have an EV with a dedicated home charger, known as Electric Vehicle Supply Equipment (EVSE) by 2030. A typical 'wall box' EVSE typically consumes around 7kW of load – equivalent to almost double the typical peak load of the average residential premises. We need to plan for a future when EVSE ownership is far more common than it is now to minimise the risk to the network, at the feeder level and higher in our network.

EVs represent both a potential risk and opportunity in the management of the electricity network. The opportunity comes from the increased network utilisation, which can help put downward pressure on network tariffs, along with greater ability to manage our minimum demand with increased day time load. We're further anticipating the opportunity for EVs to interact with two-way tariffs allowing EV owners to participate in these tariffs without the need for the installation of solar PV.

4.1.2 Minimum demand

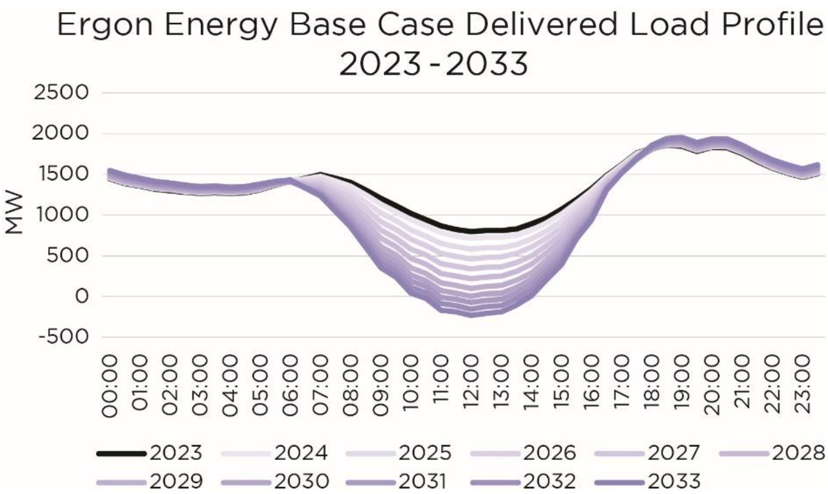
The rapid growth of solar generation from house rooftops and solar farms during daylight hours is resulting in the need to manage new and rising challenges relating to minimum demand on the network. Minimum demand can best be described as the lowest energy demand across an electricity network at a point in time.

Analysis of our zone substation data shows that:

- Historical minimum demands at most substations have shifted from overnight to being heavily concentrated in the middle of the day, mostly occurring in the period 11 am – 1 pm.
- Forecast minimum demands are expected to continue to occur in the middle of the day in 2025-30.
- Our forward-looking analysis suggests that the timing of minimum demand is unlikely to change significantly in the future.

Our forward-looking analysis (Figure 19) suggests that the timing of minimum demand is unlikely to change significantly in the future.

Figure 19 – Minimum Demand



Left unmanaged, lower minimum demands (particularly when experienced with high demands at other times) can create issues around local power quality that can be harmful to customer appliances as well as the network.

We are also experiencing day-time minimum demand windows which are creating reverse power flows in localised parts of our networks. Reverse flows can impact power system security, threatening its ability to withstand major events. We may need to invest in more infrastructure to manage the additional energy being exported to the grid. Alternatively, we can look at options that 'soak-up' the generation from solar and put it to good use for customers.

4.1.3 Greater participation of customer energy resources in markets

The Queensland Energy and Jobs plan recognises the increasing contribution that customer energy resources will make to future energy systems and markets, providing an opportunity for customers to participate in a number of ways. As a minimum we recognise that pricing arrangements will need to adapt to a more complex grid supplying the energy system of the future and the markets that support this energy system.

We recognise analysis underway to understand the roles and responsibilities for a Distribution System Operator in Queensland. We await the outcome of this analysis and the likely need for further network tariff reform.

We anticipate that this will lead to greater customer benefits of digital transformation and distributed energy resources allowing for greater network tariff opportunities.

4.1.4 Changing connections standards

Queensland Electricity Connection Manual (QECM)

As the energy transition gathers pace and more renewables are connected to the network, updates are required to ensure the Queensland Electricity Connection Manual (QECM) reflects changing customer needs, while we continue to provide a safe and reliable network.

Updating the QECM allows our technical requirements to evolve to support network access for our customers, as they embrace new energy technologies. Our network tariffs complement the QECM.

Our QECM Version 3 requires that single phase EVSEs greater than 20 amps (4. 6kW) must be able to be managed by the DNSP. Currently this control is limited load control on a separate meter. However, dynamic control options are likely to be available in future QECM revisions. Our tariff options are also being expanded to meet customer need.

Dynamic Connections

A Dynamic Connection is a new connection option for solar PV, battery and electric vehicle (EV) charging installations. It allows more excess energy to be exported at most times, while ensuring we maintain a safe and reliable electricity network at times of congestion.

Dynamic Connections avoid imposing static limits in some geographic areas allowing customers to export excess energy to the grid, even where the local area is already considered saturated with solar connections. Importantly, dynamic connections allow more solar capacity to be hosted on the network, often without the need for investment in additional infrastructure. Dynamic Connection approaches are included in our connection manuals (QECM) and relate to how the network may communicate with our customers in different periods, for example, times of congestion.

4.1.5 DER Integration strategy

This DER Integration Strategy has been compiled to provide a collective view of the various strategies and approaches allowing widespread DER integration into the distribution network. The strategies cover investments in network and non-network initiatives including ICT in the current and 2025 – 2030 regulatory periods. Investments in the 2025 – 2030 period will have a critical impact on our ability to plan, operate and maintain our networks and business well beyond 2030 as they adapt and transform to accommodate the technical, regulatory and market environments.

Without reform, customers face increasing power quality issues and curtailment of their exports, along with increased investment (and prices) to meet increasing peak demand and peak exports. Unlocking the generation potential of DER will enable us to achieve the safety, power quality, reliability, and capacity standards that customers and stakeholders require at the lowest cost. This strategy outlines how we intend to manage DER on our network, including:

- our forecast uptake of DER and associated exports
- why we need to adapt our business for the increasing uptake of DER
- our toolkit of solutions for integrating and managing increasing DER and how they work together to deliver a prudent and efficient customer solution
- our activities and expenditure in the current regulatory period to manage DER
- how our DER integration related solutions are reflected in our 2025–30 Proposal.

4.1.6 Demand Management and other strategies

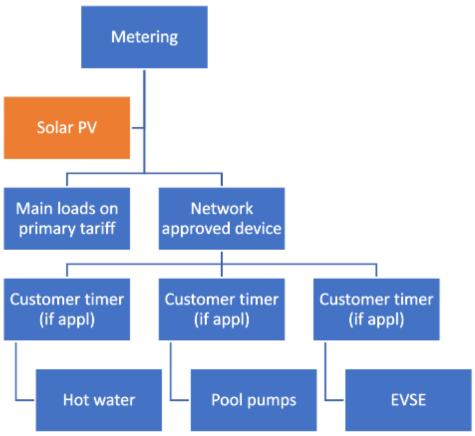
Demand management is the active management of energy to match the consumption of electricity with its generation. This means using energy efficiently; using less or generating more in peak demand times and shifting energy consumption to low demand periods (e. g. into the middle of the day when there is plentiful renewable generation). Demand management is implemented by customers or demand management providers, either in exchange for financial incentives or as a required part of a connection agreement.

Our demand management (DM) Program works in conjunction with other strategies to ensure we can effectively integrate renewables and enable the electrification of transport, while also continuing to ensure safe and reliable operation of our networks. Energex and Ergon Energy Network's customer DM program is the largest in Australia with over one million participating appliances, including hot water systems, pool pumps and air-conditioners.

Many of our DM initiatives are delivered through controlling a portfolio of appliances at homes and businesses to manage system wide and localised network issues. Our current flexible load tariffs make supply available to residential and small business customers at a lower energy rate for specified appliances (mostly hot water heating and pool pumps but in some circumstances applies to the entire connection). In return, Ergon Energy Network can control when the supply is made available for a certain period each day based on the terms and conditions of the tariff.

Figure 20 provides a summary of our load control strategy:

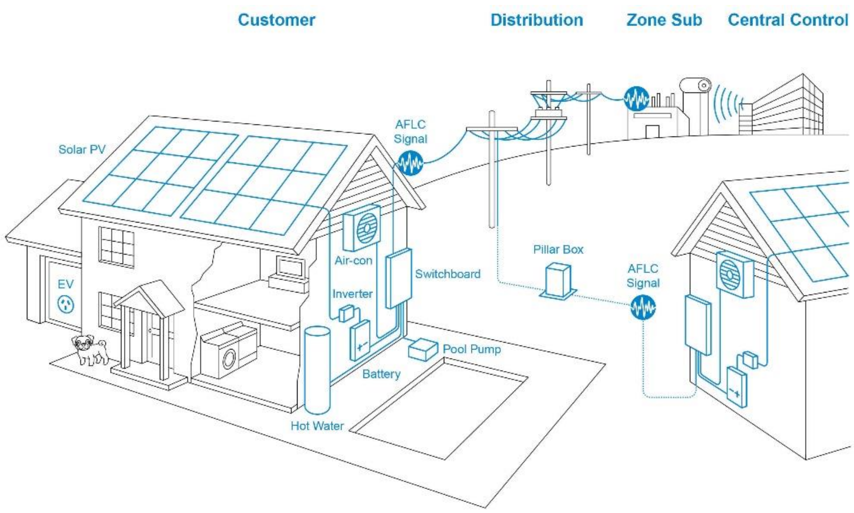
Figure 20 – Load Control Strategy



- Non-interruptible and interruptible circuits
- All consumption charged at primary tariff rates.
- Customer timers do most of the appliance control, for customers to optimise their PV and/or tariff
- Network device does ultimate control of loads:
  - Switched on "as needed" basis (similar to current "Tariff 33")
  - Network device has 3 "slots" – equipment, at the same premise, can be switched independently according to priority/need
- Customer incentive is built into the primary demand tariff daily charge – effectively a 'copy' of the primary tariff, with a lower daily charge.

Figure 21 below shows the operation of load control through the network.

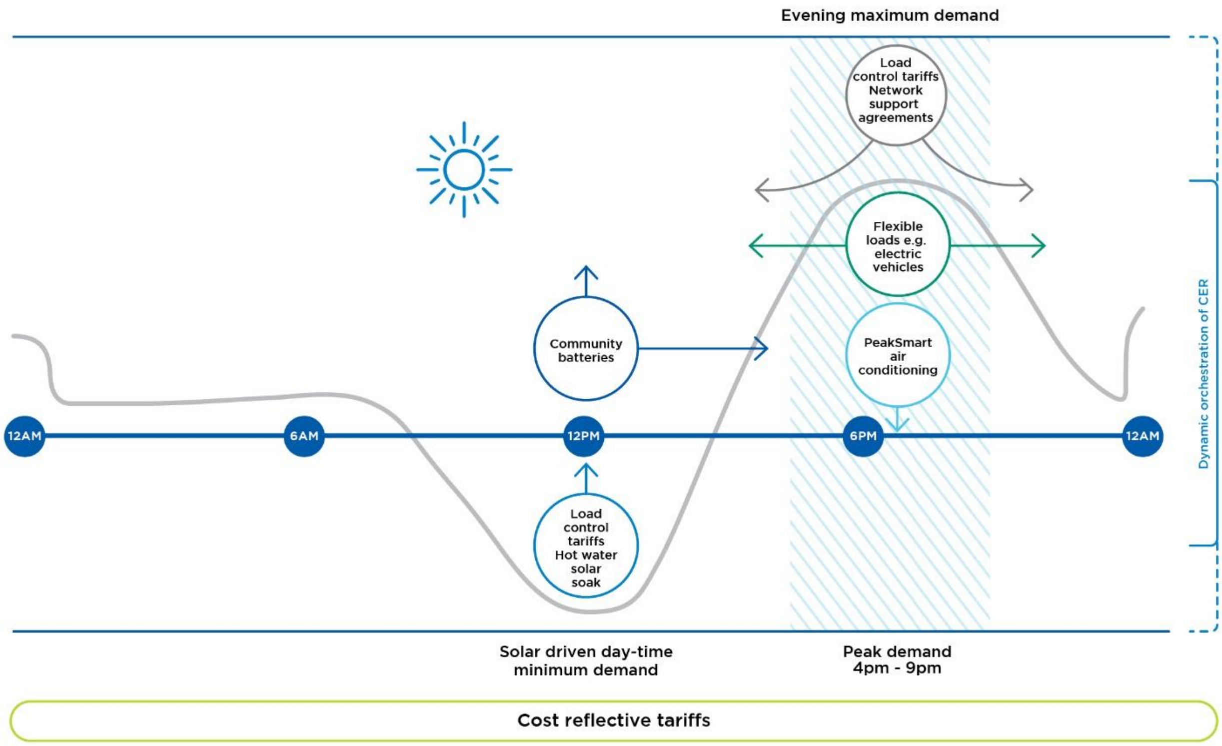
Figure 21 – Overview of existing load control



Our load control implementation links with other corporate strategies and activities, including:

- **Future Grid Roadmap** – our blueprint for evolving our network to be the network of the future.
- **Demand Management Plan** – our annual strategy and tactics to deliver network demand management programs and initiatives.
- **Dynamic Customer Standards –** we have implemented connections standards for Dynamic Connection which is smarter connection option for solar PV, battery and EV charging installations helping to maintain a safe and reliable electricity network.

Figure 22 – Load Control Load Shift



Changes in customer use and impacts on load control initiatives

Residential customers with rooftop solar PV and home charging of EVs have told us that they want to maximise the self-consumption of their solar generation to reduce their electricity bills and environmental impact.

Existing tariff options do not enable this as they are metered and billed separately from the household's primary load and generation. In response customers are moving equipment that was connected to the secondary load control tariff, to their primary tariff.

Electricians and rooftop solar PV installers are also advising customers to rewire and connect their hot water circuit and other loads previously connected to secondary tariffs, to the main element of the meter in order to maximise the value from their solar PV.

We are experiencing a decline of around 2 to 3% each year of load connected to load control tariffs. This trend may continue if customers see more benefit from offsetting their consumption with self-generated energy than the value they gain from lower prices with flexible load tariffs from their retailer.

4.2 Stand Alone Power Systems

The energy industry is facing unprecedented change and we need new ideas and new ways to tackle the challenges this presents to the way we build and operate our network. Our Stand Alone Power Systems (SAPS) initiative is a great example of fresh thinking that delivers a safe, affordable, reliable energy solution for both the customer and our network.

A SAPS is a great alternative to replacing aging network where perhaps we run a long SWER line to service one or two customers. It contains solar, batteries and backup diesel generation. These systems have enabled us to deliver power in areas with impassable access, following fire/storms/flooding, or even reducing our impact in sensitive ecological environments.

We will continue to offer our current suite of network tariffs to SAPS customers to ensure that these customers are treated no less favourably to our grid-connected customers.

4.3 Network Tariff Reform and its contribution to change

4.3.1 Summary

Network Tariff Reform complements other key initiatives aimed at ensuring our customers can navigate to a smarter, renewables enabled grid, while driving efficient cost outcomes and efficient and fair prices for our customers.

Electricity pricing is a critical consideration in achieving both efficiency and fairness for all customers. While less than a third of the average residential bill, network tariff reform – in terms of structure and allocation – is seen by customers regulators and policy makers alike as a change agent to delivering on efficiency and fairness outcomes.

More efficient tariff designs seek to align higher charges for using energy to the periods most likely to result in additional investment. This ensures that the recovery of future investment is allocated more to customers who use the network at peak times. If more customers, in response to higher charges during this period choose to use less energy at peak times to have money, this is likely to defer the need for future investment, keeping network costs lower for all customers.

Finally, because our revenues are capped, prices set higher to recover more revenue in peak periods must be offset by lower prices in other periods, providing even better signals for customers to move use outside of peak periods.

During the next 5 years, our network will likely pivot to a new phase in electricity tariff design, where the proportion of customers who will be able to receive and respond to more efficient pricing structures (through rollout of smart meters) will move from the minority to the majority. This change removes important barriers that for some time has slowed the pace of network pricing reform relative to other changes in the sector over the last decade.

However, with all change comes impact. Our tariff reforms have been tested with customers to ensure the pace of change is proportional to customer preferences and concerns regarding impact.

Figure 23 – Network Tariff Reform Environment

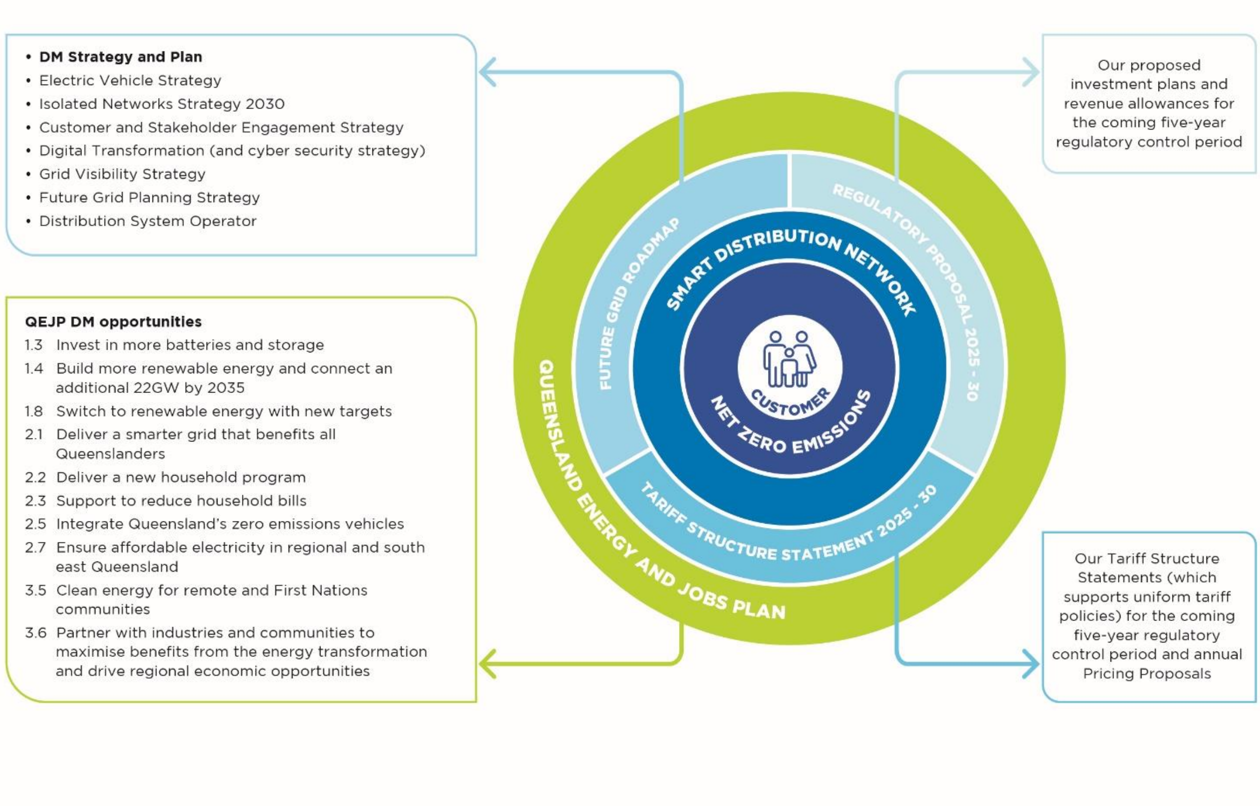
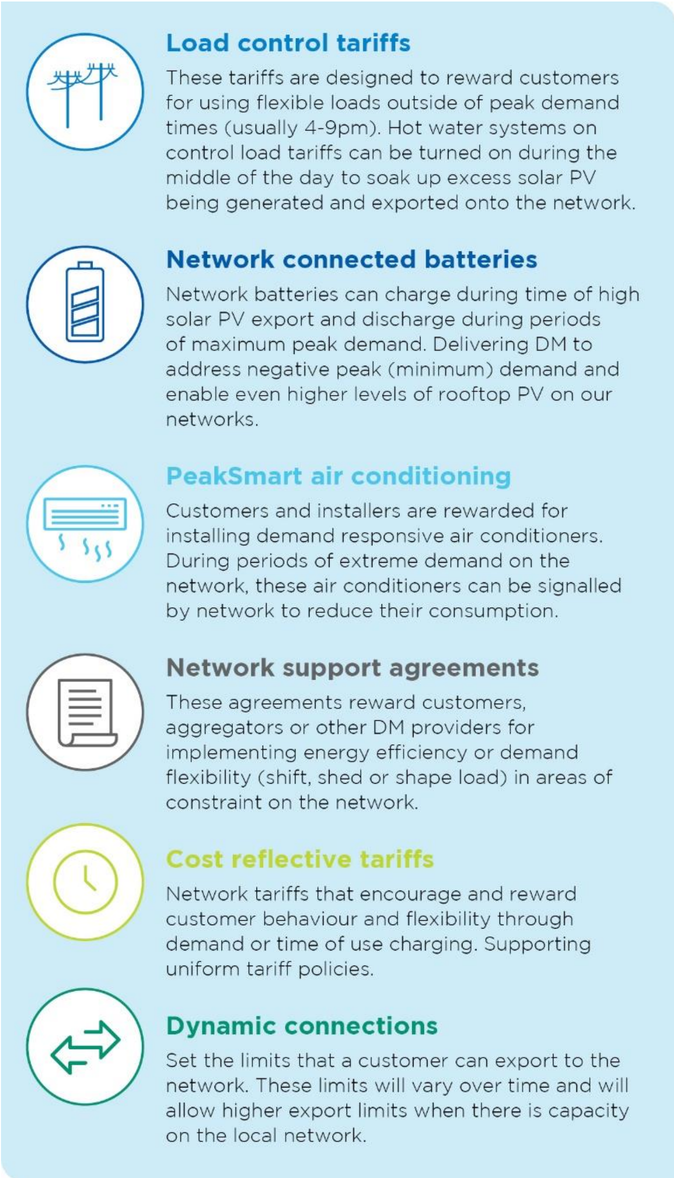


Figure 24 – Network Tariff Reform Opportunities



4.3.2 Forecasting the reduction in future network costs linked to Network Tariff Reform

Policy makers and regulators rank transitioning to more efficient network tariffs high on the agenda of key market reforms on the basis that more efficient pricing of the network promotes more efficient use of the network and has the potential to reduce the need for efficient investment over the long term.

Our Network Pricing Working Group encouraged us to work our way to demonstrate to customers why changes now will benefit customers over the long term.

We engaged Dynamic Analysis to model long term expenditure outputs that result from different scenarios of price responsiveness and dynamic load control. Their analysis suggests:

- Tariff reform provides more equitable outcomes in that changes in behaviour reward both the customer in terms of lower prices and the network in terms of less pressure on peak demand.
- Tariff reform has benefit for all customers over the long term, compared to no change especially when incorporated with dynamic control and load flexibility.

5 ENGAGING WITH CUSTOMERS

5.1 Summary

In this section we outline how our engagement has informed the development of the proposed tariffs for the 2025-30 regulatory period. Customer input and preferences regarding network tariffs have been a key focus of our engagement due to the significance of potential changes for network tariffs and the likely impacts from those changes.

Our TSS and proposed tariff reforms have been influenced by the perspectives gained from the variety of engagement sessions with different customers and stakeholders across each of the customer segments.

We commenced our tariff engagement in 2021, to develop the initial approaches towards refining network tariffs, customer impact framework and customer education. We have built on these initial works to develop a firm basis of knowledge to deliver an extensive engagement program across a range of customer segments, customer and industry representatives. This included expansion into dedicated engagement streams for residential and business customers as well as retailers.

Table 2 below provides an overview of the phases of our engagement, together with the different forums used for tariff engagement and the deliverables or outcomes of the engagement.

Table 2 - Overview of engagement and outcomes

Engagement Phase	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Phase 6
Engagement Phase Title	Gather & Plan	Listen	Share & Explore	Test & Revise	Finalise	Future
Time Period	By end of 2022	Feb – June 2023	June– August 2023	Sep 2023 – Jan 2024	April – Sep 2024	April 2025
Engagement	• TRWG Workshops • Public Lighting Forum • 1:1 Customer conversations – residential	• TRWG Workshops • Queensland Household Energy Survey • Energy Retailer – Individual conversations	• VoC Panel – Customer Consultation • Energy Retailer Forum • Large Customer Forum • NPWG • RDP2025 Stakeholder Forum • Customer Focus Group • Talking Energy – Queensland's Energy Future Survey • 1:1 Small Business Customer conversations	• Draft Plan Webinars • Large / Major Customer Forum • VoC Panel • Retailer Forum • Customer Focus Groups • NPWG • Industry Group Meetings • 1:1 Conversations	• Large / Major Customer Forum • Retailer Forum • NPWG • Industry Group Meetings • 1:1 Conversations • Customer Focus Groups	
Topics	• Public lighting tariffs • Tariffs, price signals, and incentives for modifying how and when electricity is used.		• Network tariff structure engagement themes and tariff options • Proposed tariff changes • Proposed new tariffs • Pricing windows • Load control	• Overview of Draft Plan Priorities, Revenue and Tariffs • Customer Impact Analysis • Proposed new tariffs • Network tariff structures • Public lighting tariffs • Storage tariffs • Tariff assignment • Review of draft TSS	• Evaluate customer and stakeholder feedback to the AER Issues Paper • Review of tariffs • Customer Impact Analysis	
Output			• Engagement report – Retail forum, CAC/ICC Forum. Sac Large forum, NPWG, RDP2024 Stakeholder Forum, Customer Focus Groups • Small business research report	• Draft Plan • Draft Plan Feedback • Engagement Report – SAC Large forum, Major Customer Forum, VoC Forum, Retailer Forum, NPWG, Customer Focus Groups • Regulatory Proposal and TSS	• Revised Regulatory Proposal and TSS	

5.2 Gather, Plan and Listen Phases (Oct 21- June 23)

5.2.1 Overview

In anticipation of the evolving needs and expectations of customers we commenced our network tariff engagement as early as 2021 to develop the initial approaches towards the development of network tariffs that would cater for future customer and market needs.

Feedback from AER and customers was that capacity-based tariffs (proposed in our 2020-25 TSS) are a significant evolution from the suite of network tariffs currently on offer. In response we commenced meaningful education and engagement program around tariff changes across a range of customer segments, customer and industry representatives.

In this early phase of engagement we wanted to understand and address key customer priorities around affordability and value, enabling a smart and resilient electricity network, managing the energy transition, and making customer service better. These insights were important for how we prioritise and implement network tariff reforms into our pricing structures.

5.2.2 Tariff Reform Working Group - Residential

Established in October 2021 and consisting of several customer and stakeholder representatives, our Tariff Reform Working Group – Residential (TRWG-R) was specifically tasked with working in partnership to co-design a potential new network tariff for customer trial in 2022-23.

Insights from the first few months of the tariff trial were considered and in May 2023 we ruled out the potential adoption of a ‘capacity’ based network tariff for residential and small business customers in the 2025-30 regulatory control period. It became clear through the tariff trial that the concept of a ‘capacity’ based tariff was too difficult for customers to understand and respond to. There was a stronger preference for the focus for engagement to move to Time of Use charging, load control, two-way tariffs (exports tariffs) and the pace of tariff reform.

In July 2023 the TRWG-R evolved into a new Network Pricing Working Group (NPWG), created to support the wider tariff engagements required of the Regulatory Proposal. The NPWG has brought together both residential and business customer representatives for coordinated in-depth network pricing discussions.

5.2.3 Customer interviews on tariffs

As part of our engagement with residential customers around tariffs we also undertook 15 interviews with individual customers in December 2022. We engaged independent consultants, Vocatif, to undertake research interviews with the aim of better understanding opinions, knowledge and needs of residential electricity customers regarding tariffs, price signals and incentives for modifying how and when electricity is used. This research was important in helping us assess both the gaps and opportunities when considering residential tariff reform.

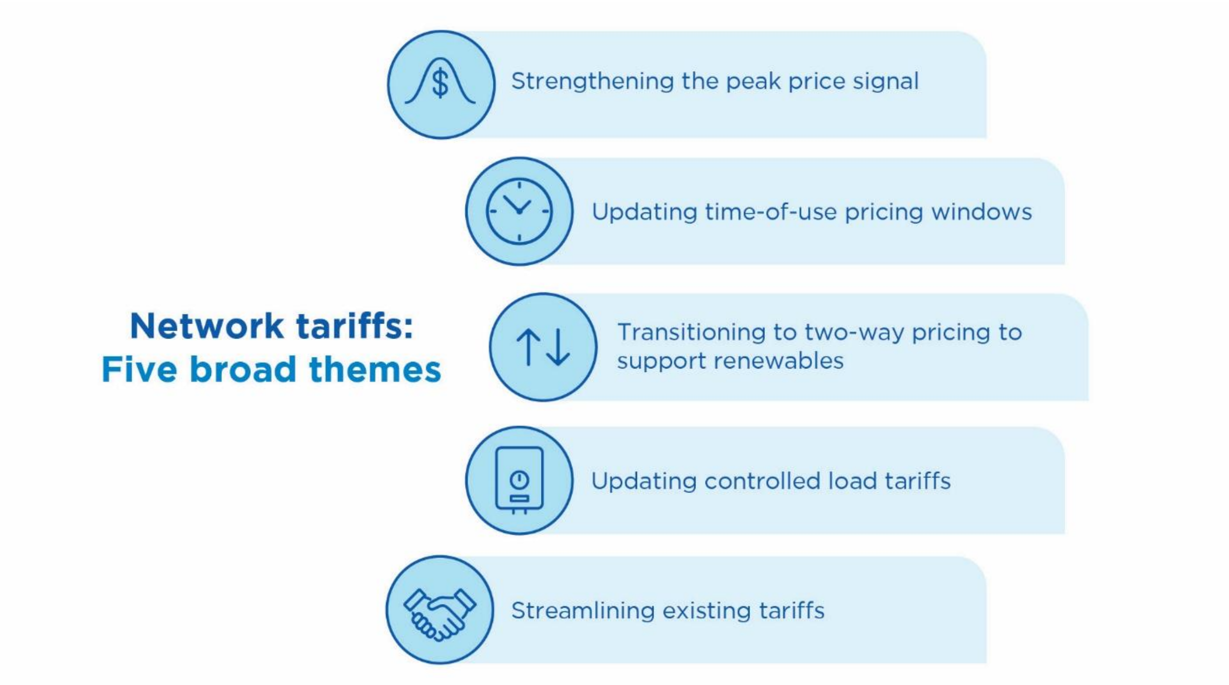
5.3 Share and Explore Phase (June-Sep 2023)

5.3.1 Summary

Section 4 above outlines a range of change factors driving the need for further reform of network tariffs. Our engagement with various customer groups provided initial context around these change factors, noting the acceleration of change in the last decade has been unprecedented. We also provided context as to the role and impact of network tariffs in the context of the retail bill, the reasons why efficiency in tariff design is important and why, historically, network tariff changes have not kept up with broader changes in the sector.

This context of change allowed us to centre our engagement around the pace of change in the context of customers' own perspectives and circumstances. We engaged with different customer groups on specific issues relating to tariffs they were assigned to, which can be categorised into five broad themes (refer to Figure 25 below):

Figure 25 – Engagement Themes



Customers were asked to trade-off different preferences in the context of the pace of change according to each theme:

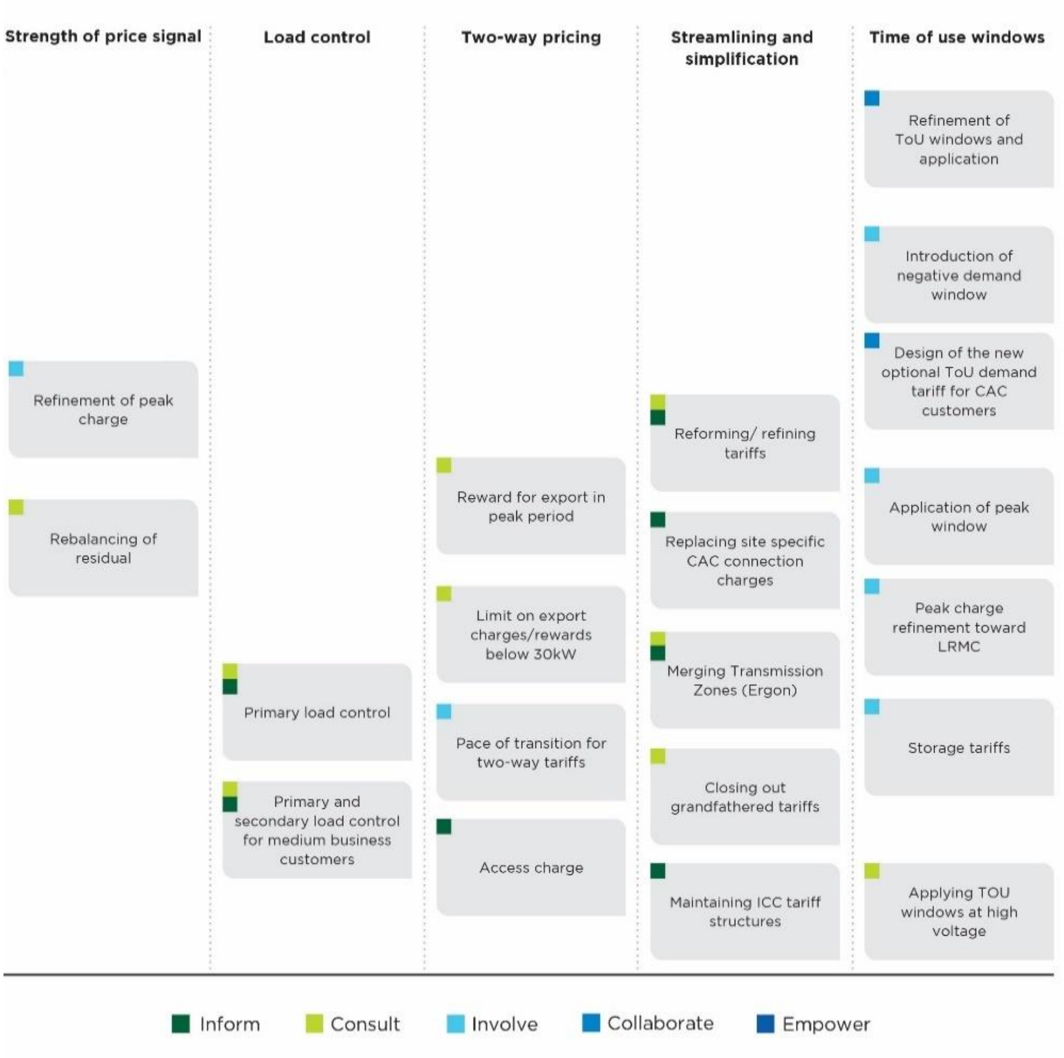
- **Strengthening of the peak price signal** to ensure residential and small non-residential tariffs better reflect the costs when demand on our network is highest.
- **Updating our ToU pricing windows** to provide customers with more accurate price signals about the costs required to service demand at different times of the day, including both evening peak and day off-peak periods.
- **Transitioning to two-way pricing** for low voltage customers to encourage exports during peak demand periods and self-consumption during the day.
- **Updating our controlled load tariffs** to ensure they continue to remain relevant to customers and to maximise the benefits for the network.

- **Streamlining our existing tariff offerings** to make it easier for retailers to pass through our tariff structures and for customers to understand and respond to our price signals.

Network tariff design is inherently complex and the scope of potential issues quite broad. It was important for meaningful engagement that we focussed on areas of change where customers could participate and influence outcomes. We worked with our Reset Reference Group on priorities for engagement on network tariffs and used the IAP2 Spectrum of Participation to assist us in prioritising our engagement tasks.

Figure 3 below depicts the various engagement topics mapped against the five engagement themes and the impact to revenue. Topics which had the potential for greatest customer influence and have the greatest impact in terms of outcome were prioritised against those with less potential for influence or had lesser outcomes.

Figure 26 – Mapping of engagement topics against engagement themes



Our engagement activity reflected the above topics but consistent with broad objectives to understand customer preferences to the pace of change across the five broad themes. Figure 27 below outlines the timetable of engagement for the second phase of engagement:

Figure 27 - Engagement Themes

5.3.2 Summary of feedback from customer groups

From the extensive consultation and engagement across the various customer and stakeholder segments, Table 3 below provides an overview of the feedback provided mapped against the five engagement themes:

Table 3 - Summary of feedback provided against engagement themes

Strengthening of the peak price signal	Updating our ToU pricing windows	Transitioning to two-way pricing	Updating our controlled load tariffs	Streamlining our existing tariff offerings
Residential Customers				
Ergon VoC Panel suggested educating consumers on how they can manage their electricity usage to allow them to benefit from on and off-peak times.	Ergon VoC suggested seasonal ToU tariffs and cheaper tariffs on weekends.	Preferred delay of two-way tariffs until ToU tariffs are in place and reviewed. The majority of VoC Panel wanted Ergon to build up the pace of tariff reform.	The Customer and Community Council encouraged expansion and promotion of controllable load options.	VoC Panel recommended tariffs should be simple and easy to understand.
Small Business Customers				
Many interviewees preferred to prioritise business activities over energy reduction. Some indicated they would only modify behaviour after receiving an abnormally high bill.	The majority of respondents preferred the 5-9pm peak window and 11am-5pm negative demand window and want them to only apply on weekdays.	Most small businesses are not in a position to install solar or batteries. Many customers disliked the idea of being charged for exporting energy.	Generally, small business customers were unaware of load control tariff options. Businesses disliked the idea of losing flexibility and felt it may impact their customers' experience.	Small business customers wanted details on the process of tariff retirement so they can be prepared. Small business customers believed that more tariff options meant cost savings for their businesses.
SAC Large				
Minimal changes – no engagement.	SAC Large customers were most comfortable with the 11am-1pm negative demand window and 5-8pm peak window. Preferred refinement of one tariff structure to accommodate additional windows.	The majority of SAC Large customers either did not support the 30kw limit for export, or feel they needed more information. The majority of SAC Large customers preferred implementation of two-way tariffs from 2025.	The majority of SAC Large customers supported primary and secondary load control tariffs.	Most SAC Large customers were comfortable with transitioning to a new tariff that applies to all customers.

Strengthening of the peak price signal	Updating our ToU pricing windows	Transitioning to two-way pricing	Updating our controlled load tariffs	Streamlining our existing tariff offerings
CAC				
Not applicable.	Preferred longer negative demand (11am-4pm) and peak demand windows (4-9pm). Preferred opt-in ToU demand tariffs for existing customers.	Ergon CAC customers were only slightly comfortable with deferral of export charges and rewards.	There was not strong support for modifying or expanding existing primary or secondary load control tariffs for medium businesses. High voltage and prospective storage customers expressed a preference for a specific tariff to recognise new technology that will dispatch stored energy.	Majority of Ergon customers were comfortable with the removal of grandfathered tariffs.
ICC				
Not applicable.	Ergon customers were somewhat comfortable for ToU not applying to ICC.	Ergon customers were somewhat comfortable for two-way tariffs not applying to ICC.	Not applicable.	Not applicable.
Retailers				
Minimal changes – no engagement.	One retailer was against ToU tariffs due to complexities with forecasting.	One retailer requested consistency with NSW/ACT tariffs.	Retailers advised that they are unable to pass on load control prices to customers due to higher wholesale energy costs. Supportive of reducing the number of secondary load control tariffs.	The majority preferred streamlining tariffs.

5.3.3 Summary of engagement by customer group

In this section we summarise the engagement processes and outcomes for each customer group and forum we engaged with. The content and detail of these various engagements can be found in our various engagement reports with additional detail on our Talking Energy website.

Further information relating to the different forms of engagement that has been undertaken to date is provided below.

Reset Reference Group

Our Reset Reference Group (RRG) is an independent advisory group, comprising five customer representatives from the Customer and Community Council together with external regulatory experts. The RRG was established to work constructively on the development and implementation of the Customer and Stakeholder Engagement Plan underpinning the 2025-2030 Regulatory Proposal and to challenge us on a range of matters relating to the substance of their proposal.

The RRG identified network tariff challenges and tariff structure design as a key area they expected us to engage on. They emphasised the need for broad engagement on necessary changes to our tariffs, recognising the significance of the changes and the likely impacts for customers.

Given the importance of matters being addressed RRG members also participated in our Network Pricing Working Group along with other community and cohort representatives to work with customers on key themes of tariff reform and design.

Network Pricing Working Group

The Network Pricing Working Group (NPWG) builds on earlier work undertaken as part of a Tariff Reform Working Group -Residential (TRWG-R) when developing tariff trials. The NPWG membership comprises representatives from the RRG and industry to represent a broad set of customer groups including consumer groups, vulnerable customers, agriculture, retail, business and industry. It is tasked with providing input on our tariff strategies and negotiating balanced outcomes for customers.

Full day sessions of the NPWG in June, August, September and November 2023 included deep dives into engagement activities, tariff design and assignment arrangement, draft plan content and TSS and Explanatory Statement content. In addition to providing advice on engagement approaches, the NPWG provided key input into tariff design and implementation decisions in the context of wider engagement with broader customer groups. Most meetings were observed with either AER staff and/or Consumer Challenge Panel representatives present.

Many NPWG representatives either participated in or observed engagement activities particularly as related to pricing. This allowed the group to use their own observations on engagement to test our outcomes and recommendations from the same sessions.

Voice of the Customer Panel

Residential customer pre-lodgement pricing engagement focussed on perspective focus group sessions, interviews and surveys to help inform key issues for in-depth discussion. Insights from this engagement helped frame the next phase of deliberative processes. Deliberative processes work on the premise that people can deliver smart long-term decisions which earn public trust if they are given enough information and time to weigh up pros and cons and consider trade-offs associated with a particular option or issue.

The Ergon Voice of the Customer (VoC) Panel was a deliberative forum involving 35 randomly selected residential customers coming together to explore the topic of how Ergon should plan for the new energy future, while providing affordable services that meet changing customer and community needs. The panel included residential customers from different cultural and linguistic backgrounds and a range of ages.

The panel met over six sessions including five full days and was tasked with writing recommendations for Ergon regarding two key engagement areas of customer service and tariffs. The panel used virtual tools to bring together panel participants, network representatives, stakeholders and industry advisors over several months. Content provided to the panels mixed network tariff education, network cost drivers/forecast utilisation and independent providers to explore options for Network tariffs.

The above table summarised the VoC Panel recommendation around key themes.

Most customers in our VoC Panel sessions recognised the trade-off between cost-reflectivity and bill volatility depending on when a customer used the network. Customers also noted that stronger price signals give customers more control over their bills. However, there was concern over the impact of the pace of change for some customers.

The VoC Panel recognised tariff reform as complex, with different aspects that need to be considered when assessing the speed of implementation. Panel members saw the importance of building up the pace of tariff reform but stopped short of more aggressive changes which would shorten peak time windows.

Our VoC Panel recommended that the networks increase education provided to its customers on its role in the supply-chain so customers better understand how, what and why they are being charged. They saw information and education as vital to the success of tariff reforms.

Figure 28 below provides an overview of the feedback received through the VoC Panel engagement.

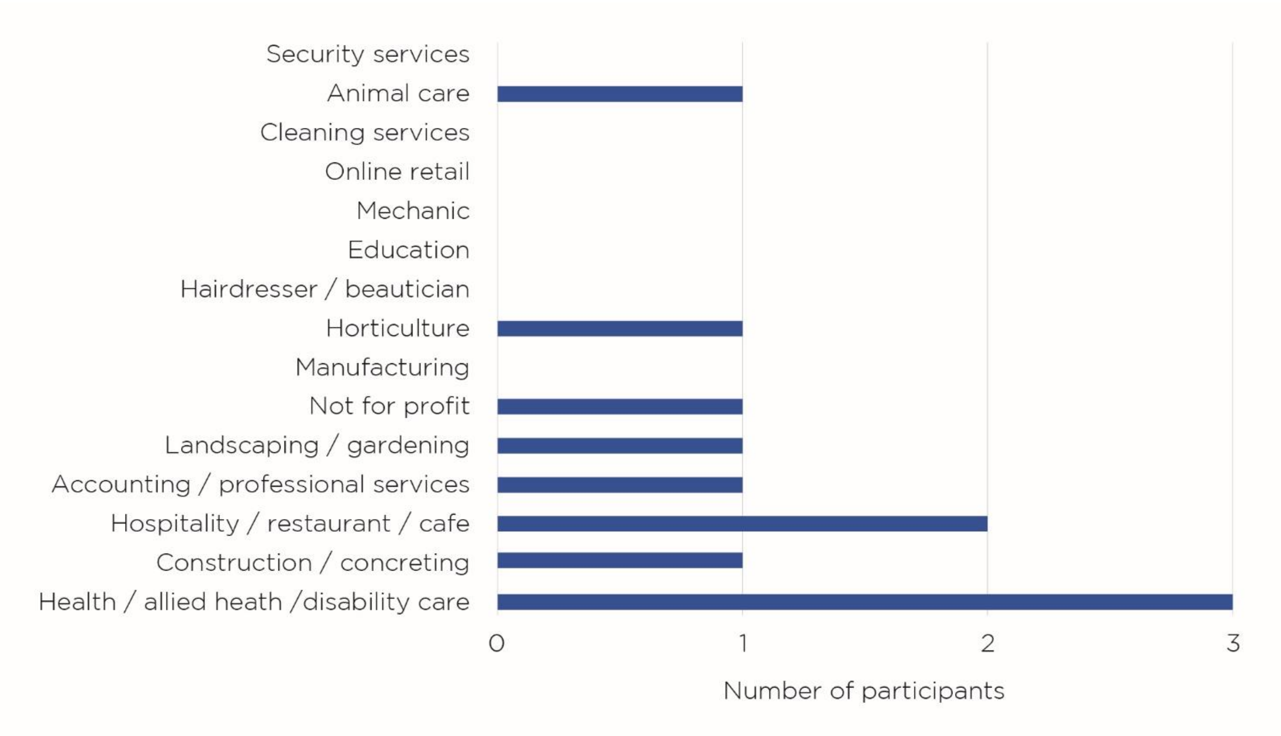
Figure 28 – Summary of the feedback received through the VoC Panel engagement process

Small Business

Our small business customers are some of our most highly diverse customers. They are also some of the most time constrained in terms of providing insights into network tariffs. With this in mind, we engaged specialist facilitators to identify a range of small business operators to participate in one-on-one interviews in August 2023. The outcomes of these interviews are captured in the Small Business Customer report and have been incorporated into our tariff strategy.

11 customers were interviewed to understand their current energy services and behaviours as well as preferences for future network tariffs. Figure 29 below provides an overview of the breakdown of small business customers who were interviewed and the industry they represent.

Figure 29 – Small business customers by industry



It was noted that through this process that energy literacy was low and whilst most customers knew about time-of-use tariffs their understanding of peak and off-peak times was limited. Most small business customers are already cost sensitive and are already modifying their behaviour to reduce energy costs where possible.

We also acknowledge that while a retailer assigns the business classification, a portion of these customers may represent other forms of customers, such as community use infrastructure.

Feedback from small business customers during the 1:1 interviews on the five engagement themes included:

- **ToU Tariffs** - customers prefer ToU tariffs to apply on week days. The majority wanted the peak period to start after 5pm
- **Strength of peak price signal** – most small business customers are cost sensitive and are already modifying their behaviour to reduce their energy costs where possible. However,

some are unwilling to modify energy consumption if it means it negatively impacts customer or employee experience or profitability.

- **Two-way tariffs** – there were mixed results with some customers disliking being charged for exporting energy as they associate solar with rebates whereas others viewed two-way tariffs positively.
- **Load control tariffs** – some customers found it difficult to understand the tariff and its applicability to their business. Many struggled to identify suitable high-energy equipment for load control.
- **Tariff streamlining** – most customers support retiring tariffs, provided they receive sufficient notice and education to make informed decisions.

Medium/Large Business

In line with our engagement themes, we undertook engagement with medium to large business customers where we presented options and benefits across our themes, with special focus on ToU windows as this had featured in feedback over the proceeding 12-24 months.

Forums for this customer segment were held in August and October 2023 with the purpose of the Large Business Customer Forums being to consult with large Standard Asset Customers (SAC), Connection Asset Customers (CAC) and Individually Calculated Customers (ICC) on preferred network tariff structure engagement themes and tariff options for the 2025-30 period.

Ergon participants at the first session voted two-way pricing as their top engagement theme.

In the August session, SAC Large customers were engaged on ToU windows, to seek input on different options and the trade-offs against customer education, retail simplicity and network management. The engagement included options for an additional window for the negative demand period. To inform the engagement, independent analysis was undertaken to understand the system load profile at different times of the day, and the result was the suggestion of various ToU windows. The following three options were presented at the forum:

1. **Slow and steady**: update the 4-9pm peak demand window currently included in the Large ToU Demand & Energy (LV ToUD).
2. **Builds up pace**: introduce a middle of the day trough or negative peak demand window.
3. **Fast and furious**: introduce a short and sharp negative peak demand window, and reduce the length of the current 4-9pm peak demand window.

A majority of large customers were comfortable with adding a negative demand window in the middle of the day. However, customers indicated that they would be more comfortable transitioning to a single tariff that could apply to all customers, as opposed to making changes to all SAC large tariffs. Overall, there was clear support for the streamlining of tariffs.

5.3.4 Other Stakeholder engagement in the share and explore phase

Retailer Engagement

We undertook retailer engagement through a two-step process, first commencing with an opportunity to provide an overview of our engagement themes to all retailers in a public forum, and secondly initiating individual sessions with larger retailers to get their feedback on these engagement themes.

Retailers accepted that networks need to respond to changes in pricing frameworks to include appropriate incentives for exports but also highlighted the significant challenges in explaining these changes to end use customers.

Retailers expressed a strong preference for simpler residential tariff designs, requesting commonality with other network businesses where possible. However, retailers held different views on how simplicity is best applied. One retailer expressed a preference for applying time of day energy charges and eliminating demand charges. Other retailers expressed a preference for maintaining demand charges, noting the reversion costs involved in moving all customers from demand to energy.

Retailers advised us that the continuation of two load control rates and network flexibility in controlling appliances reduces their capacity to pass network price discounts through to the final bill. Further, in our engagement with retailers, we heard that some retailers were unable to pass on the load control prices to customers due to higher wholesale energy costs.

In our follow up engagement post the Draft Plan, some retailers expressed concerns regarding retailer led meter rollouts. They expressed a preference for a transition period between a meter upgrade and a movement away from a basic meter tariff.

Queensland Government

The Queensland Government has been engaged on the development of the TSS, while noting the requirements of the Rules. This engagement included a range of issues, including approaches to time of use windows and two-way tariffs. Given the significant changes across the energy sector, we also provided the Queensland Government early versions of TSS and TSES for comment.

One issue raised through this review included the setting of notified prices for customers choosing Ergon Retail as their energy retailer. The Queensland Government will seek to consider the outcomes of the AER Final Decision along with the associated impacts for notified prices. In such instances, feedback outlines the processes for the setting of notified prices for where the underpinning network tariff is withdrawn requires a notification period of at least one year, with preference for two years. Examples of such an occurrence include three small business Transitional Network Tariffs with no network tariff uptake. In response to this feedback, we have departed from our Draft Plan position to delay withdrawal of some network tariffs until 1 July 2026. Further details are available in Section 6.6.1.

Following announcements made by the Queensland Government, CopperString 2032 includes 1,100 km high-voltage electricity line from Townsville to Mount Isa that will connect Queensland's North West Minerals Province to the national electricity grid. We may seek to alter our approach to Transmission and/or Jurisdictional revenue allocation for SAC and CAC customers if required to support CopperString 2032. This may include structure and revenue approach for ICC Customers.

Classification of Small and Large Customers

The National Energy Retail Law (Queensland) Act 2014 sets out the 100MWh threshold for small and large customers. During the course of our engagement, a small number of customers have requested that this threshold be raised to 160MWh similar to the approaches by some other jurisdictions. We note that as a distribution provider, we do not have the ability to alter this threshold.

With this in mind, we understand that for many customers the underpinning driver for customers requesting this change is due to the bill impacts of being re-allocated from small to large. To reduce this impact, we have re-developed our above 100MWh Low Voltage Network Tariff to provide customers opportunities to manage this transition.

5.4 Test and Refine Phase (September 23-Jan 24)

5.4.1 Our Draft Plan

The Draft Plan for Ergon Energy Network published on 15 September 2023, included an overview of our short term and long term focus areas in respect on network pricing. We provided information relating to our engagement with customers prior to the draft plan. We engaged early with the Network Pricing Working Group prior to the release of the Draft Plan. Their specific feedback on these issues was included in the Draft Plan to assist with further engagement.

Recommendations from our various customer groups in our share and explore phase were summarised. We outlined proposed changes to our network tariffs based on the engagement with our customer base across the 5 themes. This was also presented in webinars, presentations and forums post the release of the Draft Plan.

Formal Draft Plan and Webinar Response

Responses to the Draft Plan questions were varied but in general the following feedback was provided:

- There was general support for the introduction of a negative demand window or low-priced midday pricing window to support implementation of consumer energy resources for small non-residential and large business customers.
- There was support for shortening the peak pricing window.
- There was support for the proposed ToU for CAC HV customers with DER technology.
- At the webinars on the Draft Plan, participants were more comfortable with an opt-in only change for tariffs.
- Retailers present at the webinars expressed a preference for ToU energy tariffs to be the default choice for residential customers. Retailers also expressed a preference for export windows to be either the same or have clear differentiation.
- Retailers wanted network businesses to consider the operational abilities of their proposed tariffs and specifically how they can be explained and shared with customers. It was highlighted that more complex tariffs are ineffective as retailers need to 'blunt' them for their customers. Overall, the preference was for consistency when designing tariffs.
- Retailer responses included expanding eligibility for the 12 month tariff assignment grace period and supported tariffs which are easy for customers to understand, which encourage demand during peak solar generation and which reward customers for shifting exports. Penalties for export were not supported, benefits of a free export allowance was recognised as was streamlining the range of tariffs and ToU windows.
- In the context of electric vehicle tariffs, the option for residential customers to opt-in to energy based tariffs was welcomed noting that the export reward should be available with both energy and demand tariffs. Extending access to the volume tariffs to 160 MWh per annum was advocated as was access to the export rebate without capacity (30kW) or sole use constraints.

Our engagement processes continued with different customer groups to test and refine (or change) our proposed changes prior to finalising our Tariff Structure Statement.

Voice of the Customer Panel Recall Day

We presented our response to the Voice of the Customer Panel recommendations (the outcomes in our Draft Plan) back to the VoC Panel in our recall day in October 2023. We provided more detail of proposed changes to ToU windows, two-way tariffs and proposed streamlining our tariffs to our large (low voltage connected) customers.

Large and Major Customer Draft Plan forums

We highlighted in our Large Customer Forum our proposed assignment policy which would assign all customers to the new, revised SAC large tariff, with the option for customers to revert to a legacy tariff upon request. Such an opt out approach ensures a faster transition to more efficient pricing while managing customer impacts.

Customers were given opportunity to understand potential network impacts for their bill in follow up conversations. Most customers at the forum were generally agreeable with the approach.

Our Major Customer Forum following the Draft Plan outlined the proposed new optional time of use demand tariff, with a similar offer to explain individual customer impacts in follow up meetings. We provided an overview of the impacts to SAC Large customers under an approach which assigns all customers to the proposed LV Demand ToU tariff. Analysis was provided comparing bill impacts for SAC Large in the financial year 2025-26, with and without the proposed tariff structures.

There were no major concerns with the direction provided in the draft plan. However, some customers did accept the offer to understand the potential impact of changes to network structure for their specific connection.

Retailer Forum

Our Retailer Forum focussed predominantly on Alternative Control Services. However, there was some interest in ensuring that there was a transitional delay between smart meters installed through a retailer rollout and the adoption of a new demand tariff. One retailer proposed that transition occur 12 months after installation while another retailer preferred some flexibility depending on the time of the installation.

5.4.2 NPWG Engagement on Draft TSS and Explanatory Statement

We sought feedback from the NPWG on the early draft of both the Ergon and Network Tariff Structure Statement and Tariff Structure Explanatory Statement. The NPWG discussed the documents on 23 November 2023. It was generally recognised the TSSs and TSESs drafted at that time were largely reflective of its discussions with EQL to date and that EQL is on a journey of network tariff reform.

The NPWG recommended that Ergon revise and provide further detail in the TSESs on the following topics prior to submission on 31 January 2024:

- Ensure a customer focus in the use of terminology.
- Explain the allocation of revenue across tariff classes to avoid cross subsidisation.
- Outline how certain issues and forecasts (e.g., population growth) have impacted the narrative for network tariff reform and design.
- Redefine the narrative to not only focus on prices but the transition to a services market (e.g., controllability) and the benefits that customers may receive from those services.

- Explain why the recommendation from the Voice of the Customer Panel to not apply time of use windows on the weekend was not adopted, including supporting analysis.
- Reference the role that the Government and others in the industry have in increasing awareness of and helping educate customers on tariffs.

The NPWG also recommended we need to do more work on the potential need for future network tariff reform for embedded networks – accepting that the issue has not been consulted on to date.

In relation to the TSS, the NPWG were concerned with the inclusion of contingency triggers that would delay or defer the introduction of two-way tariffs as this may further delay the transition to tariff reform and cost reflectivity.

We have attempted to address these comments in the final versions of our TSS and TSES but will test this with the NPWG when we next meet.

We expect the role of the Network Pricing Working Group (NPWG) will continue during and beyond the TSS engagement process as a forum for us to work with stakeholders to collaborate on opportunities for pricing reform and tariff innovation which will improve utilisation of the network, lowering the overall costs.

5.5 Ongoing Engagement

Since 2021 we have undertaken engagement activities commencing with our Tariff Reform Working Group before migrating to our Voice of the Customer Panels and Network Pricing Working Groups. We seek to continue to this into our future engagement activities through embedding the Network Pricing Working Group in our business-as-usual engagement activities and to ensure that it has an input from end-use customers as well as stakeholders.

The intent of the NPWG going forward is to invest in the development of a diverse cross section of the community to represent our wider customer base in an ongoing nature. This supports our view that engagement is a journey and will continue beyond the lodgement of our submission.

6 CONSULTATION OUTCOMES: PROPOSED CHANGES IN 2025

We are proposing changes to both tariff structures and assignment arrangements across most of our tariff classes. In making these changes we have taken into account feedback from customers on the trade-offs in tariff structure decisions, with a key focus on understanding customer attitudes to the pace of change.

6.1 Time windows for Demand and Energy tariffs

In response to expectations raised by the AER in terms of improving efficiency in our tariff designs we engaged with customers and stakeholders on the issue of pricing windows and tested their appetite for:

- a shorter, narrower period for measuring the peak demand window, and
- introducing an additional daytime pricing window that most closely matches periods of high export – with the potential to apply much lower rates during this period.

One of the issues we explored through engagement with customers and stakeholders is the trade-off between accuracy and simplicity (refer to Figure 30 below) – noting that the wider pricing windows remove the need for introducing an additional 'shoulder' pricing window between the day and evening pricing periods.

Figure 30 – Trade-offs discussed through engagement

Several customers and the AER had previously questioned whether the peak demand window is appropriate for signalling peak demand on the network. We analysed the system-wide demand on the network over the past 10 years. Analysis of the timing of historic and future peak demands suggest that the current 4pm-9pm window is still broadly appropriate. However, there is scope for introducing a narrower peak period between 5-8pm.

Our review of the historic and forecast demand on our network indicates that periods of high export are becoming increasingly concentrated in the middle of the day, driven by the continued uptake of rooftop solar. This trend is likely to continue throughout 2025-30.

Other networks have introduced a new low-price window in the middle of the day to encourage higher energy use in that period. While providing better signals, the introduction of an additional time window for setting prices increases the complexity of the tariff and can make it more difficult to understand. We therefore considered options which introduced a wide low-price day pricing window of 11am-4pm, as well as a shorter period between 11am-1pm which could be combined with a shorter peak demand window (5pm-8pm).

Maintaining a wider peak period and including a similar wide window for the low-price period would likely include periods that are less likely to result in maximum or minimum demands. Extended windows represented a more simple outcomes for customers – an important consideration raised by residential customers and retailers specifically.

Our engagement with customers looked at the trade-offs between these different options. To help customers better understand how different pricing windows would work, we presented examples showing how different network tariff structure options could impact different customers based on four personas with different income and household composition (refer to Figure 31 below).

Figure 31 – How tariff options impact different customer types

John
- Family of four
- Majority of energy usage outside school hours and weekends
- 5,200kWh/year
- With solar

Zahara
- Family of three
- Majority of energy usage in the evening when electricity demand is high
- 3,800kWh/year
- With solar and electric vehicle

Arush
- Retired couple
- Majority of energy usage through the day to make use of solar
- 2,300kWh/year
- With solar

Azami
- Single parent, family of five
- Works from home. Energy usage spread over the day
- >8000kWh/year
- Without solar

CUSTOMERS	FY26 Network distribution bill per annum	Move from flat/ anytime tariff	Shift import from evening peak to daytime	Opt-in to two-way tariff	Shift export timing & increase self-consumption	Potential bill reduction
John Family of four Majority of energy usage outside school hours and weekends 5,200kWh/year With solar	$635	-*	-$46	$5	-$3	-$48
Zahara Family of three Majority of energy usage in the evening when electricity demand is high 3,800kWh/year With solar and electric vehicle	$625	-*	-$45	$16	-$10	-$39
Arush Retired couple Majority of energy usage through the day to make use of solar 2,300kWh/year With solar	$369	-*	-$19	$14	-$2	-$7
Azami Single parent, family of five Works from home. Energy usage spread over the day >8000kWh/year Without solar	$784	-$52	-$61	-	-	-$113

*customer is already assigned to the default smart meter tariff

Our proposed changes to our existing residential default tariff are consistent with the Draft Plan:

- maintain the current wide 4pm-9pm peak demand window, noting that this window will continue to apply every day for residential customers, and
- introduce a lower priced 11am–4pm midday pricing window from 1 July 2025 applying daily.

Our proposed changes to small business default tariffs are also consistent with the Draft Plan:

- change the evening peak demand window to 5pm-8pm, noting that this window will apply weekdays only
- introduce a lower priced 11am–1pm midday window from 1 July 2025, noting that the new window will apply daily

6.1.1 Transitioning the strength of the price signal

Throughout the 2020-25 regulatory control period, a 'transitional' peak price signal was introduced to our default tariff to allow customers to adjust to tariffs with which they might not be familiar.

In 2020, all customers with a smart meter were assigned to the transitional tariff. To manage customer impact, peak evening charges for our residential transitional tariff were significantly lower. An optional tariff was introduced which provided a much stronger signal. However, take-up of the optional tariff has been minimal.

In line with the various feedback received from our customers and stakeholders, peak evening charges for both our default demand-based tariffs and optional ToU energy tariffs will continue to progress towards the full cost of future network augmentation in the next regulatory control period. We will progressively move peak charges in these tariffs closer to long run marginal cost by 2030. We will remove the 'transitional' peak charge application as a tariff offering but will change our assignment approach for retailer initiated meter change.

We consider this approach provides an appropriate balance between moving to full cost-reflectivity in our tariffs and meeting customer preferences.

To offset the impact of the stronger signal, the draft plan targets a zero rate for distribution charges in the minimum demand window. We also removed the application of energy consumption charges from the peak pricing window, so that the peak window would only signal the costs of future network augmentation.

Setting peak prices to reflect the full cost of future network augmentation promotes more efficient use of our network which helps reduce:

- the need for additional investment, particularly given the rise in distributed energy resources such as rooftop solar, batteries and electric vehicles, and
- the amount of network infrastructure that needs to be maintained, thereby limiting network charge increases for all customers in the long term.

To the extent that customers can smooth out peak demand usage and consume more energy in the middle of the day, their network bill will be lower.

6.1.2 Assignment arrangements and proposed transition approach

As noted earlier, residential and small business customers from July 2020 who already had a smart meter (as well as those customers who received a smart meter since that time) were immediately assigned to the applicable transitional demand tariff[5]. To manage customer transition to new tariffs, the peak charge represented only a small percentage of long run marginal costs.

Two important changes are influencing our decision to change assignment arrangements for customers moving from basic to smart meters from 1 July 2025.

Firstly, the AEMC's report into a review of Metering Services includes changes which will likely accelerate retailer rollout of smart meters in the next regulatory control period. This review acknowledges that automatic tariff re-assignment policies may create a risk to customers where there is an immediate transition to cost reflective tariffs from legacy tariffs. In response to this review, some retailers have expressed that a change to assignment rules is necessary to manage the customer impacts from a retailer led rollout of smart meters.

Secondly, our proposed suite of tariffs from 1 July 2025 will no longer offer a transitional based tariff. Our preference is to have one default tariff with a stronger LRMC signal applied to the peak demand period. On this basis there is an argument in favour of a lag between smart meter installation and tariff assignment.

Alinta Energy's response to our draft plan made a strong case for tariff assignment arrangements which would delay a move to our default tariff until 12 months after installation. There was also strong support for a change in tariff policy at our retailer forum.

For Customers below the small customer threshold, in the event a meter is upgraded from Basic to Smart, we propose that the following 'upgrade assignment rules' apply:

- Customer Initiated – A customer initiated Basic Meter upgrade represents a change to the NMI that would otherwise prompt a meter upgrade, for example, the installation of Solar PV, EV Charging, three-phase, customer requested upgrade to Smart Meter.

  In the case of a customer initiated upgrade a customer will be immediately re-assigned to the default Network Tariff for Smart Metered customers.

- Retailer Initiated – Instances where the meter is upgraded for a reason other than a customer initiated upgrade (described above). A retailer initiated upgrade includes upgrades associated with the implementation of the AEMC Metering Review Final Report as well as an upgrade caused by a failure or end of life meter replacement.

  In the case of a retailer initiated upgrade a customer will remain on the Basic Meter Tariff for 12 months following the end of the financial year in which the upgrade occurred. However a customer or their retailer may transfer to smart meter tariffs at anytime following the upgrade (noting they will not be able to transfer back to a basic meter tariff if they do so).

[5] An exception existed for customers who had their meter replace due to failure of the existing meter.

All other options not included in the Customer Initiated or Network upgrade are deemed to be Retailer Initiated. For customers above the Small Customer Threshold, customers will be immediately assigned to the default Smart Meter Tariff.

For our SAC Large Customers, we propose to assign all customers to our default Large ToU Demand & Energy Tariff. The existing Demand Small tariff will remain as an opt-out choice to assist in managing customer impact.

6.1.3 Retaining the choice of both demand and energy tariffs

We propose to offer ToU energy as an optional tariff for all small customers until 2030. The windows for the ToU energy tariffs will align with the ToU pricing windows proposed for the default tariffs.

6.2 Two-Way Network Tariffs

6.2.1 Rationale for two-way tariffs

Over the last ten years the number of people taking advantage of the benefits of investing in rooftop solar has been so successful that, in some areas there was not enough available capacity to allow new solar connections to export back to the grid. These 'static export' constraints made it less attractive for many customers to take up solar. Regulatory frameworks were changed in requiring networks to invest more to allow at least some level of export (a basic export level) across the network.

To minimise non-solar customers subsidising infrastructure investment for export, changes to the regulatory framework now require us to consider incentives through our pricing structures which encourage exports at times most likely to benefit the network. Two-way tariffs (reflecting both a charge and a payment component) represent one aspect of these incentives.

Two-way tariffs provide rewards for customers who export energy at times most likely to trigger investment due to high import demand. Charges above a basic export level are aimed at ensuring that future network investment required to manage exports in the middle of the day is paid by those causing that investment.

We investigated a range of options developed by other networks for two-way export tariff structures that best align to our default tariff pricing mechanisms, recognising our own customer preference for ToU windows. Our engagement with customers included videos and fact sheets with explanations as to why we are transitioning towards two-way tariffs.

Our proposed approach for export charges is consistent with our Draft Plan and is to be applied as follows:

- residential customers would be charged for the highest export to the network above a 1.5kW threshold during the 11am–4pm window daily, and
- small non-residential customers would be charged for the highest export to the network above a 1.5kW threshold during the 11am–1pm window daily.

Export rewards is to be applied as follows:

- residential customers would receive a payment for exporting electricity during 4pm-9pm daily (see Figure 32 below for the proposed export tariff structure), and
- small non-residential customers would receive a payment for exporting electricity during 5pm-8pm weekdays (see Figure 33 below for the proposed export tariff structure).

The ‘payment’ will be included as negative charge on the invoice we send to retailers on the customer behalf.

The proposed export charge (in kW) would reflect our long run marginal cost of supplying export services, while the reward would mirror the peak evening demand charge (in kWh).

Figure 32 – Residential Two-way Tariff

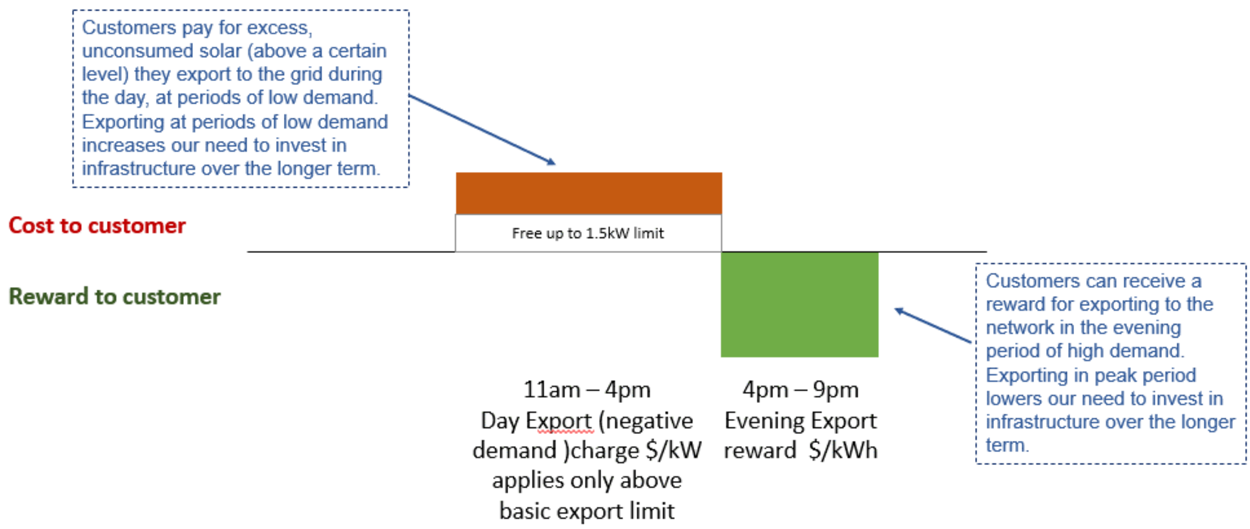
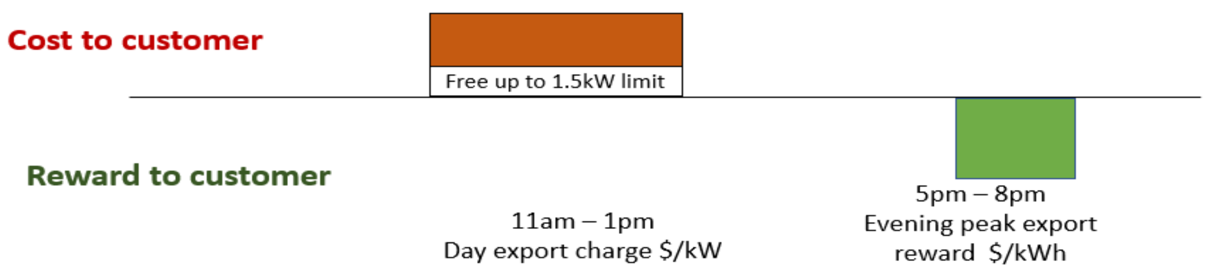


Figure 33 – Non-Residential Two-way Tariff



6.2.2 Transition approach

The key focus of our engagement for this topic related to informing customers around the regulatory changes that have brought about the need to transition towards two-way tariffs and reasons why these changes are positive for all customers in the long term. We sought customer feedback in what they needed to understand to be comfortable with the changes and preferences to the ’pace of change‘ for the introduction of charges and rewards.

Our proposed transition approach to introduction of two-way tariffs is consistent with our Draft Plan and outlined in Table 4 below:

Table 4 - Proposed two way tariff transition approach

Transition Period	Approach
1 July 2025 to 30 June 2026	• No proposal to introduce two-way tariffs.
1 July 2026 to 30 June 2028	• Optional for existing customers. • Mandatory for new customers • New customers entering into a dynamic connection arrangement may opt-out of the two-way tariff.
1 July 2028	Once dynamic connection offers are widely available to customers (anticipated 1 July 2028): • Mandatory for all customers. • Customers entering into a dynamic connection arrangement may opt-out of the two-way tariff.

The comfort levels for customers on transitioning to two-way tariffs was not as strong as their comfort for CAC changing time of use windows. We heard from customers the need for optionality and time to adjust, which is reflected in our transition approach. Customers were also interested in the ability to avoid export charges prompting our introduction on dynamic connections as an opt-out approach. Additional customer education material will be required in anticipation of the indicative July 2028 deployment date.

6.2.3 Further information regarding Two-way Tariffs

Export Charging Mechanism

The two-way tariff includes charges and rewards based on long-run marginal cost (LRMC) that sends efficient signals to consumers. This development is in response to the AEMC DER Access and Pricing rule change that was made in August 2021 and the new AER pricing principles.

These changes introduce greater symmetry between how import and export services are priced.

LRMC-based import tariffs have been a feature of network tariff design for some time. These tariffs apply LRMC to a charging mechanism which signals to consumers the cost of network augmentation during periods of peak demand.

Similarly, export tariffs will include a form of export LRMC applied to minimum demand periods to help to align the incentives facing consumers regarding exports with the needs of the overall system.

Details of our approach to deriving LRMC can be found in Section 8.3.

Basic Export Level (BEL)

The basic export level is the threshold customers can export that networks make available to customers without charge. Where network constraints occur, we will make investments to maintain this capability in the network.

We have undertaken an analysis of our network capability and our subsequent capability to deliver on a basic export level for customers. The full analysis is provided in our DER Integration Strategy finds that there is a tipping point in both capacity and subsequent investment that occurs at around 1.5kW.

We have balanced the need for the required level of investment to ensure this is provided to customers while ensuring that the existing capacity in our network can be utilised by the connection of customer with sufficient capacity in their network to be able to export to the grid.

Our TSS notes that export capacity above 30kW or connections to the HV network are not subject to a two-way tariff.

Interaction with Dynamic Connections

Dynamic connections are arrangements which allow the network to set the limits that a customer can export to the network dynamically. These limits vary export limits over time and location based on the available capacity of the local network or power system as a whole.

Under dynamic connections, the customer potentially foregoes export at peak times where the impact of that investment may otherwise result in a constraint on the network. However, this also avoids or defers the need to invest in the network into the future to address the constraint. The transition to both two-way tariffs and dynamic connection arrangements during the period allows customers choice between avoiding dynamic curtailment of export but incurring some charge for export at peak times, or saving on charges for export, but allowing some form of curtailment at peak times.

6.3 Storage Network Tariffs

Our engagement with business customers included interest from a small number of prospective customers seeking to install storage across our networks. These groups are typically seeking to install batteries and comprise of the following offerings:

- Neighbourhood scale batteries typically low voltage and small in nature and often funded via grants for arbitrage or ancillary markets.
- Grid scale batteries, typically installed at the low end of high voltage and aimed at hedging and arbitrage markets with less emphasis on ancillary markets. Proponents may be either new to energy markets or existing customers looking to expand.
- Large scale batteries operating at the upper limits of the distribution network with installations at commercial scale and often linked to other significant works. We view these as best suited to our ICC Tariff Class.

For the most part, customers are seeking to install storage across the network in areas they can secure land access. Customers told us that network pricing arrangements need to cater for storage connections that present to the network slightly different profiles to a traditional import or export customer. We have joined other networks in trialling different tariff options that cater for storage customers.

6.3.1 Rationale for Storage Network Tariffs

Recent regulatory reforms recognise the emergence of customers which take load from the network as storage for the primary purpose of exporting back into the grid. These customers blur the traditional market boundary between energy consumption and energy generation. From a network perspective, these customers are highly elastic, have high access to support arrangements and may contribute a material benefit (and in some circumstances cost) to the network.

We received strong feedback from these customers prior to the release of our Draft Plan regarding better pricing arrangements to cater for greater levels of storage investment across our network. There were concerns that our existing structures did not cater for the unique nature of these investments. Customers encouraged us to view what other network businesses have delivered in response to the differing characteristics of this type of customer.

We engaged with customer representatives on the conditions of the tariffs as well as a structure and price that reflects the mixed nature of this customer type which will incentivise storage to 'soak up' solar in the middle of the day and export at times most likely to avoid or defer future network investment.

This Storage tariff is not to be confused with the Low Voltage two-way network tariff operating between 1.5kW and 30kW of Export.

Our TSS proposes the introduction of storage specific tariffs to cater for customers that combine both load and generator characteristics. The tariff is largely built on storage tariffs which were offered to customers in Ausgrid's network following positive consultation with customers and which since has been largely accepted by the AER. The proposed tariffs will include both import and export elements directly linked to localised and system constraints. Our proposed approach is to develop similar structures that incorporate both critical peak pricing and flexible load elements.

6.3.2 Eligibility

From 1 July 2025 we will introduce a storage tariff for this emerging customer type. These network tariffs are by application and acceptance to assign customers to the tariff is at discretion of the network, with eligibility criteria including:

- The customer must only import load from the network for the purpose of exporting it back to the network[6]
- Low Voltage and above 30kW
- 11-66kV and are below 10MVA

Two optional tariffs will be offered for different voltage connections. However, acceptance of a customer to move to such a tariff will not be automatic – it will be at the discretion of the network based on network considerations.

[6] Customers must also meet AEMO classification as both load and generator market participation

6.3.3 Dynamic flex storage

The LV and HV Dynamic Flex Storage Tariff will be the preferred optional tariff for customers wanting to connect storage to our network in the initial years of the regulatory period.

The Dynamic (flex) storage tariff focusses on dynamic control of import and export with a notional fixed charge. The structure assumes customer adoption of a Dynamic Connection which employs the use of a Dynamic Operating Envelope (DOE) on both Import and Export aspects of the tariff. A Dynamic Connection is one that meets both the connection standards for a Dynamic Connection and also a Dynamic Connection contract.

Recognising the network benefits of load and generation flexibility and the potential for future cost avoidance through the operation of a DOE, Distribution Use of System rates for import and export demand during a Critical Peak Period Import or Export will be initially set to zero.

The structure includes a rebate price mechanism that may be exercised by the network for up to 40 hours per year for export based on day ahead time indicators. Exercise of the mechanism (based on critical peak event criteria which will be defined in the pricing proposal) is at the discretion of the network.

Details of critical peak event criteria is outlined below. We will look to trial similar structures in the last year of the 2020-25 regulatory control period.

Additional time of use energy charges are included for the purposes of transmission and jurisdictional scheme passthrough.

6.3.4 Dynamic Price Storage

The Dynamic (price) storage tariff will only be available at the discretion of the network. The tariff focusses on a locational and time specific signal for export or import at times of constraint in a way that encourages avoidance of import or export at the critical event. Given the elastic nature of storage, we expect that in most circumstances the storage will operate in a similar way as under a flex tariff.

Mechanisms for critical event charges or rebates will be developed and likely implemented mid-period before offering at scale.

6.3.5 Storage Critical Peak Period

For the Dynamic Flex Storage Tariff a Critical Peak Period will occur for Export Reward (CPPR). For the Dynamic Price Storage Tariff a Critical Peak Period may occur for Import (CPPI), Export (CPPE) or Export Reward (CPPR). These periods may occur individually or concurrently. Each form of Critical Peak will include its own Critical Peak Cap, nominally set at 40 hours (80 periods) per year.

6.4 Load Control Tariff Changes

6.4.1 Rationale for Load Control Tariff Changes

Tariff reform, integrated with dynamic connection agreements, will contribute positively towards addressing some of the network challenges that are emerging, while giving customers more optionality in how they use and pay for the network.

Similarly, the need for the flexible load management provided through our existing load control tariffs and existing load control tools will remain significant to ensure that different customer types and different customer needs are supported.

Declines of around 2 to 3% each year of load connected to load control tariffs are likely to continue if more customers find a better value proposition through integration usage with solar at their main connection (our current load control tariffs separately control and meter the appliances under control). Our engagement process looked at options to ensure load flexibility continues to remain relevant to deliver better options, better price and lower cost outcomes for customers.

6.4.2 Proposed way forward for primary and secondary load control

Our flexible load options will provide wider customer choice in the evolving energy market, allowing customers to benefit through lower prices. We will benefit from being able to manage emerging key loads and the existing load control fleet, for day to day load switching and emergency network management response, as required.

In the next period we will retain all existing load control options while also introducing a new flexible load tariff which will apply to one or more appliances connected to the main circuit, rather than separately metered and controlled. The proposed new flexible load tariff featuring load control will provide wider customer choice and the ability for us to flexibly manage emerging EV loads using existing AFLC control methodology, and other approved demand management methodologies as defined in our Queensland Electrical Connections Manual (QECM).

6.4.3 Secondary Load Control Tariffs

In the next regulatory period, we intend to retain our existing load control tariff offerings as they continue to provide value for customers through having a wider suite of tariff choices. These secondary load control features and benefits are outlined in Table 5 below:

Table 5 - Secondary Load Control Tariffs – conditions and benefits

Tariff	Eligibility and Conditions	Customer Benefits
Volume controlled	Minimum 18 hours supply Basic or Digital metering Any appliance allowed	Lower consumption charges. Can help with avoiding peak demand changes on primary tariff. Suited to any non-essential appliances, typically:

Tariff	Eligibility and Conditions	Customer Benefits
	Generally hardwired appliances only, with several exceptions	• Water heaters • Pool pumps • EVSE's • Air conditioners
Volume Night	Minimum 8 hours supply Basic or Digital metering Any appliance allowed Generally hardwired appliances only, with several exceptions.	Lower consumption charges. Can help with avoiding peak demand changes on primary tariff. Generally suited to suitably sized electric storage water heaters.

Conditions for the tariff and operation will reside in the Network Tariff Guide, providing for opportunity to adjust the criteria as required throughout the regulatory period, based on operational factors, the implementation of dynamic connection offerings and customer take-up.

6.4.4 Flexible load control tariff options.

Our proposed new flexible load control tariff will apply as a secondary tariff discount on the daily fixed charge, against one of the existing primary tariffs, where the premises provides one or more loads under DNSP direct or indirect control, as per the eligibility terms and conditions.

Our view is that the network benefit is highest in focussing on EVSE's initially for eligibility for this tariff. Our Queensland Electricity Connection Manual (QECM) is being updated to define other (non-AFLC) operational pathways for the network to manage loads, introducing a concept of *Active Device Management*. This will include, for example, dynamic management of loads (we have already implemented that for the dynamic management of export from inverter energy systems). As our new dynamic connection standards are taken up by customers, we intend to include eligible sites with this type of connection to be eligible for this tariff.

Applicable rates of the nominal primary tariff will apply. Load control equipment will be installed upstream of the appliance and any appliance timer, ensuring that the ability to interrupt supply remains with the DNSP.

We expect supply availability will be consistent with the existing volume-controlled tariffs (18 hours per day). However in most instances, supply is rarely interrupted for more than a few hours in any one individual managed event and therefore we expect minimal customer impact when supply is interrupted.

A separate channel in our AFLC load control system will be to manage loads on this tariff, which allows loads on this to be treated / switched independently from any other secondary load control at the connection. For premises participating through other eligible demand management pathways (as per Active Device Management definition in the QECM), the intent is to rely on the operating protocols defined in those pathways.

Customer and stakeholder education will be undertaken to ensure the purpose and application of these tariffs, including supply interruptions are well understood by customers. This will take learnings from the previous successfully rolled out of non-domestic load control tariffs in the 2020-25 regulatory control period, where we used multiple means to educate customers, including detailed web page content to explain the tariff, eligibility and conditions.[7] Eligibility rules and conditions are found in Table 6 below.

Table 6 - Flexible Load Tariff eligibility and conditions

Tariff	Eligibility and conditions
Flexible Load Tariff	Minimum 18 hours supply in any one control day Digital metering Control methodologies: standard network device (load control relay) OR Other approved demand management methodologies as defined under Active Device Management in the QECM Eligible equipment: EVSE only on AFLC. Other hardwired appliances permitted under approved demand management pathways, as defined by the QECM.

6.5 Tariff Trials

6.5.1 Approach to Tariff Trials

We recognise the importance of undertaking appropriate assessment of the value and feasibility of proposed new tariffs from a customer, key stakeholder (ie industry groups) and retailer perspective. This assessment can take the form of real world, sub-threshold in-market trials; 'paper' trials where customers receive simulated bills based on the proposed tariff; or other methods, including detailed modelling and 'what if' analysis of the bill impact on groups of customers or individual customers.

We have sought retail partners for these trials through issuing of expression of interest in 2020-25, with mixed results as most retailers generally have minimal interest in being involved in trialling tariffs. We will continue to evaluate proposed tariffs through trials or other means – the findings from these trials provide valuable lessons that can be applied in the tariff deployment phase, where these tariffs are approved by the AER.

6.6 Network Tariff Streamlining

6.6.1 Streamlining SAC Small Network Tariffs

Customers and retailers told us that we should do more to reduce the number of tariffs we have and simplify existing tariffs to make it easier to understand what tariffs are designed to do. For

[7] – e.g https://www.ergon.com.au/loadcontroltariffs

example, the number of ToU tariffs with different pricing windows makes it difficult to understand the difference between the legacy tariffs and newer cost-reflective tariffs.

In response to this feedback, we will close our residential and small business tariffs that were grandfathered during the 2020-25 regulatory control period. Few customers are currently assigned to these tariffs, and we would therefore expect that the withdrawal of these tariffs would have little impact on customers. Table 7 shows the number of customers currently assigned to these tariffs and the tariffs to which we propose to transfer these customers.

We will simplify the structure of our optional small business ToU energy tariff. This tariff currently has five inclining fixed charge blocks. A customer is assigned to one of the five blocks depending on their annual electricity consumption. In response to retailer feedback, we propose to simplify this tariff by removing the top four bands. This will also align this tariff structure with the residential version of the ToU energy tariff.

As outlined in our 2020-25 Explanatory document, we outlined that *a ToU energy tariff is proposed to be offered on a strictly limited access basis. This ToU energy tariff would only be available customers who have been on a retail transitional tariff in the period 1 July 2017 to 30 June 2020*. This statement referred to Transitional Network ToU Energy Tariffs 1/2/3. Noting that these network tariffs were immediately grandfathered upon introduction into the 2020-25 TSS we seek to close this network tariff. No network tariff re-assignment is required, however had there been a customer, they would be assigned to the default network tariff based on their meter type. We also note that the introduction of Primary Load Control tariffs as part of 2020-25 which have seen strong interest from customers. We hypothesise that customers have instead opted for these optional tariffs.

Our position included in the Draft Plan for these grandfathered retail transitional tariffs had outlined a withdrawal date of 1 July 2025, however following discussion with the Queensland Government, for administrative purposes it has been suggested that this date will be extended to 30 June 2026. These underpinning network tariffs will continue to be closed throughout this period.

Finally, we will rationalise our tariff offering for residential and small non-residential customers by closing our optional demand tariffs.

Table 7 - Residential and small business tariffs we propose to permanently close from 1 July 2025

Tariff to be closed	Number of customers affected	The tariff affected customers would be transferred to
Large Residential Energy (NTC REST)	0	Residential Flat (NTC RIB)
Residential Demand (NTC RDEM)	182	Residential Demand and Energy (NTC RTDEM)
Small Business Demand (NTC BDEM)	295	Small Business Demand and Energy (NTC BTDEM)
Transitional Network ToU Energy Tariff 1 (NTC BFRM)	0	Small Business Demand and Energy (NTC BTDEM)
Transitional Network ToU Energy Tariff 2 (NTC BIRR)	0	Small Business Demand and Energy (NTC BTDEM)
Transitional Network ToU Energy Tariff 3 (NTC BPMP)	0	Small Business Demand and Energy (NTC BTDEM)

Tariff to be closed	Current Number of SAC Tariffs	Number of SAC Tariffs to be withdrawn	Proposed new SAC Tariffs
Ergon Energy Network	135	99	12

Tariff to be closed	Current Number of CAC Tariffs	Number of CAC Tariffs to be withdrawn	Proposed new CAC Tariffs
Ergon Energy Network	42	34	12

6.6.2 Streamlining – Large Low Voltage (SAC Large) and High Voltage Network Tariffs

With the modification of our default SAC Large tariff, we propose to withdraw our optional Demand Large and Demand Medium tariffs. This is our preferred alternative to modifying the legacy tariffs to reflect new pricing windows and consistent with customer and retailer preferences to reduce the complexity and number of tariffs over time. The Demand Small tariff will remain available for existing customers who are impacted from the change to the new default ToU Demand.

Both tariffs do not signal times of peak demand or negative demand on our network and would need to be modified to be consistent with changes to other tariffs with likely impacts on customers.

In our engagement with SAC Large customers, they expressed support for a single tariff that applies to all customers as opposed to making changes to all SAC tariffs. Further, the Network Pricing Working Group was supportive of tariff streamlining, noting the importance of providing education and options for customers.

Our engagement with retailers and major customers to date highlighted that we have complicated tariff arrangements for our SAC Large customers, with complex legacy tariff structures, including a threshold for application of demand charges. These arrangements create additional administrative burden for retailers, the regulator, our customers, and our business, with no additional gains.

In response we propose the following changes from 1 July 2025:

- Removal of the Seasonal HV Network Tariffs
- Withdrawal of Demand Medium and Demand Large
- Removal of kW version for Demand Small
- Amalgamation of Transmission Regions 1/2/3 for Price Zones East and West.

The tariffs we propose to close for large customers on low and high voltage connections are set out in Table 8 below.

Table 8 - Medium and large business tariffs we propose to permanently close from 1 July 2025

Tariff to be closed	Number of customers affected	The tariff affected customers would be transferred to
Demand Medium (NTC DMT)	1,154	LV Time of Use Demand (NTC LTOUD)
Demand Large (NTC DLT)	189	LV Time of Use Demand (NTC LTOUD)

Tariff to be closed	Number of customers affected	The tariff affected customers would be transferred to
SAC Seasonal Time-of-Use Demand (NTC STOUD)	451	LV Time of Use Demand (NTC LTOUD)
CAC Seasonal TOU Demand (NTC STOUD)	4	Default CAC tariff, depending on customer's connection characteristic

6.7 Other issues raised in engagement

6.7.1 Classification of Small and Large Customers

The National Energy Retail Law (Queensland) Act 2014 sets out the 100MWh threshold for small and large customers. During the course of our engagement, a small number of customers have requested that this threshold be raised to 160MWh similar to the approaches of some other jurisdictions. We note that as a distribution provider, we do not have the ability to alter this threshold.

With this in mind, we understand that for many customers the underpinning driver for customers requesting this change is the bill impact of being re-allocated from small to large. To reduce this impact, we have re-developed our above 100MWh Low Voltage Network Tariff to provide customers opportunities to manage this transition.

We have further attempted to streamline the network tariff descriptions in our TSS to support adaptation via AER TSS re-opener to support a future change of threshold should the Queensland Government update relevant legislation.

6.7.2 Embedded Networks

Based on learnings from AER Decisions for other distribution networks, Our NPWG and the AER asked us to investigate whether issues existing with emerging embedded networks with respect to network tariffs. In embedded networks, the owner of a site may seek a connection with the network but then on-sell to other sub-connected customers. Examples of this may include shopping centres, apartment buildings or retirement villages.

From a network perspective, it is difficult to identify instances where an embedded network has been configured, especially for the purposes of applying a network tariff or bill. On this basis, we reviewed the list of Australian Energy Market Operator (AEMO) registered embedded networks on our distribution network.

For Ergon Energy Network, the AEMO register finds there is a small number of registered embedded networks operating primarily across our low voltage network. We recognise that there may be further non-registered embedded networks.

While we will continue to monitor embedded networks, we did not consult with customers on introducing a specific tariff for embedded networks and therefore have not included any changes in our Draft TSS submission. We welcome further feedback on this issue.

7 OUTCOMES FOR CUSTOMERS

7.1 Network Bill Impacts

Customers have stressed the importance of understanding the impact of changing tariff structures on individual bills. Given the increasing divergence in the ways customers source and use energy, analysing average or even typical bill movements may not provide a full picture of the range of impacts that may result from changes in structure.

Additional challenges arise when comparing bill outcomes when customers are experiencing increases in prices (due to higher levels of revenue that need to be recovered in future years) and changes in tariff design or assignment.

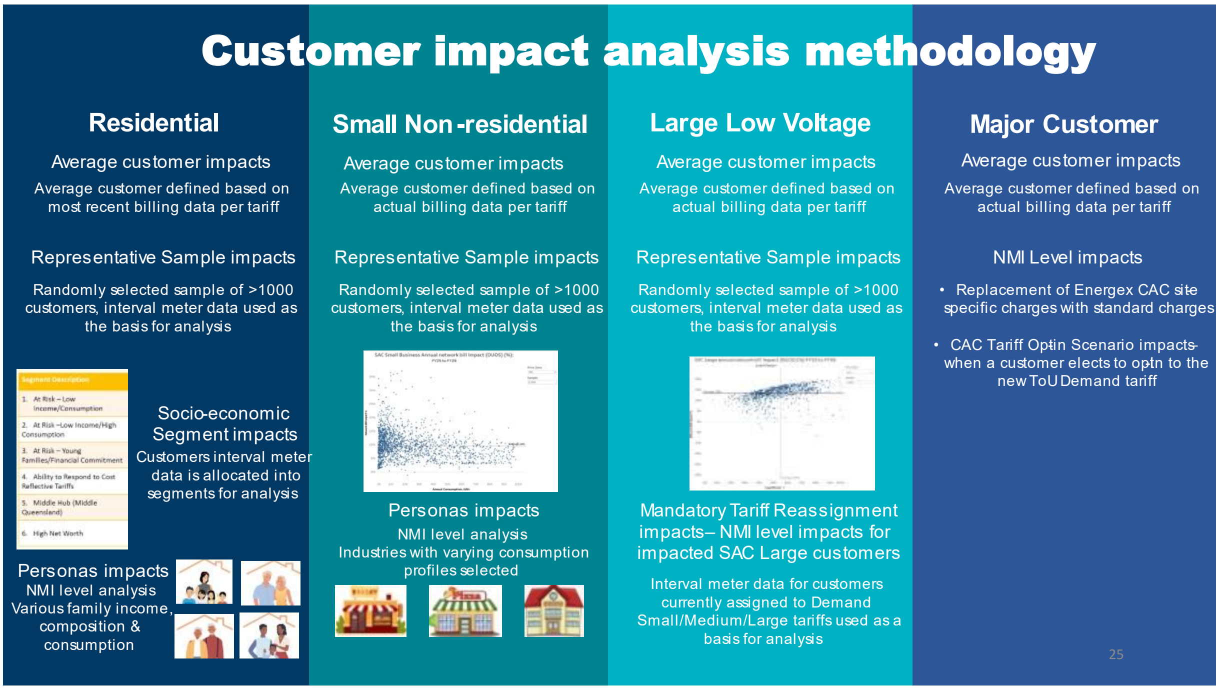
Given the substantial changes to a range of tariffs, a separate document (Ergon - 9.02 - Network Bill Impacts - January 2024 - public) has been prepared to assist customers and the AER understand network bill impacts associated with:

- changes in revenue across all years for default tariffs
- movement between default and optional tariffs within the same tariff class
- movement to default tariffs as a result of a tariff being withdrawn.

We provide a range of impact assessments based on:

- impacts based on a large sample size using all available information
- segment based impacts for some customer classes
- personal based impacts for some customer classes.

The figure below provides an outline of the different types of bill impacts we have analysed by customer group.



The Network Bill Impact attachment has been provided to the AER to complement this document.

7.2 Managing change

Our proposed changes are driven by the need to ensure our tariffs structures are supporting the current and future changes in how customers source and use energy. Providing efficient signals though our prices ensures that customers have better information as to how they use the network, providing fairer outcomes to all customers and the potential for lower investment in future years.

Our pricing strategies are interlinked with a range of other strategies to allow customers more opportunities to adopt greater levels of distributed energy resources, more technology (such as EVs) and more flexibility to reduce their energy bills. We've expanded our use of flexible tariffs to provide greater levels of support for those customers that are unable to adopt load shift practices.

We do acknowledge that there are risks associated with changes to our network tariffs, chiefly the need to adopt a smart meter to access many of the opportunities, the manner in which retailers pass through our structures and rapidly evolving customer technology that may present in the latter part of the regulatory control period. We have attempted to mitigate these impacts through greater levels of customer education, contingency change factors and notifying Government of potential issues.

7.3 Long term benefits for consumers

At the recommendation of our NPWG we sought to project the long-term impacts of tariff changes and dynamic controls on customers.

We asked Dynamic Analysis to look at future expenditure and revenue outcomes as well as bill impacts based on 'book-end scenarios' to understand the individual and economic benefits that may be associated with transitioning to more efficient tariffs - with and without controls on load and generation.

In this case, Dynamic Analysis constructed three 'bookend' scenarios for both the Energex and Ergon networks from FY2030 (the last year of the next determination) to FY2050:

- Scenario 1 – From FY2030 to FY2050, all customers would not be subject to 'time variable' import tariffs (ie: they would be on a fixed/energy volume tariff) and no export tariffs would apply. There would also be no application of controls on any appliances.
- Scenario 2 – From FY2030 to FY2050, all customers would be on tariff structures consistent with the demand and export tariffs outlined in this TSS. However, there would be no dynamic controls of CER or appliances.
- Scenario 3 – Dynamic controls would complement tariff changes, and be applied to customer energy resources and controllable appliances such as electric vehicles.

For both networks, the modelling suggests that capital (capex) and operating expenditure (opex) would likely be significantly higher under Scenario 1 where no 'time variable tariffs', export tariffs or dynamic controls are applied. Scenario 2 would result in significantly lower capex and opex than Scenario 1. Scenario 3 would result in the lowest expenditure.

Higher peak demand growth is likely if customers are not provided with tariff incentives to shift demand to off-peak periods. In particular, most recent data shows that electric vehicles are likely to be disproportionately charged in the evening peak if customers are provided with no incentives to shift charging times.

Higher peak demand results in more investment in augmenting (new infrastructure) the network under Scenario 1. Under Scenario 2, customers respond to the peak demand signal by shifting a significant amount of load to off-peak periods, lowering investment in new infrastructure.

Scenario 3 has the lowest amount of new infrastructure investment as it provides customers with the convenience of shifting load to off-peak periods (such as electric vehicles) without having to 'plug in' and 'plug out' themselves. Further, Scenario 3 allows for more control over expected surges in peak demand such as during the holiday periods where customers are anxious about having fully charged electric vehicles.

Lower expenditure drives lower average network prices in Scenario 2 compared to Scenario 1. Scenario 3, which includes time variable network tariffs and controls results, in the lowest unit cost for customers as a result of lower expenditure in the FY30 to FY50 period.

Dynamic Analysis also modelled the long-term customer impacts for each scenario for different customer segments. In particular, it examined whether a customer without access to energy efficiency, electric vehicles and CER would share in the overall price benefits that accrue more generally across the customer base. The key finding was that if customers shifted a small proportion of their load during the peak time, they would likely share in the benefits.

8 COMPLIANCE WITH PRICING PRINCIPLES

In this section we outline how we developed our proposed tariffs and how our proposal satisfies the AER pricing principles.

8.1 Overview of Pricing Principles

Clause 6. 18. 1A(b) of the NER requires that a TSS must comply with the pricing principles which are set out in clause 6. 18. 5 of the NER. The pricing principles require that:

- The revenue to be recovered must lie between an upper bound (stand-alone cost) and a lower bound (avoidable cost) (clause 6. 18. 5(e))
- Tariffs must be based on the Long Run Marginal Cost (LRMC) of providing the service to which it relates to the retail customers assigned to the tariff (clause 6. 18. 5(f))
- Tariffs must be designed to recover revenue in a way that minimises distortions to the price signals, efficient costs of serving the retail customers that are assigned to the tariffs (clause 6. 18. 5(g))
- We must consider the impact on retail customers of changes in tariffs from the previous year and may reasonably vary from the need to comply with the pricing principles after a reasonable period of transition to the extent necessary to mitigate the impact of changes (clause 6. 18. 5(h))
- The structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff, having regard to the type and nature of those customers, and feedback resulting from the engagement with customers (clause 6. 18. 5(i)), and
- A tariff must comply with the NER and all applicable regulatory instruments (clause 6. 18. 5(j)).

These are further discussed in the following sections.

8.2 Standalone and Avoidable Costs

The NER requires the revenues recovered from each tariff class to be within a band that is:

- less than the standalone cost of providing network services to that tariff class; and
- at least equal to the avoidable cost of providing network services to that tariff class.

The upper and lower bands provide useful guardrails for each tariff class and to ensure that there are no inefficient economic cross-subsidies contained within the tariff classes for the following reasons:

- **Stand-alone cost**: If customers were to pay above the stand-alone cost, then it may be beneficial for customers to switch to an alternative service arrangement creating the possibility of inefficient bypass of the existing infrastructure.
- **Avoidable cost**: If customers were to be charged below the avoidable cost, it would be economically beneficial to stop supplying the customers as the associated costs would exceed the revenue obtained from the customer.

The NER does not prescribe the methodology that should be used to calculate the stand-alone and avoidable costs of tariff classes of the network. We have chosen to base our cost estimations by first classifying each of our network cost categories on the basis of the following two dimensions: whether costs are direct or indirect; and whether costs are scalable or non-scalable.

8.2.1 Methodology

Our stand-alone and avoidable cost estimates are prepared using building block costs from the post-tax revenue model. The avoidable costs include scalable operating costs for assets and customer services. Stand-alone costs also include the indirect component for operating costs and the return on capital expenditure. We derive standalone and avoidable cost boundaries for each tariff class in line with the methodologies applied by other DNSPs which largely involves the following steps:

Avoidable costs

1. Collate relevant operating and capital costs associated with standard control services.
2. Determining the proportion of different operating and capital expense categories that would be avoidable.
3. Assigning what percentage of these avoidable costs are allocated based on different measures (ie those allocated on a customer or energy related basis).
4. Sum all categories for each customer class using relevant weights for the number of customers and energy consumption.

The equation below provides a graphical description of the methodology:

Equation 1

$$\mathit{Avoidable\ cost}_{ct} = \mathit{customer\ related\ costs}_t * \frac{\frac{\mathit{Customer\ numbers}_{ct}}{\mathit{Total\ customer\ numbers}_t}}{\mathit{Total\ building\ block\ cost}_t} + \mathit{energy\ related\ costs} * \frac{\frac{\mathit{Energy}_{ct}}{\mathit{Total\ energy}_t}}{\mathit{Total\ building\ cost}_t}$$

Standalone costs

1. Collate relevant operating and capital costs associated with standard control services.
2. Determine if the cost is either scalable - meaning that cost varies with the number of customers or energy consumed, or non-scalable - where the cost is fixed and does not vary with customer numbers or consumption.
3. Calculate standalone costs, which are a function of avoidable costs (those that depend on a customer class), scalable indirect costs and non-scalable indirect costs.

The equation provides a graphical description of the methodology:

Equation 2

$$\mathit{Standalone\ cost}_{ct} = \mathit{avoidable\ cost}_{ct} + \frac{\mathit{Non-scalable\ costs}_t + (\mathit{Scalable\ costs}_t * \mathit{Proportion\ of\ scalable\ costs})}{\mathit{Total\ building\ cost}_t}$$

Where c denotes customer class and t denotes year.

The table below demonstrates that our distribution revenue for 2025-26 from each tariff class falls between the avoidable and stand-alone cost boundaries:

Table 9 - Standalone and Avoidable Costs

Transition Period	Avoidable Cost	2025-26 Distribution Use Of System (DUOS) Total	Stand-alone Cost
Standard Asset Customers (SAC)	$236,626,302	$1,316,186,460	$1,327,669,248
Connection Asset Customers (CAC)	$18,681,276	$80,937,388	$543,285,873
Individually Calculated Customers (ICC)	$56,985,399	$65,943,557	$266,902,025
Note: Figures above are GST exclusive			

8.3 Long Run Marginal Cost

8.3.1 Overview

Efficient tariffs are based on the LRMC of providing the service to customers assigned to that tariff.

The pricing principles set out in the NER require each tariff to be ’based on‘ the LRMC of providing the service to the retail customers assigned to that tariff class, with the method of calculating such cost and the manner in which that method is applied to be determined having regard to the following:

- The costs and benefits associated with calculating, implementing and applying the method.
- The additional costs associated with meeting incremental demand for the customers assigned to the tariff at times of greatest utilisation of the relevant part of the distribution network.
- The location of customers and the extent to which costs vary between different locations.

In accordance with clause 6. 18. 5(f) of the NER, we have estimated the LRMC values at each major voltage level of our network for use as the basis of network tariffs.

Changes to the NER in 2021 aimed at integrating DER more efficiently into the electricity grid[8] remove previous barriers for export charging and create a framework for DNSPs to charge and reward customers for export into the distribution grid. These changes, along with the AER Export Tariff Guidelines, require tariffs to be set based on LRMC for *both* import and export services.

[8] For more information on the rule change, see AEMC, Access, pricing and incentive arrangements for distributed energy resources, Rule determination, 12 August 2021. Available at: https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources

8.3.2 NER Requirements

As set out in the National Electricity Rules (NER), a DNSP's tariff structure should be aligned with pricing principles to reflect sound economic practices whilst protecting consumers. Specific to LRMC, the three primary sections of the rules are:

- Section 6. 18. 5 (a) Network pricing objective
- Section 6. 18. 5 (f) Pricing principles
- Section 6. 8. 1B (c) Export Tariff Guidelines.

8.3.3 LRMC approach in 2020-25 TSS and Associated Feedback

There are three main approaches for estimating import and export LRMC:

- The perturbation (Turvey) approach
- The average incremental cost (AIC) approach
- The long run incremental cost (LRIC) approach.

The Turvey and AIC approaches both involve forecasting costs and demand over a long time period. The LRMC is then determined by dividing the present value of costs attributable to meet a change in anticipated demand by the discounted sum of the anticipated change in future demand.

The LRIC approach is based on the cost of building a hypothetical network to supply a total coincident demand of 500 MW. The Optimised Replacement Costs (ORC) forms the basis for LRMC estimation. This was the approach we adopted for the 2020-25 TSS.

In the 2020–2025 TSS, the LRIC approach was used to estimate LRMC. While the LRIC approach embodies the state of the network such as spatial characteristics and regulatory standards, the AER indicated that the model did not account for a grounded measure of spare capacity – important as a part of a long-term transition strategy to increase the awareness of cost-reflective tariffs structures and time of congestion.

Since LRMC is a forward-looking concept, the AER noted that its estimate should consider a time dimension in both expenditure and demand specific to the network. The AER's expectation for any future TSS would include consideration of alternative approaches. In response to the AER's decision we assessed different LRMC estimation methodologies before finalising our approach in the 2025-30 TSS. Our findings are outlined below:

- The AIC approach remains the most widely used industry practice and it is the recommended method for us to adopt to calculate LRMC based on the current and anticipated future state of our network.
- The AIC calculation is an improvement to better match the augmentation costs and the associated increase in demand.
- Expenditure inputs should consist of peak demand growth-related costs such as augmentation costs and growth-related connections costs.
- Common practice is to exclude replacement costs from LRMC estimation where the costs are non-demand driven, noting replacement costs play some role in deriving the cost savings per unit of reduction in demand.
- Minimum demand export charge pricing principles should be based on LRMC in a similar way as import charges. Given the anticipated growth in customer export to the distribution

networks and associated network augmentation expenditure over the regulatory period, AIC is the recommended approach to calculate export LRMC at times of minimum demand.

Based on our findings, we have adopted the AIC approach for LRMC estimation for both import and export services in the 2025 - 2030 TSS.

8.3.4 Average incremental cost approach overview

The AIC method entails estimating the LRMC by considering the expenditure required to meet the forecasted increment demand between each time period (e. g. year), then averaging these costs over the long run period. Conceptually, it involves:

1. Forecasting demand over the long run period (e. g. 10 years)
2. Developing the optimised capital expenditure investment plan to meet the forecasted demand
3. Deriving LRMC as the present value of the additional costs of meeting incremental increase in demand divided by the present value of the future increase in demand.

It is calculated as:

$$LRMC = \frac{PV(additional\ costs\ to\ meet\ incremental\ demand)}{PV(incremental\ demand)}$$

8.3.5 Capital Expenditure Inputs

Distribution businesses commonly include direct costs driven by the growth in peak demand for AIC calculation. Common categories include:

- growth related augmentation capex (augex)
- any system augmentation costs that are included in new connections.

The AER suggested the inclusion of replacement costs in LRMC calculation should be included since the decision regarding the timing and size of any replacement may be influenced by the change in demand.

We note the Expenditure Forecast Assessment Guideline by the AER which states:[9]

> *'Replacement expenditure is the **non-demand driven** capex to replace an asset with its modern equivalent where the asset has reached the end of its economic life.'*

This suggests that only the replacement of assets with increased capacity can be considered as demand driven and included in the LRMC calculation. In practice, this type of replacement costs is classified as augmentation cost for many distributors so the entirety of growth-related expenditure in AIC calculation might not consist of any replacement costs.

[9] AER, Explanatory Statement – Expenditure Forecast Assessment Guideline, November 2013, p.184.

8.3.6 Import LRMC approach

We have adopted the growth/declining categorisation of zone substations as a refinement to address the assessment criteria of deriving a more cost-reflective estimate, as well as investigating the inclusion of replacement expenditure.

We consider expenditure costs relevant to this group are growth-related augmentation and connection costs. No replacement costs have been included because this forecast is non-demand driven. Capacity enhancing capex - where it is demand-driven - is routinely classified as augmentation costs. Growth-related connections cost is input as a percentage of total connections cost.

8.3.7 Export LRMC approach

The export LRMC considers only the augmentation expenditure in a forward-looking manner, similar to that of import LRMC. Customer export capacity is forecast to continue to grow strongly which is consistent with adopting an AIC approach to calculating export LRMC. Export services are largely across the LV network, and with identified investment impact on the LV and HV network assets.

Consistent with our approach to calculating the import LRMC, we have adopted the AIC method for estimating export LRMC. This involves considering the expenditure required to meet the forecast incremental export between each time period (e. g. year), and then averaging these costs over the long run period.

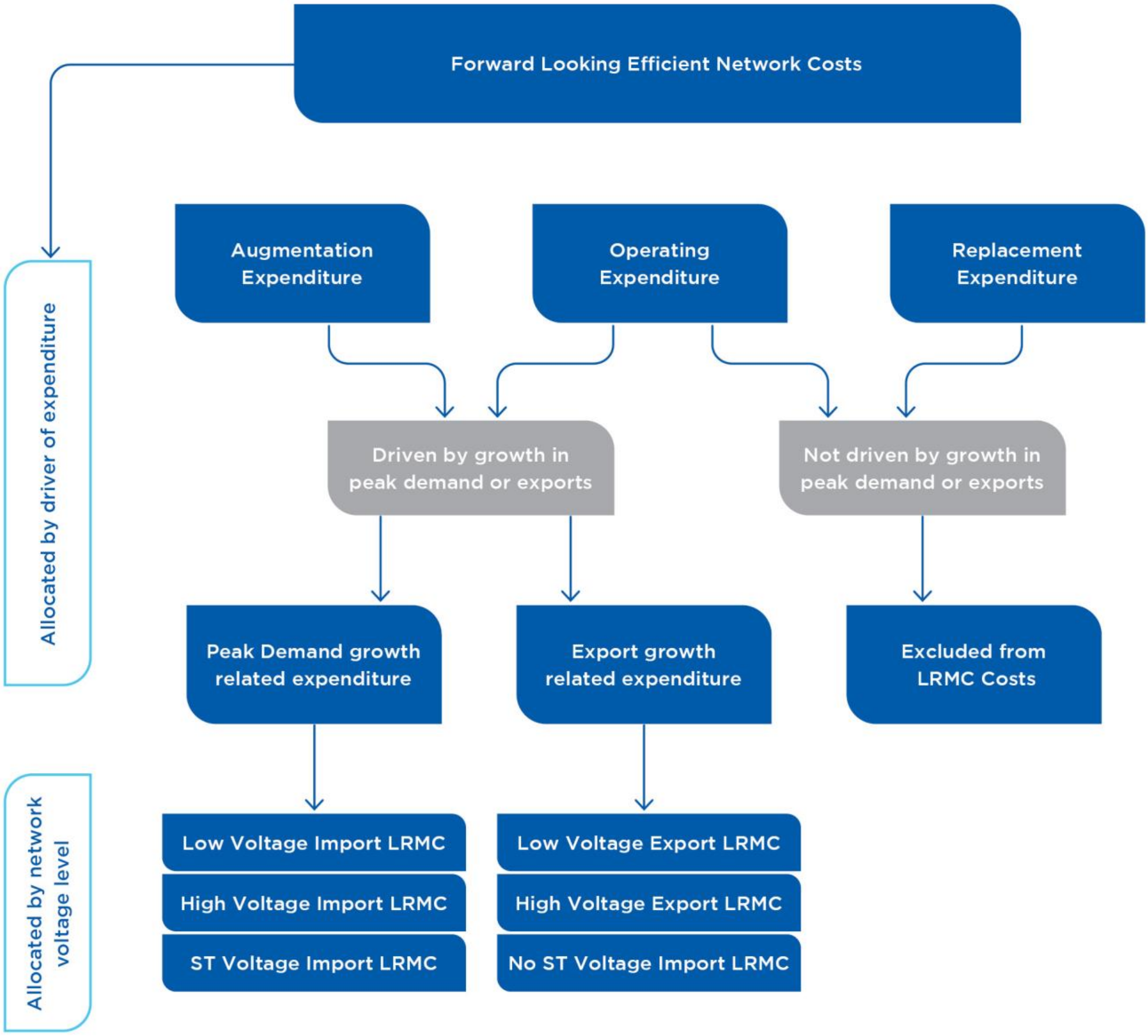
Conceptually, the LRMC calculation involves:

1. forecasting export capacity over the long run period (e. g. 10 years).
2. developing the optimised capital expenditure investment plan to meet the forecasted export capacity.
3. estimating the present value of the additional costs of meeting incremental increase in customer export divided by the present value of the future increase in export capacity.

8.3.8 Model and results

Figure 34 – Import LRMC provides an overview of allocation of network expenditure for import LRMC.

Figure 34 – Import LRMC overview



Control parameters and assumptions

The control parameters are listed in Table 10 below. These parameters will stay constant over the forecasting horizon.

Table 10 - Control parameters and assumptions

Parameter Name	Description
Real Vanilla WACC	Real Vanilla WACC
Opex Proportion of Capex[10]	A percentage of total Capex to estimate the total Opex for each year.
Percentage repex saved per percentage demand reduction	The percentage of total repex that can be saved per percentage demand reduction on average.
Growth Related Repex Percentage	The proportion of total repex that is classified as growth-related.
Growth Related Connections Cost Percentage	The network augmentation proportion of total new connections cost (growth-related).

Granular inputs

The granular inputs required for the model are listed in Table 11 below. These inputs are sourced from our internal forecasts. The growth/declining group categorisation of zone substations, as discussed above is part of the preparation of our model inputs. There is no granularity by expenditure type for export expenditure.

Table 11 - Granular inputs

Parameter Name	Description
Import forecast	Aggregated coincident demand forecast for substations for each granularity combination
Export forecast	Aggregated export capacity forecast for substations for each granularity combination
Import expenditure forecast	Aggregated demand driven expenditure forecasts for substations or programs for each granularity combination
Export expenditure forecast	Aggregated export driven expenditure forecasts programs for each granularity combination
Asset Specification	Asset specification and loss factors such as Distribution Loss Factors (DLF) and Power Factors (PF) for assets in each granularity combination

Demand and export capacity summary

[10] As noted above, the functionality for classifying growth-related repex as a percentage of total repex is to preserve model versatility, rather than the proposed recommendation on the treatment of repex.

Existing demand/capacity refers to the total demand/capacity aggregated to the stated granularity. Incremental demand/capacity is the growth each year. The NPV of incremental demand (or existing demand for import declining category) will be used for LRMC calculation.

Expenditure

The formula of total capex varies between each category. While the import declining group only accounts for reduced replacement cost as capex and export capacity group takes total capex as input, the import growing group calculates the total capex as:

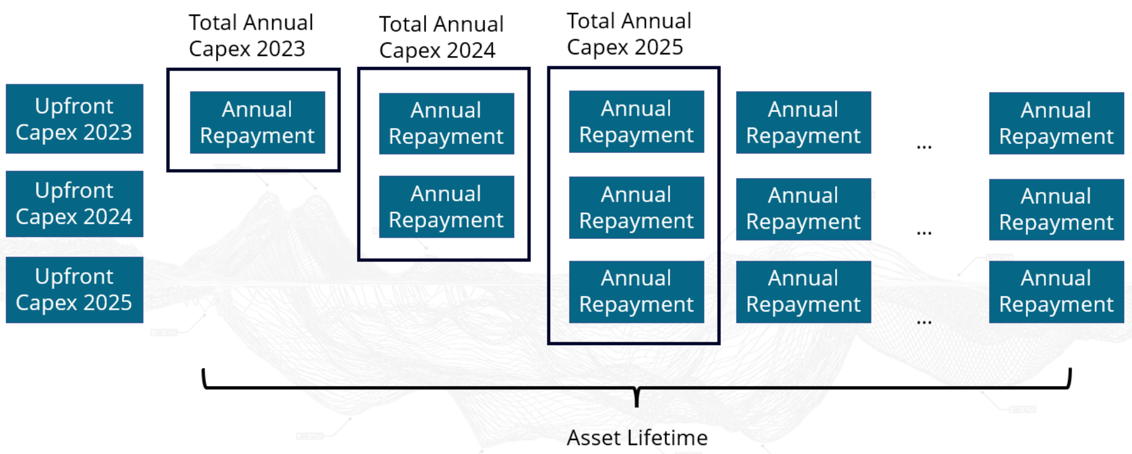
$$Total\ capex = augex + \%growth\ repex \times repex + \%new\ connections \times connections\ cost$$

The tables in the model lay out sequentially each calculation step applied to the expenditure data throughout the LRMC calculation. The LRMC model (Ergon - 9.05 - Endgame Economics LRMC model - January 2024 - public):

1. Calculate total capex (and opex as a percentage of capex).
2. Annualise capex by splitting the total upfront capex into annual payments over asset lifetime, discounted by WACC.
3. Calculate cumulative annualised capex – the total annual capex payment from all previous years plus new annualised capex incurred at present year (as described in Figure 35).
4. Total annual cost is the sum of cumulative annualised capex and opex
5. (Import declining) Calculate the repex saving by multiplying the total annual cost by the percentage repex saved per percentage demand reduction.

The resultant total annual cost each year will be used to calculate the NPV of expenditure for LRMC estimation.

Figure 35 - Annualising capex payments



LRMC segmentation

To provide clarity and transparency in cost reflectivity for customers, segmentation of LRMC is considered to allocate LRMC to each part of the network. In other words, when a consumer decides to produce an additional unit of output at any voltage level, the following cost allocations are calculated:

- The costs to each of the upstream assets.

- The aggregated total cost to all upstream assets.

The cost allocation procedure splits the NPV of total costs for any asset to each of the downstream consumers by coincident demand proportions. Figure 36 describes this approach:

Figure 36 – Example cost segmentation to upstream assets for consumers

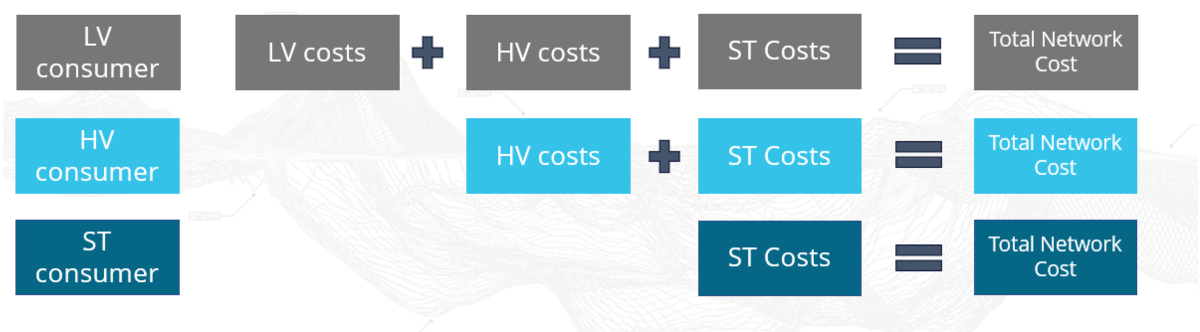
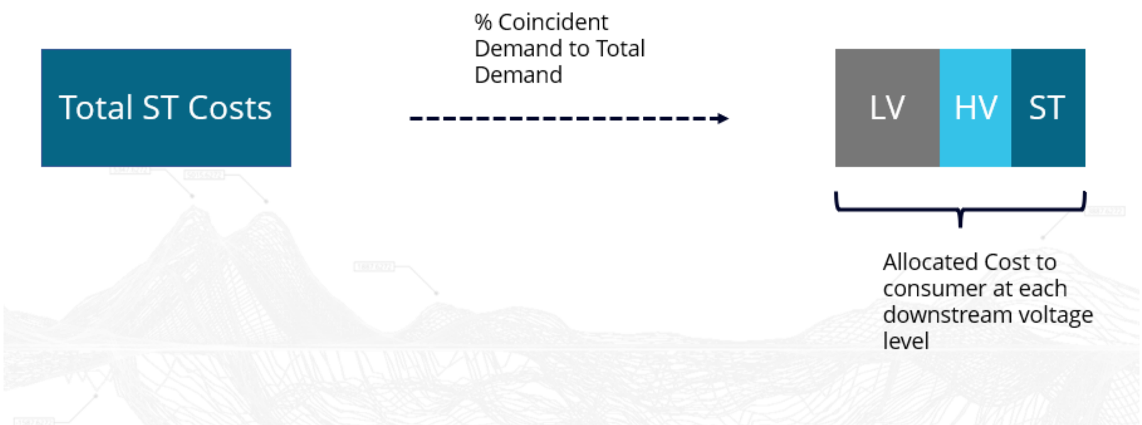


Figure 37 – Example allocation of asset costs to downstream consumers



The LRMC assigned to consumers at each voltage level is estimated by dividing the allocated total network costs by the NPV coincident demand. Further, dividing any voltage level allocated costs by the NPV coincident demand will give an isolated LRMC estimate specific to the costs incurred to the assets at that voltage level. Note that the segmentation approach is analogous for the import declining group where the NPV reduced costs is used in place of NPV total costs.

8.3.9 LRMC Estimates

Table 12 - Long Run Marginal Cost Estimates – Ergon East

Voltage	Annual Import		Annual Export	
	$/kW	$/kVA	$/kW	$/kVA
Low Voltage	262.440	236.190	54.890	49.400
High Voltage Line	223.810	201.430	6.040	5.440
High Voltage Bus	124.570	112.120	6.040	5.440
Sub-Transmission	46.860	42.180	N/A	N/A

Table 13 - Long Run Marginal Cost Estimates – Ergon West

Voltage	Annual Import		Annual Export	
	$/kW	$/kVA	$/kW	$/kVA
Low Voltage	270.590	243.530	53.600	48.240
High Voltage Line	214.370	192.930	5.900	5.310
High Voltage Bus	205.670	185.100	5.900	5.310
Sub-Transmission	55.430	49.880	N/A	N/A

Table 14 - Long Run Marginal Cost Estimates – Ergon Mount Isa

Insert Table Voltage	Annual Import		Annual Export	
	$/kW	$/kVA	$/kW	$/kVA
Low Voltage	176.320	158.690	54.890	49.400
High Voltage	87.640	78.880	6.040	5.440

8.4 Recovering Efficient costs and minimising distortionary signals

8.4.1 Tariff Setting Methodology

To ensure revenue recovery for each tariff class remains between upper and lower bounds we allocate allowed revenues based on a relative contribution of each tariff class to system and non-system assets. In relation to system assets we attribute relative costs of the network to voltage levels based on the relative contribution of the class to the voltage level. For example, the low voltage tariff class receives a larger distribution cost allocation given a low voltage connection uses more network assets.

ICC and CAC Tariff Classes

Tariff setting for ICC and CAC customers reflects a historical approach of establishing site specific prices to reflect the customers specific contribution to existing and forward looking costs of dedicated connection and shared infrastructure assets at a locational level.

This is because there is significant variation across our customers in these classes in respect to:

- how far upstream they are connected to the network, and therefore the extent to which they use common infrastructure.
- the geographic location of the customer
- the nature and extent to which customers have funded (or contributed in advance) connection infrastructure.

Site specific tariffs are not unique to our network. They are accepted as a suitable means for introducing locational charging parameters and can better signal to large customers the actual costs of their connection and network use.

Our 2023-24 Annual Pricing Proposal outlines our methodology for calculating tariffs for our major customers. Tariffs for ICC and CAC tariff classes are set having regard to LRMC of providing services for all customers in the tariff class, the relative share of common infrastructure the contribution arrangements at time of connection and the relative contribution to shared infrastructure.

In relation to the ICC tariff class the attribution relates to each sites relative contribution to dedicated connection and shared cost elements based on the customer's specific location, recognising the more complex nature of these connections and connection arrangements and the significant attribution to each connection to fully dedicated and shared infrastructure.

CAC customers also have attribution to both their contribution to dedicated infrastructure as well as shared infrastructure for their class.

We do have regard to the LRMC values established as part of our LRMC Methodology (AIC). However, the AIC methodology provides an average LRMC value for all customers in the ICC class, whereas the methodology for ICC customers provides more locational signals. For a majority of customers in this class connecting close to the bulk supply point, connection agreements often reflect a capacity which they contributed much of the investment for up front – and the extent to which these connections increase capacity significantly, would require additional investment and contribution under the relevant connection policy. Nevertheless, the LRMC component is proportionally collected through the demand charge.

LRMC values form the basis for the CAC optional network tariff structure. A critical peak price arrangement is in place for the proposed new storage tariffs. For these customers we also adopt an approach for allocation of transmission charges in away that preserves where possible the locational basis of these signals at a transmission connection point.

SAC Tariff Class

LRMC values are derived for all major voltage levels and form the basis for all SAC default network tariff structures. Import LRMC values are applied to the peak demand period changes assigned to tariffs. In some circumstances a value less than full LRMC is applied to manage customer impact with an aim to build the LRMC signal over time.

Export LRMC is applied in a similar way, having regard to the Basic Export Level. A critical peak price arrangement is in place for storage tariffs. The NER allows for Ergon to recover its residual costs which are included in its expected revenue allowance. However, it establishes constraints on the recovery of these costs in that:

- the revenue expected to be recovered from each tariff must reflect the total efficient cost of serving the customers assigned to each tariff
- the revenue expected to be recovered from each tariff must minimise distortions to the price signals for efficient usage that would result from tariffs that reflect LRMC.

Residual revenue (remaining revenue after ICC and CAC revenue as well as LRMC based revenue is removed) reflects current residual recovery applied to the tariff. Revenue is allocated to remaining charges in a way that meets pricing principles, balancing the need for recovery in the least distortionary manner, customer impact and customer and retailer preferences.

Residual revenue is usually collected from outside the peak demand window. For some tariffs we have also incorporated differential rates for recovery of residual charges for different times of the day. This includes targeting a zero rate for DUOS charges for the midday window. The implementation of time varying rates to recover residual revenues provides the greatest incentive for customer to move energy usage to the middle of the day, with the potential to:

- defer or avoid investment to remove future import constraints
- defer or avoid investment to remove future export constraints.

Time varying rates also minimise distortions that could otherwise occur through inefficient use of the network – this may occur where customers bypass residual network charges in the middle of the day through adoption of solar.

Where customers have choice between legacy and cost-reflective tariffs, residual costs are assigned so as to encourage customers to shift to tariffs that have the most efficient price signal.

Over time, charging parameters are rebalanced to ensure that the shifting of customers between tariffs:

- does not lead to under- or over-recovery of revenue; and
- does not result in unacceptable bill shock.

Lower charges are offered to customers who take up connection arrangements which allow us to control the operation of appliances dynamically. Appliances on secondary load control tariffs do not face peak demand charges. Volume rates are also discounted to encourage retention.

The flexible load tariff applies a discounted rate to the fixed charge in return for dynamic control of appliances on the primary circuit.

8.5 Impact on retail customers

Our engagement approach tested customer preferences to the pace of change to network tariffs which are necessary for efficient customer outcomes given the rapid energy sector and environment changes. We have also tested outcomes of different tariff structures and prices having regard to network bill impact for all customers and, in some cases customer segments to ensure we balance equity and fairness in the short term with efficient tariff design.

During our engagement phase, customers asked us to do more to inform and educate customers on tariff structures and impacts for customers. We have already addressed some concerns by refining our website material and information sheets. We aim to address other concerns with additional information and education over time.

8.6 Side Constraint

The side constraint limits how much revenue can be recovered from a tariff class (a class of customers) relative to the revenue recovered from the same tariff class in the preceding year. The objective of the side constraint is to limit large variability in revenue recovery between tariff classes during a regulatory period.

The Rules limits changes in revenue recovery from any one tariff class to no more than the revenue changes plus 2%. While the Rules set out the limitation to be imposed by the side constraint, the specific application of the side constraint mechanism is set out in the AER’s distribution determinations.

To abide by the side constraint Rule requirements, we will ensure that the DUOS revenue recovered from each tariff class does not exceed the permissible side constraint limit. Compliance with the side constraint mechanism will be demonstrated in our annual Pricing Proposals.

8.7 Compliance Checklist

Rule Reference	Requirement	Document Reference
6.8.2	**Submission of regulatory proposal, tariff structure statement and exemption application**	
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 Providers distribution system.	TSS Section 1.1
6.8.2(a1)	A Distribution Network Service Provider must submit to the AER any exemption application for an asset exemption under clause 6.4B.1(a)(1) or 6.4B.1(a)(2) for the regulatory control period at the same time as submitting the relevant regulatory proposal under paragraph (a).	Noted
6.8.2(b)	A regulatory proposal, a proposed tariff structure statement and, if required under paragraph (a1), an exemption application must be submitted: (1) at least 17 months before the expiry of a distribution determination that applies to the Distribution Network Service Provider; or (2) if no distribution determination applies to the Distribution Network Service Provider, within 3 months after being required to do so by the AER.	Noted
6.8.2(c)(7)	A regulatory proposal must include a description (with supporting materials) of how the proposed tariff structure statement complies with the pricing principles for direct control services including: (i) a description of where there has been any departure from the pricing principles set out in paragraphs 6.18.5(e) to (g); and (ii) an explanation of how that departure complies with clause 6.18.5(c).	TSS Section 5
6.8.2(c1)(2)	The regulatory proposal must be accompanied by an overview paper in reasonably plain language which includes a description of: (i) how the Distribution Network Service Provider has engaged with relevant stakeholders including distribution service end users or groups representing them and (in relation to the tariff structure statement) retailers and Market Small Generation Aggregators in developing the regulatory proposal and the proposed tariff structure statement including the export tariff transition strategy; (ii) the relevant concerns identified as a result of that engagement; and (iii) how the Distribution Network Service Provider has sought to address those concerns;	TSES Section 5&6

Rule Reference	Requirement	Document Reference
6.8.2(c1)(5)	The regulatory proposal must be accompanied by an overview paper in reasonably plain language which includes a description of the key risks and benefits for distribution service end users of the regulatory proposal and the proposed tariff structure statement including the export tariff transition strategy;	TSES Section 6.2 TSES Section 8
6.8.2(d1)	The proposed tariff structure statement must be accompanied by an indicative pricing schedule.	Attached
6.8.2(d2)	The proposed tariff structure statement must comply with the pricing principles for direct control services.	TSS Section 5
6.8.2(e)	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.	TSS Section 1.1
6.8.2(f)	If, at the commencement of this Chapter, 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.	Noted
6.18.1A	**Tariff structure statement – must include:**	
6.18.1A(a)(1)	the tariff classes into which retail customers for direct control services will be divided during the relevant regulatory control period	TSS Section 2.1
6.18.1A(a)(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)	TSS Section 4
6.18.1A(a)(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)	TSES Section 6.2
6.18.1A(a)(3)	the structures for each proposed tariff	TSS Section 3
6.18.1A(a)(4)	the charging parameters for each proposed tariff	TSS Section 3
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 **Note** Under clause 11.141.13(a), a tariff structure statement of a Distribution Network Service Provider applicable during the tariff transition period for the Distribution Network Service Provider must also include, for each proposed export tariff, the	TSES Section 5 TSES Section 8

Rule Reference	Requirement	Document Reference
	basic export level or the manner in which the basic export level will be determined and the eligibility conditions applicable to each proposed export tariff.	
6.18.1A(b)	A tariff structure statement must comply with the pricing principles for direct control services.	TSS Section 5 TSES Section 8
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.	Attached
6.18.3	**Tariff classes**	
6.18.3(b)	Each retail customer for direct control services must be a member of 1 or more tariff classes	Section 2.1
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)	Section 2.1 & 2.2
6.18.3(d)	A tariff class must be constituted with regard to: (1) the need to group retail customers together on an economically efficient basis; and (2) the need to avoid unnecessary transaction costs.	Section 2.1
6.18.4	**Principles governing assignment or re-assignment of retail customers to tariff classes and assessment and review of basis of charging**	
6.18.4(a)	In formulating provisions of a distribution determination governing the assignment of retail customers to tariff classes or the re-assignment of retail customers from one tariff class to another, the AER must have regard to the following principles:	Noted
6.18.4(a)(1)	retail customers should be assigned to tariff classes on the basis of one or more of the following factors: **(i)**the nature and extent of their usage or intended usage of distribution services; **(ii)**the nature of their *connection* to the network; **(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;	TSS Section 2.1
6.18.4(a)(2)	retail customers with a similar *connection* and distribution service usage profile should be treated on an equal basis, subject to subparagraph (3A)	TSS Section 2.1

Rule Reference	Requirement	Document Reference
6.18.4(a)(3A)	retail customers connected to a regulated SAPS should be treated no less favourably than retail customers connected to the interconnected national electricity system	TSES Section 4.2
6.18.4(a)(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. **Note:** If (for example) a customer is assigned (or reassigned) to a tariff class on the basis of the customer's actual or assumed maximum demand, the system of assessment and review should allow for the reassignment of a customer who demonstrates a reduction or increase in maximum demand to a tariff class that is more appropriate to the customer's load profile.	TSS Section 2.2
6.18.4(b)	If the charging parameters for a particular tariff result in a basis of charge that varies according to the distribution service usage 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.	TSS Section 2.2
6.18.5	**Pricing principles**	
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. **Note:** Charges in respect of the provision of direct control services may reflect efficient negative costs.	TSS Section 5 TSES Section 9
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).	TSS Section 5 TSES Section 9
6.18.5(c)	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: (1) to the extent permitted under paragraph (h); and (2) to the extent necessary to give effect to the pricing principles set out in paragraphs (i) to (j).	TSS Section 5 TSES Section 9
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.	TSS Section 5 TSES Section 9
6.18.5(e)	For each tariff class, the revenue expected to be recovered must lie on or between: (1) an upper bound representing the stand alone cost of serving the retail customers who belong to that class; and	TSS Section 5 TSES Section 9

Rule Reference	Requirement	Document Reference
	(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 of providing the service to which it relates to the retail customers assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to: (1) the costs and benefits associated with calculating, implementing and applying that method as proposed; (2) the additional costs likely to be associated with meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant service; and (3) the location of retail customers that are assigned to that tariff and the extent to which costs vary between different locations in the distribution network.	TSS Section 5 TSES Section 9
6.18.5(g)	The revenue expected to be recovered from each tariff must: (1) reflect the Distribution Network Service Provider's total efficient costs of serving the retail customers that are assigned to that tariff; (2) when summed with the revenue expected to be received from all other tariffs, permit the Distribution Network Service Provider to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the Distribution Network Service Provider; and (3) comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage of the relevant service that would result from tariffs that comply with the pricing principle set out in paragraph (f).	Pricing Proposal TSES Section 9
6.18.5(h)	A Distribution Network Service Provider must consider the impact on retail customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the Distribution Network Service Provider considers reasonably necessary having regard to: (1) the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one regulatory control period); (2) the extent to which retail customers can choose the tariff to which they are assigned; and (3) the extent to which retail customers are able to mitigate the impact of changes in tariffs through their decisions about usage of services.	TSS Section 5 TSES Section 9
6.18.5(i)	The structure of each tariff must be reasonably capable of: (1) being understood by retail customers that are or may be assigned to that tariff (including in relation to how decisions about usage of services or controls may affect the amounts paid by those customers) or	TSS Section 5 TSES Section 9

Rule Reference	Requirement	Document Reference
	(2) being directly or indirectly incorporated by retailers or Market Small Generation Aggregators in contract terms offered to those customers, having regard to information available to the Distribution Network Service Provider, which may include: (3) the type and nature of those retail customers; (4) the information provided to, and the consultation undertaken with, those retail customers; and **(5)**the information provided by, and consultation undertaken with, retailers and Market Small Generation Aggregators.	
6.18.5(j)	A tariff must comply with the Rules and all applicable regulatory instruments.	Noted
11.141.13	**Basic export levels to be specified in tariff structure statements**	
11.141.13(a)(1), (2)	For the purposes of new clause 6.18.1A(a), a tariff structure statement of a Distribution Network Service Provider that will apply during the tariff transition period for the Distribution Network Service Provider must include, in addition to the elements in new clause 6.18.1A(a): (1) for each proposed export tariff, the basic export level or the manner in which the basic export level will be determined; and (2) the eligibility conditions applicable to each proposed export tariff.	TSS Section 3.5.2 TSES Section 6.2