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10 July 2025

Australian Energy Market Commission – via www.aemc.gov.au

Response to AEMC Pricing Review Discussion Paper

Dragoman is an Ottoman word meaning guide or interpreter. We are a boutique advisor in political risk and strategic matters. A key focus area of our work is the public policy and regulatory aspects of the energy and climate transition.

Please find accompanying this letter a public submission for the consideration of the AEMC.

Dragoman was engaged by Energy Consumers Australia to develop this work. We understand that it may be cited or incorporated as supporting material for ECA's submission.

We have been tasked with providing analysis and advice in relation to ECA's objective of improving the equity and fairness of the energy transition for small consumers.

For the purposes of the AEMC Pricing Review, we have focussed on equity and fairness in relation to network costs, and cost recovery processes including (but not limited to) the appropriate design of network tariffs.

We find a variety of areas where there are concerns in this regard, both under the status quo and anticipated as the energy transition progresses.

Of these, perhaps the most material and tractable is the issue between solar PV and battery "haves" versus "have-nots" – and so we examine it carefully and develop some specific recommendations. CER adoption by consumers raises some complex questions about equity and fairness:

- Should the CER "haves" pay more for the network because of the additional benefits they receive from it, rather than less?
- Does CER adoption by some consumers simply lead to material network cost transfers to those without CER (the *prima facie* situation, as we demonstrate)? Or do the system benefits partly or wholly offset this, by providing lower costs to the "have nots"?[1]
- What is the implication for fairness if government-subsided CER investments by the "haves" result in higher comparative network costs for the "have-nots"?

We suggest the AEMC explore these questions as part of further rounds of consultation as the pricing review evolves.

We find many areas of commonality with the AEMC's analysis in the June 2025 Discussion Paper, especially:

1. **Broad network price signals** (e.g. demand charges under postage-stamp tariffs) **are problematic** in regard to whether they are really cost-reflective for the majority of consumers. If not, they are creating deadweight losses.
2. In reality, **most network costs are effectively fixed in the short and long run**, from the perspective of a small electricity consumer and their opportunity to change behaviour in response to price signals.

[1] Well-addressed here: https://www.researchgate.net/publication/299400314_A_Design_Approach_to_Innovation_in_the_Australian_Energy_Industry

3. Complex network tariff design can **impede the development of a broad range of retail tariffs** that may better suit a range of consumers' needs.
4. Given findings that the large majority of system benefits from rooftop PV and batteries accrue in the reduction of wholesale prices, **network pricing should not run counter to wholesale prices signals managed by retailer (or consumers)**.

As a result, we think the AEMC's Pricing Review is an opportunity to rethink network pricing for the evolving grid, and the long-term interests of consumers – whether or not they are willing and able to participate as CER-enabled 'prosumers'.

Our key recommendations are:

- **Basic Access Charge (BAC).** Recover the bulk of network costs via a fixed annual charge per connected household, which maintains the access to import of electricity, but does not include any electricity consumption. This recognises that network access is a basic essential service.
- **Consider alternative channels for recovering the BAC.** Including via councils rather than retailers. This could create a preferential obligation on property owners, rather than electricity consumers, to pay for these costs.
- **Focus concessions on the BAC.** Government has an existing role in ensuring fairness of the energy system for households, including distributionally via means-tested tax and social welfare. The BAC is a simple way to target concessions, ensuring access to electricity is not out of reach.
- **CER tariffs for CER households.** In addition to the BAC, households with rooftop PV, batteries, EV charging or other flexible loads enjoy a greater range of services from their network connection. Secondary CER tariffs should ensure these consumers equitably contribute to network costs, in a way that supports lower overall system costs – via charges and credits similar to emerging two-way tariff structures.
- **Retailer-led tariff design**. When designing CER network tariffs, a primary objective should be alignment of price signals with wholesale. This may mean imperfect network price signals, but better overall price signals for system costs and therefore lower system costs for all consumers.

The BAC+CER Tariffs model we propose has been designed to address the most pressing inequity concern, now and especially in future as CER deployment continues (but not ubiquitously).

It may, if carefully designed and implemented, do little harm in other areas of inequity, and in several cases seems likely improve the situation.

There are various means by which concerns about fairness – such as the impact on smaller or low-consumption households – can be mitigated. Equally, there are other, more equitable levers available to ensure levels of CER adoption meet jurisdictional ambitions, if those exceed what might occur from proper in-market price signals.

Implementation might benefit if the collection of a BAC from was devolved to councils, on a basis similar to council rates, where the onus is on property owners to maintain compliance with the supply of certain essential services – this has several apparent attractions.

Kind regards,

David Heard
Executive Counsellor, Energy

Dragoman

Equity and Fairness in Network Pricing

Dragoman's response to the AEMC's Discussion Paper

Released as a public submission

10 July 2025

Contents

Key Messages and Recommendations

As noted in our covering letter, we find a variety of areas where there are concerns about equity and fairness in network cost recovery from residential consumers, both under the status quo and anticipated as the energy transition progresses.

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Energy Consumers Australia's (ECA) Objectives

In undertaking this research and analysis, Dragoman has worked closely with ECA to understand their objectives in contributing to the AEMC Pricing Review.

ECA is seeking to understand **how to recover network costs equitably and fairly in the energy system of the future**.

This work intends to outline what we know about the current state and direction of the system, its costs and the way consumers use it.

Considering this future, it is important to understand what this may mean for the materiality of inequity or unfairness under current approaches – including the risks of new but foreseeable problems emerging.

ECA has tasked us with considering potential solutions that can anticipate and address future harms from inequity or unfairness now, rather than attempting to redress them in the future.

Defining equity and fairness in network cost recovery

This work has required us to carefully consider some definitions.

In the AEMC's work, reference is made to the National Energy Equity Framework.[2] This suggests *"Energy equity exists where all consumers can fairly benefit from the energy system and access and use energy services to live a comfortable, dignified and healthy life."*

For our purposes, we need to go a little deeper – noting that we are talking narrowly about the allocation of network costs, and so our concern needs to be more specifically about whether **network costs and benefits are equitably and fairly shared among small energy consumers**.

We deliberately use two terms - fairness and equity – which can be subtle to define and may contradict each other in some cases. They may also need to be traded off against other objectives, such as complexity for consumers, efficiency of cost recovery, or minimisation of deadweight costs.

However, it is important that fairness and equity remain a primary focus in designing electricity network pricing and network cost recovery arrangements, and the broader social welfare system. This recognises the fact that access to electricity is an essential service for all households. In this paper, we define each term as follows:

Equity	Fairness
Costs and benefits are allocated appropriately among consumers connected to the network, based on their behaviour and how they interact with the network.	Network pricing structures and levels do not (a) unduly add to social and economic inequalities or (b) prevent households accessing basic energy services.

In practice, this means we assess **equity** without regard for a consumer's financial circumstances (e.g. their capacity to pay). Rather, we assess the generic benefits enjoyed from the network, and the costs contributed. We consider **equity** to be a valid objective of the design of pricing network services to consumers.

As a result, we consider **fairness** to be a question of evening the scales among citizens with differing financial resources, which is generally understood to be a role for government via the tax and social welfare system.

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[2] See: https://www.energy.gov.au/sites/default/files/2025-06/national-energy-equity-framework.pdf

Defining Consumer Energy Resources and their roles

In this paper we use Consumer Energy Resources (CER) as a generic term to represent assets within a small consumer's household which interact with the network in a manner beyond a passive load.

This effectively means rooftop PV generation, and household Battery Energy Storage Systems (BESS), as well as Electric Vehicles (EV) assets that may charge in response to price signals, or mimic a BESS and discharge to meet household self-consumption. It may also represent large flexible loads (pool pumps, air-conditioning) that some highly-engaged consumers (or their agents) may operate flexibly in response to price signals.

In our view, all CER assets represent consumers investing their time and/or money, to then enjoy additional benefits from their access to the network, over and above the basic service of access to electricity imports. These are often economic, but may also be other benefits such as enhanced reliability under network outages, or the satisfaction of replacing higher-carbon electrons from large-scale thermal capacity.

CER challenges to address

While these CER-enabled consumers have made investments and expect to enjoy benefits as a result, it is also important to note:

- Many CER asset investments by consumers have enjoyed explicit policy support from state and federal jurisdictions.
- The benefits of CER can extend beyond their owners to lower overall system costs – IF operated in alignment with appropriate price signals.[3]

CER investment by consumers is not a straightforward choice. There are substantial barriers faced by many consumers, including the necessary financial resources to invest – to some extent, partial government support for CER deployment is regressive.

Even those with the capacity to invest may face other barriers, especially the ability to install CER if renting, or the impracticality if living in apartment-style housing without a suitable rooftop, and/or with administrative barriers via strata arrangements.

Because of these considerations, CER deployment by some household consumers raises complex questions about equity and fairness which we deal with in some detail in this report

[3] According to Energeia's work for the AEMC, 88% of these system benefits are related to wholesale electricity costs, with network costs a substantial minority at 11%. See: https://www.aemc.gov.au/energeia-finds-cer-flexibility-could-deliver-45b-benefits-2050

Executive Summary

We find a variety of areas where there are concerns about equity and fairness in network cost recovery from residential consumers, both under the status quo and anticipated as the energy transition progresses.

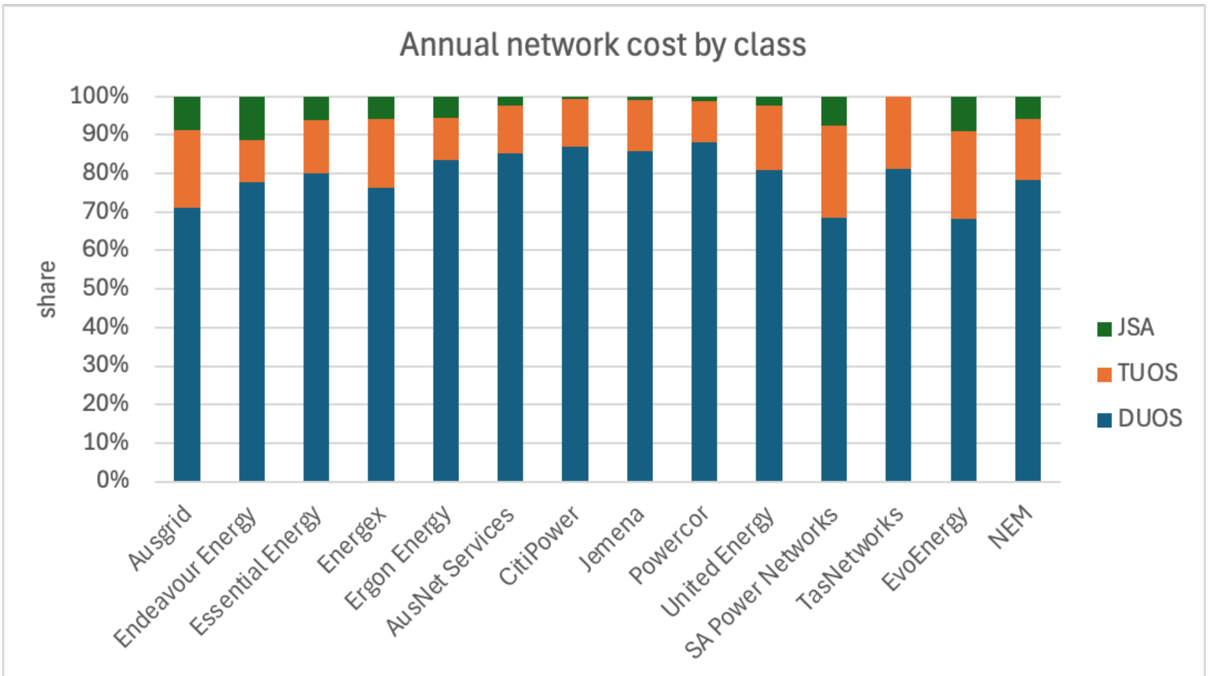
This leads us to our key recommendations.

Network costs are material and forecast to grow

Network charges are substantial contributors to consumer electricity costs – AEMC's Discussion Paper notes they account for roughly 40% of a residential consumer's bill, and AEMC Residential Electricity Price Trends Report indicates these are forecast to grow based on investment required under the energy transition and demand growth.

There are three main components of these costs:

1. **Transmission** networks (aka TUOS)
2. **Distribution** networks (aka DUOS)
3. A variety of **Jurisdictional Scheme Amounts** (JSA) – which are costs related to energy and environmental policies at State or Territory level, such as the ACT's renewable energy offtake costs, and NSW's Electricity Infrastructure Roadmap.



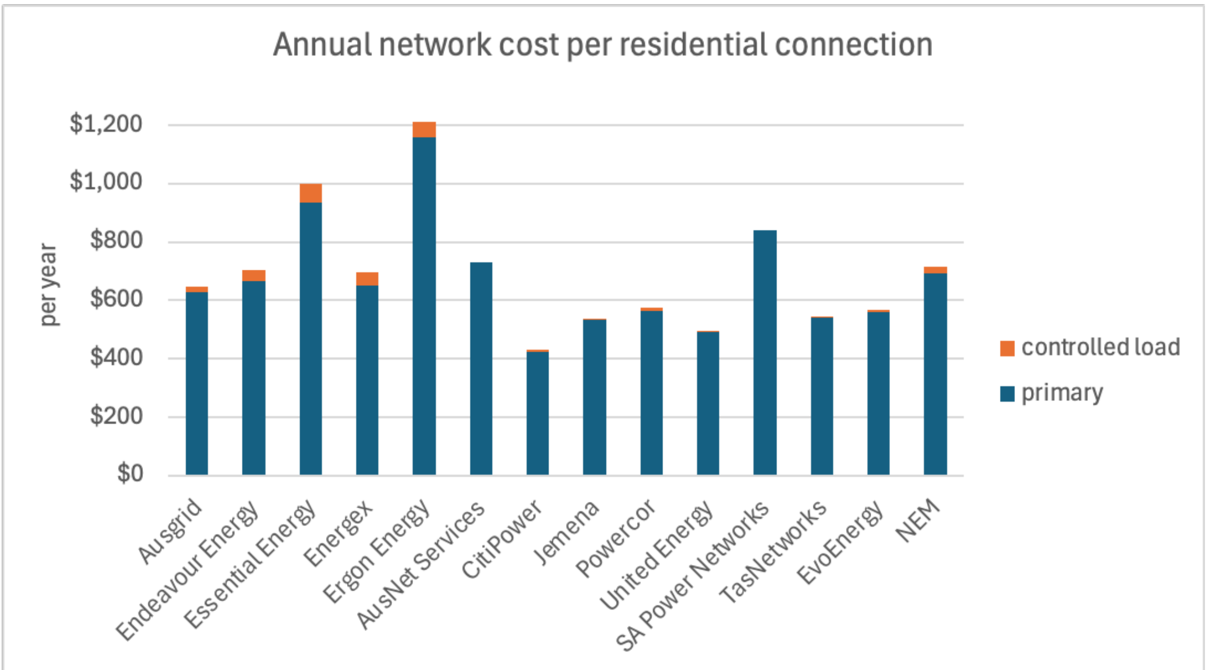
Source: Dragoman analysis of 13 DNSPs SCS pricing models for FY24

While the bulk of current network costs are from the distribution network element, **transmission costs are material** (around 16% on average in the NEM) and **could rise strongly** under the transition of the system envisioned by the Integrated System Plan (ISP).

Certain JSA amounts may also prove to be much more material in the future, as recent schemes mature. As such, we note that a forward-looking pricing review should not ignore how TUOS and JSA amounts are passed through to consumers, merely because they are currently the minority of network costs.

Across the NEM, on average a residential consumer contributes a little over $700 per annum to network cost recovery. This varies widely between the DNSPs (as shown below) which we believe is partially or mainly explained by differences in network geography: Ergon, Essential and SAPN cover very large network areas, with greater physical network assets required as a result, while CitiPower is a compact network in urban Melbourne.

However, within a network area, on average, we find that the cost-recovery per customer is fairly consistent regardless of the type of network tariff applied – flat, or a variety of cost-reflective structures based on time of use and in some cases, peak demand.



Source: Dragoman analysis of 13 DNSPs SCS pricing models for FY24

Network costs are largely fixed, as far as consumers can realistically influence them

We have analysed the disclosures from the 13 DNSPs in the NEM, and we find that whether we examine annual operating expenditures (today's costs), or the nature of capital expenditures (tomorrow's costs), most of the drivers of network expenditure bear little if any relation to consumer behaviour in the short or long run.

Most costs are either based on historical investments made, overheads that consumers cannot impact, growth in network extent that is irrelevant to a consumer once connected, or other drivers such as financing costs.

There is certainly a consumer-influenced element of network costs, related to:

1. The anticipated cost of augmentation if consumers raise the peak demand beyond the current capacity of the network – especially locally.
2. Disturbances to the network that consumers might cause (e.g. via large PV exports), that demand investment to rectify. DNSPs estimate this as part of their tariff-setting processes, and it is clear they are a small minority of overall costs to be recovered.

The balance is so-called 'residual costs' – which are not related in any way to current or future consumer behaviour but nevertheless must be recovered.

Even where forward costs are related to consumer behaviour (such as peak demand requiring augmentation expenditure) the actual impacts are both highly localised (unsuited to price signals delivered very broadly via postage-stamp tariffs), and/or highly uncertain (one major unexpected addition or loss of a load from an area might change the situation, independent of consumers' responses to price signals previously).

<u>The problem with postage-stamp tariffs for distribution network costs</u>

It seems to us there is no point developing and deploying intricate cost-reflective network price signals if in reality, the channel to deliver the price signal to consumers – postage-stamp tariffs – is too broad to be effective.

Looming congestion in a substation in Mount Gambier is not going to be effectively addressed by a peak demand or ToU consumption charge in the SAPN network, that will also be experienced by a consumer in Port Pirie where (we imagine for the sake of the argument) the distribution network is unconstrained for the foreseeable future.

- If the price signal is strong enough for the Mount Gambier consumer to shift their consumption away from the peak, it implies deadweight losses for the consumer in Port Pirie who does the same, curtailing consumption they value (e.g. air-conditioning on a hot afternoon) for no network cost or benefit.
- If the price signal is weakened to preserve the Port Pirie consumer's utility, it will not be strong enough to drive change by the Mount Gambier consumer – and now the deadweight loss is in the additional network costs to relieve that congestion that could (potentially) have been deferred or avoided.

One possible answer to this dilemma – significantly more localised tariffs – may be worth considering in some circumstances, especially if they are incentive-based and opt-in. We have a partial analogy emerging in the community battery space, where investment in a community battery to relieve congestion and/or increase PV hosting capacity (and the interface with local consumers to share costs and benefits) can be very targeted.

However, in general we conclude the answer to this dilemma is greater simplicity (in the form of generally higher fixed charges), rather than further complexity of generally applicable network tariff structures.

Even the National Electricity Rules seem confused on this issue of postage-stamp prices for residential customers:

Rule 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. …; 2. …; 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****.*

Rule 6.18.4(a)(2): *"retail customers with a similar connection and usage profile should be treated on an equal basis"*

Rule 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."*

The last of these clearly makes good sense… but the first two appear to be at cross-purposes.

We do not think this is a controversial finding at all – reading DNSPs Tarriff Structure Statements, this point is often emphasised by the networks themselves. So too the AEMC's Discussion Paper calls out the issue clearly.

For example, from Endeavour's TSS Explanatory Statement, p65:

> *"Ideally, the basic export level would vary with respect to:*
>
> - *the geographic area of network in which the connection occurs, i.e., a location specific basic export level; And*
> - *changes over time in the size and number of embedded generators and storage units installed in the area of the network in which the connection occurs.*
>
> *In practice, the application of postage stamp pricing for our two-way tariffs lends itself to uniform basic export level across the network, rather than a location specific basic export level. In addition, we wish to provide our export customers with certainty regarding the costs of installing solar PV assets over the 10-year tariff transition period."*

And p91

> *"Theoretically, it is most efficient for us to recover from our customers the residual costs we incur exclusively from the fixed charge tariff component because these charges are independent of a customer's usage decisions and therefore minimise the distortion to the LRMC-based price signals that promote efficient usage of our network service."*

From Essential's TSS, p12:

> *"Essential Energy calculates LRMC at a voltage level for all customers, with an LRMC estimate for low-voltage, high-voltage, and sub-transmission customers. The LRMC estimate is not specific to location or feeder, but an average for all customers connected at the same voltage level within the same customer class using an AIC approach.*
>
> *Because these costs are all variable over time, the variable components of our distribution network charges are set to at least reflect our LRMC estimates. This is consistent with our tariff classes having tariffs that are averaged across those classes and with our customers' strong preference for postage stamp pricing."*

From Essential's TSS Explanatory Statement, p13

> ***"Issue:*** *postage stamp pricing means there is cross-subsidisation between high and low cost-to-serve customers.*
>
> ***Potential tariff solution:*** *locational tariffs - recognising that our stakeholders are against this proposal consider semi-locational like urban/rural, climatic zones or nodal pricing."*

Current recovery of network costs relies heavily on consumption-based charges

We find that in aggregate over the NEM, most network costs (59%) are currently recovered from residential energy consumers based only on the quantity of electricity imported – either under older-style "anytime" tariffs, or Time of Use (ToU) enabled by modern metering. 29% is recovered from fixed charges, and 12% from hybrid tariff elements that include both demand charge and consumption components.

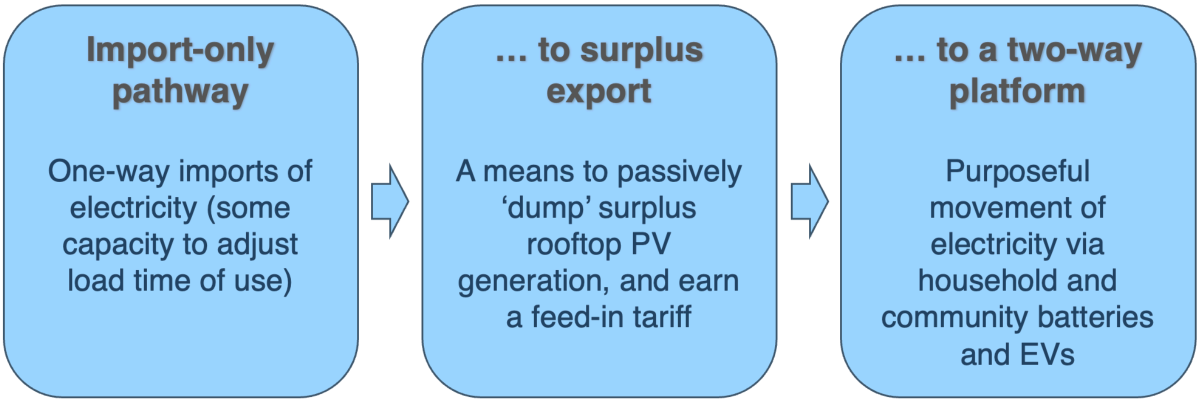
A great deal of work has been undertaken by stakeholders in designing and deploying cost-reflective network tariffs, and the results include both ToU and demand-style pricing. However, the effectiveness of a mandatory transition to these is open to debate – including what a cost-reflective network tariff would really look like given the nature of the costs networks are recovering.

The AEMC's Discussion Paper is notable in how it has clearly challenged the conventional wisdom here (p73):

> *"The current approach to designing network tariffs may have long-run benefits, but at a cost to consumers. Broadcasting long-run cost signals through network tariffs was a sensible decision when made in 2014, anchored as it was within the technological landscape at the time. But the sector, and its technology, have developed since then. The current network tariff framework may therefore not be optimally positioned for the future, as consumers continue to adopt new technologies that enhance opportunities to reduce network costs."*

CER uptake is increasing, and changing the role of the network

The rise of CER – most obviously rooftop PV and batteries today - means consumers' use of networks is evolving towards something much more sophisticated:



About 24% of residential connections are estimated to have rooftop PV today, up from 18% only 5 years ago[4]. For batteries, the figures are around 1.1% now, from 0.3% 5 years ago.

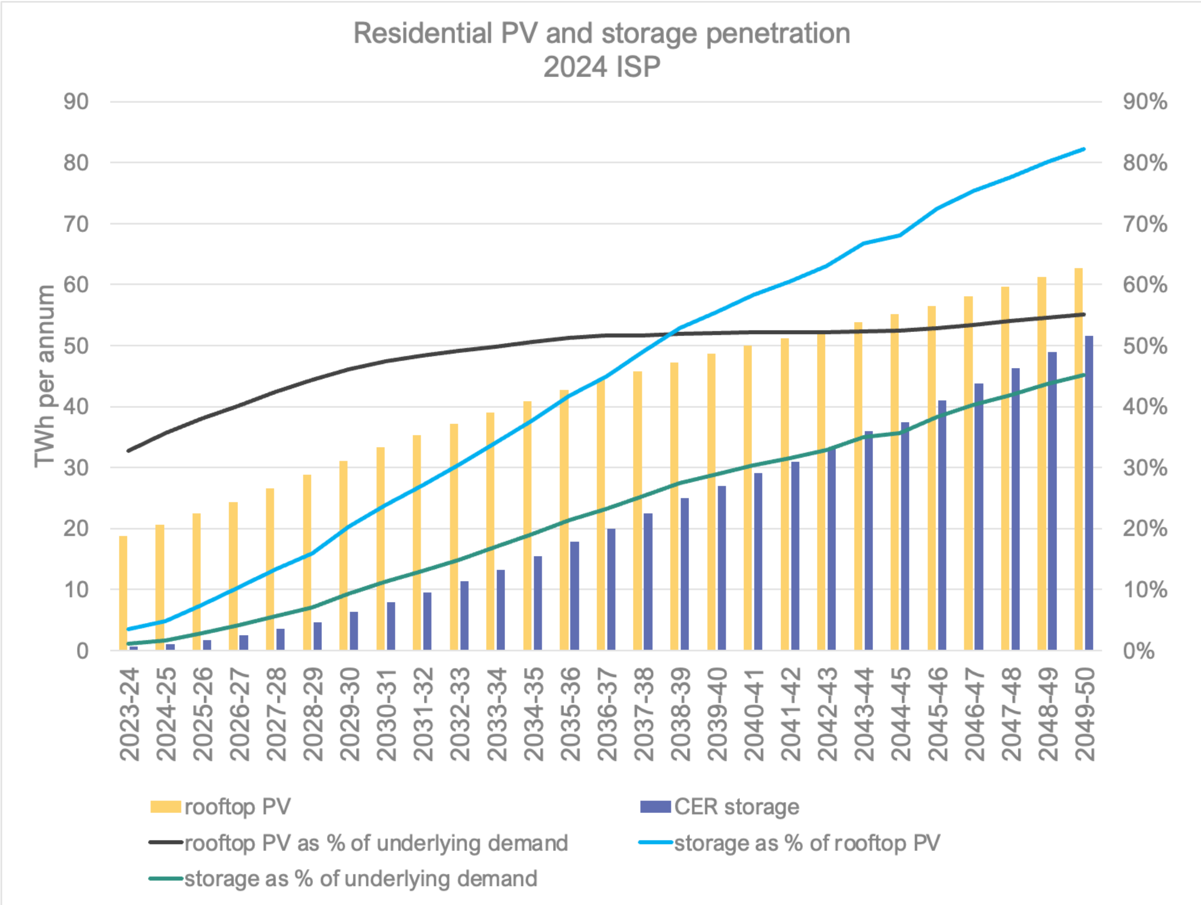
Already in 2023-24, residential rooftop PV supplied 19TWh of electricity, equivalent to 33% of residential underlying demand. The chart overleaf shows the 2024 ISP forecasting this to rise to 31TWh or 46% by 2030, 52% by 2040 and 55% by 2050.

Battery storage is expected to grow tenfold from 2024 to over 6GWh in 2030 – sufficient to store about 1/5th of rooftop PV production by then, 55% by 2040 and 82% by 2050.

Rapid growth in residential storage is now underpinned by the Commonwealth's $2.3bn battery subsidy scheme – which follows from the strong incentives for small-scale PV provided by the Small-scale Renewable Energy Scheme (SRES). The government appears to be pushing on an open door here: when ECA surveyed small consumers in April 2025 (before the announcement of the policy), they found 15% of households with solar PV are currently researching options to add a Battery Energy Storage System (BESS).[5]

[4] See: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/metering-data/nem-der-and-interval-metering-dashboard

[5] Source: July 2025 Energy Consumers Australia - Consumer Energy Report Card



Source: Dragoman analysis of 2024 ISP central scenario forecast

With this in mind, the ISP's forecasts of CER penetration should be taken seriously when assessing equity and fairness in network pricing.

When we assess the equity impact of CER "haves" versus "have-nots" we find serious concerns today, which will be greatly exacerbated under these forecasts if clear steps are not taken to reconsider how network costs are recovered – especially given the very significant avoidance of network costs we observe today for battery-enabled households.

Historic network cost recovery models were once somewhat defensible

Before the rise of solar and batteries, it was reasonable to argue that consumption-based pricing was a sensible, fair and reasonably simple way to recover network costs: "use more power, pay more for access to power" would have likely passed the 'pub test'.

On one view this could be progressive – those who use more electricity may have greater capacity for consumption, via larger households and more appliances, an indication of wealth. However, there were always problematic elements to this assumption. Lower-quality housing may be less energy-efficient (and occupants, especially if renters, may have less capacity to improve that situation). If so, consumption-based charging for networks would be regressive.

Either way, this approach evidently overrode consideration about whether consumption was in fact a good proxy for network cost drivers (and as we have noted, most agree it is not).

A reluctance to follow through on this conclusion, as least until now, needs to be examined. We think it is likely because if networks costs were recognised as largely fixed and priced accordingly, then fixed-cost pricing per household might be considered more unfair (i.e. more regressive) than the alternative.

This remains a challenge today. Given we advocate in this paper for exactly this approach, it must be addressed – albeit in doing so, we note our definitional choice which distinguishes between equity (achieved via pricing models) and fairness (ensured via a social welfare overlay and specifically in this case, the appropriate targeting of energy concessions funded by government / taxpayers).

In any event, if the largely consumption-based pricing model was ever fit for purpose in the pre-CER past based on arguments of fairness, it no longer is today (or in future).

The network is an access-based service, not a consumption-based good

With the rise of rooftop solar PV, CER-enabled customers draw less energy from the grid and so contribute less to residual cost recovery based on consumption. As batteries are increasingly added, even ToU or demand-based alternative cost-recovery approaches in network tariffs can be effectively avoided as well.

Regardless of lower import usage, there is no evident reduction in networks' cost to serve these CER-enabled consumers – who, like all consumers, need to maintain their basic access to the network.

In fact, from a narrow perspective of the network, they may be creating as many or more costs than they are offsetting if we consider the system security and power quality challenges networks are facing in the integration of PV exports into the distribution network.

Even as imports by CER-enabled consumers are lower, the grid provides these consumers (and their CER investments) not just with power when they do not have solar or battery energy, but also with important and valuable additional services including financial opportunities that are not available to those without CER:

- to benefit from feed-in tariffs for excess PV generation
- to profit from wholesale price arbitrage using a BESS
- to gain from participation in a Virtual Power Plant (VPP).

In addition to these opportunities, CER-enabled consumers benefit from frequency and voltage regulation, and the 'silent co-ordination' that allows then to rely on their CER thanks to its connection to the broader grid.

As a result, it seems plausible there is a major *prima facie* issue of inequity between CER "haves" and "have-nots" in relation to the recovery of network costs – especially if we maintain the use of consumption pricing to recover most network charges.

The "haves" receive greater utility from a network connection (via a broader range of services it enables them to access), yet under current network pricing mechanisms we show they pay much less.

We have examined several areas of inequity – but we think this issue is both the most material, and the most easily addressed – so we devote significant attention to it in this paper.

Left unmanaged, inequity will increase

Looking forward, as CER penetration rises, this inequity seems likely to increase.

We assume network costs – whatever they may be – continue to be recoverable from small consumers as a whole, given their regulated nature.

With more consumers under-contributing to residual network cost recovery, consumption-based pricing will increasingly place the burden on the CER "have-nots".

This is a self-reinforcing impact, as it increases the incentive to install CER and avoid consumption-based costs – further increasing the necessary consumption charges on the lower levels of grid imports. This is the "death spiral" made famous (for energy policy nerds) in 2012 by AGL's economists Paul Simshauser and Tim Nelson.[6]

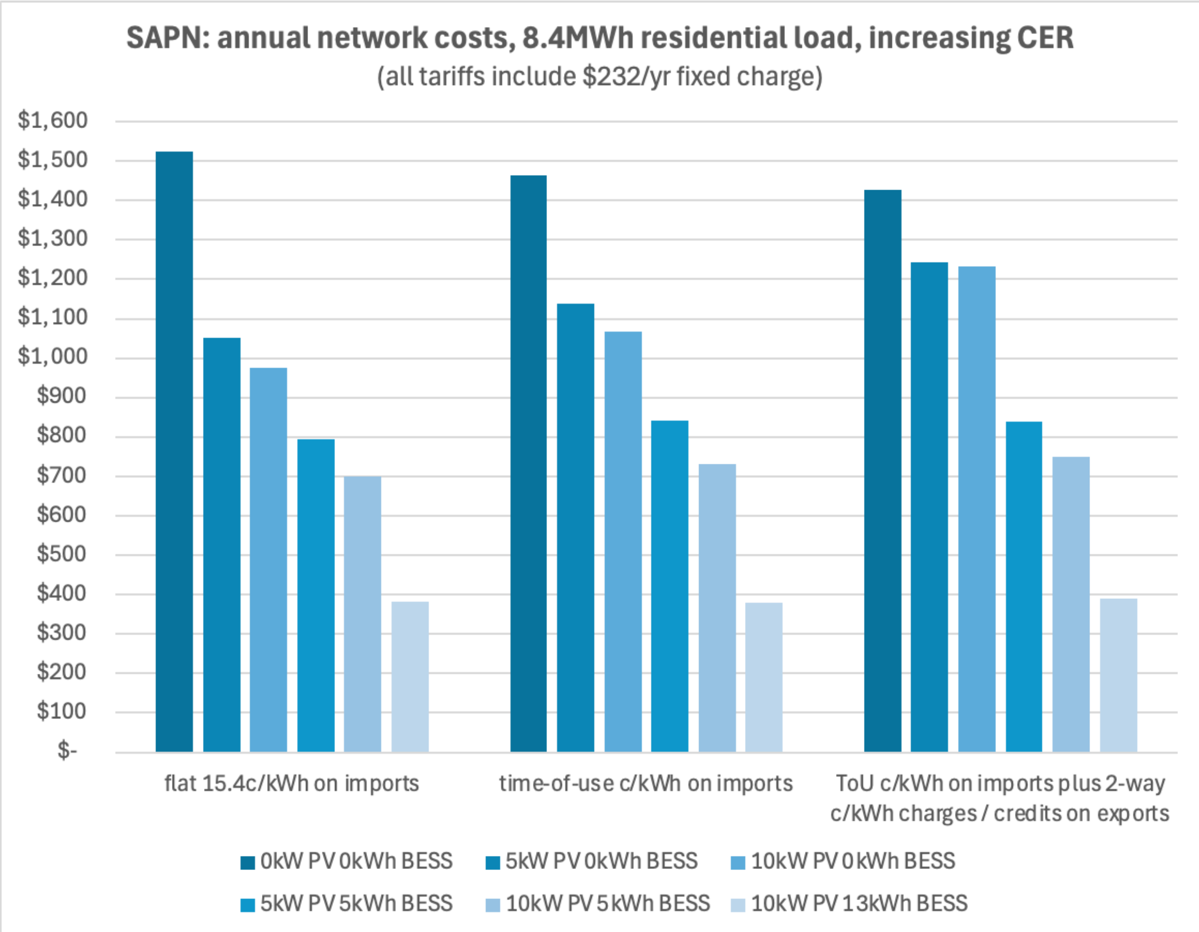
It is important to note we are only considering network tariffs and cost recovery here, prior to any actual imports, exports or consumption occurring.

On top of this all consumers pay for their actual consumption of electricity, via the wholesale cost pass-through from retailers in an overall retail tariff (and in many cases, via their capital investment in rooftop PV). This is the consumption good that complements the access services provided by a network connection, and provides a critical price signal, separate from network tariffs, to encourage efficient energy use and lower system costs.

Tariff evolution is not adequate to mitigate the problem

It is possible that the evolution of network tariffs away from "anytime energy" consumption towards more complex structures is effectively pushing back against this problem.

To test this, we have modelled a range of scenarios for residential consumers, of varying consumption levels, and varying levels of CER investment. We find that current network tariffs are NOT effective in closing this inequity – the following is a typical outcome, based on SA Power Network's tariffs.



Source: Dragoman analysis of SAPN tariffs for various CER cases

[6] See: https://www.energynetworks.com.au/news/energy-insider/the-death-spiral/

The modelling is fully described in ***Part 8: Testing specific tariff structures versus residential CER cases.***

Here, we can see that as CER investment by the household increases (from left to right in each of the three tariffs analysed), contribution to network cost recovery steadily decreases.

The more recently-developed tariff structures (e.g. SAPN's RSELE "electrify" tariff at right) do sometimes act to narrow this gap in network costs charged to CER "haves" and "have nots", but in general, it remains large – especially when households pair a BESS with their PV.

This arises because households with solar and a battery can optimise use to avoid any type of network consumption tariff.

CER raises major, fundamental questions about equity and fairness

As a result, we have some complex questions about equity and fairness here:

- Should the CER "haves" pay more for the network because of the additional benefits they receive from it, rather than less?
- Does CER adoption by some consumers simply lead to material network cost transfers to those without CER (the prima facie situation, as we demonstrate)? Or do the system benefits partly or wholly offset this, by providing lower costs to the "have nots"?[7]
- What is the implication for fairness if government-subsided CER investments by the "haves" result in higher comparative network costs for the "have-nots"?

What to do?

Addressing the CER Haves versus Have-nots

One approach might be to make ToU charges more extreme, including via the two-way tariff structures[8] we now see emerging – such as large credits for imports during daytime, large charges for exports during daytime, and the reverse in evening peaks.

Among the problems this approach would create are:

- Not all non-CER consumers can shift their load to benefit from such signals – this is not equitable.
- As the AEMC's Discussion Paper has made very clear, there is a substantial risk of conflict between such network price signals, and the more impactful benefits available if instead, consumers are exposed to wholesale prices signals.

Given this, a key suggestion arising from our analysis is to **re-think network pricing as two components**.

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[7] Well-addressed here: https://www.researchgate.net/publication/299400314_A_Design_Approach_to_Innovation_in_the_Australian_Energy_Industry

[8] Directed at CER consumers, typically involve a 'solar soak' period where grid exports are charged, offset by a peak period where grid exports receive a credit – as is the case for the SAPN tariff in the example. For non-CER consumers, the 'solar soak' period can offer very low import charges (or potentially, credits) to encourage shifting of load to the middle of the day when PV exports are often substantial.

Basic Access Charge		**CER Tariff**
Fixed annual cost for a household to have access to grid imports.	+	Additional network charges & credits associated with the connection and operation of various CER

The **Basic Access Charge** (BAC) would be in effect, a higher daily charge (if recovered via a network / retail tariff at all).

About $2/day per residential connection, on average across the NEM, would recover the full cost of networks for serving residential customers.

All imports of actual electricity consumed would be separately and additionally charged as a retail tariff component (as they are now).

We assume the BAC would be the appropriate basis to recover not just residual DUOS costs, but also TUOS costs that are currently passed through (typically as a consumption charge), and any JSA costs which are examined closely by the AEMC's Pricing Review and judged appropriate to be levied on electricity consumers.

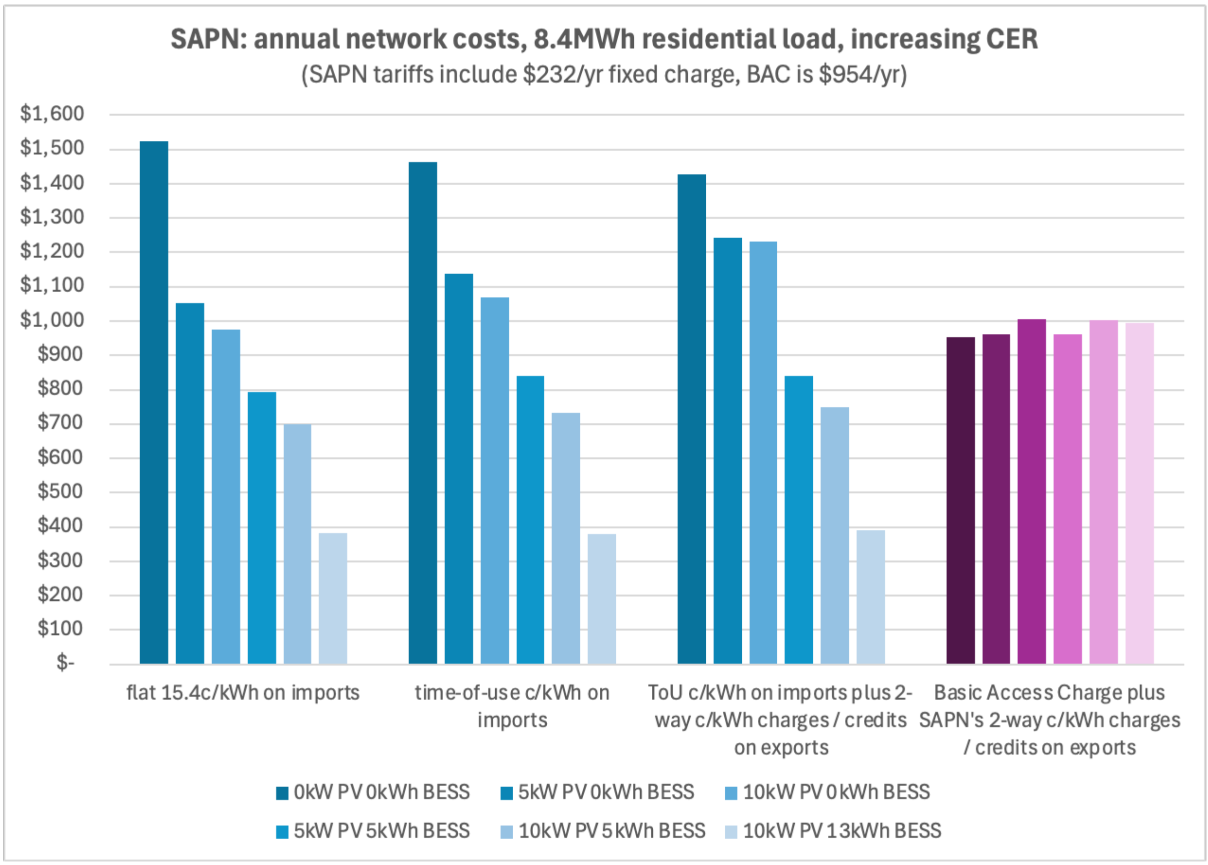
CER Tariffs would only apply to CER-connected households (including on an opt-in basis for consumers who may wish to shift load actively in a similar manner, should the tariff make that attractive).

In aggregate, CER tariffs would be broadly cost-reflective for the network but designed in alignment with retailers' wholesale signals. They may result in a small net positive or negative contribution to overall network cost recovery (depending on whether CER behaviour is judged to net increase of decrease system costs).

As noted, there are strong arguments for simple fixed network pricing for basic access – and this may also allow for better retail tariff design, and / or more appropriate cost recovery channels outside a retail electricity bill – as we discuss in further detail in the body of this paper.

Below we show how this might work.

We replace all the ToU import charges in SAPN's 'electrify' tariff with a fixed charge of $2.70/day (up from $0.64) and then apply the two-way tariff (unchanged) for exports to the CER cases (refer below the new case added at right in the figure below).



Source: Dragoman analysis of SAPN tariffs for various CER cases

The result is broadly similar network cost recovery from all consumers, regardless of their CER investment or otherwise.

- The households with modest PV and BESS investments (5kW PV, or 5kW PV plus a 5kWh BESS) pay a very similar amount to the non-CER household.
- The householders with larger (arguably, oversized) CER investments (10kW PV with 0, 5 or 13kWh BESS) pay a little more (driven by SAPN's charges for exports during the solar soak period in the middle of the day.

While this is just an illustrative example, it is this type of outcome that we believe represents a more equitable recovery of network costs from small consumers.

How should a BAC be collected?

In the body of the report, we note that a BAC – as a fixed annual charge per household – need not be recovered in the traditional manner via electricity bills. Instead, we suggest the BAC "looks like" the type of service charge collected via councils, and might be better recovered via that channel for several reasons:

1. **Locational pricing at LGA level:**[9] Councils represent local government areas, which are typically much smaller than DNSP regions. This may provide a useful mechanism for networks to apply more localised prices, better reflecting actual network fixed costs. It would be a way to step back from postage-stamp tariffs covering very broad and diverse network areas in some DNSPs – and that could lead to more equitable outcomes.

[9] We are presuming the DNSP's network area boundaries and congested areas align reasonably with LGA boundaries.

2. **Consistency with other Council charges:** Rates are accepted as a fixed cost, based on a measure of home value – there is no expectation that ratepayers are charged based on their volume of rubbish collected, or whether they actually use the roads. It seems likely ratepayers might accept the same for a network charge – perhaps with some simple variations based on whether it is an import-only connection, or a two-way connection with PV, or an EV charger.
3. **Onus on the property owner:** Rates are the legal responsibility of the property owner, not a tenant. While this can be adjusted via the terms of a rental contract, there may be some public policy attraction to property owners accepting the cost of maintaining access to the electricity network. Tenants would still pay consumption charges and any non-fixed network charges related to their consumption via retailers.
4. **Relatively efficient:**[10] Councils have existing billing systems for all properties. Networks and councils have existing commercial relationships, including the provision of public lighting by networks to councils.

Impact of a BAC approach on fairness

The most immediate concern with shifting residual network cost recovery towards a single BAC is that it may be considered unfair for a number of consumers, especially lower-income single person households who use little energy, and for whom the BAC would likely cause an increase in overall electricity costs, all else equal.

This is where a distinction between equity (via network pricing) and fairness is essential.

In practice, a key existing method to achieve **fairness** in electricity is via means-tested energy concessions funded by government.

Directing concessions towards relief from consumption-based charges is increasingly problematic, when broad proxies like grid import levels are an increasingly worse indicator of household wealth - especially as wealthier households face fewer barriers to deploy CER.

In this case, the introduction of the BAC would make it a natural target for redirecting existing government welfare funding support for energy concessions, and potentially also any future versions of recent ad-hoc policies such as broad electricity bill rebates – ideally on a means-tested basis.

Impact of a BAC approach on other inequity cohorts

Our recommendations focus primarily on one inequity issue, the *CER Haves versus Have-Nots*, as we judge this is both the most material, but also the most amenable to correction via the BAC.

The introduction of a BAC may also indirectly impact other inequity cohorts we have identified in the body of this report – summarised here:

[10] There would be some additional billing and co-ordination costs, since CER-related tariffs would still be recovered through retailers.

CER Haves	vs	CER Have-nots	New Connections	vs	Existing Connections
Rural Customers	vs	Metro Customers	Congested Consumers	vs	Uncongested Consumers
High Income	vs	Low Income	Tomorrow's Consumers	vs	Today's Consumers

Generally, we find that the BAC model could also assist with (or at least, not worsen) other inequity vectors if carefully designed and implemented, as follows.

Cohorts	Possible Impact under BAC + CER Tariffs model
Rural vs Metro	The quantity of network assets per small consumer (and thus an equitable share of residual cost recovery) is larger for consumers in a rural part of a network area, than in a denser urban part. This means there is a cost-to-serve cross subsidy inherent in postage-stamp tariffs used in some network areas which are geographically large and diverse. Recovery via Councils could allow for network residual cost distinction at the LGA level, below the DNSP postage-stamp level. As is the case for means-tested concessions applied to the BAC, a similar approach could be taken by governments to subsidise higher evident BAC costs for rural small consumers (similar to the Uniform Tariff approach taken by Queensland for Ergon vs Energex DNSP areas).
High vs Low Income	BAC would be progressive due to the greater likelihood of higher-income households possessing CER, as more likely to be owner-occupiers and/or living in detached housing with better energy efficiency. But could be regressive in cases where wealthy non-CER households consume more electricity than lower-income equivalents – highlighting the importance of targeted concessions for the BAC.
New vs Existing Connections	Consumers in established areas of a network, whose assets were built at a much lower historical cost and have been largely depreciated, cross-subsidise new consumers joining the network as it extends at today's cost. This is particularly relevant where network areas include long-established residential areas as well as major residential growth. The identification of a BAC would possibly help highlight differences in new-build connection costs per household versus existing, however

	effectively addressing this would require additional policy related to up-front contributions to the network cost of new residential development areas, to ensure the net impact does not raise residual costs for all consumers in the DNSP area.
Congested vs Uncongested	A BAC + CER Tariffs model would deliberately de-emphasise peak demand charges, which are very problematic due to the locality of DNSP congestion relatives to an overall postage-stamp tariff (and the inherent uncertainty about future augmentation needs). This is in favour of price signals to CER exports (and likely EV charging), aligned closely with wholesale price signals, while also targeting cost-minimisation in the network in regard to CER hosting. Properly designed, these should ALSO be broadly aligned with reduction in NET peak demand (i.e. incentivised CER exports during evening peak netting off against nearby peak consumption). Also, with a simpler basic approach, it may allow for more targeted, localised opt-in tariffs for consumers who may wish to be incentivised to shift consumption to alleviate peak imports (rather than seeking to impose such tariffs across all the DNSP area, and all consumers regardless of their capability or willingness to act cost-reflectively).
Tomorrow's vs Today's Consumers	The most pressing version of this inequity is likely to be upstream of the distribution network, related to the cost of new transmission and (in some cases) generation and firming capacity costs that are passed through (the latter, via some cases of JSA). The nature and cost-recovery practices for both TUOS and JSA costs are more relevant than they may seem today – currently minorities of overall network costs, but likely to rise. These transmission assets (such as enhanced regional interconnection and the development of new Renewable Energy Zones) and certain policies are: 1. partly related to overarching decarbonisation policy objectives, not the simple provision of the most efficient electricity system, and 2. likely to be underutilised initially (in the case of transmission) when assets are accumulating onto the Regulated Assets Base but are incomplete or not yet ramped up to full use (i.e. prior to coal closures). The BAC model is not likely to directly impact this, but if TUOS and JSA costs form part of the BAC amount (instead of being 'disguised' as consumption-based charges) it may be easier to identify and establish who should pay. Choices include taxpayers, transmission asset owners, large industrial consumers and landlords before defaulting to small electricity consumers.

Impact of a BAC approach on CER adoption

Clearly, the approach we propose would diminish the economic attractiveness of installing CER. From a consumer's perspective, payback periods would increase – all else equal.

Rather than deriving part of the value from avoided residual network costs – which we establish are fixed and not reduced merely by virtue of less imports occurring – investment would need to be made based on actual reductions in system costs associated with CER being operated efficiently.

Fortunately, these are material (as the Energeia[11] report shows) and includes reduced large-scale generation, reduced call on new transmission infrastructure in future, and reduced firming and storage needs elsewhere in the system.

There are reasonable grounds to consider transitional arrangements for current and recent household investors in CER, which may take the form of partial BAC relief for a period consistent with a typical CER payback period – perhaps ~7 years from purchase.

To the extent CER adoption is to be further encouraged, there are a number of alternative mechanisms which jurisdictions could employ – including:

1. Capital subsidies, as already exist at Commonwealth and several sub-national jurisdictions.
2. A BAC Rebate paid by jurisdictions to CER investors, for a limited period.[12]
3. A continuation of the principle of the SRES, providing CER with a credit for the value of emissions reduction they may represent.[13]

In addition to these out-of-market incentives, if justified by cost-reflectivity, CER tariffs may be set by DNSPs such that CER owners are able to receive a net credit when operating their assets efficiently.

Conclusion – A BAC + CER Tariffs model is worthy of consideration

The BAC+CER Tariffs model we propose has been designed to address the most pressing inequity concern, now and especially in future as CER deployment continues (but not ubiquitously).

It may, if carefully designed and implemented, do little harm in other areas of inequity, and in several cases seems likely improve the situation.

There are various means by which concerns about fairness – such as the impact on smaller or low-consumption households – can be mitigated. Equally, there are other, more equitable levers available to ensure levels of CER adoption meet jurisdictional ambitions, if those exceed what might occur from proper in-market price signals.

Implementation might benefit if the collection of a BAC from was devolved to councils, on a basis similar to council rates, where the onus is on property owners to maintain compliance with the supply of certain essential services – this has several apparent attractions.

[11] See: https://www.aemc.gov.au/energeia-finds-cer-flexibility-could-deliver-45b-benefits-2050

[12] Hopefully it is obvious this must NOT be recovered as a JSA from network charges that form part of the BAC in the first place!

[13] This becomes challenging when increasingly, rooftop PV may be curtailing utility-scale PV at the margin, not coal or gas. When combined with BESS, there is a much better argument the CER is offsetting thermal firming or storage. In any case, the principle might be that any recognition of emissions reduction value available to large-scale solar PV and BESS, should be similarly recognised for the CER version. That mirrors the join operation of the LRET and the SRES.

Report Structure

In the main body of this report, we support the preceding conclusions and recommendations as follows (click through to access):

Part 1: Evidence Base for networks and their costs

A snapshot of the NEM's 13 DNSPs, and the nature of the costs they recover from consumers.

Part 2: Principles to assess network cost recovery equity & fairness

A dozen principles which frame how we have assessed equity and fairness in this work.

Part 3: How does inequity and unfairness arise?

Five causal factors that can lead to inequity and unfairness.

Part 4: Inequity Cohorts

We divide electricity consumers into six 'A versus B' cohorts where inequity is apparent.

Part 5: Network cost recovery concepts

First ask what costs should be recovered, from who, via which channels, before defaulting to simply examining tariffs.

Part 6: Network tariff design principles

A look at the economic theory that supports our approach.

Part 7: Evidence Base for the status quo in DNSP cost recovery

How are costs actually recovered by DNSP and tariff type now – fixed, volumetric, …?

Part 8: Testing specific tariff structures versus residential CER cases

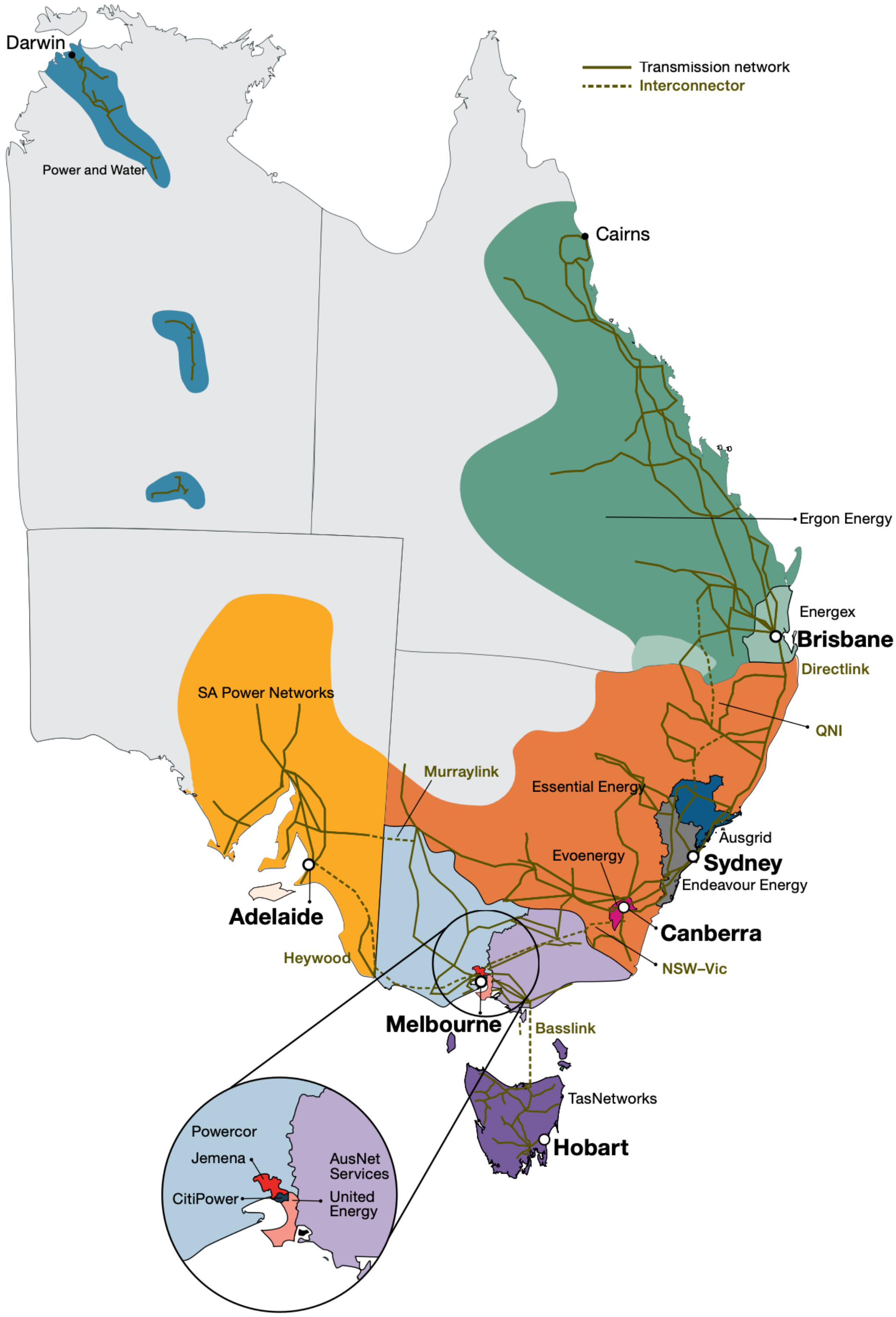
Delving into how specific cases of consumption levels and CER investment impact network cost recovery under currently applying tariffs for four of the DNSPs.

Part 9: An alternative: fixed Basic Access Charge plus CER tariff

Applying the same analysis to a version of our suggested BAC+CER Tariff approach.

Part 1: Evidence Base for networks and their costs

To investigate the nature of network costs and the equity and fairness of their recovery from residential consumers, we have assessed the current public information releases from the 13 Distribution Network Service Providers (DNSPs) operating in the NEM.



Source: Figure 3.1 from AER's State of the Energy Market report 2024

Data sources

The data is taken from:

- 2023-24 Regulatory Information Notices (RINs)
- 2024-25 Standard Control Services pricing models (SCS)
- Various DNSPs Tariff Structure Statements, TSS Explanatory Statements and detailed pricing documents in relation to specific tariffs analysed.

Our approach is a 'snapshot' of the status quo[14]. – we are not undertaking any historical analysis.

Overarching assumptions

We make several large simplifying assumptions in our analysis:

1. The overall cost allocation made by DNSPs between residential customers and larger customers is broadly fair (i.e. we are not contemplating any inequity between residential consumers as a whole with larger consumers).
2. DNSP costs are passed through in full to residential customers (i.e. retailers neither profit nor lose when they package DNSPs tariffs into retail offers, in aggregate) and
3. The DNSPs tariff structure is passed through to residential customers (i.e. the structure of DNSP tariffs to retailers become equivalent parts of the fixed, consumption-based or demand-based charges in the retail tariff).

Objectives of the analysis

In this analysis, we are interested to understand three main things:

1. **DNSP costs:** The nature of the costs DNSPs incur and recover from residential customers, and in particular, to what extent they are driven by customer behaviour.
2. **Cost recovery:** The manner in which costs are recovered in retail tariffs in aggregate, at DNSP level, among their various residential tariffs. This provides a useful average against which more specific outcomes can be compared, as well as revealing some interesting differences between various DNSPs.
3. **Equity implications:** When network tariffs are translated through a representative range of residential consumer situations, what type of divergence do we observe, and how can we interpret this from and equity and fairness perspective?

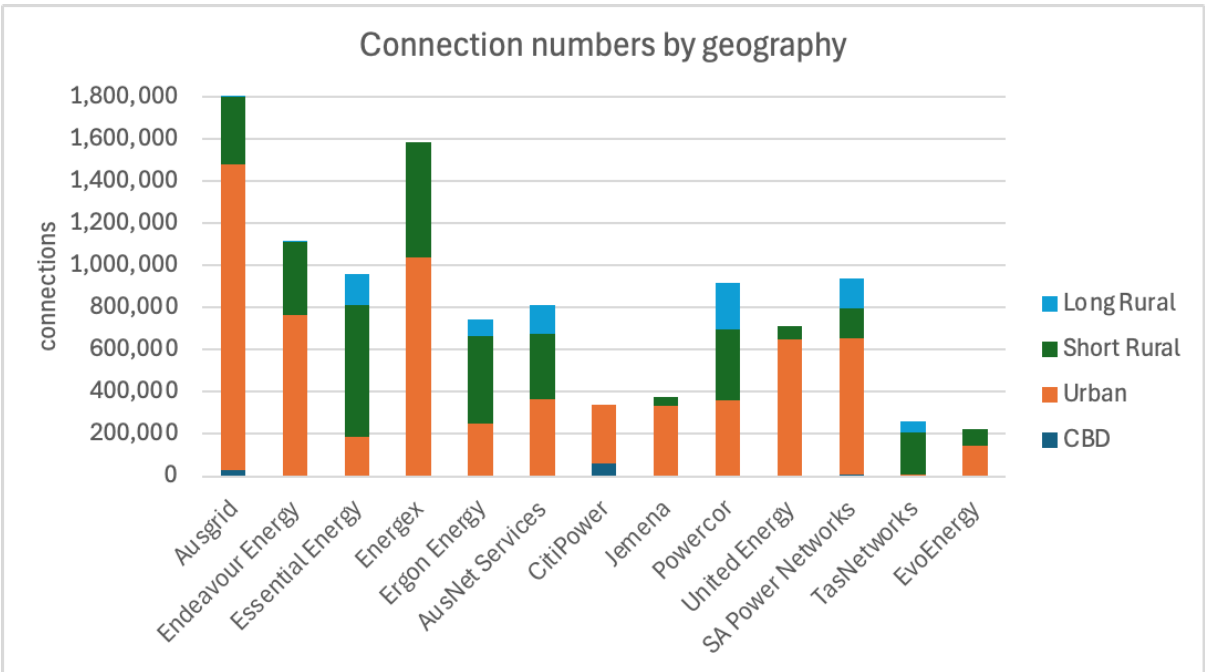
This helps inform our views about appropriate cost recovery mechanisms (such as tariff design), as well as more fundamental questions about who should fund certain costs, and whether the DNSP and retailer is the right channel for them to be recovered.

[14] Deeper analysis could look at longer-term cost trends (e.g. rise and fall of augmentation expenditure) - we address this briefly with reference to the AER's existing analysis. We might also have more explicitly considered likely future pathways for costs, and how recovery may change as tariff assignments evolve, including as smart meter rollout is accelerated. However, we think the direction of CER deployment is clear and we have considered this in our focus on 'CER Haves versus Have-nots'.

Overall data by DNSP

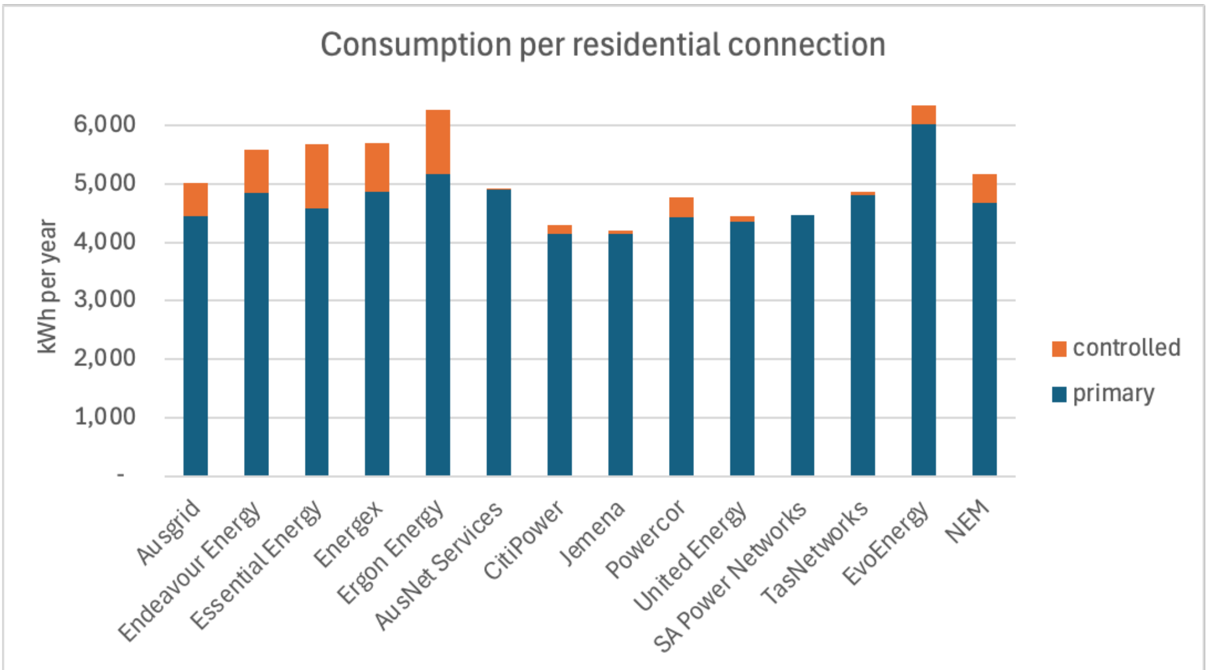
There are 9.9mn residential customer connections among the 13 DNSPs, which range broadly in terms of customer connections (from 0.2m with EvoEnergy in the ACT, to 1.6m with Ausgrid in NSW). DNSPs also serve about another 0.8m non-residential connections in the NEM.

There are broad differences in the physical area served, and the geographic distribution of residential customers – with wide dispersion in the blend of serving urban or rural customers.

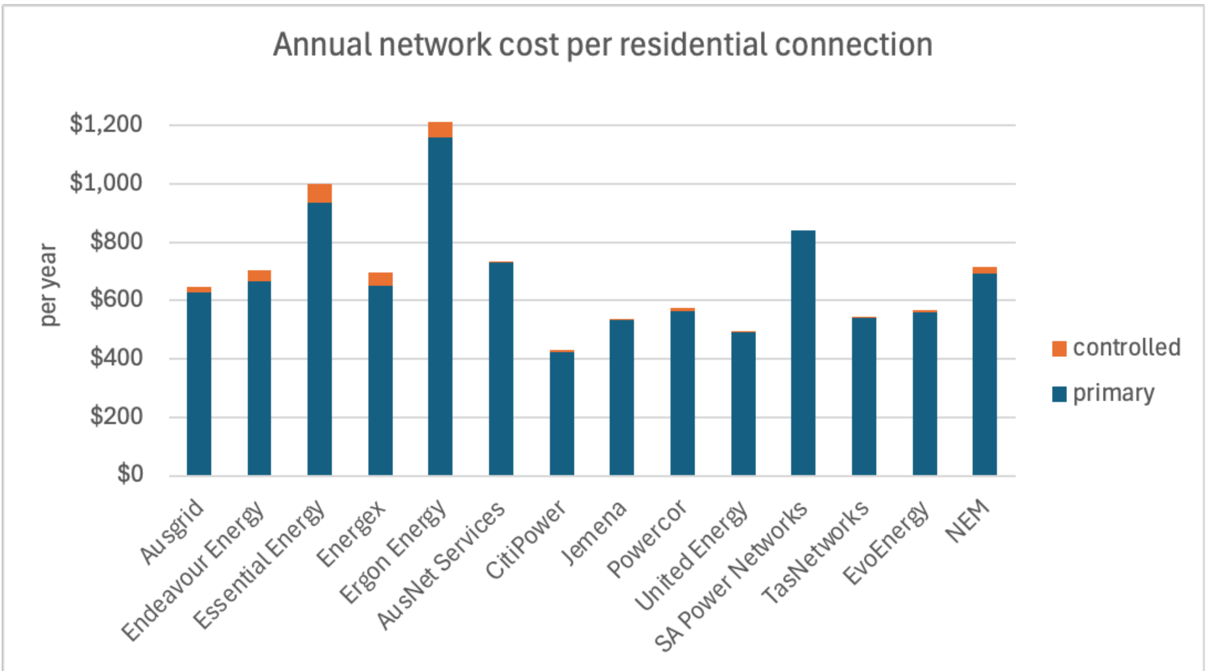


(note: includes non-residential)

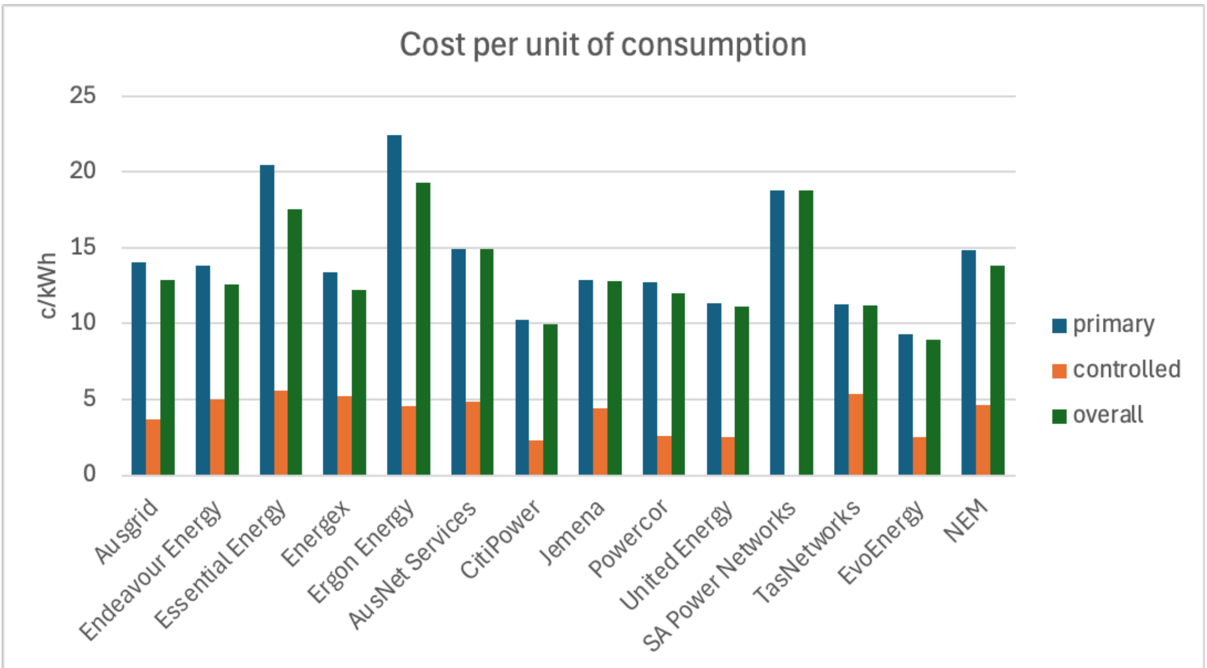
Residential customers have total consumption of 46.2 TWh (plus 5.0 TWh of controlled loads) – an average of 5.2 MWh per residential customer, per year. Between DNSPs, this varies quite widely, from as little as 4.1 MWh in some Victoria networks (where gas use is more prevalent as an alternative) to 6.3 TWh in Ergon (regional Qld) and EvoEnergy (the ACT).



The total cost recovery from these customers is $7.1bn, **an average of $716 per residential customer, per year** ($692 as primary tariff, plus $24 as controlled load tariff). The annual cost per residential customer varies wides between DNSPs, from as little as $429 for CitiPower in Melbourne, to over $1,200 for Ergon – where a state policy overlay equalises overall electricity costs for consumers with the Brisbane distributor, Energex.

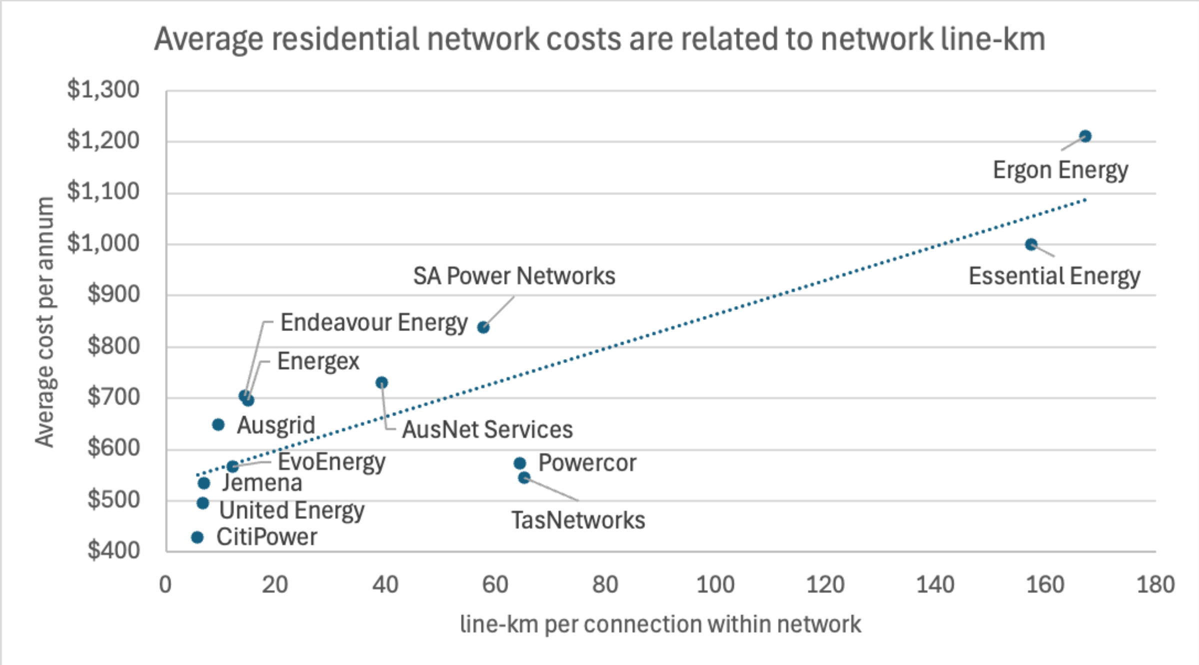


Expressed in volumetric terms, these charges represent an average 14.8 c/kWh for primary tariffs, and 4.6 c/kWh for controlled loads. Again, the range is fairly wide – for primary tariffs, as little as 9.3c/kWh in the EvoEnergy area, over 22 c/kWh for Ergon, with SA Power Networks and Essential also notably high.

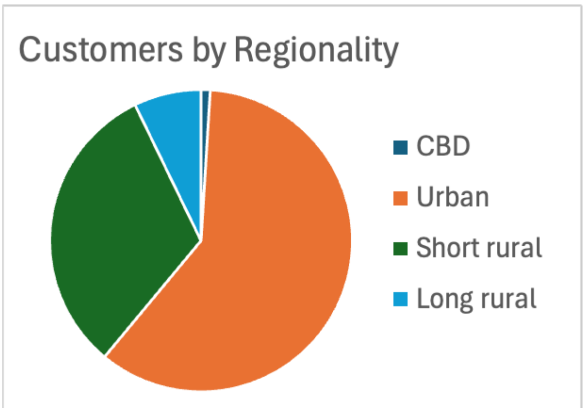


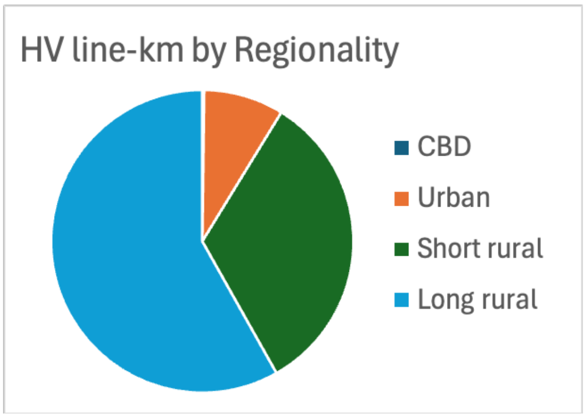
In conclusion, even at the crudest level of analysis it is clear that average residential consumer outcomes vary widely based on which DNSP serves them.

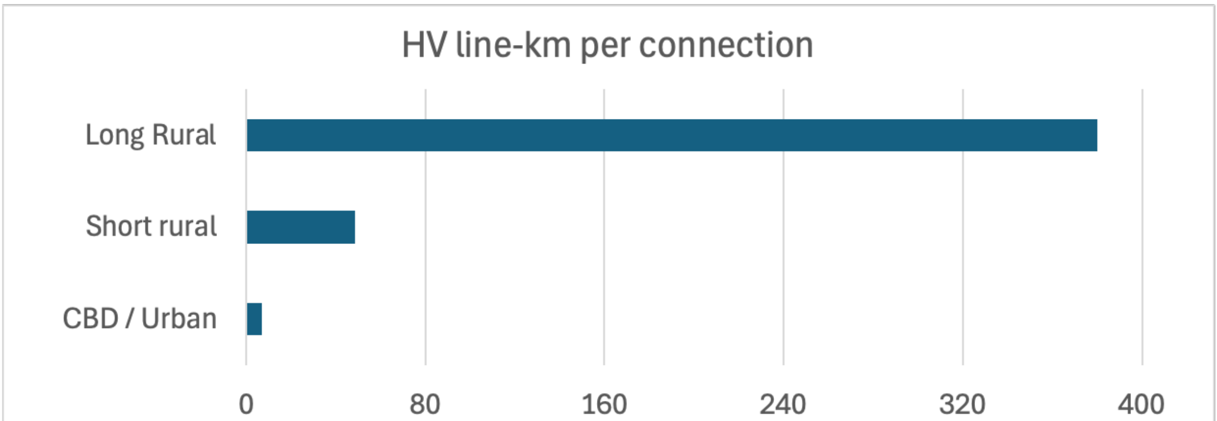
In explaining why this dispersion exists, one easy factor to identify is geography. DNSPs which include very large areas of relatively sparse rural and regional customer connections recover higher average costs than those concentrated more in cities (with smaller areas, and more densely distributed connections). There is physically less network required to serve some residential DNSP customers than others.



Most residential customers are urban. But the vast majority of DNSP network line-km are rural. Some DNSP customers account for much more network investment than others.

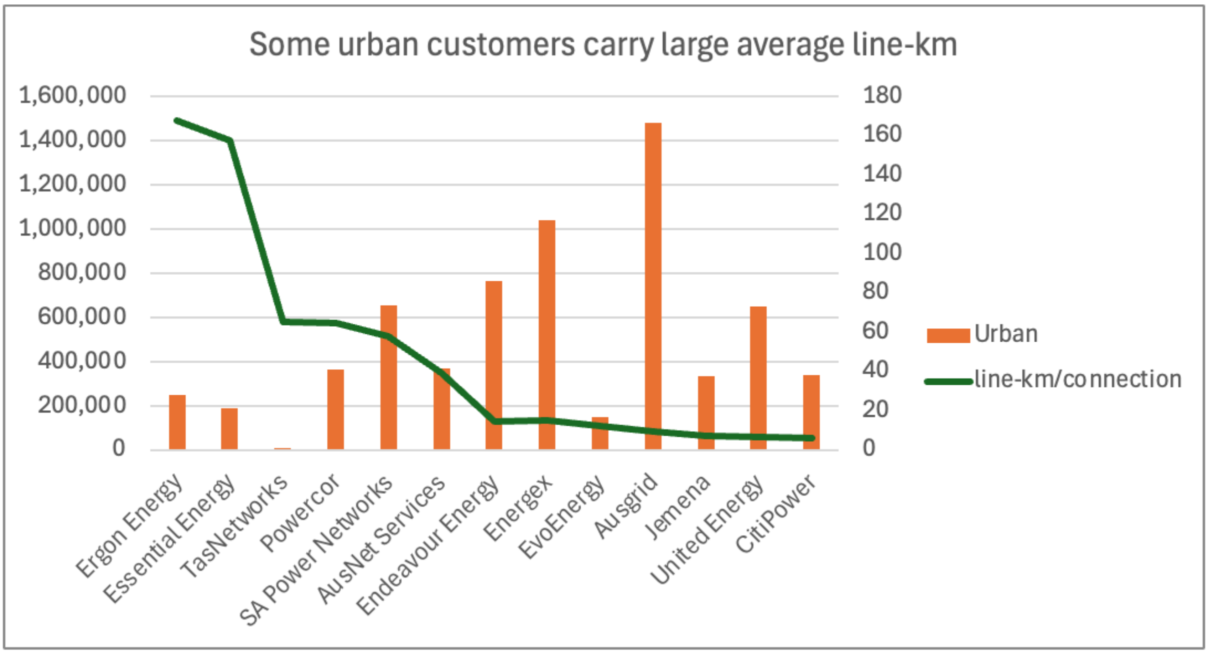






This perhaps is of most concern (on equity grounds) when a DNSP contains both material urban consumers as well as a large rural network service area.

A good example of this concern might be SA Power Networks, encompassing both an entire capital city and 0.7m urban connections, as well as most of the rest of the state of South Australia, with a further 0.3m connections. Not only does SAPN have relatively high average costs per connection compared with other DNSPs, but there is also likely a significant cross-subsidy in place, at the expense of Adelaide households.



But overall, by whatever means, DNSPs in the NEM must currently[15] recover about $716 on average per residential consumer, per year.

The question is how.

[15] Over time, this will be impacted heavily by growth in customer numbers, which better spreads fixed costs and puts downward pressure on the per-customer burden all else equal. However, this is partly or wholly offset by additional capital expenditure in the network exceeding depreciation and growing the regulated asset base, or rises in other costs (for example, the cost of debt and thus the regulated return).

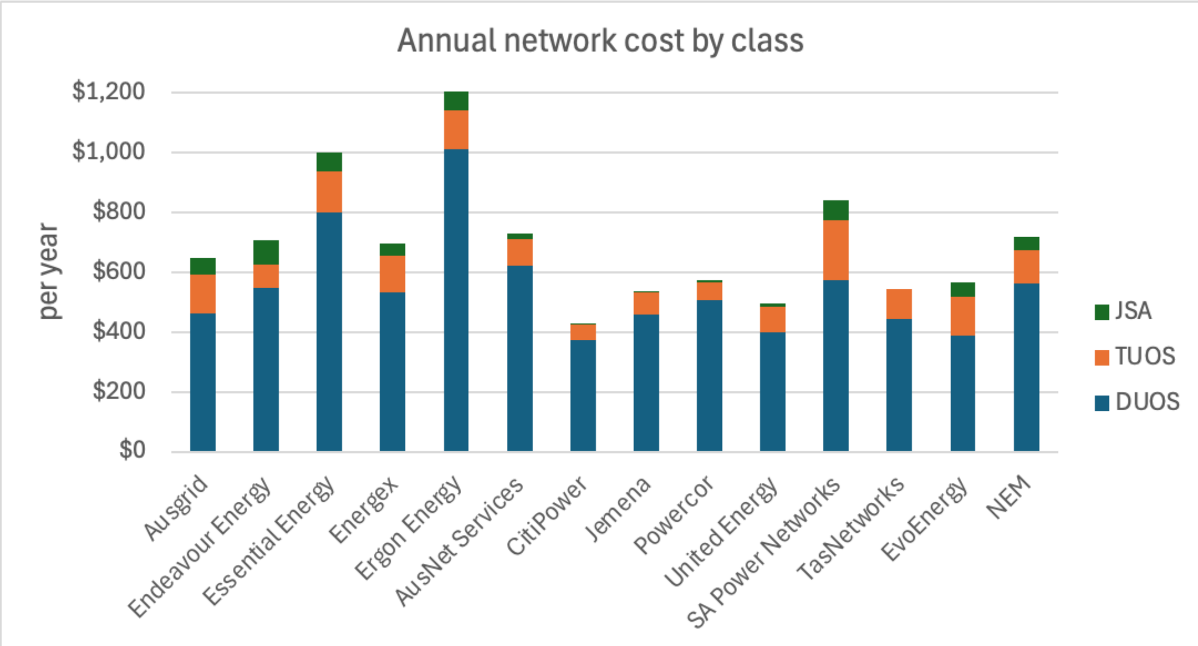
Classes of costs being recovered by DNSPs

In this analysis, we are interested to understand the nature of the costs DNSPs incur and recover from residential customers, and in particular, to what extent they are driven by customer behaviour.

This can in turn help inform our views about appropriate cost recovery mechanisms (such as tariff design), as well as more fundamental questions about who should fund certain costs, and whether the DNSP and retailer is the right channel for them to be recovered.

In broad terms, DNSPs package up and pass through three classes of cost to residential consumers in their tariffs:

1. **Distribution network costs – DUOS**, also referred to here as Standard Control Services (SCS) charges.[16]
2. **Transmission network costs** – **TUOS**, passed through to the DNSPs by the TNSPs.
3. **Jurisdictional Scheme Amounts – JSA**, charges which are created by the host State or Territory jurisdictions and levied on DNSPs to be recovered from customers.



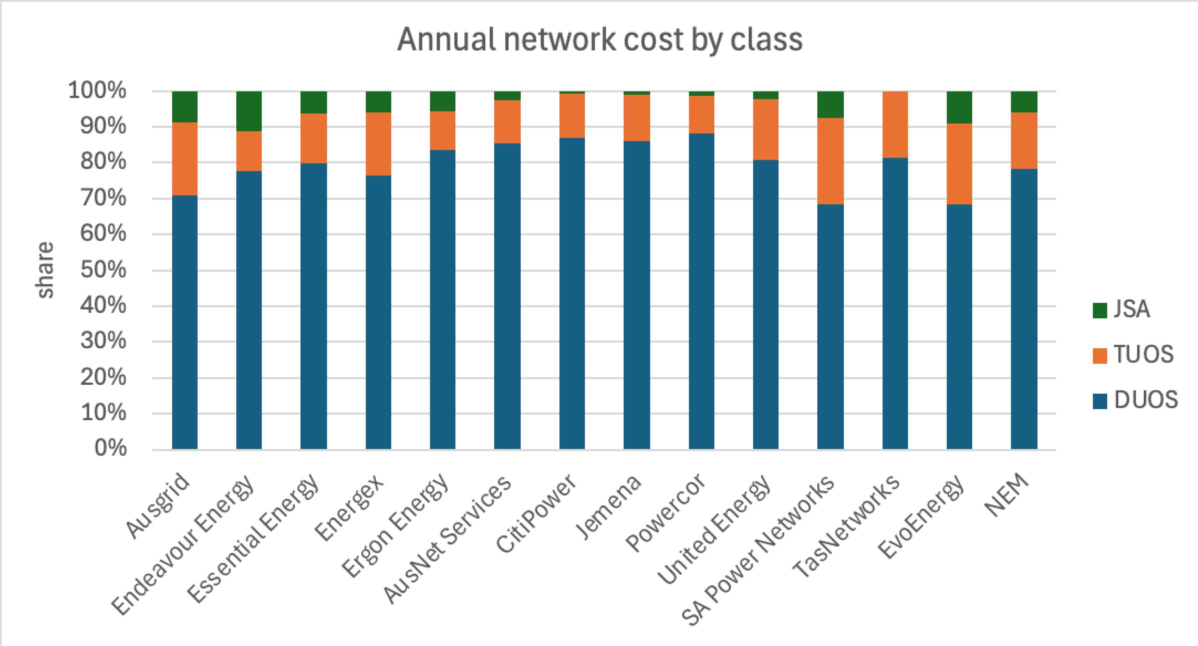
Of the NEM-average $716 of network cost recovery per residential customer annually, **DUOS** is the dominant class of cost, averaging $561 per year, or 78% of the total. **TUOS** is $113 (16%) while **JSA** represents $42 (6%).

- 95% of JSA are recovered from residential customers as a consumption-based element of the charges in a network tariff. There are a couple of exceptions in the United network (where they are part of fixed charges, 3.22c/day in 2024-25) and SA Power Networks (where they are split as 77% volumetric, 23% fixed).
- The situation is similar with TUOS: 92% are recovered volumetrically. Several networks (Energex, Ergon, Jemena and Ausgrid) partially recover TUOS from fixed charges, but a minority – ranging from 27% of TUOS at Ergon to 4% at Jemena.

Recovery of TUOS and JSA contribute to what we show is a heavy overall reliance on consumption-based charging to recover total DNSP costs from residential customers.

[16] SCS is about 90% of DNSP revenue in the NEM. We are not analysing other revenues or costs associated with the other 10% - metering, connections, ancillary services and public lighting. These are either not charged to residential consumers, or charged based on activity.

Among the DNSPs, there are significant differences in the weighting of TUOS – from as little as 11% in several networks, up to 24% in SA Power Networks.



We note that significant additions to transmission RAB could materially impact both the quantity and share of TUOS in residential consumers' bills, as substantial new investment occurs in ISP priority projects, including enhanced regional interconnections and new Renewable Energy Zones.

Looking at Jurisdictional Scheme Amounts more closely

JSA amounts vary widely, from $80 in Endeavour – 11% of the total – to nil in Tas Networks.

JSA amounts could also materially change in future – one example being future costs associated with the provision of revenue support for large quantities of renewable energy and firming capacity under the NSW Electricity Infrastructure Roadmap, a significant jurisdictional scheme in its early stages. The ACT's earlier but similar experience underwriting large-scale renewables is instructive here: that JSA is costing ACT residential customers over 9% of their total network costs in the year to June 2024.

Overleaf, we briefly summarise the range of JSA by jurisdiction. Notable points include:

1. **Premium FiTs add to non-CER householder burden:** Every jurisdiction imposing JSA has all residential customers funding early-adopter rooftop PV households, via premium feed-in tariffs. This is an additional burden on non-CER households who – as we show – are already disproportionately paying for network costs recovery compared with CER-enabled households.
2. **Network costs funding wholesale renewables penetration:** the ACT and NSW are both recovering what are essentially wholesale contracting costs (revenue underwriting for generation capacity) as a "network" cost in residential bills. In fact, this component is highly exposed to wholesale market price risk in future. They are more closely aligned with a retailer's wholesale input and hedging costs.
3. **Other unrelated things:** A number of schemes recover government obligations to fund regulators (ACT, QLD, VIC), or desires to promote decarbonisation broadly (NSW), or to support aging thermal generation capacity they don't want to exit (SA). In the ACT, they simply impose a Utilities Tax… on consumers.

Jurisdictional Scheme Amounts – state policy funding from network customers

JSA are imposed by state / territory jurisdictions on DNSPs as a means to recover costs associated with various policy initiatives.

In **NSW**, these currently comprise:

- **NSW Solar Bonus Scheme,** a PV feed-in tariff for households that installed rooftop PV to end-2016
- **NSW Climate Change Fund** – established to address the impacts of climate change, encourage energy and water saving activities and increase public awareness and acceptance of climate change
- **NSW Electricity Infrastructure Roadmap** – the underwiring scheme for large-scale renewable energy and storage assets

In **Victoria**, JSA amounts fund:

- **Premium Solar Feed-in Tariffs**, similarly to the NSW case
- A recent **Energy Safe Victoria levy**, to support a regulatory body involved with regulating the safety of energy infrastructure.

For **Queensland**:

- **Queensland Solar Bonus Scheme**, another PV feed-in tariff
- Queensland's share of the **AEMC Energy Industry Levy**

In **South Australia**:

- **PV Incentive Scheme**, paying a 44c/kWh feed-in tariff.
- **AGL Designated Services**, a three-year programme for supporting one of AGL's generation units at Torrens Island Power Station.

In the **ACT**, there are the widest range of JSA amounts:

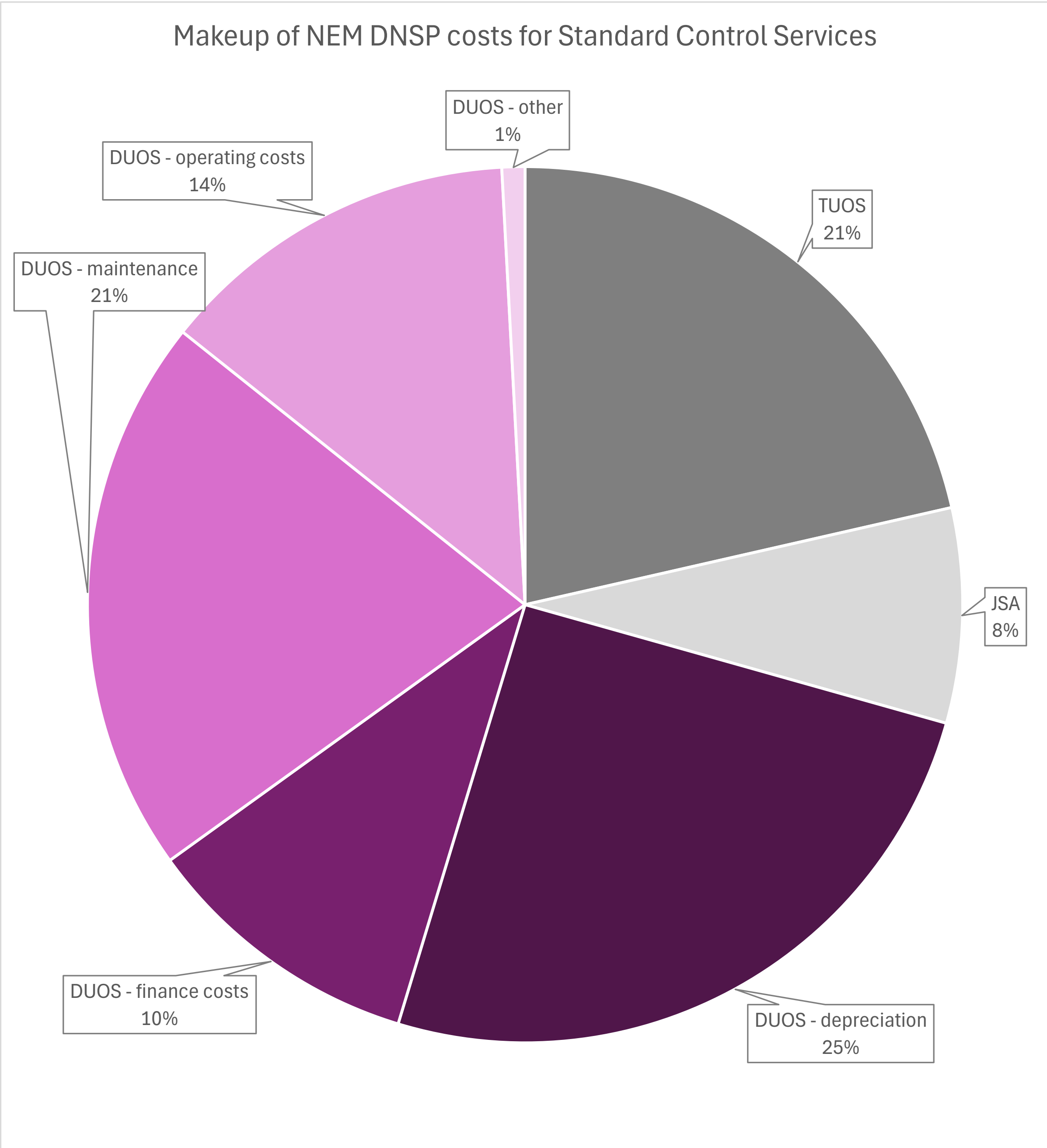
- An **Energy Industry Levy**, similar to that imposed on the QLD networks
- A **Utilities Network Facilities Tax**
- **Small-scale Feed-in Tariffs** for rooftop PV
- **Large-scale Feed-in Tariffs** to support the ACT's procurement of 210MW of large-scale renewables via fixed-price long term contracts, similar to NSW's newer Roadmap.

Tasmania does not currently impose any JSA on electricity consumers.

DNSP operating costs – largely fixed from consumer perspective

Within the dominant DUOS class of overall network costs, we note that the accounting of costs by the DNSPs[17] suggests they are overwhelmingly fixed in nature (in at least the short to medium term) with respect to any consumer-driven activity.

In other words, distribution network operating costs are not driven by either the quantity of electricity consumed (or exported), the time of use (or export), or the peak in demand or export by consumers.



[17] Note that in this figure the numbers are for ALL DNSP SCS costs – there is no breakdown available for residential consumers. As such, the proportion of TUOS and JSA are higher than for residential consumers only, as quoted in the previous section.

Looking at these cost categories, we consider what drives them:

DUOS cost category	Cost drivers
Depreciation	sunk capital base and the depreciation rate
Finance costs	sunk capital base, capital structure and interest rates
Maintenance	activity needed to keep the existing asset base in good condition
Operating costs	likely related to staffing, accommodation, IT, procurement, and other overheads required to run the corporate business

It seems to us that operating costs are NOT materially driven by any behaviour of customers (such as the specifics of usage of their network connection) in the short or medium term.

However, to some extent these will scale up with the size of the network and the number of customers, in relation to maintenance and customer service.

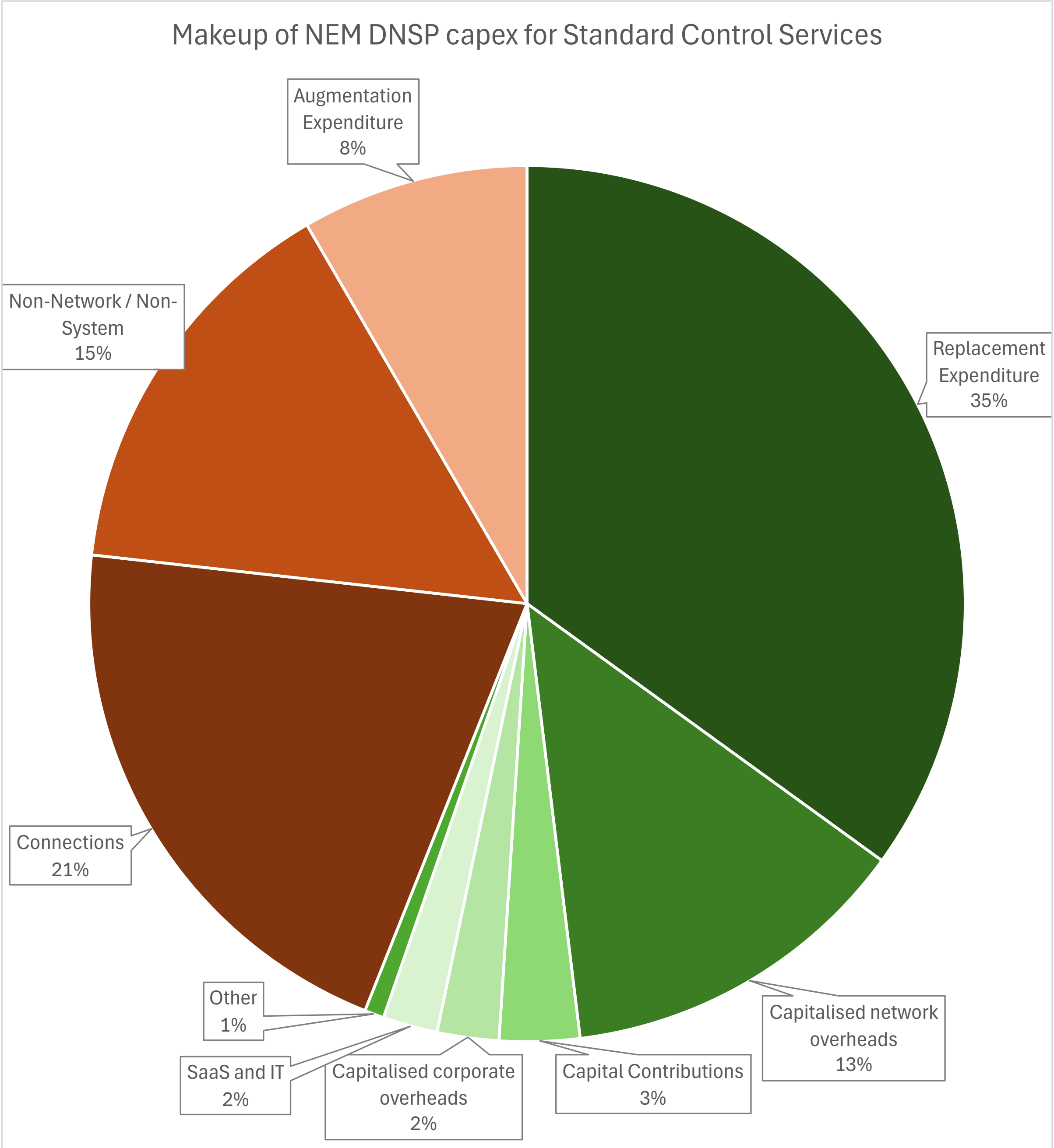
But importantly, we note there is **no behaviour a current customer can take to impact these costs, once connected**.

In summary, it seems reasonable to us to assume that the **current costs of a network are largely fixed and unaffected by the behaviour of residential customers connected to the network.**

DNSP capital expenditure – limited forward-looking costs to address

SCS capital expenditure for the 13 DNSPs in the NEM was $6.6bn in FY24, which is significant compared with total SCS operating costs of $10.8bn. A given year's capex becomes future years' depreciation, finance costs and maintenance needs.

Therefore, in understanding how customer behaviour drives DNSP costs in the future, it is important to look at capex.



Here, we see that the majority of capex (about 56% in our view) is not related to changes in the network at all – these are made up of:

- **Replacement** expenditures of the existing network (e.g. like-for-like, at end of life) – 35% of all capex.
- **Capitalised network and corporate overheads** – a further 15%
- **Capital contributions** (paid by large connecting customers) – 3%
- **Software, IT and other** – 3%

There are substantial categories which likely ARE related to changes in the network, such as:

- **Augmentation** – allowing the network to host greater demand – 8%
- **Connection** – growing the size of the network, with new customers – 21%
- **Non-network / non-system** – likely related to intangible investments to increase network capabilities – 15%

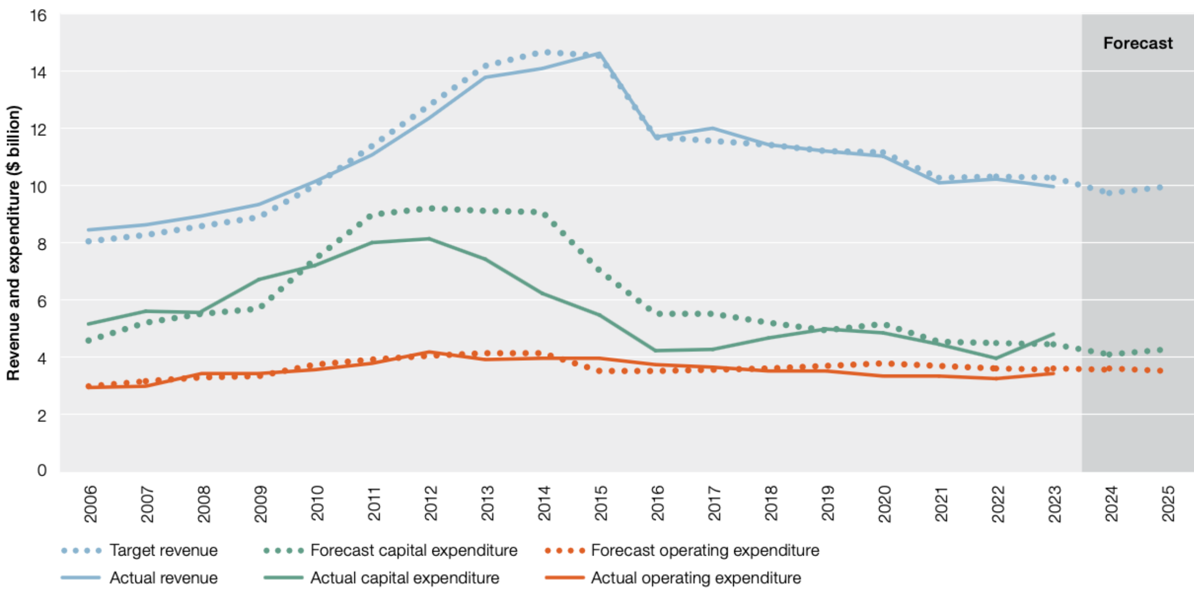
Note that connection costs are unrelated to the behaviour of EXISTING customers.

Augmentation expenditure is clearly very important as it adds capacity to the network – whether for greater peak consumption imports, or PV exports.

It also grows the regulated asset base beyond the depreciation of the current network assets and thus, increased future consumer costs for the long-term as the additional capital is recovered plus a regulated return.

We have shown only a snapshot of 2023/34, but it does not appear to be unrepresentative. The following analysis, all taken from the AER's State of the Energy Market Report 2024, helps put it in context.

Figure 3.9 Revenue and key drivers – electricity distribution networks (aggregate)

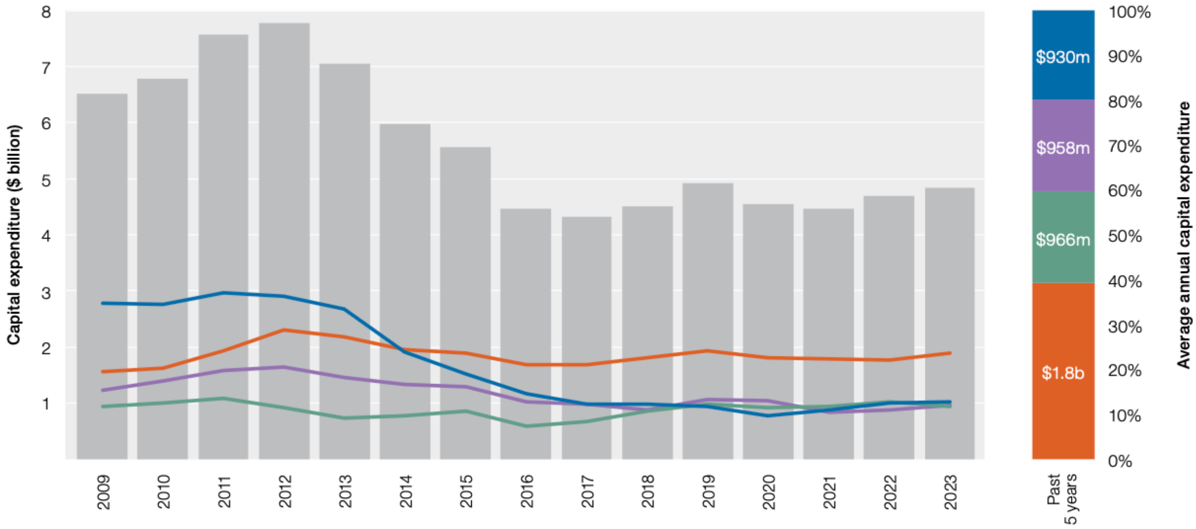


Note: All data are adjusted to June 2023 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). The exception is the Victorian networks, which until year end 2020 reported on a 1 January to 31 December basis. Target revenue for the Victorian distribution networks for the 2021 year has been derived from the transitional year (1 January to 30 June 2021). To enable reporting on equivalent terms, these values have been doubled. Target revenue is derived from regulatory determinations but adjusted to present it on a comparable basis to actual revenues. The adjustments include rewards and penalties from incentive schemes, cost pass-throughs and other factors that are considered in determining the target revenues used to set prices each year. The exception is the Victorian networks, which until year end 2020 reported on a 1 January to 31 December basis.

Source: Revenue: economic benchmarking RIN responses; capital expenditure: AER modelling, category analysis RIN responses; operating expenditure: AER modelling, economic benchmarking RIN responses.

In the figure above, we see aggregate distribution network capex has been relatively stable since declining from a peak in 2012.

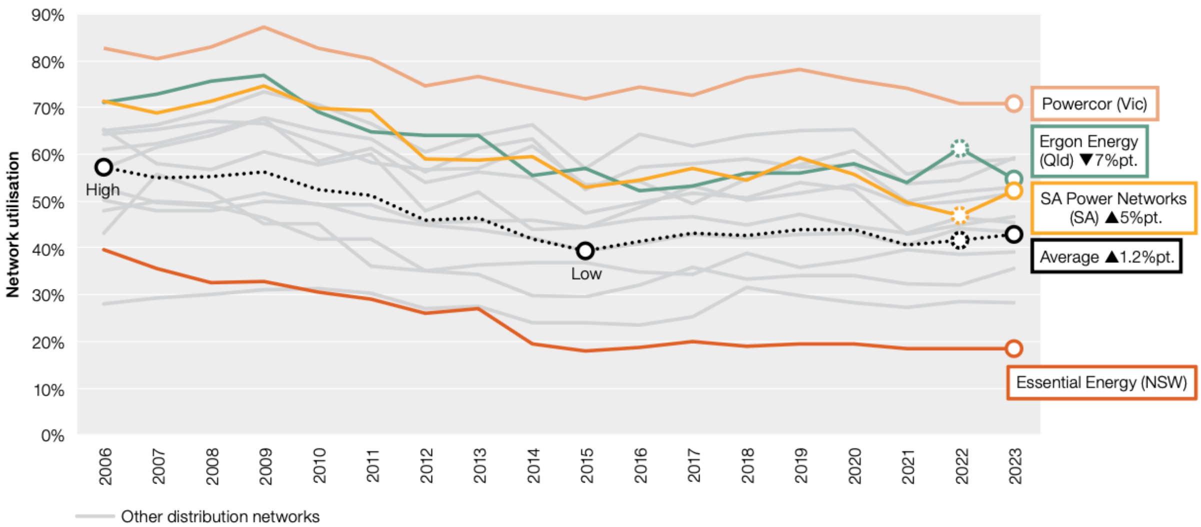
Figure 3.22 Drivers of capital expenditure – electricity distribution networks (aggregate)



Note: All data are adjusted to June 2023 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).
Source: Category analysis RIN responses.

Breaking this down, augmentation in particular has stepped down from about $3bn per annum over 2009-13, to about $1bn per annum since 2017.

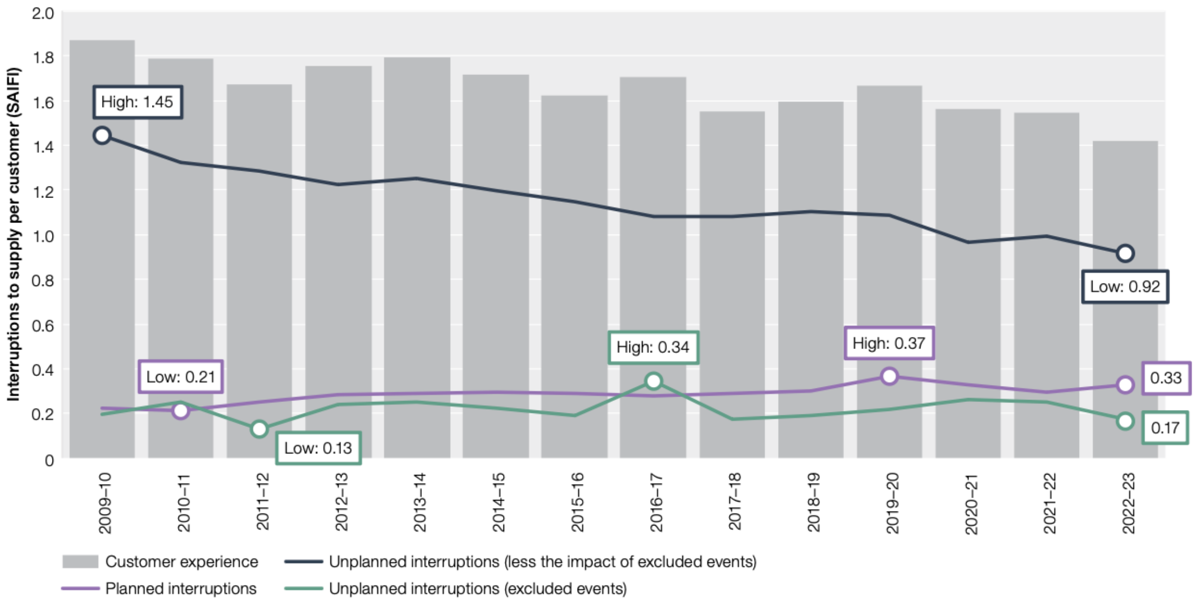
Figure 3.31 Network utilisation – electricity distribution networks



Note: Network utilisation is the non-coincident, summated raw system annual peak demand divided by total zone substation transformer capacity. The changes identified in the labels refer to the relative change in utilisation in percentage points over the previous year.
Source: Economic benchmarking RIN responses.

The flipside of augmentation investment is network utilisation – which we can see here has also declined materially from 2006 to 2015, then remained fairly stable. This indicates relatively low overall pressure on networks compared with the past and so suggests little imminent risk of a rebound in augmentation capex being required.

Figure 3.34 Interruptions to supply (SAIFI) – electricity distribution networks



Note: SAIFI: system average interruption frequency index.
Data in Figure 3.34 shows interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current service target performance incentive scheme (STPIS) (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIFI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July to 30 June. The unplanned (STPIS excluded events) as shown in Figure 3.34 cannot be directly calculated at a whole of NEM level because the major event day calculation must be made at a network level. For example, 22 November 2022 was classed as a major event (STPIS excluded event) for AusNet Services (Victoria) but did not qualify as a major event day for any of the other 12 distribution network service providers in the NEM. As such, the unplanned (STPIS excluded events) and unplanned (normalised measures) in Figure 3.34 are calculated based on each individual network service provider's outputs and subsequently weighted to show a 'whole of NEM' measure.
Source: AER modelling; category analysis regulatory information (RIN) responses.

Another lens to consider is reliability. Network augmentation (and wise investment in general) should also maintain supply to customers against unplanned outages. Above, we see that network performance in this regard has never been better.

What can we conclude?

While our analysis is a current snapshot only, and periods of higher or lower augmentation expenditure may deviate from this average, we note the **average SCS capex per customer at $611 now is substantially more than the AER's reported 5-year average to 2023 of $432**[18], so we doubt our snapshot is underestimating typical capex levels required for augmentation or other purposes.

However, we acknowledge these levels are below the 'gold plating' era in QLD (2010-11 to 2014/15) and NSW (2009/10 to 2013/14).

Considering the scale of customer-influenced costs

So, to take the example of a network's requirements to accommodate additional demand from existing customers (e.g. from more air-conditioning, or rooftop PV exports), there is perhaps 23% of annual capex (or about $1.5bn) being invested at present – if we fully allocated augmentation expenditure and "non-network / non-system" expenditure to this.

This is about $142 per DNSP connection, and using a 7% rate of return, implies $10 per connection of future costs.

These costs do accumulate year on year, but we note they are relatively small in terms of the total $716 per residential customer that is recovered.

[18] State of the Energy Market 2024, figure 3.11

Compounding this is the question: to what extent can changes in customer behaviour move the needle?

If customer responses to cost-reflective tariffs reduced this annual capex by 10%, the impact on customers costs would be very small - $1 per year in this example.

<u>Full of sound and fury, signifying nothing?</u>

In their Tariff Structure Statements, networks estimate the long-run marginal cost (LRMC) of additional import capacity.

To take one example, Endeavour Energy estimate the LRMC for imports at $81.2/kW per annum for their low-voltage customers.

Endeavour estimate that their tariff strategy (which include time or use and demand charges) should "*reduce maximum import demand across the network by 0.8% over the next ten years*"[19]. This represents about 44MW, or $3.6m using their LRMC estimate.

In that period, peak load is nevertheless expected to rise 57% (instead of just under 58%).

So – cost-reflective tariffs in this example might reduce Endeavour's DUOS costs – which were $1.13bn in 2023-24 – by 0.3%.

Is it worth it?

Overall, the vast majority of costs are not variable with consumer actions

By the time they are networks' current operating costs, we see little if any opportunity for customer behaviour to drive them either lower or higher. Even future costs, represented by today's capital expenditure, seem to be mostly unrelated to customer behaviour.

From the figures above, the DNSPs expended a total of $17.3bn in FY24 across operating and capital expenditures, of which only $1.5bn (less than 9%) seems able to be influenced by customer behaviour.

Of that 9%, we suspect the ability to materially influence it either way based on customers realistically adjusting how they use the network would be a very small proportion.

Overall, we conclude that **residential customers have little to no agency in relation to how network costs arise and evolve.**

This is worth considering very carefully when assessing how network costs are recovered, and from whom.

Rules for setting tariffs may be counterproductive

Networks face significant legal constraints in how they can set and change tariffs, given the requirement to comply with the relevant parts of the National Electricity Law (NEL) and National Electricity Rules (NER).

Endeavour Energy expresses this very clearly in their most recent Tariff Structure Statement (our emphasis):

> "*Costs not recovered from import and export LRMC-based charges are recovered from fixed charges, energy charges and demand-based charges. In the absence of reliable information on the price elasticity of demand, this allocation is* ***guided by a rebalancing of the recovery of costs towards fixed charges and away from distortionary consumption-based charges****, subject to the extent this rebalancing*

[19] Endeavour's 2024-29 Tariff Structure Explanatory Statement, p27-28.

can be achieved without unacceptable network bill impacts for our customers. The extent to which we can move towards LRMC-based charging and higher fixed charges is constrained by prioritising the management of customer bill impacts."[20] … and

"*Theoretically,* ***it is most efficient for us to recover from our customers the residual costs we incur exclusively from the fixed charge tariff component*** *because these charges are independent of a customer's usage decisions and therefore minimise the distortion to the LRMC-based price signals that promote efficient usage of our network service."*

Within the NER, we note the following in Rule 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 … to the extent the Distribution Network Service Provider considers reasonably necessary having regard to:

(1) [compliance with cost-reflective pricing principles albeit allowing for long periods of transition extending over more than one 5-year regulatory 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.

The Australian Energy Regulator assesses whether DNSPs are compliant with these rules, and it seems to us there is a preference for extensive smoothing of any bill impacts implied in both the Rule and how it is applied.

However, **the penetration of rooftop PV and householder BESS installations is moving much more quickly that this approach can keep up**.

Adjustment of this Rule and / or how it is applied should be seriously considered as an objective of the AEMC's Pricing Review. Rather than smoothing impacts, it may be better to shift towards more equitable cost recovery quickly (per our recommendations) and manage the impacts separately – e.g. via targeted concessions where there may be unfairness created or undue harm to some consumers.

[20] Endeavour's 2024-29 Tariff Structure Explanatory Statement, p85 and p91

Part 2: Principles to assess network cost recovery equity & fairness

Our Evidence Base makes clear that most network charges – despite being fixed in nature from a residential consumer's perspective – are recovered via consumption-based pricing. This includes transmission and jurisdictional schemes which account for about 22% of the current total but seem likely to grow in relative terms.

In the context of network costs and small electricity consumers, we note a dozen principles[21] that help us to decide how best to pursue equity and fairness in cost recovery:

Firstly and importantly… the pub test (a consumer's perspective)	Largely, a fixed-cost recovery problem	Network access is not a good, it is a service	No free-riding
Cost-reflective pricing where it really will minimise future system costs	Cannot be designed in isolation from the rest of the bill stack	Network pricing exists alongside other incentives beyond the bill	Support innovation and flexibility – from networks and consumers
An overarching incentive to increase electrification	Only for efficient network services, not broad decarbonisation policy	Not to deliver social policy objectives either (-> fairness)	Avoid conflating equity with fairness in pricing electricity networks

Principle 1: The pub test

In the face of all the complexity we are outlining in this section, this is arguably the most important. In the end consumers need to be able to understand and consent to how network costs are recovered. It should be:

- relatively easy to explain to a non-expert consumer.
- reasonably transparent – which might imply better identification on retailer bills.
- not so complex for them to navigate that it requires a degree of engagement that most consumers would prefer to avoid.
- something the person in the pub would likely conclude is "fair enough".

Principle 2: It is a largely fixed-cost recovery problem

Many network costs are essentially fixed and unavoidable, at least in the short to medium term – they are related to historical / sunk costs, or activities that are not correlated with consumer behaviour such as consumption quantities, maximum demand or time of use.

We explore this in some detail for the NEM in the Evidence Base for this report.

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[21] Note some issues deliberately NOT picked up in this list:

- Cost allocation between large and small consumers – out of scope.
- Potential for distortive price signals between gas and electricity networks impacting fuel choice – somewhat out of scope, covered by the incentive to increase electrification to some extent.
- Equity for other stakeholders – networks, generators, retailers, taxpayers – which should be checked case-by-case for any proposals.

In addition, we acknowledge that complexity arises if better equity on one dimension might cause or worsen inequity in another, and these need to be weighed against each other. Another important criterion for assessing ideas.

Principle 3: The network is not a good, it is a service

Networks offer two-way access to electricity (imports and exports), but (unlike wholesale electricity) they are not the product itself. Different consumers in different circumstances will view this service in various ways – including:

A way to access to electricity imports for my consumption	A means to sell my surplus PV generation
A two-way channel to top-up BESS when prices cheap, sell to grid when expensive	An enabler of transition to an EV via home charging
A way to benefit from a community battery (and my neighbour's PV)	Allows my participation in a retailer's Virtual Power Plant
Fallback supply - insurance when my PV / BESS supply is exhausted	A cheaper service arrangement than investing to go completely off-grid

A number of these are direct financial benefits enjoyed by CER-enabled consumers, thanks to their access to the network.

Principle 4: No free-riding

Fixed and sunk costs have to be recovered somehow, and while the details differ, all consumers recognise some value – perhaps even a similar value – in having a network connection.

The burden should not be placed too heavily or lightly on any class of consumer based on their circumstances or behaviour, such as their consumption levels (which they pay for via wholesale costs) or what (if any) CER they possess.

Principle 5: Cost-reflective pricing to minimise future costs

It is important to be rigorous in ensuring that only those consumers whose actions genuinely have material impacts on network costs, pay for those additional costs.

Equally, if consumers lack the capacity to respond to price signals, they may improve equity of cost recovery via better allocation of now-fixed costs in hindsight but may not actually act to reduce future system costs. If this is largely the case for many consumers, the benefit of cost-reflective network price signals is limited and should not dominate network pricing debates.

While we show the large majority of network costs are fixed, some certainly are not – especially future costs. The future investment networks make will support:

- Physical network growth (connecting new consumers in new areas).
- Augmentation of the current network footprint to cater to higher consumer demand.
- Changes to the network to accommodate CER and distribution-embedded storage.

If these costs can be minimised, deferred or allocated more equitably, this should be a consideration – and may justify appropriate pricing signals.

However, there is likely to be a significant trade-off between truly cost-reflective network pricing and other objectives, especially complexity. Postage-stamp tariff approaches appear to be particularly problematic in this respect.

Principle 6: Cannot be designed in isolation

Network charges form an important part of consumers' bill stack – but only a part. The recovery of network charges should not be designed in isolation of the whole.

In particular, there are elements of the bill stack – such as the wholesale costs – which are:

1. much more clearly related to the consumer's usage; and
2. much more impactful in term of minimising system costs via price signals, if consumers respond.[22]

Some of the price signals which apply to wholesale costs will correlate to some extent with price signals we may wish consumers to respond to in relation to networks. However, these wholesale price signals are likely to be much stronger than an equivalent measure of cost-reflection in terms of forward network costs.[23]

It is worth considering whether the complexity of time-of-use network tariffs are worthwhile, if they overlap with, but are much weaker than, a wholesale price signal to consumers. The AEMC's Discussion Paper (refer p. 59) has made clear that in fact, they may directly conflict.

Principle 7: Exists alongside other incentives

In addition to the rest of the bill stack, network pricing coexists with out-of-market incentives, such as government subsidies in relation to CER including rooftop solar, batteries and electric vehicles.

The existence of these subsidies means that governments are ensuring faster and greater penetration of CER than consumers as a whole would choose otherwise.

To the extent this has distortive impacts on equity and fairness, government should consider its obligation to 'lean back' against this.

As far as network cost recovery is concerned, this is a reason why equity might justifiably include economically favouring those without CER (especially where in many cases, this is not by choice, but due to financial, contractual or physical constraints). This suggests equity should contemplate placing these 'CER have-nots' in no worse a position than they might have been in, but for governments subsidising others' CER investments.

Principle 8: Support innovation and flexibility – by both networks and consumers

There are a number of areas where consumers can be rewarded for making sensible decisions that improve the efficiency of the system, raise the utilisation of the fixed-cost network asset, and lower overall electricity system costs for everyone.

Equally, there are opportunities for networks to invest in and operate their networks to achieve the same outcome.

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[22] Per the AEMC's Energeia report: https://www.aemc.gov.au/energeia-finds-cer-flexibility-could-deliver-45b-benefits-2050

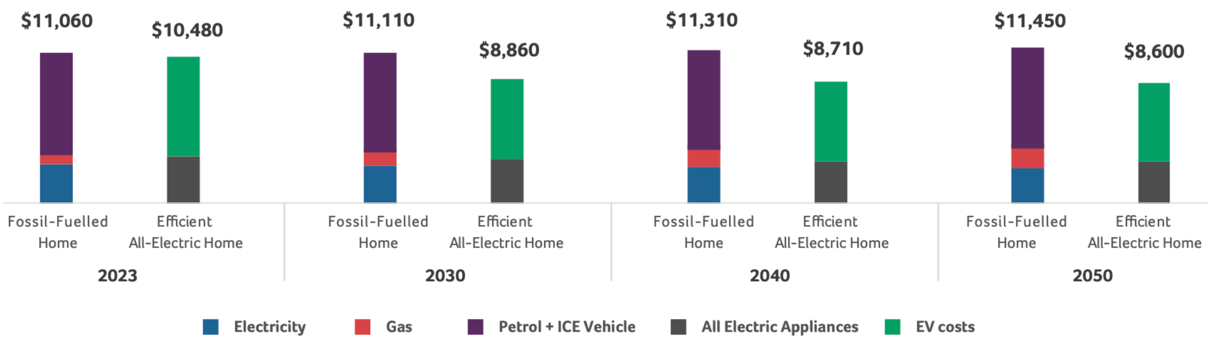
[23] The AEMC's Discussion Paper notes that the ACTUAL network prices signals are typically far in excess of the estimates of genuinely cost-reflective pricing – refer their Figure 10 in appendix D.

Pricing arrangements for consumers and cost-recovery opportunities for networks should reflect and encourage this. These particularly include consumer flexibility in load and exports, and community-scale batteries that can maximise collective local PV self-consumption and PV hosting capacity.

However, the limitations should be recognised, especially in any sensible trade-off against complexity. DNSP-wide tariffs are a blunt instrument when many cost drivers are actually quite localised. Consumers should not face either penalties or rewards for behavioural change that do NOT in fact improve system efficiency and lower system costs.

Principle 9: An overarching incentive to increase electrification

Within electricity pricing, we consider there to be a valid objective to increase electricity's share of the household's overall energy budget. This is based on good evidence that electrification of household and water heating and transportation (via EVs) can represent a lower overall 'energy wallet' for consumers – and with further benefits from decarbonisation consistent with the National Energy Objectives.



Source: ECA Stepping Up report, August 2023, based on 2022 ISP Step Change scenario

As a result, electricity network pricing should at the very least, not discourage electrification. In particular, if network costs at the margin are largely unaffected by consumer usage levels (as we claim is the case) then volumetric pricing appears to run counter to this principle.

Principle 10: Consumers pay for efficient electricity network services, not broad decarbonisation

While there is a good theoretical basis for recovering unpriced externalities (such as the value of emissions reduction) from consumers, this has its limits. The benefits of emission reductions are global and should not be paid only by grid-connected electricity consumers – noting that they have already paid significant environmental costs associated directly with wholesale and small-scale electricity generation, via the RET and retailers' LGC and SRES cost recovery, since 2001.

In addition to that, network pricing based on consumption has clearly supported rooftop PV deployment in the past, with avoided network costs being a significant aspect of the savings consumers enjoy.

Several other elements of network costs are questionable in this respect, including some jurisdictional schemes, and the rebuilding of transmission networks to accommodate large-scale REZ development and enhanced regional interconnection.

If these are arguably wholesale costs (e.g. CFD costs to support renewables and firming capacity), they should be identified as such and might be better recovered (like LGCs are) by retailers for pass-through.

To the extent they are costs over and above (or accelerated) compared with a least-cost electricity system in order to achieve a jurisdictional decarbonisation goal, they should be recovered more generally, from taxpayers.[24]

Principle 11: Don't use network pricing structures to deliver social policy objectives either

Postage-stamp tariffs for small consumers covering large and diverse distribution networks introduce a range of inequities and cross-subsidies.

Some of these are more obvious than others, and some are perhaps more justifiable than others – but in principle, it would be better if EITHER consumers paid a price that reflects the actual cost of "their" network, OR any subsidies that are judged to be warranted were explicitly funded by the appropriate government budget, not all other electricity consumers.

However, we recognise that this is a good example of where one principle will come into conflict with others. This includes the benefits of relatively simplicity in network pricing, as well as generally accepted views of what consumers would consider equitable between urban and rural citizens (refer "the pub test"?).

There may nevertheless be alternative models where the important price signal is not obscured: if distribution network service is more expensive in rural areas, there should be a clear signal to prefer non-network solutions that would lower overall system costs.

Principle 12: Avoid conflating equity with fairness in pricing electricity networks

Energy is an essential service, and fairness of network cost-recovery can be summed up as recognising that all households should have the opportunity to access electricity, regardless of their socioeconomic circumstances.

We note that this assertion risks running headlong into an equity-based view that all consumers should fund a similar network cost, as that implies a much greater burden on households with lower incomes.

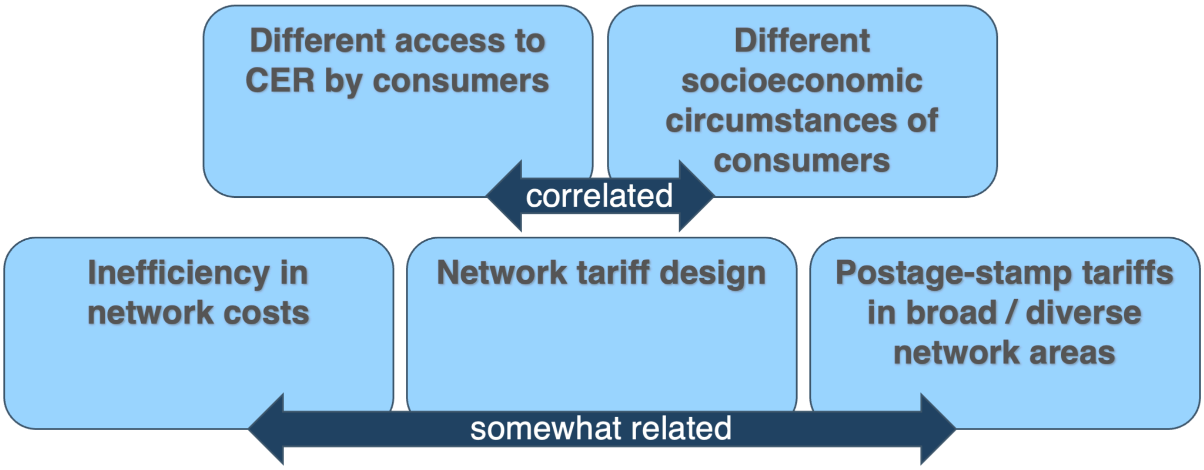
However, the appropriate channel to ensure distributive fairness in society is not network pricing design, it is the tax and social welfare systems. Government should ensure that on a means-tested basis, all households are able to maintain a network connection (even if they might then face significant economic trade-offs about how much electricity they can then afford to consume).

[24] As is the case for the most recent policy of this type, the Commonwealth's Capacity Investment Scheme.

Part 3: How does inequity and unfairness arise?

In supporting a case for change, it is important to clearly identify where equity and fairness problems may exist, their materiality, and whether they are likely to worsen or improve under the status-quo conditions and processes that dictate network cost recovery.

It is helpful to identify five mechanisms by which inequity and unfairness may arise, before considering the specific examples they cause:



A. Inefficiency in network costs

If network costs are higher than they could be for the same level of access to electricity, this is not fair to all consumers, regardless of how those costs are distributed.

This becomes relevant to the extent network pricing and cost-recovery can be designed to improve network utilisation, or lower network costs.

B. Different socioeconomic circumstances of consumers

Unfairness arises when the burden of paying for access to electricity is large relative to household financial resources. It can be exacerbated if network charges are structured as largely fixed (as we in fact propose, driven by equity considerations) because consumers have no means to change their behaviour to avoid such costs, if they wish to maintain that access.

Under our principles, the primary concern in network pricing is equity. Fairness must be addressed at a higher level - in terms of cost-recovery, by considering "who pays"? This allows for means-tested measures, funded outside electricity consumers' wallets by government / taxpayers.

This can ensure fairness without compromising equity.

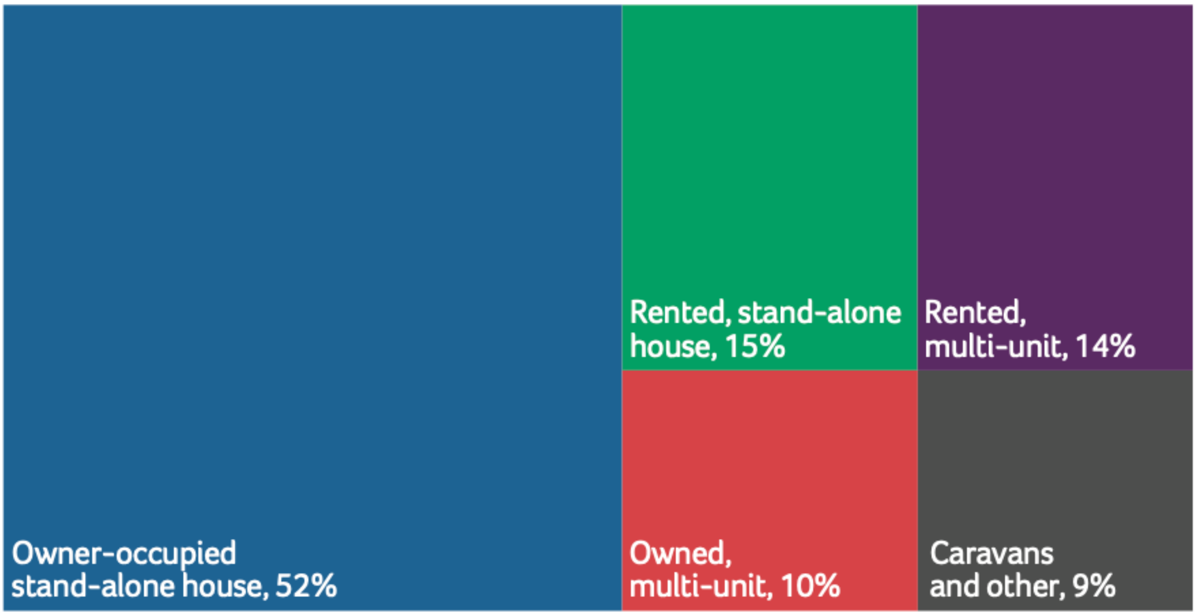
C. Different access to CER by consumers

CER has significantly diversified the ways in which consumers interact with networks, including both the value they derive from them, and the cost they pay to do so based on network tariffs.

If all consumers had equivalent access to CER, ensuring equity would be simpler – but they do not. In some cases, this is a socioeconomic issue (see above), but in many others, it is due to other circumstances such as:

- What type of housing they live in (from freestanding homes to high-rise apartments)
- Whether they own their housing and are free to add CER, or not.

- Whether their housing is otherwise suitable for CER – is the roof shaded? Is there no off-street parking to install an EV charger?



Source: ECA analysis of Census of Population and Housing: Housing data summary, 2021

As a result, ensuring equity includes accommodating these different circumstances of consumers in relation to CER access.

D. The use of postage-stamp tariffs in broad, diverse network areas

Postage-stamp tariff design is the accepted norm, and means within a distribution network, all consumers of a broadly similar type (e.g. residential households) have access to identical network tariffs, regardless of a number of specifics that may indicate their connection's share of network cost may be materially higher or lower than other consumers of that type.

In some cases, tariff design has evolved (or likely will) to ensure inequities and cross-subsidies are not too egregious – such as the introduction of tariffs which sub-segment residential consumers into those with or without solar PV, batteries, controlled loads, or (likely in future) EV chargers.

But in other cases, and especially in certain network areas that are particularly diverse, there will be other areas where postage-stamp tariffs imply cross-subsidies and a degree of inequity among residential consumers – these include:

- **Geography**: the physical network assets required to serve a connection vary widely between CBD, metropolitan, regional and rural areas within a distribution network.
- **Network age**: in older, well-established parts of a network, the historical cost of the asset is relatively low, and has been heavily depreciated. By contrast, where the network is expanding (e.g. to new housing developments) the cost of the physical assets required per connection are relatively high.
- **Network congestion**: some parts of distribution networks are congested in relation to imports and/or PV hosting capacity and require augmentation or other solutions (such as community batteries), others are not congested for the foreseeable future.

In all these cases, postage-stamp tariffs imply cross-subsidies to some extent. In the case of network congestion, they also call into question the validity of cost-reflective pricing based on network-wide demand charges, versus very localised congestion.

To be clear, we do not suggest that a baroque system of locational network tariffs would be a more sensible solution. Nevertheless, there may be other ways in which some elements of these inequities can be mitigated – taking each of the above in turn:

- **Alleviate geography**: Carefully consider cheaper non-network solutions in high cost-to-serve parts of a network, that are not obscured by postage-stamp pricing signals.
- **Alleviate network age**: Closely assess the appropriate level of capital contributions made (e.g. by developers) when new network connections are added.
- **Alleviate network congestion**: Offer relatively bespoke locational opt-ins, where relevant consumers can make an informed choice to alleviate network cost pressures if they have the capacity to do so (in return for a price incentive of this nature).

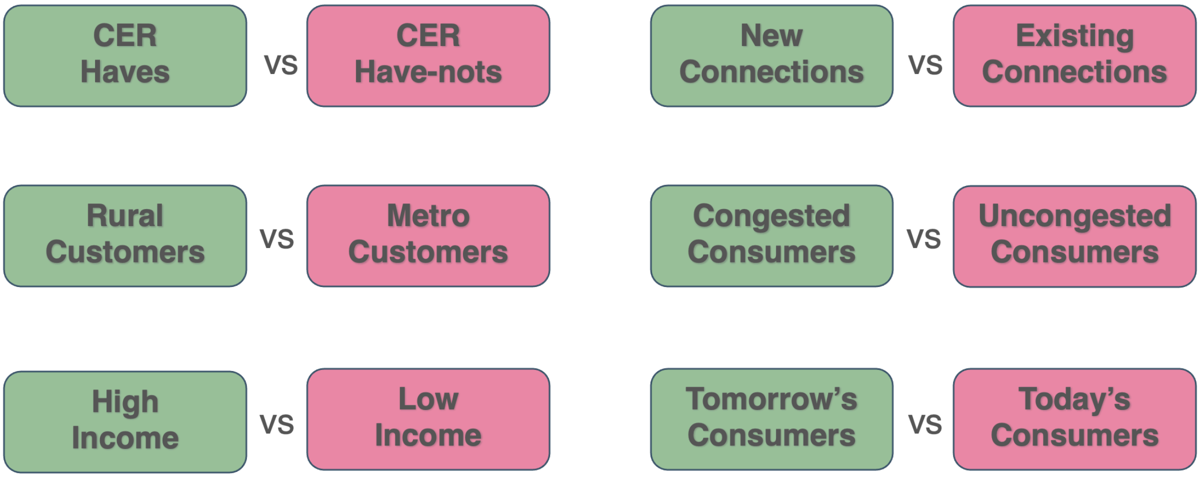
E. Network tariff design

Tariff design can lead to inequity and unfairness. We discuss this in some detail in the following sections, after first considering alternatives to recovering certain costs from small electricity consumers via tariffs at all:

> ***Q5: What are the better forms of tariff design to achieve*** equity?
>
> and
>
> ***Part 6: Network tariff design principles***

Part 4: Inequity Cohorts

In this section we outline a range of potential inequities, unfairness and cross-subsidies that may occur under current and expected network cost recovery mechanisms, by considering a separation of residential electricity consumers into various cohorts.



Not all are necessarily solvable problems, especially not simultaneously – and so while this is a long-list, we later narrow our focus somewhat based on materiality and ease of addressing the challenge as we move towards deeper analysis and recommendations.

Inequity One: CER Haves versus Have-nots

Some consumers have invested in assets (often with subsidies from jurisdictions) that modify their energy consumption and load shape: rooftop PV, batteries, EVs. Many questions arise:

- How much are these consumers paying for network costs, compared with those without CER?
- Do new tariff structures (like two-way charging) sufficiently push back against such customers underpaying relative to non-CER households?
- How much does operation of CER assets drive network cost, in the short and long run?
- To what extent to CER assets benefit non-CER households via lower overall system costs (e.g. via depressing wholesale prices and / or peak demand)?

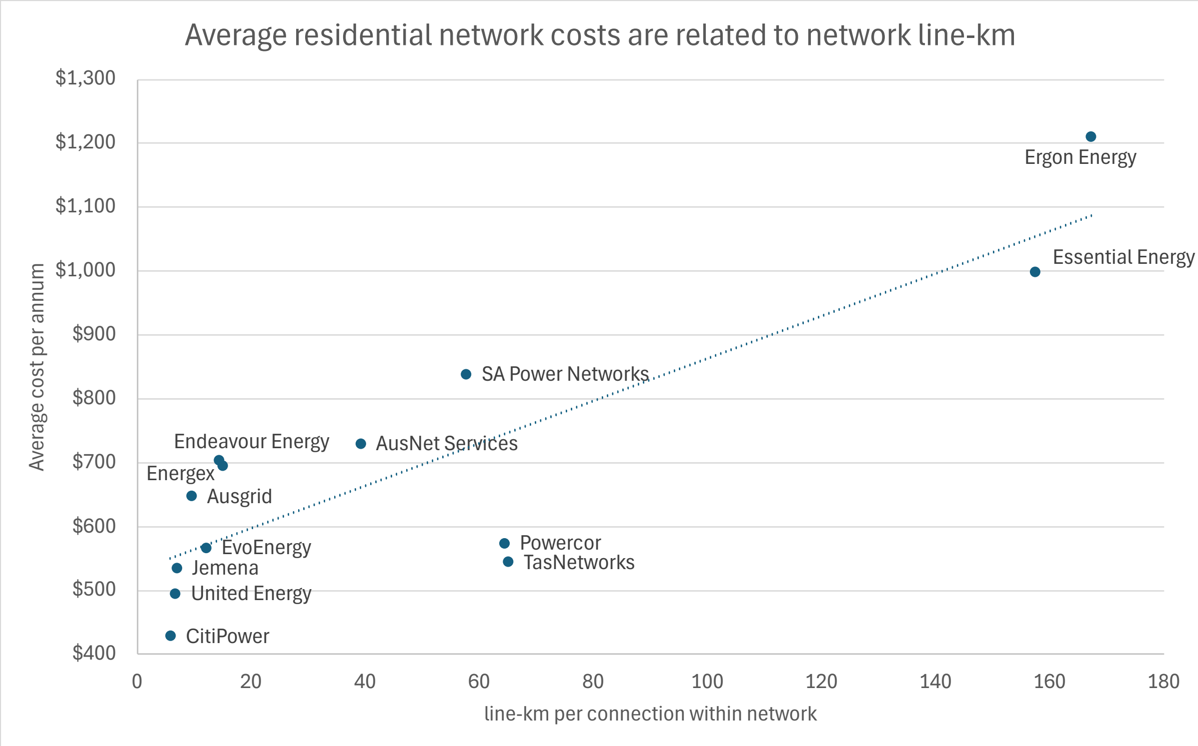
We dedicate substantial analysis to a number of these questions in the Evidence Base, in addition to developing some recommendations which focus on a solution to what appears to be a highly material problem.

Inequity Two: Rural versus Metro

Some consumers live in dense parts of the network (i.e. in cities) where the quantity of network infrastructure required to serve them is relatively low compared with consumers living in more sparsely populated areas.

At the DNSP level, there appears to be a correlation between average network costs, and the physical size of the network (which can be expressed as kilometres of lines per consumer). These linear "overhead assets" are estimated to comprise about 36% of the total Regulated Asset Base for distribution networks.[25]

[25] AER State of the Energy Market 2024, Figure 3.14



Although cost-to-serve differences are clear between networks (for example, CitiPower's $429/yr average for that urban network area, versus Ergon Energy's $1,210/yr average in regional and remote Queensland), this is arguably equitable, at least within the network in question.

But looking across networks, which provide the same services regardless of these differences, there are questions of fairness – is it OK for more rural and remote distribution customers to pay more than city households? Or should our tax and welfare system push back against this disparity, as a form of support for regional and rural citizens?

At least in Queensland, the answer seems to be yes, the government should. Consumers in the Ergon network are subsidised via the State's Uniform Tariff Policy, paying the same as the denser Energex region for their electricity.[26]

Equity issues start to become more concerning in (for example) the SAPN network, with relatively high average costs of $838/yr. This network is very diverse, encompassing both the entire capital city of Adelaide, as well as extensive areas of regional and remote South Australia.

Fortunately for Adelaide electricity consumers, SAPN's longstanding and unique use of 'stobie poles' with their very long asset lives has blunted this impact somewhat and reduced costs for consumers – but apparently the incentives in the system are not sufficient for this innovation to leave the state.[27]

SAPN has about 10 times the line-km per connection of the CitiPower network. Within the SAPN network, postage-stamp tariffs likely mean a significant cross-subsidy is being provided by urban consumers in favour of ex-urban consumers.

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[26] See: https://www.qld.gov.au/housing/buying-owning-home/energy-water-home/electricity/electricity-prices/understand-electricity-system

[27] See section 3.11.2 for the AER's State of the Energy Market 2024 report.

Inequity Three: High versus Low Income

In general, the relative impact of a given network bill on consumers with differing socioeconomic status is an issue we defined as 'fairness', and best managed, in our view, by means-tested concessions via the welfare system.

However, there is another dimension which risks being overlooked. Lower incomes among consumers may also be correlated with living in housing that is less energy inefficient, driving up consumption.

Such consumers may also disproportionately be renters, and/or live in apartments – both of which are additional barriers to adoption of CER (beyond access to the capital to invest). Our Evidence Base makes clear CER-enabled households contribute much less to network cost recovery under current cost-recovery methods.

This highlights the compounding nature of equity and unfairness on consumers in this cohort. For the purposes of this report, we draw the conclusion that it is another reason to push back against consumption-based charging in recovery of network costs.

Inequity Four: New network connections versus Existing

In the Evidence Base, we find network growth is identified as 21% of overall network capital expenditure, - not immaterial, and likely much higher in certain networks hosting more substantial residential growth areas.

Within any network area, some consumers are accessing 'new-build' distribution network assets, associated with residential growth areas and new connections. Others are connected to parts of the network that are decades old, built at much lower historical costs, and largely depreciated.

Postage-stamp tariffs mean all consumers see an average cost across these extremes. New-build network assets (where a network is physically extending to new residential connection areas) therefore drives up regulated asset base-related costs for all consumers compared with a network that does not include such growth areas. There is potentially a cross-subsidy in favour of new-connecting customers, who may not be paying a network cost that reflects the assets recently built to serve them.

However, this will be offset by the spreading of other fixed costs (including operating costs) over a larger number of connections.

While we have not taken the analysis any further quantitatively in this report, we wonder – what is the net effect?

If it means network costs rise for all consumers due to growth in connections (compared with the counterfactual of no new connections), and if the impact is material, then it begs the question: should there be an equalisation payment made at the time of connection via developers?

This would eliminate the cross-subsidy and reveal the true cost of expanded housing development and the infrastructure it requires.

We are well-aware that such an idea is likely to be contested given the challenges faced in housing supply and affordability more generally!

Inequity Five: Congested network areas versus Uncongested

The AEMC Discussion Paper deal with this issue in some detail, and consistently with our view. Within a network area, some consumers are located in areas where there is localised congestion, and looming requirements for augmentation – while other consumers are located in areas where localised congestion is not an issue for the foreseeable future.

When applied as a postage-stamp tariff over the whole network, cost-reflective pricing (such as demand charges) will be either insufficiently signalling to the congested consumers, or improperly constraining / charging uncongested consumers… or both.

This is a very difficult problem (given the complexity implied by any more localised tariffs) and it isn't clear this would pass the pub test with consumers… especially as the future is to some extent unknowable even for network planning engineers.

Rather than seeking to solve this problem, our recommendations take a different direction, towards simplicity, as we instead focus on a larger and more tractable issue between CER Haves and Have-nots.

We do this in a manner that we think treats network congestion and augmentation costs more pragmatically, as something where a 'close enough' alignment with much more impactful wholesale price signals (and the ability of CER to respond to them) is probably adequate.

Inequity Six: Today's versus Tomorrow's consumers

Some network investment being made now will take an extended period of time to reach target utilisation, particularly for transmission. This includes the Integrated System Plan's (ISP) inter-regional projects, and new Renewable Energy Zone transmission investments.

However, accumulation of Regulated Asset Base for these investments will drive higher TUOS pass-through costs for consumers now.

These investments are arguably partly related to the imperative to reduce carbon emissions, not to serve "business as usual" electricity demand – if not in their nature, at least to some extent in their timing, where ISP outcomes are constrained by jurisdictional targets for renewable energy penetration and emissions reductions.

We have previously noted as a principle of equity in network pricing, that electricity consumers should not be assumed to be the source of funding for such policies.

However, it adds insult to injury if today's consumers pay these costs when the underlying assets remain unfinished and then, underutilised for a period.

This becomes a question of "who pays?", outside a network pricing debate. On one view, TUOS pass-through costs of this nature could be discounted to reflect utilisation, with the gap funded via general government revenues and taxpayers as a whole.

Part 5: Network cost recovery concepts

In considering the broad question of how best to recovery network costs – most equitably and fairly – there are several levels of questioning that are useful:

What types of costs should continue to be recovered from electricity consumers?

What is the role of electricity pricing versus governments in addressing fairness of access to electricity networks?

What type of channels (including but not limited to retailers) could best be used to recover electricity network costs?

What types of inequities are we prepared to accept, and what might we be prepared to address?

To the extent electricity network costs continue to be recovered via retail electricity billing, what are the better forms of tariff design to achieve equity?

Note that tariff design is the last question we ask, not the first!

Considering these can assist us in proposing better overall approaches.

Q1: What types of costs should be recovered from electricity consumers?

Arguably, electricity consumers might reasonably expect to pay only for the most efficient system that provides them with reliable access to electricity.

This would be an efficient portfolio of:

- consumer energy resources – funded directly by consumers (albeit with a subsidy in many cases)
- wholesale generation capacity
- networks providing metering and (two-way) access
- retail services including billing and risk-management to stabilise the price volatility in wholesale markets (to the extent consumers value that stability).

It <u>does not</u> necessarily include the costs associated with deviating from this most efficient, low-cost system, for the purposes of decarbonisation, to any extent beyond the Value of Emission Reduction[28] – which has been developed by the market bodies for the purposes of including assessment of decarbonisation alongside the other National Energy Objectives – especially cost.

[28] See: https://www.aer.gov.au/system/files/2024-05/AER%20-%20Valuing%20emissions%20reduction%20-%20Final%20guidance%20and%20explanatory%20statement%20-%20May%202024.pdf

Reduction in emissions is a jurisdictional policy choice, to the benefit of all citizens – not just electricity consumers.

It is also a policy choice to require the electricity sector to provide such a significant proportion of the decarbonisation being achieved to date, and in the medium term as we look forward.

Decarbonisation policies for the electricity sector are effected via several schemes, including:

- The national-level LRET and SRES (funding large- and small-scale renewable capacity deployment)
- State / territory initiatives to deploy new renewable energy zones and associated transmission capacity, storage and firming capacity.
- National support for the financing of new regulated transmission, such as the Rewiring the Nation fund.

Notably, the costs of these schemes have often been recovered from electricity consumers via consumption-based pricing, either via retailers (such as the LRET and SRES), or networks (such as the ACT's renewables contracting, or the NSW Electricity Infrastructure Roadmap costs). LRET and SRES costs in particular have represented a significant proportion of total electricity cost for consumers – but will cease in 2030.

An important exception is the Commonwealth's Capacity Investment Scheme, where the contingent costs (payouts under the contracts with supported capacity) will be funded from the Commonwealth's resources – in other words, <u>paid for by taxpayers, not electricity consumers</u>.

In future, the costs of these schemes could be large – especially if wholesale market prices are low, requiring material payments to capacity under the CIS and NSW LTESA contracts.

The scale of new transmission associated with enhanced regional interconnection and the creation of new REZs is also going to be significant.

To some extent, these new costs will represent a higher-cost system, than if decarbonisation policy had not imposed a rapid pace of change on the electricity system – especially via the LRET and SRES. These policies have driven large quantities of renewables in, and consequently destabilised the economics of much thermal capacity, accelerating exits and requiring further rapid replacement of capacity and new transmission investment to cater for it.

So, these costs are not <u>solely</u> driven by increased consumption, or end-of-life asset replacement, or a cost-based transition to cheaper delivered electricity to consumers – but also directly by jurisdictional policy.

Therefore, a portion of these costs reflect a broader social good that all citizens gain reward from, not just energy consumers.

Overall, it seems likely that electricity consumers will be asked to bear most of the burden of decarbonisation, unless more schemes follow the lead of the CIS and shift that burden to taxpayers – where it can be distributed more fairly and progressively via the tax system.

In practice, we think it is worth considering:

- **Partial / initial taxpayer funding of new transmission** network costs associated with the electricity transition, so that element of electricity consumer costs does not rise steeply.
- **Relieving electricity consumers of the burden of decarbonisation-related Jurisdictional Scheme Amounts** that currently are added to network costs for

recovery by most state and territories. This is especially important for large schemes such as the NSW Roadmap[29], or possibly the SA FERM.

It is clear the tax system has limited resources, and an implication might be the need to fund this explicitly.

Something modelled on the Medicare Levy could be considered: an Energy Transition Levy that could relieve electricity consumers of costs and be funded more progressively (e.g. as a percentage of taxable income, for both individuals and businesses).

Q2: Electricity pricing vs. governments in addressing fairness of access?

Generally speaking, designing for equity among electricity consumers may not lead to fairness.

An equitable outcome might recognise that all consumers require network access, and the value they derive is not really related to how much electricity they consume – this would suggest relatively flat, fixed costs of network access. This becomes particularly important when considering the impact of rooftop PV, where some consumers draw much less electricity than others, despite having similar usage.

However, a shift away from volumetric charges to fixed charges would see some vulnerable customers worse off: those who consume little not because they have PV, but because they have limited financial resources to pay the electricity bill.

In this scenario, a re-think of the philosophy of electricity access is probably needed.

All consumers require access to the network – even if they then choose to economise on electricity usage to minimise their consumption charges.

If the equitable outcome is a high fixed charge for network cost recovery (in place of volumetric charges) then fairness would require means-testing and rebates for low-income electricity consumers, to offset that cost – perhaps down towards the level of fixed network charges in today's status quo (about 29% fixed on average over the NEM).

This may be the best way to target existing government investment in bill concessions (alongside investments to subsidise low-income consumers' access to energy efficiency improvements).

Another dimension here would be considering the differential costs of urban versus rural distribution networks.

If there is a philosophy of fairness that implies rural customers should not have to face the burden of a sparse, expensive network needed to serve them, then a similar approach could be applied.

The cheapest network is CitiPower in Melbourne at about $429 per residential connection per annum, and three of the other VIC networks are below $600. The NEM average is about $716, and Ergon is the most expensive at about $1,210.

[29] Even less-ambitiously, JSA recovery should be better-designed. Under the NSW LTESA, the benefits of the assets being supported accrue to all electricity consumers large and small in the state, but recovery via DNSPs relieves the largest transmission-connected consumers of any burden.

Governments (state or Commonwealth) could choose to apply regional funding budgets to rebate consumers in more expensive networks down to the typical level of urban distribution networks – perhaps about $550.

This would provide significant benefits in reduced costs to consumers in Essential, Ergon, AusNet Services and SA Power Networks areas. An approach like this would extend the QLD government's approach to equalising costs between Energex and Ergon areas.

Note that SA Power Networks is a particularly clear example where a network includes both Adelaide and all of regional and rural South Australia – the result a major cross-subsidy being paid by Adelaide consumers to their non-urban peers.

Q3: What type of channels could best be used to recover electricity network costs?

The status quo sees network costs recovered from electricity consumers, and via retail electricity bills.

We canvass a reduction in scope of the costs recovered this way, including via taxpayer funding of electricity transition costs, and means-tested relief from the cost of basic access to electricity networks.

However, we should also consider who may be best placed to recover the basic costs of the network from consumers, as an alternative to retailers. This is particularly relevant if, as we suggest might be appropriate, the majority of network costs are most equitably recovered as a fixed charge per household per annum.

One alternative would be for networks to determine what is a genuinely cost-reflective element of charges, and for these to continue to be passed through via retailers. An example would be the type of two-way time-of-use tariffs applicable to consumers with batteries and / or PV, or the element of ToU or demand charges that networks consider to be cost-reflective in relation to minimising the future investment in the network.

This approach is the essence of our key recommendations.

The residual fixed charges could then be recovered via a number of alternative channels:

- **Via retailers**, but as an explicit "network access fee" on retail bills, helping to make clear to consumers that they are paying a fixed amount unrelated to electricity consumption in order to be connected.
- **From consumers directly as a separate bill** from the network – although this would imply a large duplication of billing infrastructure and operational costs.
- **Via councils**, as an element of rates.

In our view, the last of these – recovery via councils – has a number of interesting potential advantages:

5. **Locational pricing at LGA level:**[30] Local government areas are typically much smaller than DNSP regions and may provide a useful mechanism for networks to apply more localised prices, better reflecting actual network fixed costs. It would be a way to step back from postage-stamp tariffs covering very broad and diverse network areas in some DNSPs – and that could lead to more equitable outcomes.
6. **Consistency with other Council charges:** Rates are accepted as a fixed cost, based on a measure of home value – there is no expectation that ratepayers are charged

[30] We are presuming the DNSP's network area boundaries and congested areas align reasonably with LGA boundaries.

based on their volume of rubbish collected, or whether they actually use the roads. It seems likely ratepayers might accept the same for a network charge – perhaps with some simple variations based on whether it is an import-only connection, or a two-way connection with PV, or an EV charger.

7. **Onus on the property owner:** Rates are the legal responsibility of the property owner, not a tenant. While this can be adjusted via the terms of a rental contract, there may be some public policy attraction to property owners accepting the cost of maintaining access to the electricity network. Tenants would still pay consumption charges and any non-fixed network charges related to their consumption via retailers.
8. **Relatively efficient:**[31] Councils have existing billing systems for all properties. Networks and councils have existing commercial relationships, including the provision of public lighting by networks to councils.

Q4: What types of inequities do we accept, versus seek to address, and how?

In the preceding Part 3, we identified a number of ways in which cohorts of residential electricity consumers can be split, to highlight areas of inequity.

The natural response is to wonder how tariff design might be employed to fix these, but in many cases, we suspect that is not the right path. Instead, we need to:

2. Decide whether the issue is material enough to warrant attention
3. If so, decide whether it is something we are prepared to address – given it will by definition create winners and losers among consumers (or if not, costs for government / taxpayers to compensate losers)
4. If so, decide whether another approach might be superior to using a tariff design – such as investment to fix the problem, or targeted rebates or subsidies to alleviate the inequity.
5. Only then resort to tariff design – for the problems where price signals are most likely to be both effective, and simple enough to be accepted.

As we have worked through this, we find that some areas of inequity do indeed seem necessary to **address via network tariff design** – this especially includes the impact of CER-enabled consumers when pricing is volumetric. Broadly the two main approaches to do so are:

- **Replacing volumetric charges with fixed charges**, so that lower imports by PV-enabled households becomes irrelevant. Fixed charges might arguably vary based on service: we make clear network access is more valuable to a consumer with CER, a battery and an EV than a consumer who only imports.
- Or, **persisting with increasingly powerful time-of-use signals** to try to equalise outcomes – we doubt this is feasible under widespread adoption of batteries.

Others may be **addressed outside tariff design** – for example, any equalisation of costs for regional versus urban consumers could be provided through taxpayers via regional budgets. The cost-reflective alternative would see rural and regional electricity consumers facing substantially higher costs of access to a distribution network.

Some inequities may simply be **too complex to address via tariffs or other interventions** – for example, the very localised nature of network congestion might suggest very balkanised network tariffs, where one house faces a sharp cost-reflective price signal, but a neighbour

[31] There would be some additional billing and co-ordination costs, since CER-related tariffs would still be recovered through retailers.

(on a different substation) does not. Such tariffs would be highly complex to design and explain, would lead to unpredictable outcomes for consumers, and reasonable concerns about fairness: why am I charged so much in peak, just because the network wasn't planned well, or a large load relocated nearby?

Both the regional vs urban and localised congestion problems might be partly addressed by a manageable increase in tariff variation by location – such as could occur via recovering fixed costs via councils, with differences at the LGA level.

Localised congestion is one area where the best answer might be investment: these may be areas best suited to community battery deployment, to smooth network peaks and increase overall CER hosting capacity, while providing benefits (such as avoided augmentation investment) to the system. We do not rule out a role for more targeted, localised opt-in tariffs as part of the solution (with or without an associated community battery involved).

Q5: What are the better forms of tariff design to achieve equity?

From our Evidence Base, we find that the status quo sees about 29% recovery of network costs as fixed charges, 59% recovery based on volume of electricity consumed, and 12% via a blend of volume and demand charges.

This is inconsistent with the fact that the vast majority of network costs are not impacted by either consumption or maximum demand in the short run. They are driven by completely separate matters outside the control of individual consumers including the sunk investment in the network as it is, the cost to maintain it, the cost to extend it to connect new consumers, and the cost of capital in funding the network.

To the limited extent consumer behaviour in importing electricity can influence network costs, this is in relation to the quantity and timing of augmentation – but this is often quite localised and cannot sensibly be reflected in tariffs without extreme variation and complexity, to a level we doubt consumers would accept.

The result is price signals (such as demand charges) that are either irrelevant (because a consumer is not actually in a part of the network nearing a point of congestion) or too weak (even if they are, the price signal is spread too widely across all other consumers).

IF there is a clear case for cost-reflective elements in network tariffs, they should be used, but these will be relatively small for most customers, most of the time.

Before they are used, we should first consider: might other coincident price signals do the job just as well or better – such as price signals retailers will apply on consumption to avoid times of high wholesale costs (and thus high hedging costs for retailers)?

If these are largely consistent with peak demand times for networks, is there really any point overlaying another small, similar network price signal?

This suggests to us that for network tariff design, the philosophy should be that **consumers value having access to the network, and this value is not really related to how much they import**. Just as most network costs are fixed (in terms of consumer behaviour to influence them), so too is the value of a network connection to a consumer largely fixed.

As a result, the outcome of network tariffs should be largely similar costs for all consumers, with any potential variation based on how many dimensions of value they derive from their connections, after considering how their behaviour (especially in relation to operating CER) may impact system costs, positively or negatively.

On this model, a simple import-only connection would be the least annual cost.

Consumers having rooftop PV might pay somewhat more, because they can export and earn a feed-in tariff, among other benefits. A consumer with PV and a BESS may pay more again, because a BESS allows them to benefit from price arbitrage on their exports. Equally, a consumer with an EV derives a further benefit, and might be expected to pay for this.

We evolve this thinking in bringing forward our key recommendations – including a model of a fixed, common Basic Access Charge covering access to imports, with an overlay of CER-related time-of-use tariffs based on cost-reflective behaviour.

Developing our recommendations – Basic Access Charge + CER Tariffs

This thinking leads us to suggest

1. A simple range of **fixed annual costs for network access**, which might be as simple as a single fixed cost for householder import access. A more complex variation might see additional charges for additional CER-related network services enjoyed by relevant consumers, that could be 'earned back' via cost-reflective operation of the CER.
2. **Time-of-use CER network tariffs** which are secondary (overlaid on the BAC) and cost-reflective in relation to the operation of various CER assets in the network, which is likely to dominate cost-driving behaviour by consumers in relation to both network and wholesale costs in future.

An expected outcome would be total annual costs for consumers that reflect the quantity and value of service a consumer enjoys from being connected (not the quantity of electricity they import or export).

Fixed charges have the benefit of extreme simplicity, easily explained to consumers, and objectively provide equity of outcomes, when framed correctly: *I pay the same as my neighbour for the same service of being connected to the network*.

Two key design questions for the BAC + CER Tariff model

One key question is whether the lack of a temporal price signal for consumption would lead to unacceptably inefficient use of the network by consumers. This may not be the case, if:

- there is a strong pass-through of wholesale price signals for consumption at various times by retailers (rather than networks); and
- these are reasonably coincident with peaks and constraints on the network; and
- CER network tariffs provide good incentives for cost-reflective CER behaviour that will ALSO push against consumption peaks – such as charges for daytime PV exports and rewards for evening exports via PV or BESS, offsetting peak demand and congestion.

The last of these looks very much like the emerging two-way secondary tariff designs for PV and BESS households.

Another key question is whether CER-enabled households, when exposed to the CER Tariffs as contemplated, would provide system-wide cost benefits (particularly if their presence and operation depresses wholesale prices, and/or increases network hosting capacity for rooftop PV, and / or peak consumption capacity by netting off local BESS exports against peak consumption).

If so, a valid case could be made that CER-enabled consumers should continue to pay somewhat less than non-CER households.

This requires more evidence – so for now we conceive of the BAC as recovering ~100% of network residual costs, with CER Tariffs, offering charges and credits that net out in aggregate.

Addressing some implications

The most obvious concern is the impact of a uniform fixed charge on households with lower-than-average consumption – as they would pay more than the status-quo, all else equal.

This may well be equitable but becomes a challenge to fairness to the extent these households overlap with lower socioeconomic conditions, and where frugality in electricity use may be a necessity.

We also note that some low-income households in relatively energy-inefficient housing might in fact benefit, if their usage is relatively high and inelastic. The same could be said for larger households, with larger usage – and where there will also be an overlap with lower-income families at a stage of their lives – raising dependent children – when overall living costs are relatively high.

In any case, the introduction of a BAC should also involve careful re-targeting of existing energy concession budgets to means-tested reduction of the BAC where most appropriate, to ensure fairness is not a casualty of better equity.

Part 6: Network tariff design principles

Inevitably, questions of network cost recovery will intersect with assessments of the "best" tariff design. In the NEM's disaggregated market structure, network tariffs will be passed to retailers, who in turn package those as part of the retail tariffs experienced by electricity customers.

Much work has been done on this question – in considering the situation for the NEM, we think it is useful to consider how Severin Borenstein, Professor of Business and Public Policy at U.C. Berkeley's Haas School of Business approached the question in this 2016 paper, The Economics of Fixed Cost Recovery by Utilities[32]. We summarise those views, here, simplified for the case of network costs (not broader electricity costs), and residential consumers.

Borenstein nominates six basic choices to recover residual costs: all those costs above a network's short-run marginal costs (SRMC). SRMC[33] are those costs which consumers might impact via their behaviour, which we contend in the Evidence Base are minor.

Assume that the SRMC of the network is priced appropriately by whatever means but is relatively small compared to the largely fixed residual costs to be recovered. We assess Borenstein's six choices in our context.

1. Consumption-based charges (aka average cost pricing, per kWh, volumetric)

   Recovering fixed costs volumetrically causes deadweight loss (DWL) in economic parlance, by impeding consumption that would otherwise occur at a lower marginal cost.

   Consumption-based pricing has the important benefit of simplicity and is a major part of the current tariff design, as set out in the Evidence Base. This includes both "anytime" flat tariffs, as well as time-of-use consumption charges.

   While there are some superficial attractions, we do not think a consumption-based contribution necessarily represents an equitable distribution of network costs among consumers (remembering that actual consumption costs for electricity ARE volumetric, as the wholesale component of a tariff).

   Different consumers will realise different values from their network connection, but (to take a simple example), the value is that when the light switch is flicked, the lights come on. This is independent of whether the lights are LED or incandescent globes, with very different volumes of electricity consumed.

2. Ramsey pricing

   A Ramsey pricing structure would charge more to those with inelastic demand for a network connection.

   An attraction of such a differentiated price is to avoid volumetric pricing causing elastic demand falling and thus avoiding that DWL.

   However, in the case of network pricing and residential consumers, such an approach becomes binary. Not only would this be complex, but would also raise serious equity and fairness concerns, because very inelastic demand is likely to reside with consumers who

[32] See: https://www.sciencedirect.com/science/article/abs/pii/S1040619016301130

[33] Note that Borenstein includes externalities, such as the value of carbon emissions, in SRMC – so the following does NOT consider the problem in isolation from emission reductions objectives.

have limited resources (financial or otherwise) to invest in the level of CER necessary to go off-grid.

Nor is such an outcome a desirable consequence, in the case of a regulated asset where costs will not fall materially if consumers disconnect.

3. Fixed charges

There are obvious attractions in matching fixed cost recovery with fixed charges (and the status quo already partially does so, as set out in the Evidence Base).

If equity concerns are raised, they would be the converse of the above: those with price-elastic demand cannot benefit from lower costs. However, since we contend the network costs are really fixed, this objection should be resisted. Particularly given the other class of low-volume customers: CER households with significant self-consumption of rooftop PV – one of the key distortions that cost recovery must effectively address.

Fixed charges may also raise some distributional concerns – is it fair that frugal electricity users with low incomes pay the same for network access as more wealthy consumers? However, we argue that a degree of means-tested relief from a fixed network access cost is a better solution that can be made fair, while also being equitable.

One of the concerns with a tariff design that blends fixed daily charges with consumption charges (as any retail tariff is likely to do) is that consumers may fail to distinguish between the fixed and consumption-based components. The tendency may be to cognitively and behaviourally lump this together as an overall volumetric cost.

Given the attractions of matching fixed cost to fixed charges, it is worth considering carefully how this downside could be avoided.

One may be to more clearly separate a “network access cost” charge on a retail bill, as a fixed c/day amount separate from consumption or other tariff components.

Another might be to recover network access costs as a fixed amount by a separate channel, such as council rates (similar to land tax or other services / levies).

4. Tiered pricing (Inclining or Declining Block Tariffs)

These sit in between consumption-based charges and fixed charges as a hybrid – a customer’s contribution to fixed cost recovery is now related to consumption, but not exactly proportional to it.

With a **declining block** structure, the higher-volume units can be priced close to SRMC, minimising DWL if many consumers are there at the margin - but clearly that simplifies back to just a fixed charge plus a SRMC volumetric charge at the extreme – so why not just do that?

It is difficult to see why a declining block tariff would more attractive than either volumetric or fixed charges on equity or fairness grounds, unless it DOES trend back that way, leaving few if any customers to face the high price at the margin of their consumption!

It is very hard to make a case for **inclining block** tariffs at all in the case of network cost recovery from residential consumers in the NEM. Distributional arguments could be made in favour of inclining block structures, if they were viewed as a means to impose fairness, by charging larger (presumably wealthier) consumers more at the margin.

Whether the proxy of consumption for capacity to pay was ever valid is unclear, but the emergence of CER-connected households with low import volumes completely negates the argument.

5. Minimum bills

A minimum bill structure looks like a fixed charge including some 'free' electricity.

It is really an extreme version of an inclining block tariff, with the same problems noted above.

If the quantity (or value) of included electricity is low, the structure does little in terms of customer behaviour, because almost every consumer uses more, and so pays at the margin.

If it is high, the structure creates zero-cost consumption incentives (below SRMC) which creates DWL.

Overall, this is economically inferior to a smaller fixed charge to recover the residual costs, plus charging at the SRMC for every kWh over and above those residual costs.

6. Demand charges

Demand charges are a popular feature of so-called "cost-reflective" network tariff designs, but Borenstein sets out a number of good reasons to be sceptical in general:

- The structure initially made some sense when "dumb" meters could only identify cumulative consumption and peak period demand (but not when the peak occurred) – when they were the only alternative to a flat anytime consumption-based tariff.
- When meters are upgraded to "smart", the potential for more time-related demand charges are eclipsed (in Borenstein's view) by the advantages of time-of-use consumption pricing.
- A customer's peak demand in a billing period may be a poor proxy for system peak demand. This can be improved when smart meters allow for peaks to be assessed in (for example) only evening peak hours, not anytime – but that is often NOT how tariffs are structured.
- A demand charge MIGHT relate to the capital cost of the capacity of the connection, <u>but it is sunk</u>. … a fixed charge related to demand capacity would make more sense if there was a desire to distinguish pricing based on demand capacity.
- However (and importantly in our specific case), Borenstein does not rule out a role for demand charges in relation to look-forward avoided capex opportunities.

Implications of Borenstein's analysis for recovery of network costs

In summary, when we consider Borenstein's approach in the context of recovering the largely fixed costs of distribution networks from residential consumers, we have a rough roadmap.

<u>Recover SRMC with appropriate pricing signals</u>

Firstly, determine actual SRMC incurred by the network, and what the drivers are – then seek to recover it. This might be a time-of-use volumetric or demand charge, <u>but it is likely to be small</u> relative to the residual, largely fixed costs.

In doing so, be prepared to include the SRMC of externalities incurred, which might include carbon costs (this closes the gap to total costs, and is good practice because it is economically efficient).

We think this second element is interesting: a carbon charge could reduce over time as the grid decarbonises… but then fixed charges have to rise. This could be a means to smooth an introduction of largely fixed charges over time.

Recover Residual Costs with fixed charges

In any case, after dealing with the relatively minor issue of SRMC, a large "gap" of residual fixed costs remains to be recovered.

Using a consumption charge (as is the status quo to a large extent) may have initial appeal but it creates DWL and distorts consumer behaviour… especially when there are alternatives (e.g. CER, gas, EV).

Applying fixed charges instead might appear to create equity concerns relatively to a status-quo with significant consumption charges, but these objections are less-likely to be sustained given the impact of CER. Address distributional concerns with targeted means-tested programs.

To create some distinction, fixed charges within a network area could possibly be set with a relationship to value from the network – such as peak import or export capacity provided. However, this adds complexity is a risk, along with the reasonable objection that a consumer cannot 'downgrade' their capacity if they don't need it.

However, a simple version might make some sense (e.g. a higher fixed charge for a two-way CER-based connection).

In any case, avoid demand charges (unless closely related to SMRC recovery), tiered pricing and minimum bills.

In developing our recommendations, we have kept these implications in mind.

Part 7: Evidence Base for the status quo in DNSP cost recovery

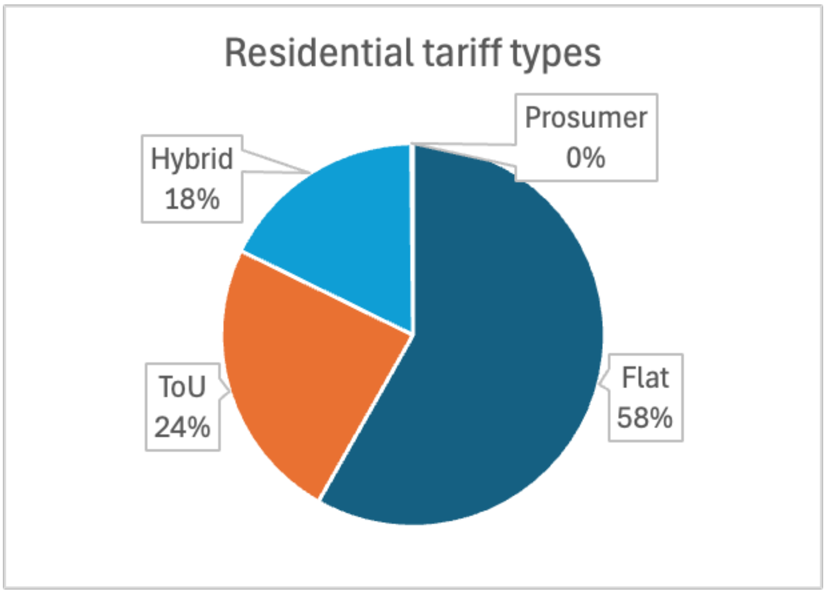
Here we assess the quantity of customers, energy consumption and dollars associated with common classes of DNSP tariffs.

The simplified classes of tariffs we consider are:

Simplified tariff class	
Flat	Consisting of only fixed c/day and volumetric c/kWh charges that **do not vary with time of day or season**. Includes some inclining block tariffs. Older-style tariffs applicable to 'dumb' meters, with residential consumers generally being migrated to alternative 'cost-reflective' tariffs at a pace dictated by smart metering rollout, DNSP tariff allocation policies, and the actions of retailer and consumers where there is choice (e.g. opt-in, opt-out)
Time of Use (ToU)	Consisting of fixed c/day and volumetric c/kWh charges that **vary with time of day and/or season.**
Hybrid Demand	Tariffs with elements of both ToU and Demand charges (i.e. based on a peak kW usage). There are no pure demand tariffs for residential consumers in the NEM.
Prosumer	Here, we refer to a tariff including two-way charges associated with exports based on time of day and/or season (e.g. a charge to export during daytime, and/or a negative charge to export during evening). These are relatively rare at present in the NEM given two-way pricing is a recent innovation but expected to increase in penetration.

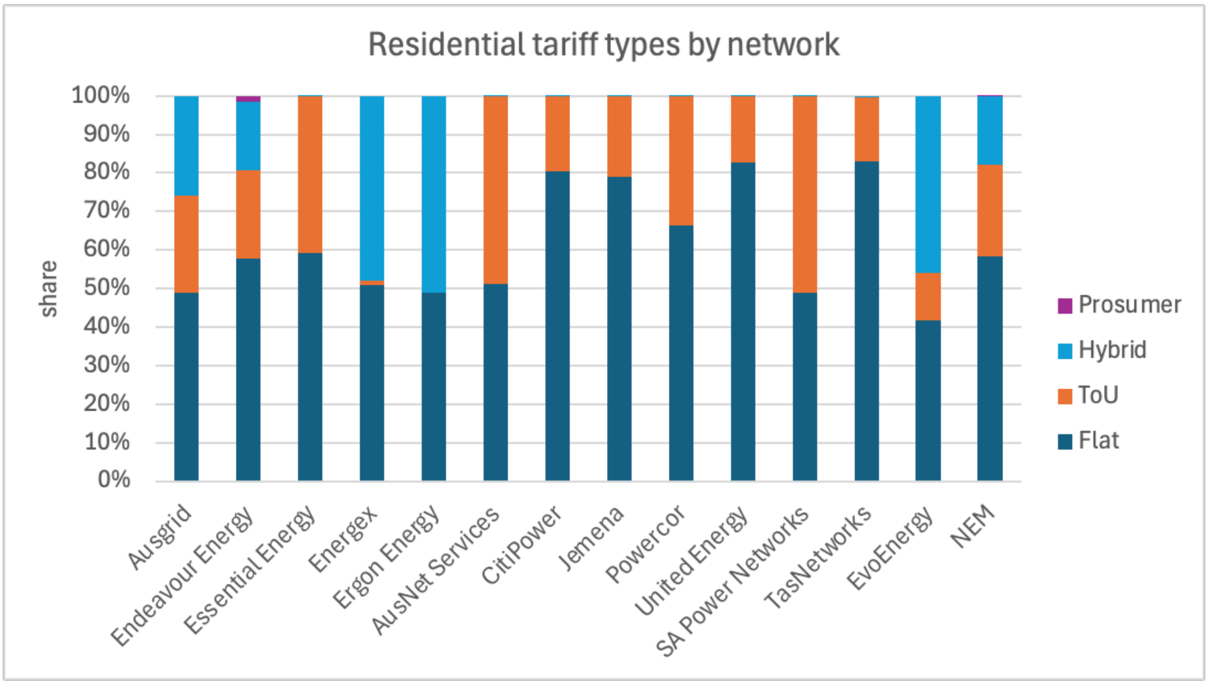
We have categorised all residential tariffs from the 13 DNSPs into this simplified framework.

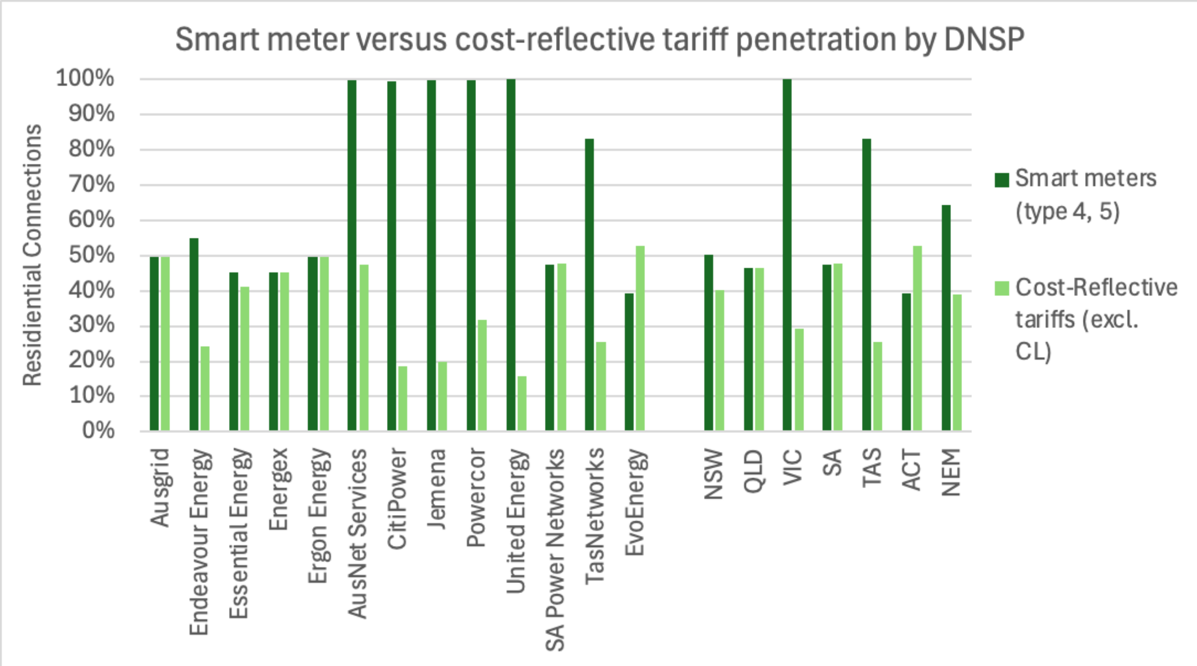
Tariff types in use



A majority of residential customers remain on flat tariffs, with substantial numbers on ToU and Hybrid Demand tariffs. Hybrid tariffs are most prevalent in Queensland and the ACT.

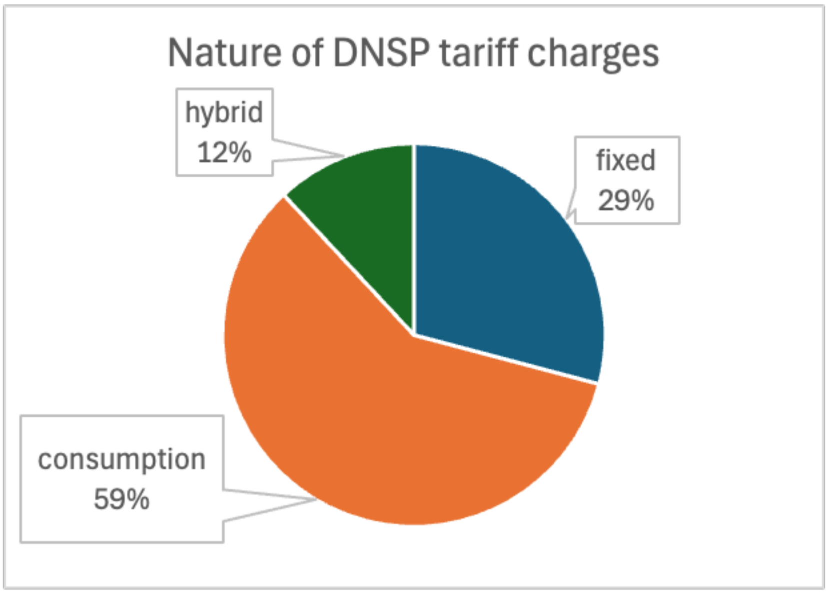
Few customers have taken up, or been placed on, Prosumer tariffs at this stage – only around 14,000 in the Endeavour network.





Any tariff other than Flat requires smart metering, and it is notable that despite Victoria's early rollout of smart meters, the move away from flat tariffs is notably slow in several of the Victorian networks.

Aggregate nature of charges

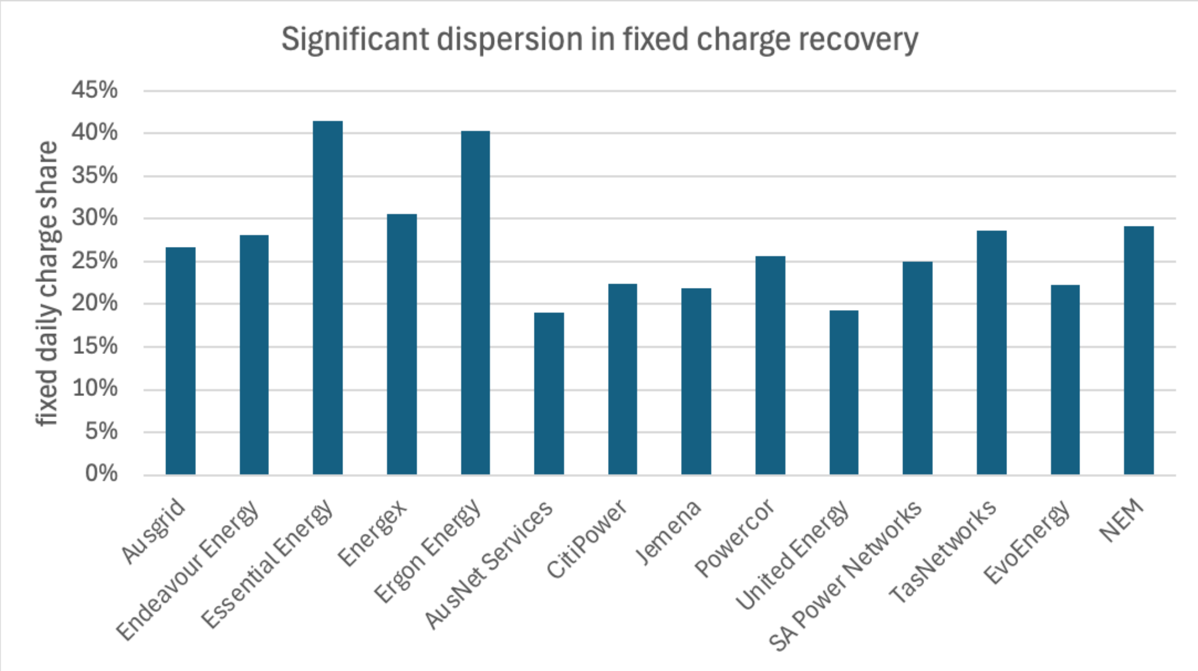


As a result, residential consumers are mostly paying for networks costs volumetrically – 59% of cost recovery is based on the quantity of energy they import via their network connection, and a further 12% are recovered via a hybrid combining consumption and demand charges.

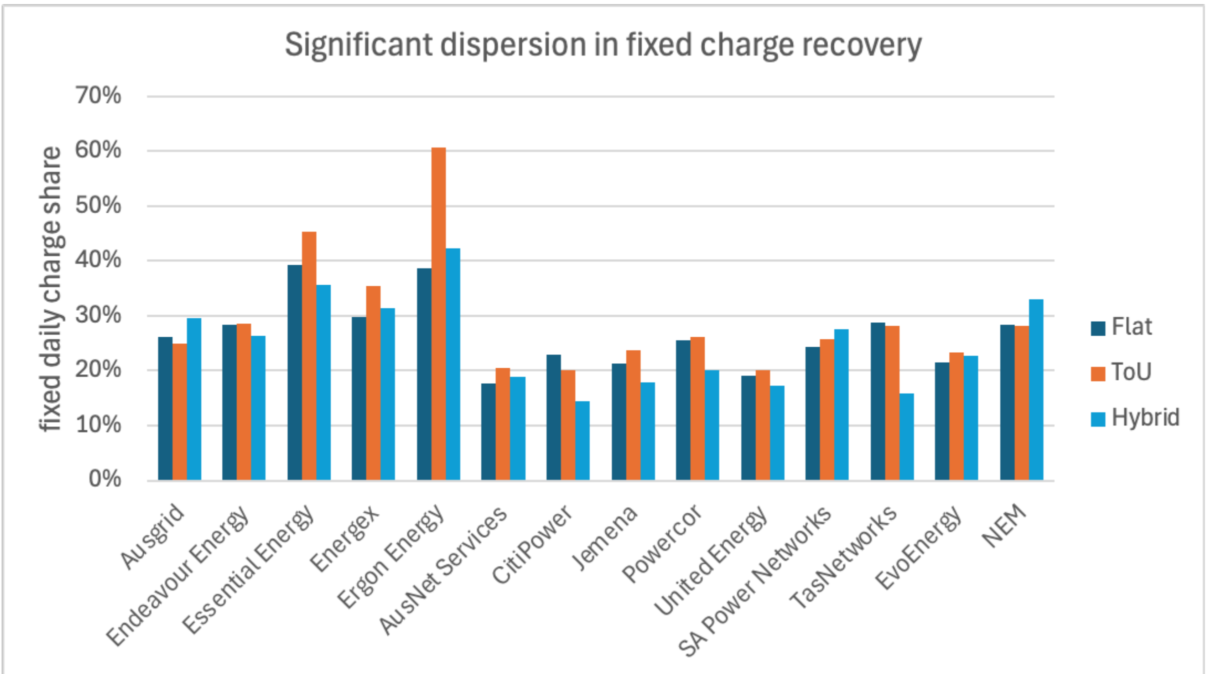
29% of the costs are recovered as fixed daily charges. While this is the NEM average, we observe significant dispersion between DNSPs.

Wide variation in proportional recovery from fixed charges

Within the 29% NEM average, two Victorian networks recover only 19% of their costs from residential customers via fixed charges, whereas at the other extreme, Ergon in Queensland and Essential in NSW recover more than double this – 40% and 41% respectively.



While not a clear trend, it is interesting that the lowest fixed charge recoveries are in very dense urban networks, with the highest in physically very large network areas.



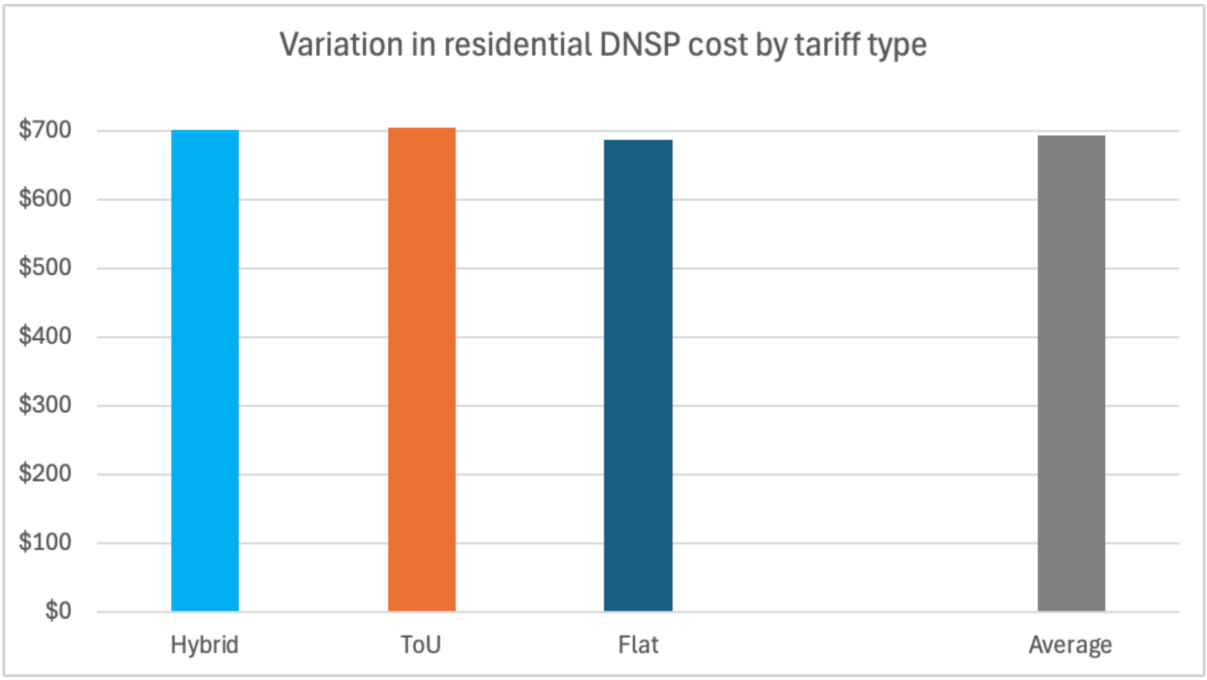
Taking a look one layer below this, we can see that the driver for larger fixed charges at Essential and Ergon appears to be from their ToU-style tariffs – with Ergon recovering over 60% of its ToU tariffs via fixed daily charges. Conversely at CitiPower, only 14% of their hybrid tariff revenue comes from fixed charge recovery.

At NEM level, hybrid tariffs – on average – recover 33% as fixed, versus 28% for flat or ToU.

This indicates migration away from flat tariffs may also be leading to proportionally greater recovery of networks' residual costs (which we have shown are largely fixed in nature) from fixed charges, albeit not in the case of ToU tariffs.

Total cost variation by tariff type

Overall for the NEM, there is no clear distinction in overall cost recovery based only on the type of tariff. Aggregated across all residential consumers on these tariffs (as reported in the DNSPs' latest RINs), the outcomes are very similar on average.



Despite the differences in these three tariff structures, on average residential consumers pay very similar total costs, regardless of whether they are facing Flat, ToU or Hybrid tariffs. Overall, Flat tariffs are slightly lower-cost ($686) than the alternatives ($701 for Hybrid, $705 for ToU) – note we are excluding the controlled load tariffs here, so the NEM average is $692.

There is no apparent cause for concern regarding equity of network cost recovery purely based on what type of tariff consumers are exposed to, on average.

However, averages mask outcomes between groups of consumers, and this is where the focus on equity becomes important.

One example of this is relatively 'peaky' consumers, who are likely to pay more under a ToU tariff than a flat tariff.

That is especially so if this evening demand is inflexible in time, inelastic to price, and cannot (for whatever reason) be managed by the addition of rooftop PV and a BESS to offset evening peak imports and minimise ToU-based network charges.

This is why we need to go deeper in our equity-focused analysis.

Part 8: Testing specific tariff structures versus residential CER cases

We have chosen to take a deeper look at the network costs a variety of representative residential households will pay, based on current, specific residential tariffs for a selection of DNSPs.

Modelling approach

For the mechanics of this analysis, we have used the underlying simulation provided by the 'Sunulator' model.[34]

The results we show here are our analysis of the one year of half-hourly outputs in relation to consumption, PV generation, battery flows and grid imports / exports, with each half-hour of grid imports and exports being passed through the network tariff to accumulate an annual network cost for that case. PV irradiance is for Sydney.

Household consumption

For the household cases, we have used two consumption scenarios of 8.4MWh/yr and 5.0MWh/yr. These could represent a relatively large household electricity usage, and a more typical case.

The Sunulator model includes a representative annual residential consumption profile, in half-hourly intervals, which we have adopted. This is a 'double peak' load shape, as shown below (for the 8.4MWh case). The 5.0MWh case is proportionally scaled to this.

[34] Available for public use here: https://renew.org.au/resources/sunulator/

CER scenarios

We assess a range of consumer energy resources interacting with this consumption profile.

8.4MWh consumption	5.0MWh consumption
No PV or BESS	No PV or BESS
5kW PV	5kW PV
5kW PV + 5kWh BESS	5kW PV + 5kWh BESS
10kW PV	10kW PV
10kW PV + 5kWH BESS	10kW PV + 5kWH BESS
10kW PV + 13kWh BESS	10kW PV + 13kWh BESS

In the modelling, the BESS operation is simply time-shifting available excess PV generation for the household each day. There is no optimisation of any tariff price signals – if there were, we expect the result would show a greater financial advantage to the BESS-enabled cases.

Tariff cases

We have chosen the available tariffs from the NSW DNSPs (Ausgrid, Endeavour and Essential) as well as SA Power Networks. We have excluded tariffs with a demand element for modelling simplicity, and so we are generally examining:

1. **Flat tariffs** – daily charge plus c/kWh at any time
2. **ToU tariffs** – daily charge plus a c/kWh that varies with time of day and in some cases, season.
3. **Two-way tariffs** – which overlay charges and credit related to grid exports.

For the flat tariffs, the parameters are:

DNSP	Code	c/day	c/kWh
Ausgrid	EA010	40.8	10.8
Essential	BLNN2AU	111.3	12.7
Endeavour	N70	52.1	10.1
SAPN	RSR	63.7	15.4

For time of use tariffs, the parameters are:

DNSP	Code	c/day	c/kWh
Ausgrid	EA025	50.0	See heatmap
Essential	BLNT3AL	111.3	See heatmap
Essential	BLNRSS2	111.3	See heatmap
Endeavour	N71	52.1	See heatmap
SAPN	RTOU	63.7	See heatmap

Note Essential have two Tou tariff structures, with BLNRSS2 offering a 'sunsoaker' price signal.

Ausgrid ToU heatmap

mth	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	26.9	26.9	26.9	26.9	26.9	26.9	4.7	4.7	4.7
Feb	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	26.9	26.9	26.9	26.9	26.9	26.9	4.7	4.7	4.7
Mar	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	26.9	26.9	26.9	26.9	26.9	26.9	4.7	4.7	4.7
Apr	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
May	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Jun	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	26.9	26.9	26.9	26.9	26.9	26.9	4.7	4.7	4.7
Jul	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	26.9	26.9	26.9	26.9	26.9	26.9	4.7	4.7	4.7
Aug	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	26.9	26.9	26.9	26.9	26.9	26.9	4.7	4.7	4.7
Sep	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Oct	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Nov	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	26.9	26.9	26.9	26.9	26.9	26.9	4.7	4.7	4.7
Dec	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	26.9	26.9	26.9	26.9	26.9	26.9	4.7	4.7	4.7

Essential ToU heatmap (BLNT3AL)

mth	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	5.403	5.403	5.403	5.403	5.403	5.403	5.403	13.16	13.16	9.503	9.503	9.503	9.503	9.503	9.503	9.503	9.503	13.16	13.16	13.16	9.503	9.503	5.403	5.403
Feb	5.403	5.403	5.403	5.403	5.403	5.403	5.403	13.16	13.16	9.503	9.503	9.503	9.503	9.503	9.503	9.503	9.503	13.16	13.16	13.16	9.503	9.503	5.403	5.403
Mar	5.403	5.403	5.403	5.403	5.403	5.403	5.403	13.16	13.16	9.503	9.503	9.503	9.503	9.503	9.503	9.503	9.503	13.16	13.16	13.16	9.503	9.503	5.403	5.403
Apr	5.403	5.403	5.403	5.403	5.403	5.403	5.403	13.16	13.16	9.503	9.503	9.503	9.503	9.503	9.503	9.503	9.503	13.16	13.16	13.16	9.503	9.503	5.403	5.403
May	5.403	5.403	5.403	5.403	5.403	5.403	5.403	13.16	13.16	9.503	9.503	9.503	9.503	9.503	9.503	9.503	9.503	13.16	13.16	13.16	9.503	9.503	5.403	5.403
Jun	5.403	5.403	5.403	5.403	5.403	5.403	5.403	13.16	13.16	9.503	9.503	9.503	9.503	9.503	9.503	9.503	9.503	13.16	13.16	13.16	9.503	9.503	5.403	5.403
Jul	5.403	5.403	5.403	5.403	5.403	5.403	5.403	13.16	13.16	9.503	9.503	9.503	9.503	9.503	9.503	9.503	9.503	13.16	13.16	13.16	9.503	9.503	5.403	5.403
Aug	5.403	5.403	5.403	5.403	5.403	5.403	5.403	13.16	13.16	9.503	9.503	9.503	9.503	9.503	9.503	9.503	9.503	13.16	13.16	13.16	9.503	9.503	5.403	5.403
Sep	5.403	5.403	5.403	5.403	5.403	5.403	5.403	13.16	13.16	9.503	9.503	9.503	9.503	9.503	9.503	9.503	9.503	13.16	13.16	13.16	9.503	9.503	5.403	5.403
Oct	5.403	5.403	5.403	5.403	5.403	5.403	5.403	13.16	13.16	9.503	9.503	9.503	9.503	9.503	9.503	9.503	9.503	13.16	13.16	13.16	9.503	9.503	5.403	5.403
Nov	5.403	5.403	5.403	5.403	5.403	5.403	5.403	13.16	13.16	9.503	9.503	9.503	9.503	9.503	9.503	9.503	9.503	13.16	13.16	13.16	9.503	9.503	5.403	5.403
Dec	5.403	5.403	5.403	5.403	5.403	5.403	5.403	13.16	13.16	9.503	9.503	9.503	9.503	9.503	9.503	9.503	9.503	13.16	13.16	13.16	9.503	9.503	5.403	5.403

Essential ToU heatmap – (BLNRSS2 'sunsoaker')

mth	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	5.403	5.403	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	15.87	15.87	15.87	15.87	5.403	5.403
Feb	5.403	5.403	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	15.87	15.87	15.87	15.87	5.403	5.403
Mar	5.403	5.403	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	15.87	15.87	15.87	15.87	5.403	5.403
Apr	5.403	5.403	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	15.87	15.87	15.87	15.87	5.403	5.403
May	5.403	5.403	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	15.87	15.87	15.87	15.87	5.403	5.403
Jun	5.403	5.403	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	15.87	15.87	15.87	15.87	5.403	5.403
Jul	5.403	5.403	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	15.87	15.87	15.87	15.87	5.403	5.403
Aug	5.403	5.403	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	15.87	15.87	15.87	15.87	5.403	5.403
Sep	5.403	5.403	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	15.87	15.87	15.87	15.87	5.403	5.403
Oct	5.403	5.403	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	15.87	15.87	15.87	15.87	5.403	5.403
Nov	5.403	5.403	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	15.87	15.87	15.87	15.87	5.403	5.403
Dec	5.403	5.403	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	5.403	5.403	5.403	5.403	5.403	15.87	15.87	15.87	15.87	15.87	15.87	15.87	5.403	5.403

Endeavour ToU heatmap

mth	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	3.0	3.0	3.0	3.0	9.7	9.7	20.8	20.8	20.8	20.8	9.7	9.7	9.7	9.7
Feb	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	3.0	3.0	3.0	3.0	9.7	9.7	20.8	20.8	20.8	20.8	9.7	9.7	9.7	9.7
Mar	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	3.0	3.0	3.0	3.0	9.7	9.7	20.8	20.8	20.8	20.8	9.7	9.7	9.7	9.7
Apr	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	3.0	3.0	3.0	3.0	9.7	9.7	13.0	13.0	13.0	13.0	9.7	9.7	9.7	9.7
May	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	3.0	3.0	3.0	3.0	9.7	9.7	13.0	13.0	13.0	13.0	9.7	9.7	9.7	9.7
Jun	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	3.0	3.0	3.0	3.0	9.7	9.7	13.0	13.0	13.0	13.0	9.7	9.7	9.7	9.7
Jul	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	3.0	3.0	3.0	3.0	9.7	9.7	13.0	13.0	13.0	13.0	9.7	9.7	9.7	9.7
Aug	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	3.0	3.0	3.0	3.0	9.7	9.7	13.0	13.0	13.0	13.0	9.7	9.7	9.7	9.7
Sep	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	3.0	3.0	3.0	3.0	9.7	9.7	13.0	13.0	13.0	13.0	9.7	9.7	9.7	9.7
Oct	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	3.0	3.0	3.0	3.0	9.7	9.7	13.0	13.0	13.0	13.0	9.7	9.7	9.7	9.7
Nov	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	3.0	3.0	3.0	3.0	9.7	9.7	20.8	20.8	20.8	20.8	9.7	9.7	9.7	9.7
Dec	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	3.0	3.0	3.0	3.0	9.7	9.7	20.8	20.8	20.8	20.8	9.7	9.7	9.7	9.7

SAPN ToU heatmap

mth	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	10.0	10.0	10.0	10.0	10.0	10.0	20.1	20.1	20.1	20.1	5.0	5.0	5.0	5.0	5.0	5.0	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1
Feb	10.0	10.0	10.0	10.0	10.0	10.0	20.1	20.1	20.1	20.1	5.0	5.0	5.0	5.0	5.0	5.0	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1
Mar	10.0	10.0	10.0	10.0	10.0	10.0	20.1	20.1	20.1	20.1	5.0	5.0	5.0	5.0	5.0	5.0	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1
Apr	10.0	10.0	10.0	10.0	10.0	10.0	20.1	20.1	20.1	20.1	5.0	5.0	5.0	5.0	5.0	5.0	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1
May	10.0	10.0	10.0	10.0	10.0	10.0	20.1	20.1	20.1	20.1	5.0	5.0	5.0	5.0	5.0	5.0	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1
Jun	10.0	10.0	10.0	10.0	10.0	10.0	20.1	20.1	20.1	20.1	5.0	5.0	5.0	5.0	5.0	5.0	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1
Jul	10.0	10.0	10.0	10.0	10.0	10.0	20.1	20.1	20.1	20.1	5.0	5.0	5.0	5.0	5.0	5.0	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1
Aug	10.0	10.0	10.0	10.0	10.0	10.0	20.1	20.1	20.1	20.1	5.0	5.0	5.0	5.0	5.0	5.0	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1
Sep	10.0	10.0	10.0	10.0	10.0	10.0	20.1	20.1	20.1	20.1	5.0	5.0	5.0	5.0	5.0	5.0	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1
Oct	10.0	10.0	10.0	10.0	10.0	10.0	20.1	20.1	20.1	20.1	5.0	5.0	5.0	5.0	5.0	5.0	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1
Nov	10.0	10.0	10.0	10.0	10.0	10.0	20.1	20.1	20.1	20.1	5.0	5.0	5.0	5.0	5.0	5.0	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1
Dec	10.0	10.0	10.0	10.0	10.0	10.0	20.1	20.1	20.1	20.1	5.0	5.0	5.0	5.0	5.0	5.0	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1

For two-way tariffs, the parameters are:

DNSP	Code	c/day	c/kWh import	BEL kWh/d	c/kWh export
Ausgrid	EA029	As for EA025	As for EA025	6.85	See heatmap
Essential	BLTTEX1	As for BLNRSS2	As for BLNRSS2	7.5	See heatmap
Endeavour	N61	As for N71	As for N71	4.8	See heatmap
Endeavour	N95	143.0	See heatmap	4.8	See heatmap
SAPN	RSELE	63.7	See heatmap	9	See heatmap

Note Endeavour have two tariff structures of this type, with N61 called ‘prosumer’ and N95 ‘residential storage’. Several of these tariffs are secondary tariffs, which we have modelled on top of the noted primary tariffs in the table above.

The upper part of the heatmaps which follow are the peak credits, the lower part are the ‘sun soaker’ charges (subject to a Basic Export Limit).

Ausgrid two-way heatmap

mth	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan																	-2.4	-2.4	-2.4	-2.4	-2.4			
Feb																	-2.4	-2.4	-2.4	-2.4	-2.4			
Mar																	-2.4	-2.4	-2.4	-2.4	-2.4			
Apr																	-2.4	-2.4	-2.4	-2.4	-2.4			
May																	-2.4	-2.4	-2.4	-2.4	-2.4			
Jun																	-2.4	-2.4	-2.4	-2.4	-2.4			
Jul																	-2.4	-2.4	-2.4	-2.4	-2.4			
Aug																	-2.4	-2.4	-2.4	-2.4	-2.4			
Sep																	-2.4	-2.4	-2.4	-2.4	-2.4			
Oct																	-2.4	-2.4	-2.4	-2.4	-2.4			
Nov																	-2.4	-2.4	-2.4	-2.4	-2.4			
Dec																	-2.4	-2.4	-2.4	-2.4	-2.4			
Jan											1.2	1.2	1.2	1.2	1.2									
Feb											1.2	1.2	1.2	1.2	1.2									
Mar											1.2	1.2	1.2	1.2	1.2									
Apr											1.2	1.2	1.2	1.2	1.2									
May											1.2	1.2	1.2	1.2	1.2									
Jun											1.2	1.2	1.2	1.2	1.2									
Jul											1.2	1.2	1.2	1.2	1.2									
Aug											1.2	1.2	1.2	1.2	1.2									
Sep											1.2	1.2	1.2	1.2	1.2									
Oct											1.2	1.2	1.2	1.2	1.2									
Nov											1.2	1.2	1.2	1.2	1.2									
Dec											1.2	1.2	1.2	1.2	1.2									

Essential two-way heatmap

mth	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan																		-13.6	-13.6	-13.6				
Feb																		-13.6	-13.6	-13.6				
Mar																		-13.6	-13.6	-13.6				
Apr																		-13.6	-13.6	-13.6				
May																		-13.6	-13.6	-13.6				
Jun																		-13.6	-13.6	-13.6				
Jul																		-13.6	-13.6	-13.6				
Aug																		-13.6	-13.6	-13.6				
Sep																		-13.6	-13.6	-13.6				
Oct																		-13.6	-13.6	-13.6				
Nov																		-13.6	-13.6	-13.6				
Dec																		-13.6	-13.6	-13.6				
Jan											1.2	1.2	1.2	1.2	1.2									
Feb											1.2	1.2	1.2	1.2	1.2									
Mar											1.2	1.2	1.2	1.2	1.2									
Apr											1.2	1.2	1.2	1.2	1.2									
May											1.2	1.2	1.2	1.2	1.2									
Jun											1.2	1.2	1.2	1.2	1.2									
Jul											1.2	1.2	1.2	1.2	1.2									
Aug											1.2	1.2	1.2	1.2	1.2									
Sep											1.2	1.2	1.2	1.2	1.2									
Oct											1.2	1.2	1.2	1.2	1.2									
Nov											1.2	1.2	1.2	1.2	1.2									
Dec											1.2	1.2	1.2	1.2	1.2									

Endeavour two-way heatmap (N61)

mth	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan																	-11.0	-11.0	-11.0	-11.0				
Feb																	-11.0	-11.0	-11.0	-11.0				
Mar																	-11.0	-11.0	-11.0	-11.0				
Apr																	-3.3	-3.3	-3.3	-3.3				
May																	-3.3	-3.3	-3.3	-3.3				
Jun																	-3.3	-3.3	-3.3	-3.3				
Jul																	-3.3	-3.3	-3.3	-3.3				
Aug																	-3.3	-3.3	-3.3	-3.3				
Sep																	-3.3	-3.3	-3.3	-3.3				
Oct																	-3.3	-3.3	-3.3	-3.3				
Nov																	-11.0	-11.0	-11.0	-11.0				
Dec																	-11.0	-11.0	-11.0	-11.0				
Jan											1.8	1.8	1.8	1.8										
Feb											1.8	1.8	1.8	1.8										
Mar											1.8	1.8	1.8	1.8										
Apr											1.8	1.8	1.8	1.8										
May											1.8	1.8	1.8	1.8										
Jun											1.8	1.8	1.8	1.8										
Jul											1.8	1.8	1.8	1.8										
Aug											1.8	1.8	1.8	1.8										
Sep											1.8	1.8	1.8	1.8										
Oct											1.8	1.8	1.8	1.8										
Nov											1.8	1.8	1.8	1.8										
Dec											1.8	1.8	1.8	1.8										

Endeavour ToU plus two-way heatmap (N95) – upper section here is the ToU imports

mth	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7					1.7	1.7	12.7	12.7	12.7	12.7	1.7	1.7	1.7	1.7
Feb	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7					1.7	1.7	12.7	12.7	12.7	12.7	1.7	1.7	1.7	1.7
Mar	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7					1.7	1.7	12.7	12.7	12.7	12.7	1.7	1.7	1.7	1.7
Apr	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7					1.7	1.7	5.0	5.0	5.0	5.0	1.7	1.7	1.7	1.7
May	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7					1.7	1.7	5.0	5.0	5.0	5.0	1.7	1.7	1.7	1.7
Jun	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7					1.7	1.7	5.0	5.0	5.0	5.0	1.7	1.7	1.7	1.7
Jul	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7					1.7	1.7	5.0	5.0	5.0	5.0	1.7	1.7	1.7	1.7
Aug	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7					1.7	1.7	5.0	5.0	5.0	5.0	1.7	1.7	1.7	1.7
Sep	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7					1.7	1.7	5.0	5.0	5.0	5.0	1.7	1.7	1.7	1.7
Oct	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7					1.7	1.7	5.0	5.0	5.0	5.0	1.7	1.7	1.7	1.7
Nov	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7					1.7	1.7	12.7	12.7	12.7	12.7	1.7	1.7	1.7	1.7
Dec	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7					1.7	1.7	12.7	12.7	12.7	12.7	1.7	1.7	1.7	1.7
Jan																	-11.0	-11.0	-11.0	-11.0				
Feb																	-11.0	-11.0	-11.0	-11.0				
Mar																	-11.0	-11.0	-11.0	-11.0				
Apr																	-3.3	-3.3	-3.3	-3.3				
May																	-3.3	-3.3	-3.3	-3.3				
Jun																	-3.3	-3.3	-3.3	-3.3				
Jul																	-3.3	-3.3	-3.3	-3.3				
Aug																	-3.3	-3.3	-3.3	-3.3				
Sep																	-3.3	-3.3	-3.3	-3.3				
Oct																	-3.3	-3.3	-3.3	-3.3				
Nov																	-11.0	-11.0	-11.0	-11.0				
Dec																	-11.0	-11.0	-11.0	-11.0				
Jan											1.8	1.8	1.8	1.8										
Feb											1.8	1.8	1.8	1.8										
Mar											1.8	1.8	1.8	1.8										
Apr											1.8	1.8	1.8	1.8										
May											1.8	1.8	1.8	1.8										
Jun											1.8	1.8	1.8	1.8										
Jul											1.8	1.8	1.8	1.8										
Aug											1.8	1.8	1.8	1.8										
Sep											1.8	1.8	1.8	1.8										
Oct											1.8	1.8	1.8	1.8										
Nov											1.8	1.8	1.8	1.8										
Dec											1.8	1.8	1.8	1.8										

SAPN ToU plus two-way heatmap) – upper section here is the ToU imports

mth	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	3.0	3.0	3.0	3.0	3.0	3.0	10.1	33.9	33.9	33.9	33.9	10.1	10.1	10.1
Feb	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	3.0	3.0	3.0	3.0	3.0	3.0	10.1	33.9	33.9	33.9	33.9	10.1	10.1	10.1
Mar	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	3.0	3.0	3.0	3.0	3.0	3.0	10.1	33.9	33.9	33.9	33.9	10.1	10.1	10.1
Apr	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	3.0	3.0	3.0	3.0	3.0	3.0	10.1	33.9	33.9	33.9	33.9	10.1	10.1	10.1
May	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	3.0	3.0	3.0	3.0	3.0	3.0	10.1	33.9	33.9	33.9	33.9	10.1	10.1	10.1
Jun	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	3.0	3.0	3.0	3.0	3.0	3.0	10.1	33.9	33.9	33.9	33.9	10.1	10.1	10.1
Jul	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	3.0	3.0	3.0	3.0	3.0	3.0	10.1	33.9	33.9	33.9	33.9	10.1	10.1	10.1
Aug	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	3.0	3.0	3.0	3.0	3.0	3.0	10.1	33.9	33.9	33.9	33.9	10.1	10.1	10.1
Sep	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	3.0	3.0	3.0	3.0	3.0	3.0	10.1	33.9	33.9	33.9	33.9	10.1	10.1	10.1
Oct	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	3.0	3.0	3.0	3.0	3.0	3.0	10.1	33.9	33.9	33.9	33.9	10.1	10.1	10.1
Nov	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	3.0	3.0	3.0	3.0	3.0	3.0	10.1	33.9	33.9	33.9	33.9	10.1	10.1	10.1
Dec	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	3.0	3.0	3.0	3.0	3.0	3.0	10.1	33.9	33.9	33.9	33.9	10.1	10.1	10.1
Jan																		-12.9	-12.9	-12.9	-12.9			
Feb																		-12.9	-12.9	-12.9	-12.9			
Mar																		-12.9	-12.9	-12.9	-12.9			
Apr																								
May																								
Jun																								
Jul																								
Aug																								
Sep																								
Oct																								
Nov																		-12.9	-12.9	-12.9	-12.9			
Dec																		-12.9	-12.9	-12.9	-12.9			
Jan											1.0	1.0	1.0	1.0	1.0	1.0								
Feb											1.0	1.0	1.0	1.0	1.0	1.0								
Mar											1.0	1.0	1.0	1.0	1.0	1.0								
Apr											1.0	1.0	1.0	1.0	1.0	1.0								
May											1.0	1.0	1.0	1.0	1.0	1.0								
Jun											1.0	1.0	1.0	1.0	1.0	1.0								
Jul											1.0	1.0	1.0	1.0	1.0	1.0								
Aug											1.0	1.0	1.0	1.0	1.0	1.0								
Sep											1.0	1.0	1.0	1.0	1.0	1.0								
Oct											1.0	1.0	1.0	1.0	1.0	1.0								
Nov											1.0	1.0	1.0	1.0	1.0	1.0								
Dec											1.0	1.0	1.0	1.0	1.0	1.0								

Summarising the results

The following charts present the results, as total annual network costs recovered from each of the 12 household cases (two consumption scenarios, with six CER scenarios).

From these modelling outcomes we can extract some very clear conclusions:

The more energy households consume, the more they pay.

As expected, household consumption drives network cost contribution, due to the majority of charges being recovered from volumetric elements of the tariffs (in the absence of any CER). Higher-consumption households pay more network costs, all else equal.

As we have noted, high consumption is not necessarily a good proxy for recovering network costs progressively, not only due to the distortions of CER, but also because of any linkage between poor household energy-efficiency that may be associated with status as a rental occupant rather than a landlord, or simply lacking the financial resources to upgrade insulation, appliances etc.

The more CER households deploy, the less they pay

There is a very clear downward trend in these charts from left to right, as the quantity of CER increases.

Despite enjoying a broader range of services thanks to their connection to the network, CER-enabled households contribute much less to network cost recovery.

Batteries dramatically decrease network cost exposure for households

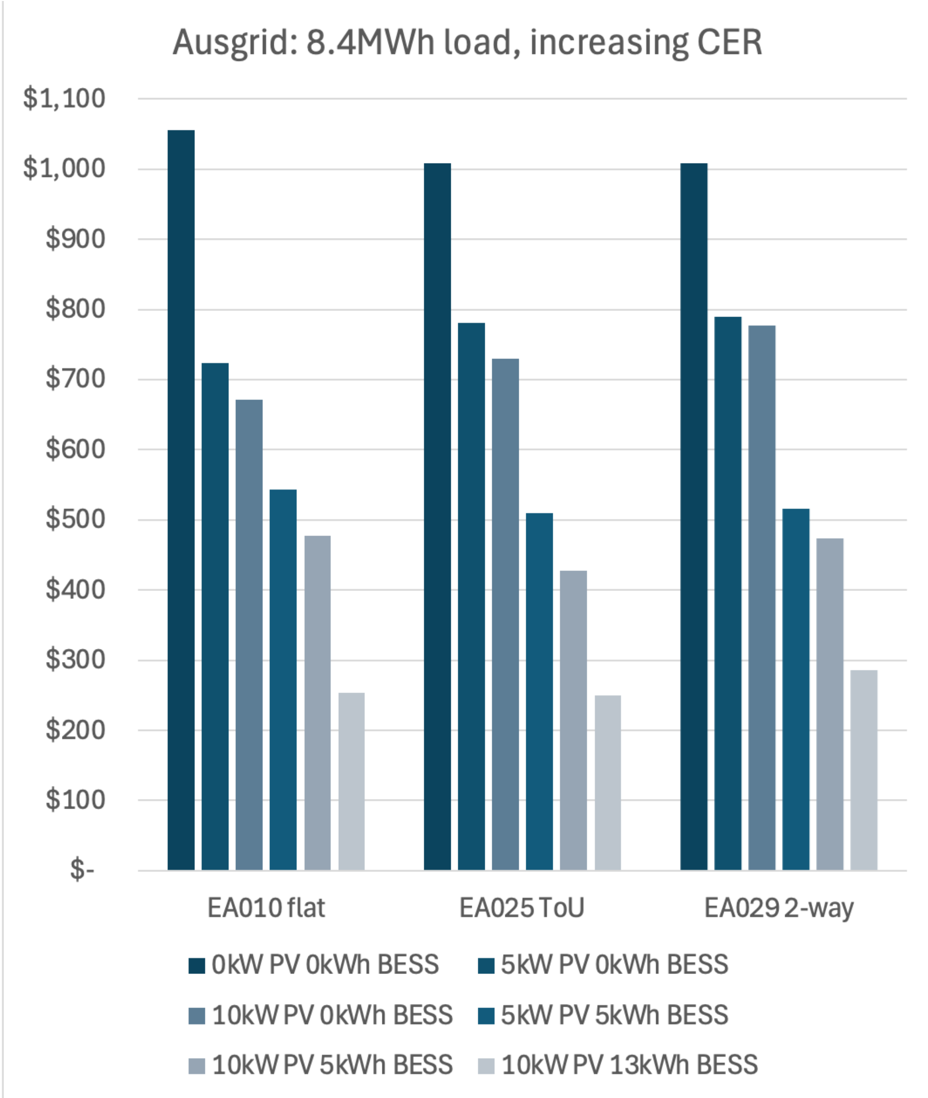
There is a major step down in the total network cost recovered from a household, once a battery is in place – increasing self-consumption of PV, and potentially also avoiding higher peak network import charges under ToU tariffs.

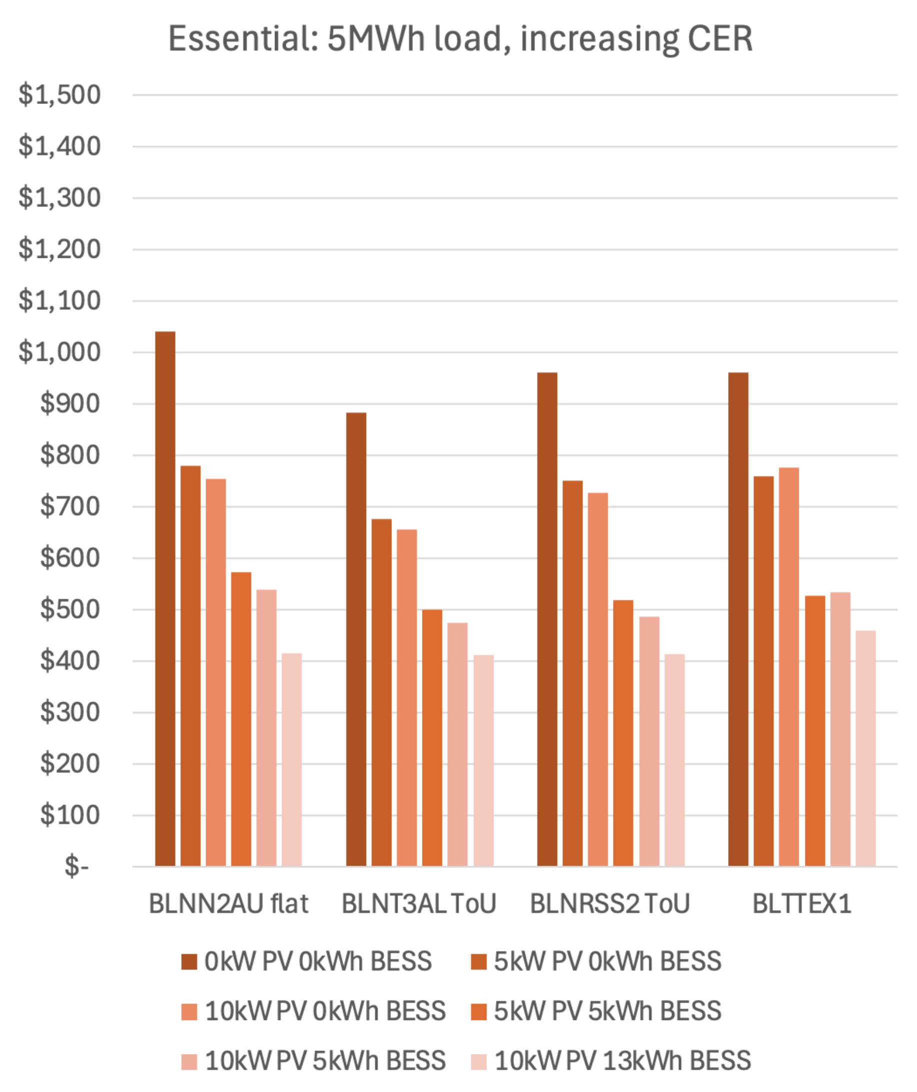
Tariffs structure generally does little to equalise outcomes

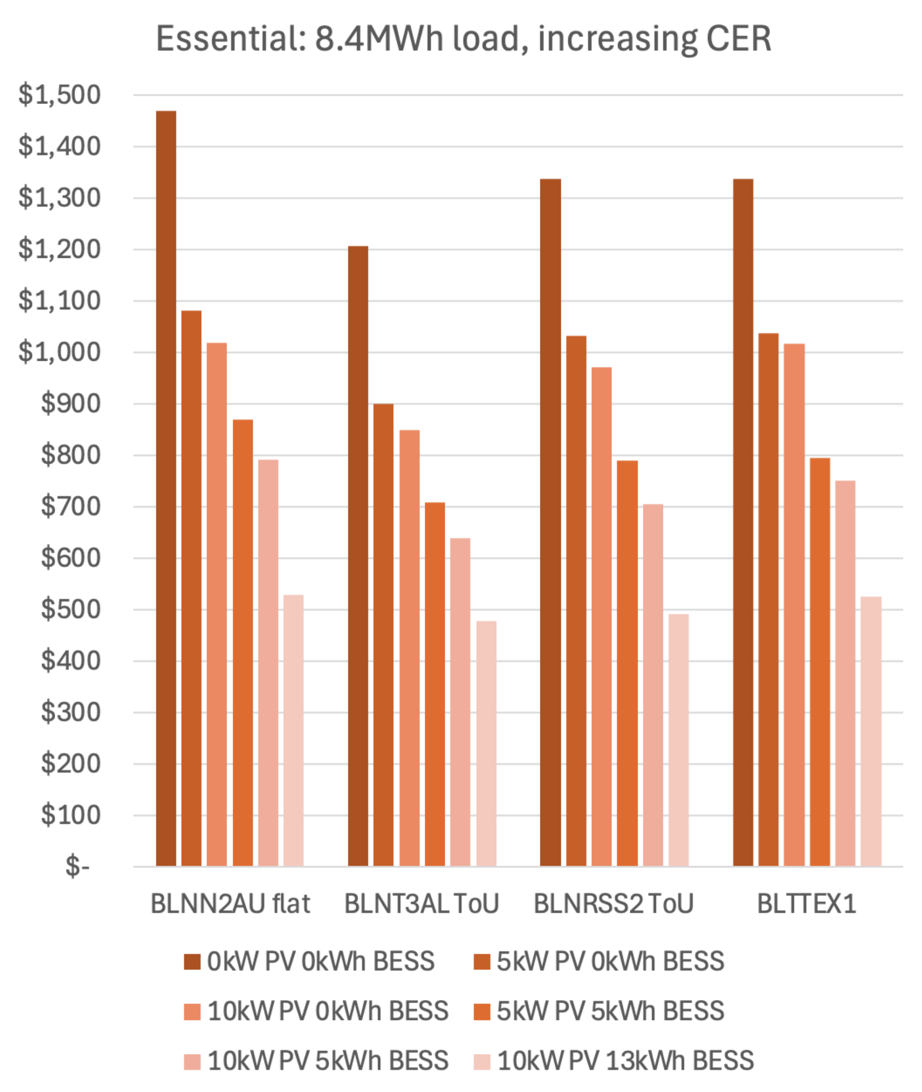
These conclusions do not change much when assessing older-style flat tariffs, ToU tariffs or two-way tariffs: non-CER households pay much more regardless.

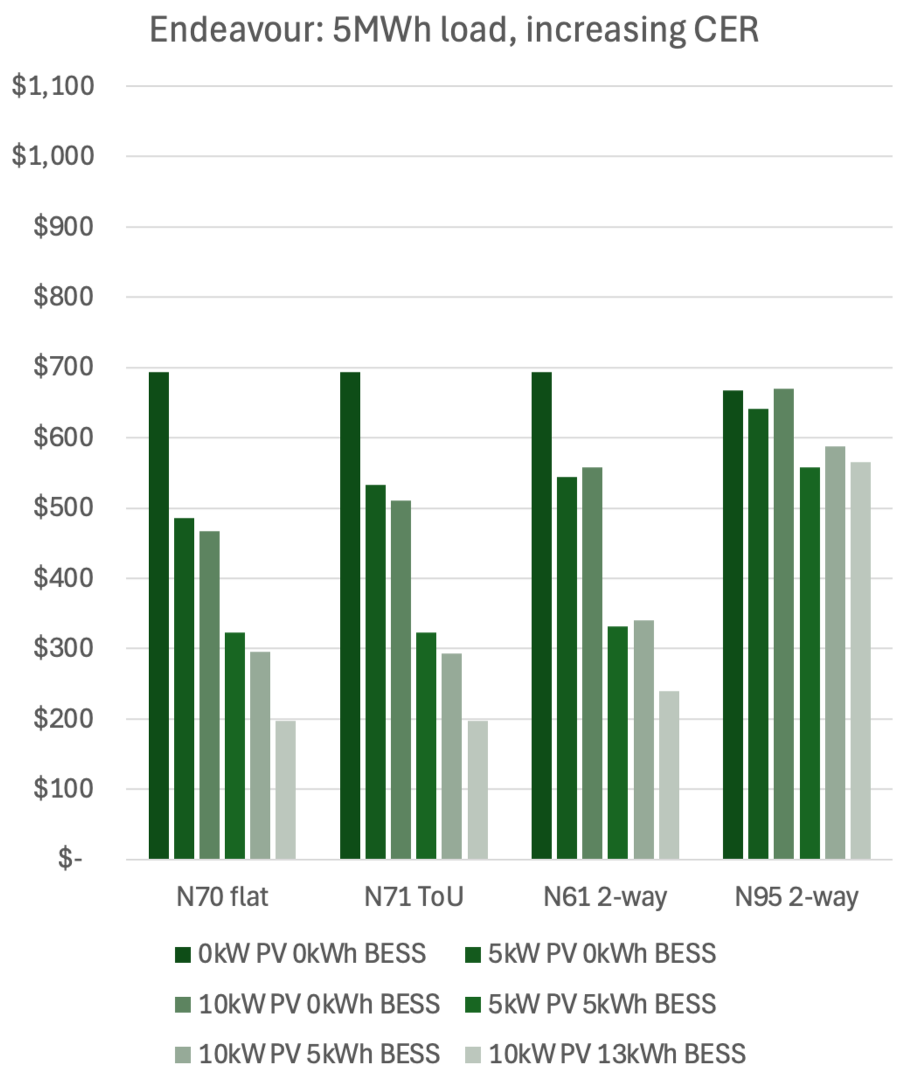
The exception is Endeavour's N95 two-way tariff, described as a "residential storage" tariff. This comes closest to clustering the cost outcomes regardless of CER status and would be materially the cheapest outcome for a non-CER household… if they were to be placed on it, which we expect is not likely!

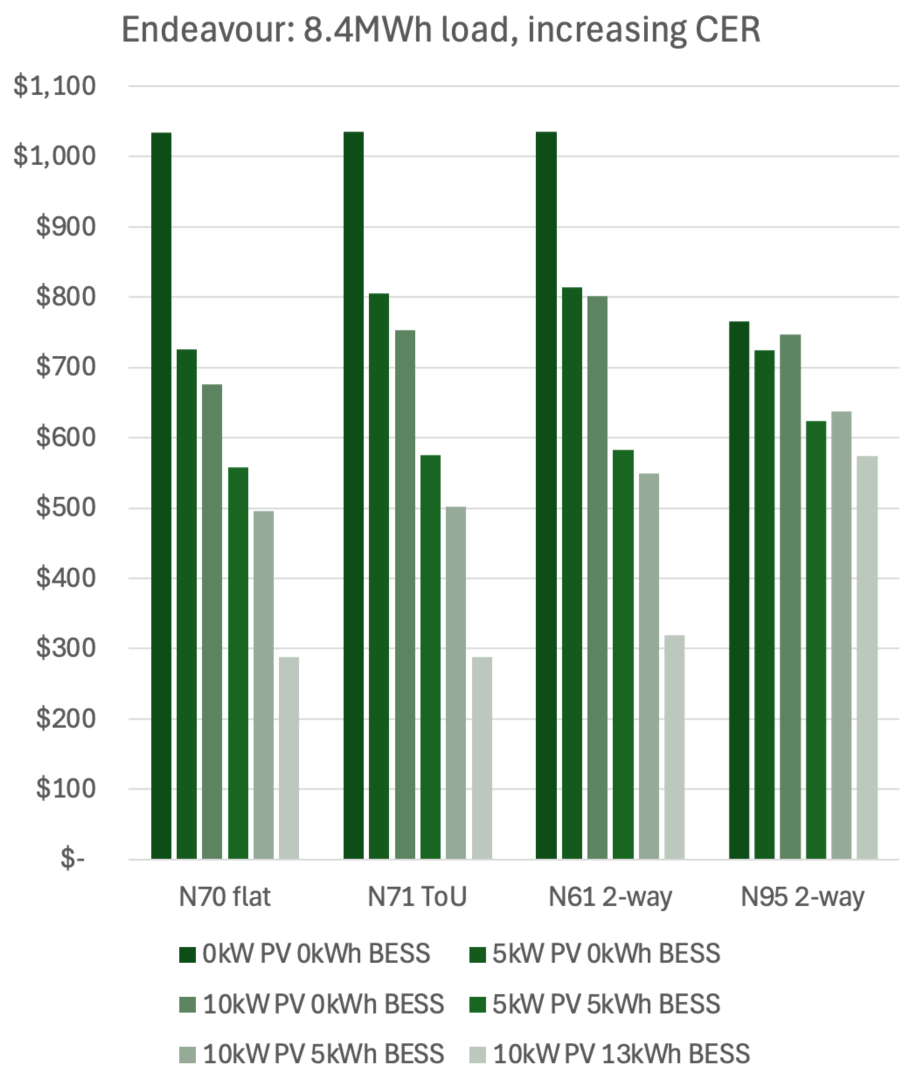

Ausgrid: 5MWh load, increasing CER
$1,100
$1,000
$900
$800
$700
$600
$500
$400
$300
$200
$100
$-
EA010 flat
EA025 ToU
EA029 2-way
0kW PV 0kWh BESS
5kW PV 0kWh BESS
10kW PV 0kWh BESS
5kW PV 5kWh BESS
10kW PV 5kWh BESS
10kW PV 13kWh BESS

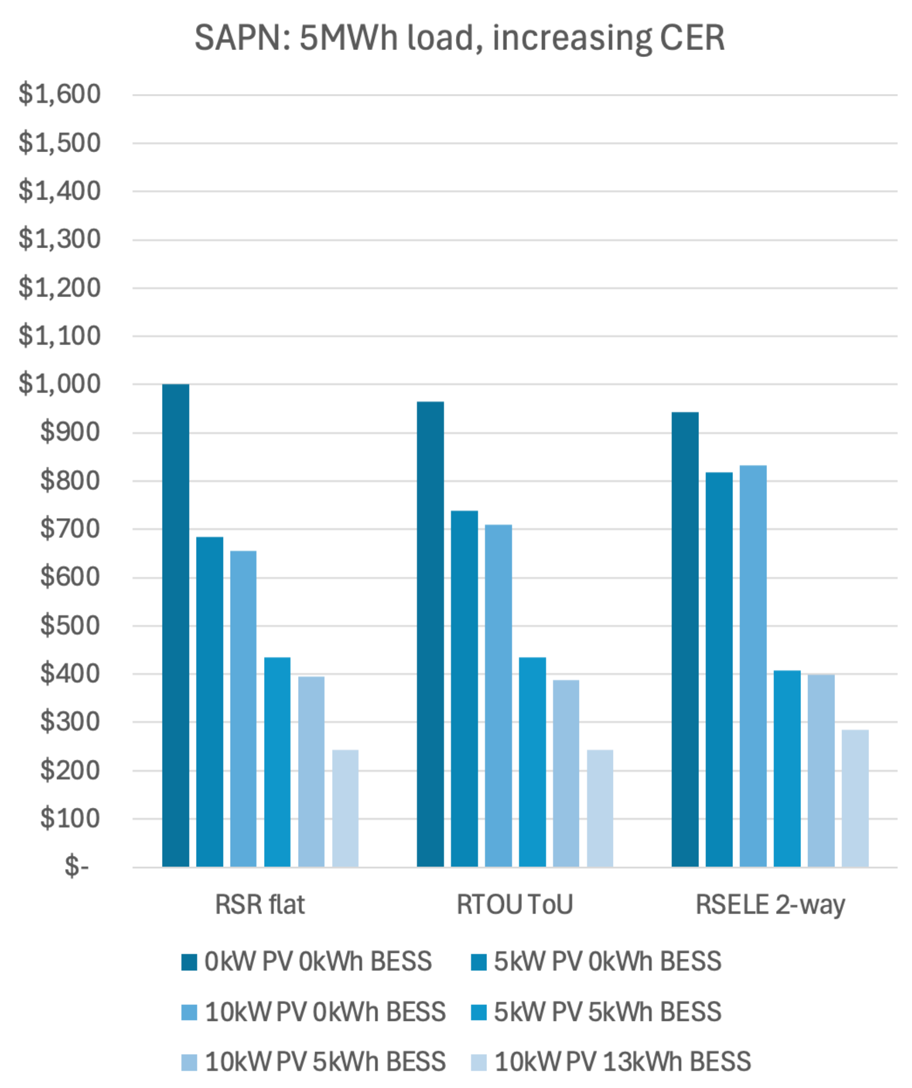

Ausgrid: 8.4MWh load, increasing CER
$1,100
$1,000
$900
$800
$700
$600
$500
$400
$300
$200
$100
$-
EA010 flat
EA025 ToU
EA029 2-way
0kW PV 0kWh BESS
5kW PV 0kWh BESS
10kW PV 0kWh BESS
5kW PV 5kWh BESS
10kW PV 5kWh BESS
10kW PV 13kWh BESS

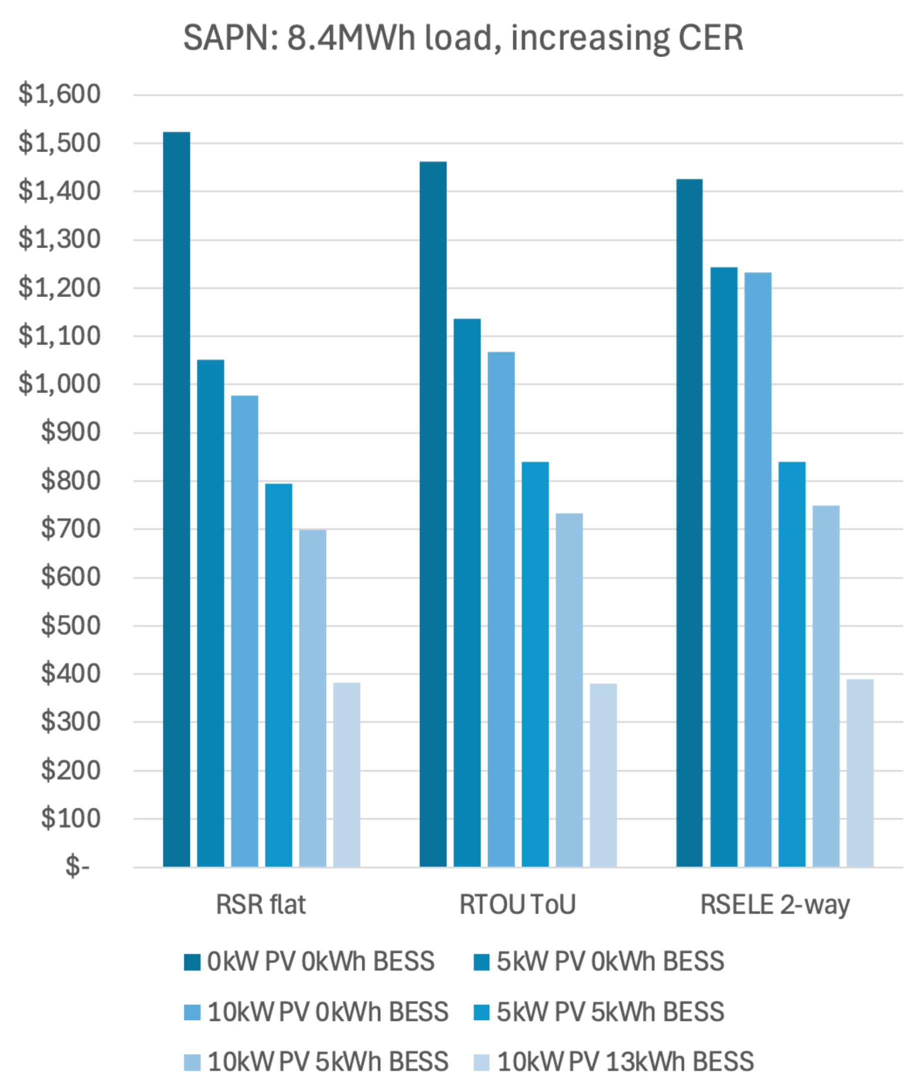

Essential: 5MWh load, increasing CER
$1,500
$1,400
$1,300
$1,200
$1,100
$1,000
$900
$800
$700
$600
$500
$400
$300
$200
$100
$-
BLNN2AU flat
BLNT3AL ToU
BLNRSS2 ToU
BLTTEX1
0kW PV 0kWh BESS
5kW PV 0kWh BESS
10kW PV 0kWh BESS
5kW PV 5kWh BESS
10kW PV 5kWh BESS
10kW PV 13kWh BESS


Essential: 8.4MWh load, increasing CER
$1,500
$1,400
$1,300
$1,200
$1,100
$1,000
$900
$800
$700
$600
$500
$400
$300
$200
$100
$-
BLNN2AU flat
BLNT3AL ToU
BLNRSS2 ToU
BLTTEX1
0kW PV 0kWh BESS
5kW PV 0kWh BESS
10kW PV 0kWh BESS
5kW PV 5kWh BESS
10kW PV 5kWh BESS
10kW PV 13kWh BESS


Endeavour: 5MWh load, increasing CER
$1,100
$1,000
$900
$800
$700
$600
$500
$400
$300
$200
$100
$-
N70 flat
N71 ToU
N61 2-way
N95 2-way
0kW PV 0kWh BESS
5kW PV 0kWh BESS
10kW PV 0kWh BESS
5kW PV 5kWh BESS
10kW PV 5kWh BESS
10kW PV 13kWh BESS


Endeavour: 8.4MWh load, increasing CER
$1,100
$1,000
$900
$800
$700
$600
$500
$400
$300
$200
$100
$-
N70 flat
N71 ToU
N61 2-way
N95 2-way
0kW PV 0kWh BESS
5kW PV 0kWh BESS
10kW PV 0kWh BESS
5kW PV 5kWh BESS
10kW PV 5kWh BESS
10kW PV 13kWh BESS

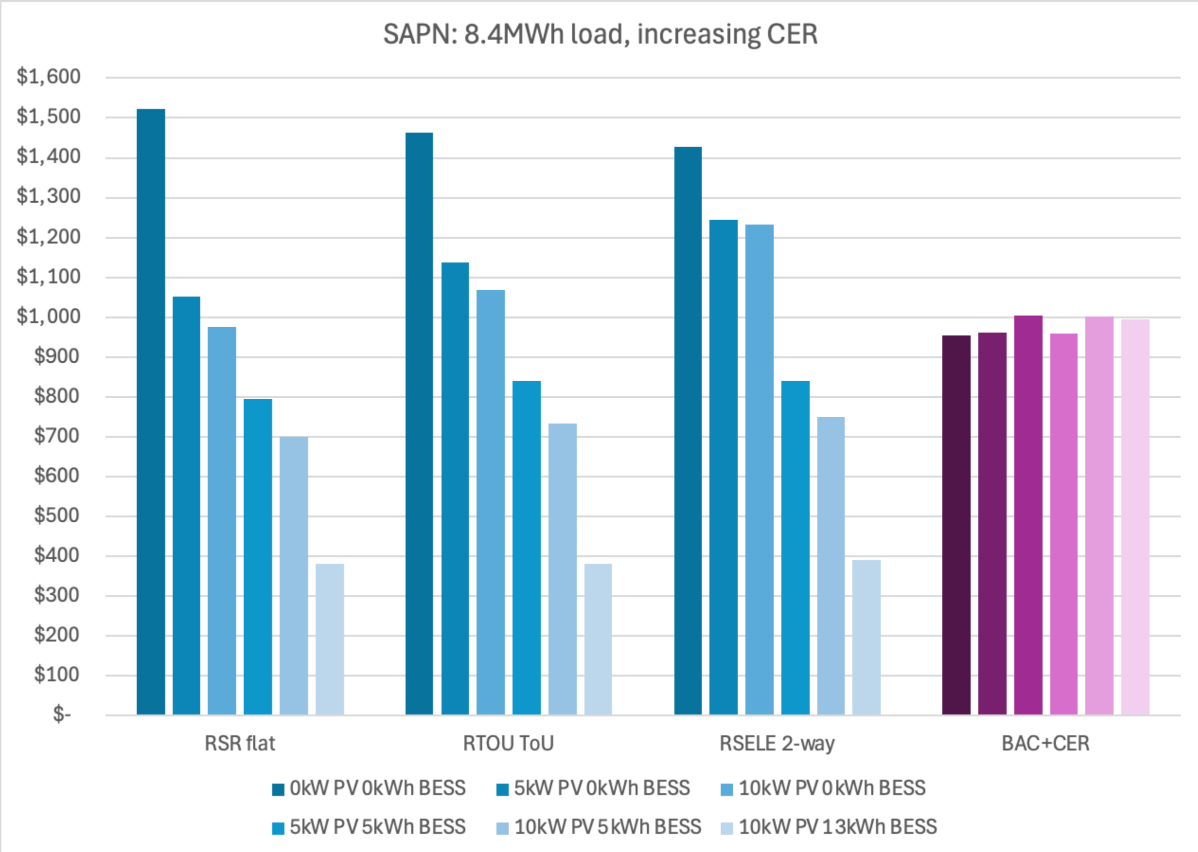

SAPN: 5MWh load, increasing CER
$1,600
$1,500
$1,400
$1,300
$1,200
$1,100
$1,000
$900
$800
$700
$600
$500
$400
$300
$200
$100
$-
RSR flat
RTOU ToU
RSELE 2-way
0kW PV 0kWh BESS
5kW PV 0kWh BESS
10kW PV 0kWh BESS
5kW PV 5kWh BESS
10kW PV 5kWh BESS
10kW PV 13kWh BESS


SAPN: 8.4MWh load, increasing CER
$1,600
$1,500
$1,400
$1,300
$1,200
$1,100
$1,000
$900
$800
$700
$600
$500
$400
$300
$200
$100
$-
RSR flat
RTOU ToU
RSELE 2-way
0kW PV 0kWh BESS
5kW PV 0kWh BESS
10kW PV 0kWh BESS
5kW PV 5kWh BESS
10kW PV 5kWh BESS
10kW PV 13kWh BESS

Part 9: An alternative: fixed Basic Access Charge plus CER tariff

Endeavour's N95 tariff clusters outcomes because it has a relatively high fixed daily charge component of $1.43, some 3.3x higher than Ausgrid's 40c/day.

To illustrate how a fixed annual charge approach would work, we created a variation to the SAPN RSELE 'electrify' tariff. We removed all ToU import charges and increased the daily charge from $0.64 to $2.62. The two-way charges and credits for PV exports remain unchanged.



We selected this so that the simple average of the cost over the six cases above for the RSELE tariff would be the same ($980).

Here, the outcomes are closely clustered:

- The non-CER household pays the least.
- The 5kW PV households pay slightly more, due to the net impact of the two-way tariffs on their exports.
- The 10kW PV households pay a little more again, given their greater exports, including in the solar soak period where this is penalised.
- There is little advantage or disadvantage to having a BESS.

While this is clearly just a simple example, outcomes of this type are much closer to an equitable sharing of network cost recovery than the status quo offers.