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Submission by Evie Networks

To The

Australian Energy Regulator

On

NSW DNSPs' 2024-2029 Pricing Proposals

12 May, 2023

About Evie Networks

Evie Networks was founded in 2017 by the St Baker Energy Innovation Fund with the aim of building Australia's largest Electric Vehicle fast and ultra-fast charging network across all Australian States and territories as part of a strategy that recognised the need for, and societal benefits of, the electrification of the Australian Transport Sector and the associated need to address concerns about "Range Anxiety" with EVs. Evie therefore has a strong focus on building quality charging stations, located on sites that are convenient for customers and underpinned by the team's relentless pursuit of reliability and customer satisfaction. Its initial rollout was on national highways and is now being expanded into major metropolitan areas and regional centres. It currently has 116 sites in operation nationally and expects to have around 300 sites nationally by June 2024.

Evie Networks is backed by funding from the St Baker Energy Innovation Fund, which is accompanied by significant grants from the Australian Renewable Energy Agency (ARENA) and the Federal Government's Future Fuels Fund. Evie Networks has also been successful in being selected to help rollout EV charging sites under a number of State Government and Local Government EV infrastructure programs. This makes Evie Networks the most well-funded EV charging operator in Australia, providing confidence that it will continue to grow and support its network across all Australian States and Territories. As such, Evie Networks has considerable experience in relation to the issues relevant to the development of a sustainable business model for the new, infant, publicly available EV charging infrastructure industry and the implications of current high electricity costs for achieving such a business model.

INTRODUCTION

Evie Networks (Evie) welcomes the opportunity to respond to the AER's Issues Papers with respect to the 2024-2029 Electricity Distribution determination for Ausgrid, Endeavour Energy (Endeavour) and Essential Energy (Essential) and, as part of this, respond to the tariff proposals submitted by the 3 DNSPs.

The primary focus of Evie's submission is electricity tariffs applying to publicly available fast, and ultra fast, EV charging stations and how the application of "traditional" business tariffs containing Demand or Capacity Charges act as a major barrier to the development of a commercially viable business model. This is because the Load (or Demand) profile of the publicly available charging sector is very different from "traditional" small and medium businesses. These traditional tariffs are not suited to this new industry for a number of reasons detailed in this submission and, therefore, result in very high electricity costs that threaten the prospect of a sustainable business model for what is, in fact, a nascent industry – with its growth being critical to the achievement of a significant reduction in emissions in the Transport Sector and, thus, the overall economy in line with the Government's Emissions Reduction Targets.

This adverse impact of the current electricity tariff structures and, particularly, Demand Charges within these tariff structures, is intensified by the fact that the EV charging infrastructure industry is necessarily continuing to build EV charging sites ahead of demand because of the critical importance of allaying concerns of potential EV purchasers of Range Anxiety (the fear of running out of "fuel" when driving an EV). Ie, the increasing availability of publicly available charging sites and the maintenance of their performance and operation gives potential EV purchasers confidence to switch from an ICE (Internal Combustion Engine) vehicle to an EV. As a corollary, adverse media coverage of unreliable, or even closed, EV charging sites could result in people looking at the prospect of purchasing an EV deciding not to do so.

EVs are now a central element of the Federal Government's Emissions Reduction Strategy, with its recent National Electric Vehicle Strategy particularly noting that "transport (is) on track to be Australia's largest emitting sector by the end of the decade". Evie considers that this is now a critical issue for the AER to consider in its deliberations on the NSW DNSPs' tariff proposals in light of the decision by Commonwealth and State Energy Ministers in 2002 to fast track the introduction of an Emissions Reduction Objective into the National Electricity Objective. This will specifically apply to the AER and, significantly, will apply to relevant matters still under consideration by the AER at the time of the passage of the amending legislation such as this current tariff review.

Additionally this submission specifically references the AER's April 2021 determination on the Victorian DNSPs' 2021-2026 tariff proposals and the basis on which Evie's submission to the AER at that time was not accepted by it for a number of reasons. Evie submits that a significant number of developments since then, in addition to the decision to include an Emission Reduction Objective in the NEO, should lead to the AER re-considering its previous position and accepting the arguments presented in this submission. The relevant developments are detailed below.

Evie would wish to particularly highlight the recent determination by the WA Regulator, the Economic Regulation Authority, which supported the concept of a specific or separate tariff for publicly available EV charging sites, as well the establishment of a mechanism to develop a specific tariff for EV charging sites for adoption in the next regulatory period. In doing so, it did not look to emulate the position adopted by the AER in its 2021 determination in which it favoured the use of Tariff Trials.

The submission also draws on detailed analysis prepared by Marsden Jacob Associates (MJA), and a copy of the MJA report is being provided with this submission.

The MJA report found that Evie is being over-charged for its network charges. This is because, amongst other things, it is being charged for capacity expansion costs when, in fact, the sites covered in the MJA analysis were only using existing assets and, therefore, are not triggering capacity expansion costs.

The MJA report particularly stated:

> "The analysis shows that total network charges applied to Evie sites are substantially higher than efficient network costs. The effective network prices applied to Evie under existing and proposed network tariffs do not correspond to efficient network costs for the location and demand profiles of Evie's charging sites……..As a result, Evie is being charged higher prices than permitted under the relevant sections of the NER. Evie's network bills are not cost-reflective".

Based on its detailed analysis, the MJA report concluded:

> "The diversity between the ZS (Zone Substation) and Evie site demand profiles mean that the Evie site only uses existing ZS capacity. Capacity and demand charges applied to Evie's maximum demand make no sense given Evie's maximum demand diverges from ZS maximum demand……
>
> "In all the 10 Evie sites for which data are available, there is a high level of diversity between Evie site maximum demand and ZS maximum demand. Therefore, there is no network cost basis for applying premium tariff components (especially those relating to Evie site maximum demand) for any of the 10 sites."

And later:

> "In all cases, Evie's maximum demand does not correspond to ZS maximum demand; Evie's maximum demand occurs at times when maximum ZS demand is light. There is therefore no basis for applying premium components (particularly demand charges) of network tariff structures for any of the 10 sites across the three NSW networks for which data is currently available".

The report also particularly noted:

> "None of the DNSP TSS proposals make changes to tariff assignment and design necessary to address the current inconsistencies between billing outcomes and the network pricing Rules……A significant risk remains that, under proposed tariff designs, divergences between Evie bills and efficient prices could in many cases increase".

More generally, the report concluded:

> "NSW DNSPs are over-estimating LRMC in their TSS proposals by failing to adjust LRMC to reflect existing surplus capacity from previous over-investment. They are incorrectly treating sunk capacity as if it were avoidable and charging premium rates instead of standard rates, raising average prices of some customers including Evie. DNSPs are proposing to charge consumers for future capacity expansion that is not required".

This analysis therefore strongly supports the position presented in this submission that publicly available EV charging sites should be enjoying significantly lower electricity costs than currently being incurred and that it is not appropriate to apply Demand Charges.

Based on a number of factors set out in detail in the submission, Evie presents a detailed set of considerations for determining the electricity network costs it should be charged, as well as the acceptance of the concept of a specific tariff for EV charging sites and the adoption of the approach set out in the WA Regulator's recent Western Power tariffs determination for then developing such a specific tariff for future adoption. In this context it is noted that the WA Regulator did not emulate the AER's 2021 Victorian DNSPs' tariff decision which supported DNSP initiated Tariff Trials.

Evie strongly believes that the proposals presented as to what electricity network costs it should be charged would be fully consistent with the new Emissions Reduction Objective to be inserted into the NEO.

Additionally Evie believes that this new NEO would, in fact, require the AER to endorse these proposals given the significant role the EV charging infrastructure industry plays in helping Governments achieve their Emission Reduction Targets as detailed in this submission.

However, if the AER believes that existing Rules restrict its ability to have full regard to this Emissions Reduction Objective in this consideration of the NSW DNSPs' tariff proposals, then there would be a need for an urgent amendment to a number of Rules.

BACKGROUND: KEY DEVELOPMENTS SINCE 2021

Evie requests that the AER have particular regard to the following developments that have occurred since its April 2021 Final Decision on the Victorian DNSPs' 2021-2026 tariff proposals and which it believes would lead to the AER re-assessing the position it adopted at that time:

1. Growth in the number of fast, and ultra fast, charging stations over the past 2 years. In its 2021 determination, the AER stated (Final decision, Attachment 19, Tariff Structure Statement, Page 41) stated:

   > "At this stage there is insufficient information to suggest that charging stations materially differ in their load characteristics, such as annual consumption and maximum demand, from other medium to large business customers".

   The accompanying analysis by MJA presents data for 10 charging sites in NSW where all relevant data, particularly from the DNSPs, is available. The analysis does not cover all of Evie's sites in NSW because of a lack of availability of annual data for Evie sites. In addition, the publicly available DNSP data is not current, so the analysis contains the assumption that broadscale patterns of demand are comparable. Evie has requested current data from each of the DNSPs and has been referred to the publicly available DNSP data. Were the data made available, the analysis would be more precise, but MJA does not expect significant changes in the conclusions made from the current analysis. If the necessary additional data is made available, Evie will be able to present an expanded analysis from MJA covering around 20 sites. Evie would propose to lodge a supplementary submission once this additional data is fully received and analysed.

   The AER may wish to consider requesting the DNSPs to provide the relevant data sought by Evie to facilitate, and expedite, this proposed expanded analysis.

   Evie does note, however, that MJA believes the demand profiles at the other Evie sites not covered in their current analysis are unlikely to be different from the 10 sites for which results are presented; ie, the outcomes from this proposed additional analysis could be reasonably expected to be in line with their current findings.

2. Greater recognition of surplus capacity in networks, both existing and potentially going forward:
   a. The head of SAPN Corporate Affairs was reported to have said in the January 2023 edition of the Energy Source and Distribution magazine that there was a very large amount of spare capacity in the network to support 100,000s of EVs and avoid unnecessary investment in network capacity.
   b. Software/AI developments that are allowing the "creation" of increased capacity, with the headline in an AFR report (online, 22 February 2023) declaring: "How AI unlocked capacity across NSW's energy grid". The article stated that "Digital modelling has revealed parts of Essential Energy's

distribution network – one of Australia's largest – can transport twice as much electricity as previously thought…..". It is expected that this will result in a material increase in overall network capacity, although this will not be consistent or uniform across the whole network. However it is considered that this technology will result in hosting capacity for EV charging being higher in some locations than previously assessed for the Essential Energy network. Given the significance of this development, it would be expected to Ausgrid and Endeavour Energy would seek to deploy the same technology, with consequential increases in hosting capacity for EV charging in their networks.

3. Greater recognition of the importance of addressing the issue of excess solar/low minimum demand in managing the electricity market and, therefore, greater recognition that the traditional evening peak demand period is no longer the only driver of network costs. This, in turn, has led to the greater recognition of:
    a. The importance of network avoided costs (eg, voltage control equipment).
    b. Network efficiency benefits being increasingly achieved through energy usage from new areas of demand (and particularly EVs) at times of excess solar energy generation and the associated low minimum demand; ie, this new demand being delivered through existing (surplus) capacity.

    This was highlighted in the AER's June 2020 SAPN 2020 to 2025 determination in which it stated (Overview, Pages 9 and 38 respectively):

    > "An important and growing challenge in South Australia is managing the minimum demand on the system in the middle of the day as a result of significant amounts of rooftop solar PV exported onto the system. These challenges include voltage rises (which could result in network costs and customers' solar exports being curtailed or "wasted")…….
    >
    > "An important and growing challenge in South Australia is managing the minimum demand on the system in the middle of the day as a result of significant amounts of solar exported onto the system. These challenges include voltage rises……"

    The WA Regulator also noted in its recent final decision on Western Power tariff proposals (ERA, Final Decision (March 2023), Attachment 11: Network tariffs, page 10; emphasis added):

    > "The draft decision noted that tariffs based on time of use periods were becoming increasingly important as demand patterns across the day change. **In the past, peak periods were the main driver of network costs. More recently, low demand periods had become a driver of network costs**".

It is noted that the issues being experienced in SA and WA due to Excess Solar Generation during the day and the associated problems with managing periods of Low Minimum Demand during the day will progressively be experienced in Queensland, NSW and Victoria as a direct result of continuing increases in the installation of household solar PV. As a result, it is considered that the Energy Authorities (the AER, AEMO and AEMC) will now need to give virtually equal focus to both the traditional daily "Evening Peak" and the daily "Solar Peak" (often referred to as the "Duck's Belly") and the associated issue of the difficulties with managing Minimum Demand and the potential costs to networks of managing Low Minimum Demand.

4 Recognition of the concept of a specific tariff for the EV charging infrastructure industry in the WA Regulator's (ERA) decision on Western Power's 2022/23-2026/7 (AA5) tariff proposals, with the ERA agreeing to the establishment of a mechanism to collect and analyse data over the AA5 period for the development of a specific EV charging infrastructure tariff to be introduced in the next regulatory period, with the ERA stating (Attachment 11: Network tariffs, Page 29; emphasis added):.

> "The **development of public EV charging structure is at a very early stage**…….However, as expressed by Evie, Western Power will need to work with electric vehicle charging infrastructure providers during AA5 to collect and analyse data from dedicated EV charging sites. The data and analysis can then be used to further **develop**, in conjunction with the electric vehicle charging infrastructure industry and engaging with both the ERA and Energy Policy WA, **tariffs that reflect the special characteristics of electricity demand at electric vehicle charging sites and promote the efficient use of the grid**".

Evie considers this to be particularly significant as:

- In its Victorian DNSPs' decision, the AER did not support the request for a specific tariff for the EV charging infrastructure industry, whereas the WA regulator accepted the position presented by Evie on the need for, and the design of the mechanism for, developing such a specific tariff for introduction in the next regulatory period.
- The WA Regulator did not advocate a Tariff Trial process in terms of the development of future tariff arrangements for publicly available EV charging sites – in contrast with the position advocated by the AER in its April 2021 Victorian DNSPs' 2021 to 2026 determination.

5. Introduction of an Emissions Reduction Objective into the National Electricity Objective. This is considered in detail below.

INCORPORATION OF AN EMISSIONS REDUCTION OBJECTIVE INTO THE NATIONAL ENERGY OBJECTIVES (NEO)

On 12 August 2022, Commonwealth and State/Territory Energy Ministers agreed to fast track the introduction of an Emissions Reduction Objective into the National Energy Objectives (NEO). Ministers were of the view this would provide greater clarity to the 3 Energy Market Bodies - the AEMC, AEMO and AER - to consider emissions reduction in how they undertook their respective powers and functions.

This is to be achieved through the National Energy Laws Amendment (Emissions Reduction Objectives) Bill 2023. It is noted that this amendment does not restrict the AER to only considering emissions reductions in the context of the Commonwealth's Climate Change Act 2022 and that it extends to "other targets" for reducing, or likely to contribute to reducing, Australia's greenhouse gas emissions under other legislation or policy statements.

The Consultation Paper particularly states (emphasis added):

> "The amendment will require that market bodies, when making decisions in line with the new emissions reduction objective, consider relevant Commonwealth, state and territory emissions reduction **and/or other targets** such as renewable energy targets, whilst still being afforded the flexibility to, after considering targets, decide which targets are relevant to that decision. **The new set of energy objectives will be taken into account by market bodies in their interpretation and application of laws and rules**.
>
> **"References to 'decisions' above encompasses the full range of functions, powers and obligations assigned to the market bodies where they are already required to be undertaken with reference to the energy objectives**, for example in system planning, rule change determinations, self-initiated and statutory reviews and reports……
>
> "The proposed amendments……. **also covers other government targets that are 'likely to contribute to' reducing Australia's greenhouse gas emissions, even if they are not purposely called out as an emissions reduction target** (e.g. a renewable energy target)……
>
> "At this stage, it is considered that the AER functions that will most likely be impacted by an emissions reduction objective would be the economic regulatory functions under the NEL and NGL.
>
> "Similarly, **the AER's economic regulatory decision-making functions and powers as outlined in the Rules will need to be performed and exercised in a way that will, or is likely to, contribute to the achievement of the NEO** or NGO".

The amended NEO will apply to relevant AER deliberations that have not been completed and, therefore, it is considered that the AER will need to (following passage of the legislation) take into account the Emissions Reduction Objective in its consideration of the NSW DNSPs' 2024-2029 tariff proposals. However, as the Government plans to fast track the passage of this legislation, Evie is also of the view that the AER should work on the basis that this new NEO will impact its decision and, as a result, take it into account from the outset of its deliberations.

In this context it is noted that the Commonwealth and State Governments see publicly available fast, and ultra fast, EV charging sites as a key element in their strategy of getting more EVs on the road as part of a strategy to reduce carbon emissions in the Transport Sector – and this is particularly aimed at concerns about Range Anxiety (the fear of running out of "fuel" when driving an EV on , particularly on long distances) inhibiting potential purchasers from deciding to buy an EV.

And as noted in the Introduction, EVs are now a central element of the Federal Government's Emissions Reduction Strategy, with its recent National Electric Vehicle Strategy particularly noting that "transport (is) on track to be Australia's largest emitting sector by the end of the decade". This will mean that emissions from the Transport Sector will exceed emissions from the Electricity Generation Sector over coming years.

Evie submits that this Government focus on EVs and the associated policy "element" of the importance of publicly available EV charging sites in terms of helping to support increasing purchases of EVs should not be seen only in terms of Governments providing funding to assist in the rolling out of charging infrastructure. Once sites are built, it will be equally important – if not even more important in terms of maintaining the confidence of potential EV purchasers – to ensure that the EV charging infrastructure operators have a commercially sustainable business model that allows them to not only maintain their existing sites in a fully operational state, but that they also have an on-going incentive to further build out their infrastructure in anticipation of the expected further take up of EVs.

A critical factor in determining whether charging infrastructure operators will be able to move to a commercially sustainable business model is their costs – and within this, the dominant cost is electricity. This is because DNSPs are applying tariffs that were designed for "traditional" businesses, not a totally new business with a very different technology (including Curtailability (considered below)) and a very different Load Profile (considered below)).

Evie further submits that if the AER believes that existing Rules restrict its ability to have full regard to this Emissions Reduction Objective in this consideration of the NSW DNSPs' tariff proposals, then there will be a need for an urgent amendment to a number of Rules, with this being initiated by either the Government (through a Minister-made Rule (although this would require an amendment to the current National Energy Laws Amendment (Emissions Reduction Objectives) Bill 2023)) or the AEMC (after receiving a Rule Change Request).

TRADITIONAL BUSINESS TARIFFS NOT APPROPRIATE FOR EV CHARGING INFRASTRUCTURE SECTOR

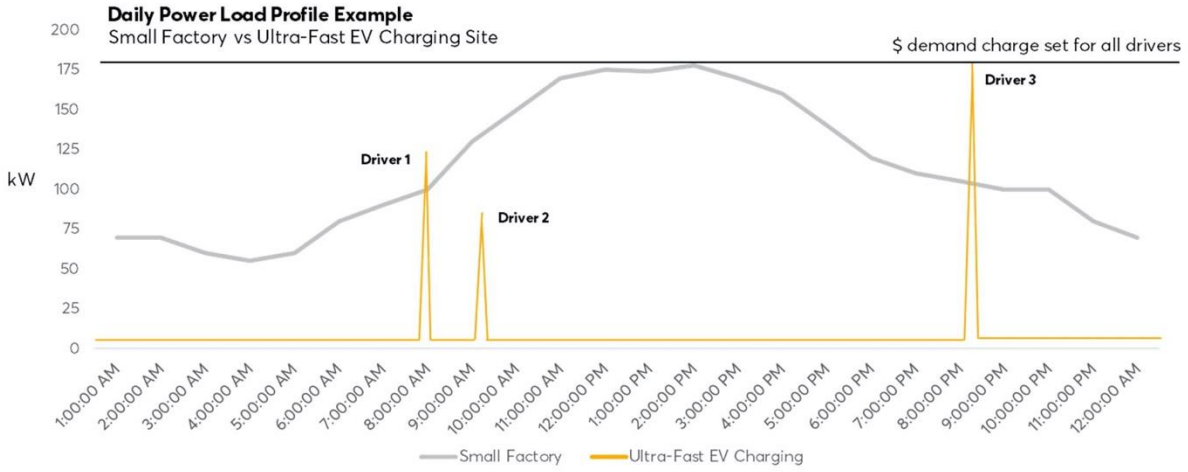
As set out above, the EV public fast charging infrastructure industry is still relatively new in Australia, and because of the still low level of EVs on the road, infrastructure providers must necessarily build out their sites ahead of demand. And as previously set out, this early provision of highly visible publicly available fast and ultra fast EV charging sites is critical to addressing concerns about Range Anxiety which, in turn, is a key factor in the decision to purchase an EV.

However the structure or design of "traditional" business tariffs acts as a major barrier to the development of a commercially viable business operation because the Load (or Demand) Profile of public fast charging is very different from "traditional" small and medium businesses. Because the tariffs that are currently applied to small and medium businesses are not suited to this new industry, they result in very high electricity costs for publicly available fast, and ultra fast, EV charging sites.

The graph below sets out the differences in the impact of a traditional business tariff containing a Demand or Capacity Charge on a small factory versus an EV charging station. The Demand or Capacity Charge is generally based on the customer's highest recorded demand in any hour or half-hour period on a rolling 12 months basis, irrespective of whether or not that peak occurred during a network peak demand event. As EV charging load profiles do not resemble typical Commercial and Industrial (C&I) use cases, when Demand or Capacity tariffs are assigned, the result is very high electricity costs. This is because the Demand or Capacity charges are necessarily amortised over a small number of users.

Given the very different Load Profile of publicly available EV charging sites, Evie believes there is a strong case for the introduction of a specific tariff for this new, fledging industry. As the technology is highly controllable (as set out below), it is further submitted that a technology specific tariff would also be justified. This position was rejected by the AER in its 2021 decision on the Victorian DNSPs' 2021-2026 tariff proposals. However, as also highlighted above, the concept of a specific tariff for the EV charging infrastructure industry was recognised in the WA Regulator's decision on Western Power's 2022/23-2026/27 (AA5) tariff proposals, with the ERA agreeing to a proposal from Evie for the establishment of a mechanism to collect and analyse data over the AA5 period to develop a specific EV charging infrastructure tariff to be introduced in the next regulatory period.

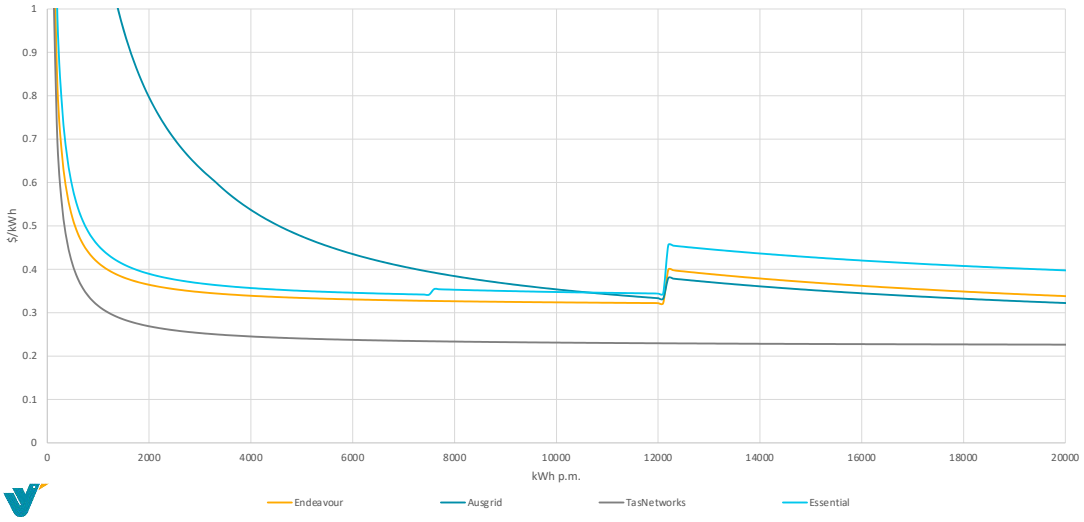
Illustrative example of ultra-fast load profile while EV uptake is low.



NSW DNSPS' TARIFFS DELIVERING VERY HIGH COSTS

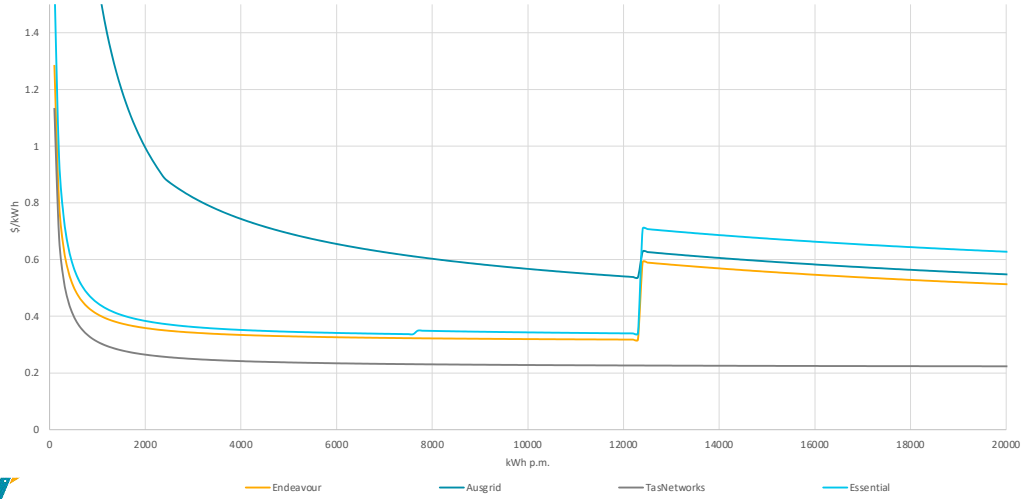
The high costs resulting from the NSW DNSPs' tariffs are highlighted in the following materials which show the cost profiles across the 3 NSW DNSPs, with the cost profile for TasNetworks being included for comparative purposes. As established in the MJA analysis, Evie is being over-charged for its network charges because, amongst other things, it is being charged for capacity expansion costs when, in fact, the sites covered in the MJA analysis were only using existing assets and, therefore, are not triggering capacity expansion costs.

Cost profile across NSW DNSPs (all inclusive). 2x 50kW charging configuration



1

Cost profile across NSW DNSPs (all inclusive). 2x 350kW charging configuration



A SPECIFIC TARIFF FOR EV CHARGING SITES

Based on the arguments presented in this submission, Evie believes that:

- The very different usage profile of publicly available EV charging sites would justify the introduction of a specific tariff for this new industry, and that this would be consistent with the National Electricity Rules (Clause 6.18.4).
- The network benefits provided, both directly and indirectly, through the operation of EV charging sites would mean that the introduction of a technology-specific tariff for publicly available EV charging sites should be considered to be consistent with the NEM Rules (Clause 6.18.5 on Pricing Principles).

Evie particularly notes that the AER stated in its April 2021 decision on the Victorian DNSPs' tariff proposals (Pages 19-40-19-41; emphasis added) that:

> "…..the distributors are unlikely to be able to establish a tariff class specifically for electric vehicle charging stations. The NER requires networks to establish tariff classes which group consumers according to their load, connection **and** metering characteristics. This means all customers must be treated like other customers with similar characteristics"

The AER referenced National Electricity Rules Clause 6.18.4(a)(1) in support of this position. However Clause 6.18.4(a)(1) states (emphasis added):

> (a) In formulating provisions of a distribution determination governing the assignment of retail customers to tariff classes or the re-assignment of retail customers from one tariff class to another, **the AER must have regard to the following principles**:

(1) retail customers should be **assigned to tariff classes on the basis of one or more of the following factors**:

(i) the nature and extent of their **usage or intended usage** of distribution services;

(ii) the nature of their *connection* to the network;

(iii) whether remotely-read interval metering or other similar metering technology has been installed at the retail customer's premises as a result of a regulatory obligation or requirement;

Ie, Clause 6.18.4(a)(1) provides that a tariff class is not determined by load, connection **and** metering characteristics, but rather on the basis of "one or more" of these characteristics. Thus, Tariff Assignment can be based solely on "usage or intended usage". Therefore, given the demonstrably different Load Profile – Usage – of publicly available EV charging sites, Evie submits that the introduction of a specific tariff for these sites would be consistent with Clause 6.18.4(a)(1) and that the AER should now endorse this view.

It is also noted that in its April 2021 Victorian DNSPs' decision (at page 19-40), the AER referenced that "a number of other industries besides electric vehicle charging stations such as irrigators and medical imaging facilities" also had peaky demand with low overall usage. However publicly available EV charging sites operate on a 24/7 basis and, of course, are a customer facing business. Thus the charging infrastructure industry necessarily has a very different usage pattern compared to these other sectors, re-inforcing the argument in favour of a separate specific tariff for this new industry based on its particular (ie, very different) usage characteristics.

Evie further notes that Ausgrid, in its "Our TSS Explanatory Statement for 2024-29", highlighted that it is proposing the introduction of a specific tariff for Embedded Network Operators on the grounds of their very different Load Profile relative to other medium or large businesses, with Ausgrid stating (Page 22; emphasis added):

> "To meet the requirement for distribution networks to assign customers to tariffs based on the nature and extent of their usage, we currently assign ENs to tariffs designed for medium to large businesses. However **the load profiles of ENs are different to other customers on those tariffs**".

A SPECIFIC TARIFF FOR EV CHARGING SITES DOES NOT REPRESENT A SUBSIDY

The general argument put in opposition to the introduction of a specific tariff for publicly available EV charging sites is that it would involve a cross-subsidy. However, the uptake of EVs, enabled by the availability of well planned, affordable public fast charging, will deliver significant benefits for electricity networks and, ultimately, electricity consumers. In summary, the benefits include:

1. Long term increased utilisation of electricity networks, creating efficiency benefits.

2. Avoiding network costs such as voltage control to help manage low Minimum Demand levels caused through "excess" solar generation by helping to absorb this excess solar generation, as public fast charging typically peaks in the middle of the day (as detailed further below). It is noted in this context that Ausgrid stated in its "Our TSS Explanatory Statement for 2024-29" (page 36; emphasis added):

   > "in locations where solar penetration is already high, high levels of customer exports and low levels of demand for imports is resulting in a lower 'minimum system load' in the afternoon than previously experienced overnight. If this continues, it could increasingly drive **additional voltage management costs** in the low voltage network in the future".

3. Improved local network stability, as fast charging often requires grid augmentation that is funded by the charging network operator.

4. Controllable technology, allowing peaks to be managed dynamically and at short notice.

The network efficiency benefits through greater utilisation, as well as significant avoided network costs (through minimising the costs to manage minimum demand created by excess solar energy during the day), will mean lower costs can be passed on to all electricity consumers, not just EV owners.

Going forward, EVs will play a major role in relation to CER, with energy stored in the EV battery being used to reduce demand during the evening peak (V2H) and/or adding energy back into the grid during the evening peak (V2G).

This has the potential to result in significant additional avoided network costs, which will further benefit all electricity consumers, not just EV owners.

Given the important role that public charging plays in supporting demand for EVs by assisting in addressing potential EV purchasers' concerns about Range Anxiety, the EV charging infrastructure industry will increasingly help deliver significant benefits that will flow through to all electricity consumers.

PUBLICLY AVAILABLE EV CHARGING SITES WILL NOT "BREAK" THE GRID

The MJA analysis highlighted that there is a high level of diversity between Evie site maximum demand and Zone Station maximum demand and noted that:

> "In all cases, Evie's maximum demand does not correspond to ZS maximum demand; Evie's maximum demand occurs at times when maximum ZS demand is light."

Evie would also wish to highlight the following considerations:

Controllability

Importantly, the new technology involved with public EV charging infrastructure is inherently more controllable than legacy technologies:

1. Charging technology is easily controllable.
2. Load Management Systems for publicly available charging sites are readily available that can address Peak Demand issues.
    - They can be designed to optimise network utilisation and stability, while avoiding impact during peak network events.
3. Technology to control public EV charging already exists and is in operation today.

That is, public EV charging infrastructure is inherently more controllable than legacy technologies and, as a result, can be designed to optimise network utilisation and stability, while avoiding impact during peak network events. Technology to control public EV charging already exists and is in operation today. This capability should therefore be recognised, and would further support the introduction of a technology specific or customer specific tariff for publicly available EV charging sites.

It is noted that in its 2021 Victorian DNSPs determination the AER made the following statement in its Overview: Final Decision document (United Energy, Page 6 – but without any apparent elaboration on this issue):

> "…….charging stations which instal load limiting devices can access alternative cost reflective tariffs".

Coincident Demand

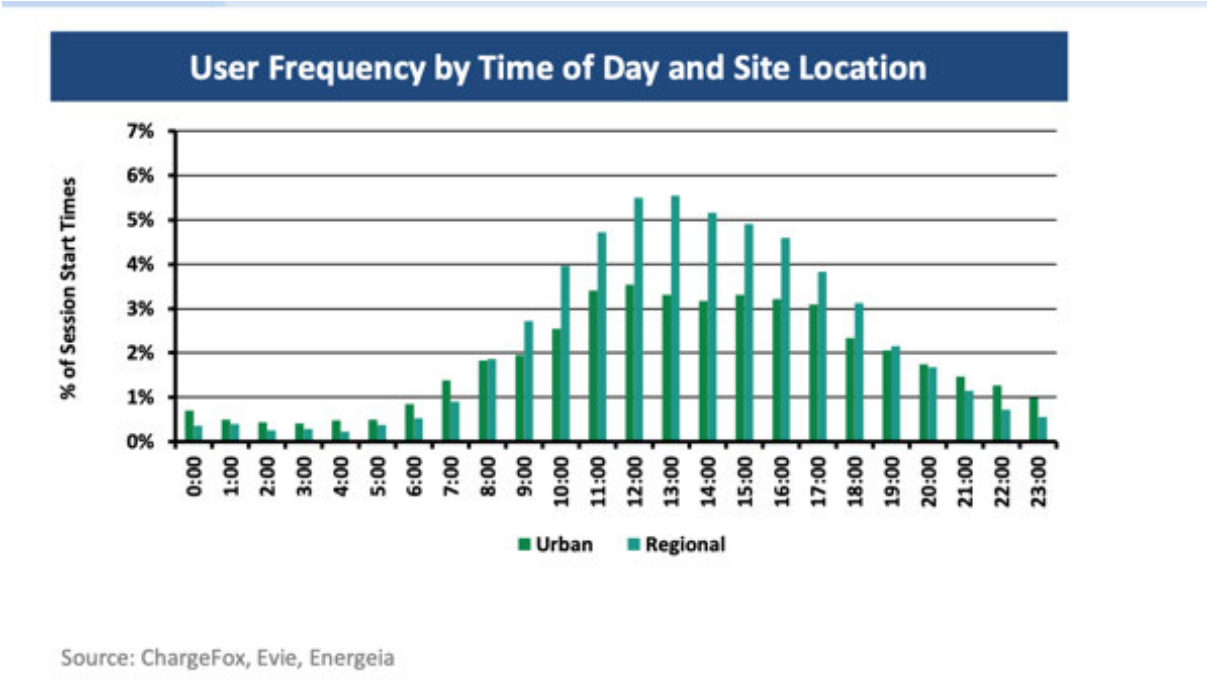
Evie also wishes to address concerns that EV public charging will, with an increasing number of EVs on the road, add to peak demand on networks, resulting in increased investment to address this increase in peak load. Evie considers this view to be misplaced, as EV charging can act as a "solar soak".

Specifically, usage of publicly available EV charging sites is generally concentrated during off-peak periods, and principally during the periods of excess solar generation. Ie, charging site utilisation is broadly coincident with the solar peak period and, thus, as noted above, can act as a "solar soak" with consequential avoided network cost benefits.

This was highlighted in materials prepared by Energeia for ARENA: "Ultra-fast Charging Data Analysis – Webinar Materials" (August 2021), with the materials making the following observations:

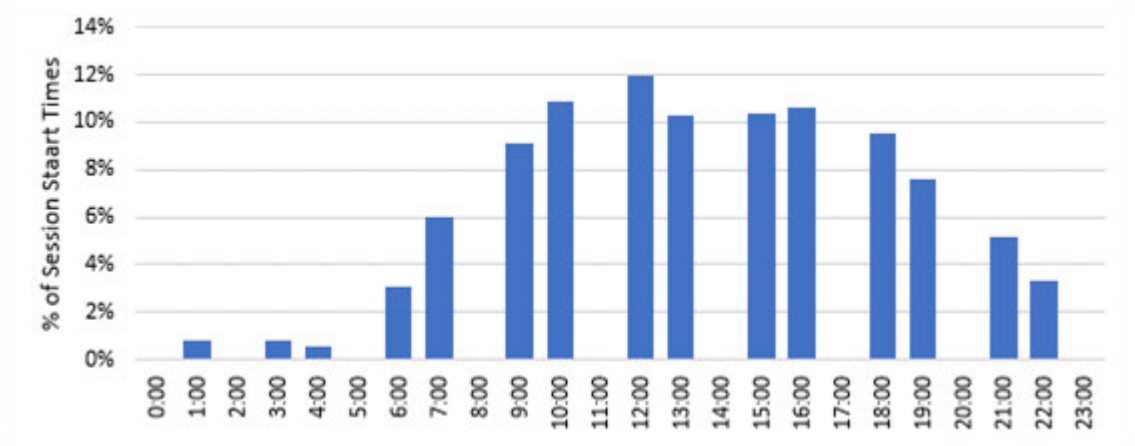
1. "Charging pattern constant by day type and correlates well with solar PV generation profile" (Page 4).
2. "Public EV charging patterns could provide a solution to min(imum) demand caused by solar PV" (Page 4).
3. "Data suggests that both urban and regional drivers use public charging most in the middle of the day, closely resembling a PV load shape" (Page 19).
4. "Early indication is that many public charging sites will not have a significant impact on peak demand if charging load is at its highest in the early afternoon" (Page 27).
5. "Public EV charging patterns could provide a solution to min(imum) demand caused by solar PV" (27).

The coincidence of public charging with solar generation (and, therefore, also at off-peak times) is highlighted in the following graph from these ARENA materials:



Source: ChargeFox, Evie, Energeia

MJA also analysed charging data from the 10 Evie sites for which data was available for a full 12 months. The results are set out in the graph immediately below and, in line with the materials from the AERNA Workshop, follows a similar pattern of increasing charge starts from around 9/10am, and then tailing off in the early evening – which is in line with the profile for Solar electricity generation over the course of the day.



Additionally, the Ergon/Energex "EV SmartCharge Queensland Insights Report" lends support to this position, with what it described as "away charging" (which included the use of public DC chargers (ie, fast and ultra fast chargers) being broadly consistent with peak solar generation during the day and falling away in the period coming through to the daily afternoon peak demand period. This was particularly evident in the materials on its findings for commercial-use passenger vehicle EVs (Page 21).

DETAIL OF EVIE'S POSITION ON THE KEY CONSIDERATIONS FOR TARIFFS APPLYING TO PUBLICLY AVAILABLE EV CHARGING SITES

Based on the factors set out above and the accompanying MJA report, Evie sets out its inter-related recommendations for consideration by the AER on the appropriate tariff structure that should be applied for publicly available fast, and ultra fast, EV charging sites. The proposed design features would:

- Facilitate the rollout of this infrastructure that is recognised as being critical to the achievement of Government Emission Reduction Objectives and associated policies, particularly noting that Energy Ministers have decided to include an Emissions Reduction Objective in the NEO.

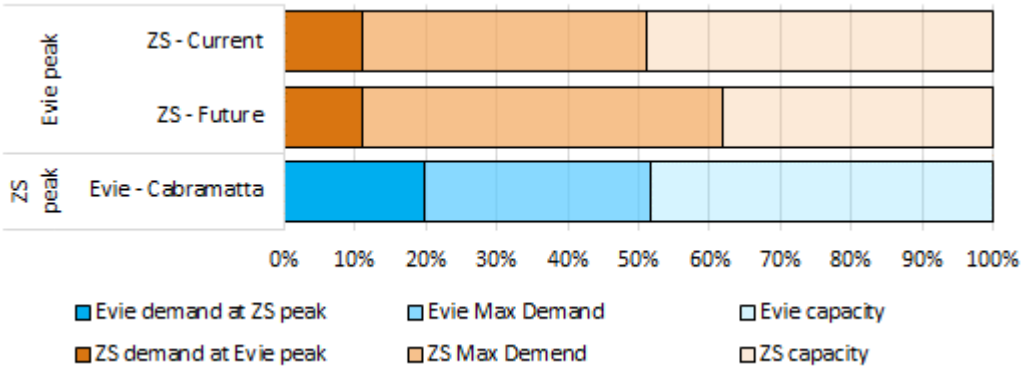
- Be critical to the development of a sustainable business model, with this then ensuring that this charging infrastructure is fully maintained and operational.

Evie particularly notes that the MJA analysis demonstrated that Evie is being over-charged for its network charges, particularly because it is being charged for capacity expansion costs when, in fact, the sites covered in the MJA analysis were only using existing assets and, therefore, are not triggering capacity expansion costs. The MJA analysis also supports Evie's position that it is not appropriate to apply Demand Charges to these charging sites.

MJA found:

> "The application of high premium prices to Evie sites is not consistent with the Rules because of the diversity between demand peaks at Evie sites versus DNSP the Zone Substations. This is shown in Figure 3.

Figure 3 An example of peak demand diversity between an Evie charging site and its Zone Substation



> "The diversity between the ZS and Evie site demand profiles mean that the Evie site only uses existing ZS capacity. Capacity and demand charges applied to Evie's maximum demand make no sense given Evie's maximum demand diverges from ZS maximum demand. As such, premium pricing of energy used at this site deters otherwise economically productive network asset utilisation.
>
> "In all the 10 Evie sites for which data are available, there is a high level of diversity between Evie site maximum demand and ZS maximum demand. Therefore, there is no network cost basis for applying premium tariff components (especially those relating to Evie site maximum demand) for any of the 10 sites".

Additionally the MJA report stated:

> "Given the diversity between Evie site demand and associated DNSP capacity, premium tariff elements should not be applied to existing Evie sites until it can be demonstrated by the relevant DNSP that Evie site maximum demand corresponds with DNSP maximum demand periods and locations. Pending this, Evie sites should only be charged at standard tariff rates (fixed connection plus non-premium volumetric charges)."

Design Features

1. Recognition of the adverse impact of the application of Demand Charges to publicly available EV charging sites at this point in the nascent industry's development, with the consequential high costs adversely affecting the prospect of developing a sustainable business model for this sector. Very significant in the context of the NEO to include an Emissions Reduction Objective.

This would necessitate a decision that Demand Charges would not be applied to publicly available EV charging sites at this point in the industry's current growth cycle.

This is particularly supported by the MJA findings:

"In all cases, Evie's maximum demand does not correspond to ZS maximum demand; Evie's maximum demand occurs at times when maximum ZS demand is light. There is therefore no basis for applying premium components (particularly demand charges) of network tariff structures for any of the 10 sites across the three NSW networks for which data is currently available".

2. Recognition of EV charging sites have a very different Load Profile from "traditional" businesses, and with a very different technology from "traditional" businesses – including "curtailability", as well as recognition that the introduction of this special, specific tariff for the EV charging sector would, based on this special Usage profile, meet the requirements under NER Clause 6.18.4(a)(1) (ie, Tariff Assignment), and that the following additional considerations should be adopted in line with the WA Regulator's recent determination that recognised the concept of a specific tariff for the EV charging infrastructure industry:

    a. This tariff to apply for a defined period of time (only).

    b. During this defined time period, a mechanism be established along the lines adopted by the WA Regulator for the collection and analysis of appropriate data in order to develop, in conjunction with the EV charging infrastructure industry, and engaging with the AER and representatives of State and Federal Energy Ministers, tariffs that reflect the special characteristics of electricity demand at EV charging sites and that will promote the efficient use of networks.

3. Recognition of the availability of surplus capacity in areas of the grid, reinforcing the position that usage of publicly available fast, and ultra fast, charging sites will not put undue pressure on the grid over coming years – and, thus, that this usage will not drive the need for DNSPs to undertake expenditure to expand capacity.

4. Agreement to the application of an Energy Only Tariff.

5. Curtailability of publicly available EV charging sites during Peak Demand Days and the Coincident nature of usage patterns of publicly available EV charging sites with the daily pattern of Solar Generation supporting the position that this Energy Only Tariff be applied at Off Peak Rate.
    - Reject a Load Control Tariff design for the EV charging infrastructure industry in recognition that it is a 24/7 customer facing business, with the need to be "always on" to fully service existing EV drivers and give potential EV drivers confidence that they will be able to access an EV charging site whenever they may choose.

6. Recognition, as demonstrated by MJA (and other) analysis, that the pattern of charging at publicly available EV charging sites broadly follows the daily pattern of solar generation. Ie, usage of publicly available EV charging sites is generally concentrated during off-peak periods, and principally during the periods of excess solar generation. As charging site utilisation is broadly coincident with the solar peak period, it can act as a "solar soak" with consequential avoided network cost benefits. This further re-inforces the position that:

    - The proposed Energy Only tariff should be applied at the Off Peak rate.

7. Recognition of the Network Avoided Costs and Network Efficiency Benefits to be derived from EV charging sites, both directly and indirectly, which will benefit all consumers, not just EV drivers – with this being reinforced by the Coincident nature of usage patterns of publicly available EV charging sites with the daily pattern of Solar Generation. As a result, these tariff design features would not involve a subsidy (or cross subsidy).

CONCLUSION

There have been a number of significant developments since the AER's 2021 determination on the Victorian DNSPs' 2021 to 2026 tariff proposals that, Evie submits, would warrant the AER reconsidering its decision to reject a number of inter-related proposals from Evie at that time and, thus, now support those positions in this review of the NSW DNSPs' tariff proposals, specifically:

- That tariffs to be applied to publicly available EV charging sites should not contain a Demand Charge.

- That a specific tariff should be introduced for this new industry based on its very different "Load Profile" compared with "traditional" small and medium businesses.

- As a result of its very different Load Profile, Demand Charges would have an unduly negative impact on the industry's electricity costs as these Demand Charges could only be amortised across a small number of customers because of the relatively low take up of EVs.

Evie therefore set out these developments since 2021 in detail, as well as the implications for the appropriate tariff arrangements (ie, Tariff Structure and Tariff Assignment) that should be applied to publicly available EV charging sites.

Evie particularly noted that there are 2 recent developments it believes should also determine the AER's decision on the NSW DNSPs' tariff proposals now under review and that these developments should result in the AER now endorsing Evie's position, namely:

1. The decision by Energy Ministers to fast track the inclusion of an Emissions Reduction Objective into the NEO, with this amended NEO applying to this current DNSP tariff review. EVs are now a central element of the Federal Government's Emissions Reduction Strategy, with the Transport Sector expected to be Australia's largest emitting sector by around 2030. This will mean that Transport Sector emissions will exceed emissions from the Electricity Generation Sector over coming years. It is submitted that this amended NEO would support the position that there is a specific need for appropriate designed tariffs to help facilitate the rollout of publicly available EV charging sites and, just as importantly, their maintenance through the development of a commercially sustainable business model. Recognition of the adverse impact of "traditional" Demand Charges on this new industry would be a crucial element to the development of this sustainable business model.

2. The recent WA Regulator determination on Western Power's AA5 tariff proposals in which it recognised the concept of a specific tariff for publicly available EV charging sites and agreed to a mechanism presented by Evie that would collect and analyse data from dedicated EV charging sites over the next 4 years to develop tariffs that reflect the special characteristics of electricity demand at EV charging sites and promote the efficient use of the network.

The submission also highlighted a number of specific features of the EV charging infrastructure industry that would support the adoption of an Energy Only tariff at the Off Peak rate for a defined period of time:

- Very different Load Profile from "traditional" small and medium businesses.
- Very different technology from other businesses, including "Curtailability".
- Site usage being generally coincident with the daily pattern of solar generation.

The submission also highlighted the significant Network Avoided Costs and Network Efficiency Benefits to be derived, directly and indirectly, from EV charging sites which will benefit all consumers, not just EV drivers – with this supporting the position that the recommended tariff design features would not involve a subsidy.

Additionally Evie commissioned detailed analysis by MJA of the operation of a number of its NSW charging sites and an assessment of the application of the DNSPs' tariff structures on Evie's network electricity bills, and whether these tariffs (and the DNSPs' tariff generally) were consistent with the NER.

The MJA report found that Evie is being over-charged for its network charges. This is because, amongst other things, it is being charged for capacity expansion costs when, in fact, the sites covered in the MJA analysis are only using existing assets and, therefore, are not triggering capacity expansion costs.

In terms of Evie's network bills it concluded that there was a significant discrepancy between the way Evie is being charged for its use of the network and the way these sites use the network. It concluded that the application of Demand Charges was not appropriate.

More generally it concluded that NSW DNSPs are over-estimating LRMC in their TSS proposals by failing to adjust LRMC to reflect existing surplus capacity from previous over-investment. It stated that this was because the DNSPs are incorrectly treating existing sunk capacity as if it were avoidable and charging premium rates instead of standard rates, raising average prices for some customers including Evie.

This analysis strongly supports the view that publicly available EV charging sites should be enjoying significantly lower electricity costs than currently being incurred and that Demand Charges should not be applied.

Evie therefore recommends that the AER endorse the positions presented in this submission:

1. The introduction of a specific tariff for the publicly available EV charging infrastructure industry.

2. An Energy Only Tariff be applied at Off Peak Rate for a defined number of years.

3. The AER agree to the establishment of a mechanism (with membership drawn from DNSPs, the EV charging infrastructure industry, the AER and State and Federal Energy Departments) that would collect and analyse data from dedicated EV charging sites over, say, 3-4 years to then develop tariffs that reflect the special characteristics of electricity demand at EV charging sites and promote the efficient use of the network for subsequent consideration by the AER.

Evie strongly believes that this set of proposals would not only be consistent with the new Emissions Reduction Objective to be inserted into the NEO, but that this new NEO would require the AER to endorse these proposals given the significant role the EV charging infrastructure industry plays in helping Governments achieve their Emission Reduction Targets and accompanying policies.

Evie also notes that if the AER believes that existing Rules restrict its ability to have full regard to this Emissions Reduction Objective in this consideration of the NSW DNSPs' tariff proposals, then there would be a need for an urgent amendment to a number of Rules, with this being initiated by either the Government (through a Minister-made Rule (although this would require an amendment to the current National Energy Laws Amendment (Emissions Reduction Objectives) Bill 2023)) or the AEMC (after receiving a Rule Change Request).

ENDS

ATTACHMENT: SPECIFIC COMMENTARY ON AUSGRID'S PROPOSALS

Evie strongly submits in the accompanying submission that Demand Charges should not be applied to the fledging EV charging infrastructure industry at this point in its development cycle, and proposes the adoption of an Energy Only Tariff for a defined period, with an appropriate mechanism being established along the lines of the recent WA regulator decision on Western Power's tariffs. That is, Evie does not support the application of Demand Charges by Ausgrid, Endeavour Energy or Essential Energy. However Evie also believes it should draw the AER's attention through this Attachment to how Ausgrid's position is totally out of line with the other 2 NSW DNSPs and, therefore, warrants the AER's particular attention. In doing so Evie presents a number of comments on Ausgrid's "Our TSS Explanatory Statement for 2024-29" document and the results of MJA's analysis of Ausgrid's tariffs.

Specifically, Ausgrid noted in its "Our TSS Explanatory Statement for 2024-29" document (Page 31) that it had identified 2 major concerns being registered by customers and retailers with respect to Tariff Assignment Policies, stating:

> "In our consultations to date, retailers and customers have raised two concerns about the bill impacts for small and medium business customers, when we transfer them to another tariff in line with our current tariff assignment polices.
>
> "First, when a small business customer on our demand tariff (EA256) uses more than 40 MWh per annum over a 2-year period, our policy is to transfer them to a medium business capacity tariff (EA302). This tariff has different structure to the demand tariff, and this can create adverse bill impacts for customers who use the network infrequently (such as electric vehicle charging stations).
>
> "Second, when new business customers connect to our network, they do not have any existing metering data to guide us in assigning them to the most appropriate network tariff. Our current policy assigns them to a demand tariff if they have a single-phase connection, and to a capacity tariff if they have a three-phase connection. However, we understand that many small business customers (using less than 40 MWh pa) are on three-phase supplies. Under this policy, they are assigned to a capacity tariff that is likely to be inappropriate. In addition, under our existing assignment policies a new customer must wait 12 months before they can request a tariff transfer.

Ausgrid then went on to propose what it described as "reforms" in the following terms ("Our TSS Explanatory Statement for 2024-29" document, Page 31):

• **Increasing the consumption threshold for transferring existing customers from a demand tariff to a capacity tariff from 40 MWh per annum to 100 MWh pa.** This will align with the *National Energy Retail Law (NSW)* definition of a small customer and improve our annual review of tariff assignments by reducing the number of tariff transfers occurring. It will also enable customers using between 40 and 100 MWh per annum to be

assigned to the business demand tariff EA256 (and to opt out to time of use tariff, should they choose too). We propose to **move the threshold to 100 MWh in 20 MWh steps over three years (FY25, FY26 and FY27)** to limit rebalancing of tariff components and possible customer bill impacts.

- **When assigning new business customers to a tariff**, we propose to replace the 'three-phase rule' with a 'greater than 100 amp rule' for assigning customers to capacity tariffs. This will ensure that smaller business customers who have three-phase supply sites are assigned to the business demand tariff (EA256) instead of the capacity tariff (EA302). These customers would still be able to opt out of this demand tariff, and move to the business TOU tariff EA225, should they choose to.

Analysis by Evie of Ausgrid's proposed tariffs and its associated low capacity thresholds demonstrated that Ausgrid's position would result in very high costs for publicly available EV charging operators, in both absolute terms and relative to the other 2 NSW DNSPs. This analysis was provided to Ausgrid in confidential materials last year which contained 6 graphs showing the impact of Ausgrid's tariff arrangements, including a Case Study comparing an EV charging site in the Ausgrid network area with a comparable site in the Endeavour Energy network area. The Case Study provided highlighted how electricity costs at the site in the Ausgrid area are well in excess of double the cost at the comparable site in the Endeavour Energy area.

This high cost outcome is in both metropolitan areas and public highway sites, but the impact on public highways is greater. It is submitted that this will:

1. Make investment in public EV charging in the Ausgrid network area going forward commercially challenging.

2. Create the risk that public charging costs for EV drivers in the Ausgrid network area (covering Greater Sydney, the Central Coast and the Hunter) will be unduly high. This would:

    a. Be highly inequitable for EV owners who are not able to charge their EVs at their residence.
    b. Potentially blunt the incentive to purchase an EV (ie, it would reduce the benefits of driving an EV versus an ICE vehicle), undermining the NSW Government's policies designed to increase the uptake of EVs.

In addition:

1. Ausgrid is not proposing to immediately address the issue it has identified with its 40MWh capacity threshold immediately in terms of increasing this threshold to 100 MWh. Instead it proposes to make this change in 3 steps, with the result that the new 100MWh threshold would not apply until FY27; ie, 5 years from now.

Evie's data and forecasts demonstrate that utilisation of chargers is likely to track ahead of Ausgrid's proposed timing of threshold increases. As a consequence, most charging stations are expected to still incur capacity charges and, therefore, Ausgrid's proposed threshold increases will have very limited tangible beneficial impact.

If Ausgrid is to address the problem it has identified then, at the very least, the threshold increases need to occur immediately and in one step. But Evie continue to highlight its opposition to the use of Demand Charges by all 3 NSW DNSPs at this point in the development of the EV charging infrastructure industry.

2. Even at 100MWh, Ausgrid's capacity threshold would be out of line with that of other NSW DNSPs, at 160MWh.

   Ausgrid submits in its TSS Explanatory Statement for 2024-29 (Page 31) that the proposed 100MWh pa threshold will align with the threshold at which the NSW ombudsman scheme and National Energy retail Law (NSW) defines a small customer. However it is noted that Endeavour Energy and Essential Energy adopt a higher threshold and, therefore, do not believe they need to adopt this same approach as Ausgrid in terms of defining a small customer.
   Ausgrid provides no other reasons as to why it should continue to apply the lowest volume thresholds for capacity tariffs of all the DNSPs in Australia.

3. The proposed tariff assignment policy that applies to new connections, with EA302 tariff applying for 3-phase connections greater than 100A, will create a barrier to deploying the higher power and multi-bay charging infrastructure that is in line with driver needs and preferences. The proposed 100MWh limit could, in fact, incentivise providers of charging infrastructure to build many single charging stations to avoid Ausgrid's tariff structure. This would result in a poorer experience for drivers and poor capital efficiency. Further, the long term capacity factor of a multi-head configuration is much greater than for small, single head configurations and, therefore, more efficient for the network, than a single head configuration.

4. We note that the proposed 100A limit would appear to unduly favour Ausgrid's own electric kiosk solution which provides single port, low power, advertising-funded charging (through Ausgrid's partner, JOLT).

5. Ausgrid's Tariff Assignment Policy position of automatically assigning new business customers to its EA302 capacity tariff on the basis that this new customer does not have any existing metering data to guide it in assigning them to the most appropriate network tariff is regarded as unduly arbitrary and, as a result, punitive.

   a. Charging stations are often very similar to existing infrastructure that is already operating.

   b. Evie has attempted on multiple occasions to demonstrate likely utilisation based on actual data from operating charging stations. We have also provided data within the first 12 months of operation.

c. Ausgrid has rejected Evie's tariff reassignment requests despite an abundance of data.

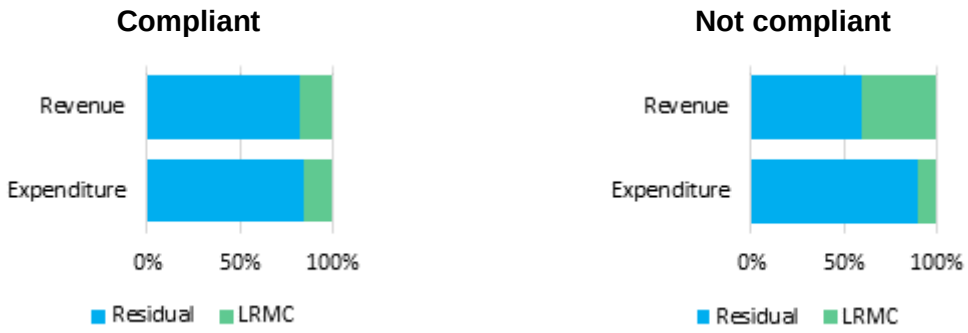
d. It is therefore submitted that if a CPO can demonstrate data from a similar charging site to support a requested tariff assignment, Ausgrid should be required to accept that data, rather than imposing punitive network charges for 12 months. Evie therefore requests that the AER endorse this position.

6. Capacity charges limit the ability to control equipment. Once a capacity charge has been incurred, customers have no incentive to reduce peak demand in subsequent months.
7. Ausgrid is not offering incentives to CPOs to reduce costs as its tariff arrangements do not afford any recognition that the technology is highly controllable.
8. Ausgrid has not recognised that public EV charging aligns with solar peaks and the potential benefits from avoided network costs.
9. Embedded Networks: Evie would wish to particularly highlight that Ausgrid's proposal would make it harder for EV charging infrastructure providers to deploy charging sites at locations that are convenient for drivers, such as shopping centres. Evie also notes that Ausgrid is proposing to treat a particular class of customer differently without considering the different types of loads and the flexibility of loads that are connected to the embedded network. Evie therefore requests that the AER reject Ausgrid's proposal. However we would propose that Ausgrid engage with Evie and the EV charging infrastructure industry (through the EV Council) on how electric vehicle charging operations can be connected via Embedded Networks in a way that reduced the current barriers to infrastructure investment, and request the AER to support this engagement.

In its report, MJA made a number of specific references to the adverse impact of Ausgrid's tariff arrangements in terms of impacts on Evie's publicly available charging sites:

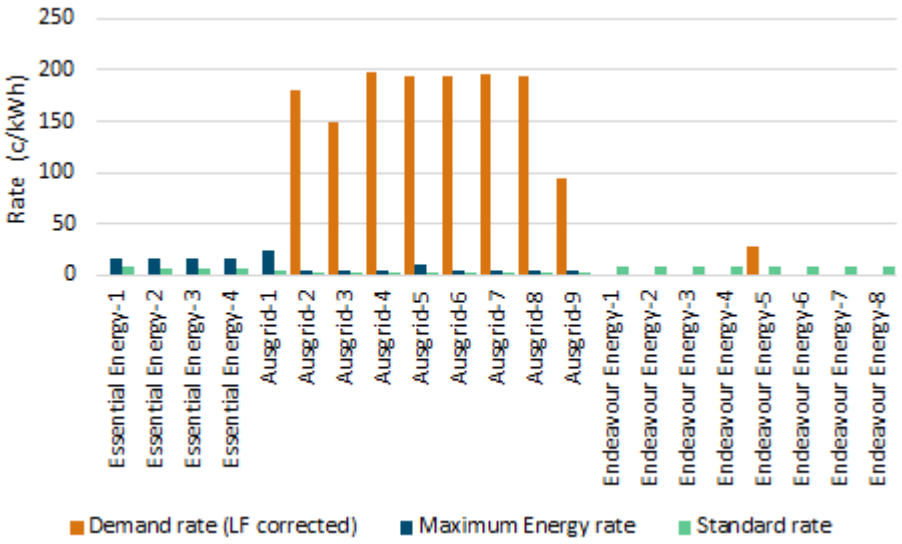
> "The report combines an analysis of Evie network billing and demand data as well as network demand and capacity data. The analysis shows that total network charges applied to Evie sites are substantially higher than efficient network costs. The effective network prices applied to Evie under existing and proposed network tariffs do not correspond to efficient network costs for the location and demand profiles of Evie's charging sites, for which data is currently available.
>
> "This means that TSS proposals applicable to the Evie sites reviewed are not compliant with the requirements under the Rules, as illustrated on the right in Figure 1 below.

Figure 1 Compliant and non-compliant revenue structures



"The mismatch between price and cost is caused by premium tariff charges that lift average unit prices. The unitised premium above standard rates is most extreme for Ausgrid but is also notable for Essential Energy, as shown in Figure 2 below.

Figure 2 Structure of Evie network bills (tariff structure)



"The figure highlights that Ausgrid premium charges are many times higher than the premium prices for the other two networks. The Ausgrid premium charges do not reflect demand diversity and are not cost-based".

Conclusion

Ausgrid has clearly identified how its tariff structures disadvantage publicly available EV charging sites, and result in these sites experiencing a higher cost per unit of energy than other customers on the same tariff. Despite this, it also clearly states that the changes it is proposing will only go part of the way in addressing this issue that is so critical to ensuring the commercial viability of this new industry, and an industry that is seen by Government as playing a fundamental role in supporting policy to promote the increased take up of EVs to reduce carbon emissions.

Analysis prepared by Evie, and presented to Ausgrid in confidential materials last year, demonstrated that Ausgrid's changes would continue to result in very high electricity costs, both in absolute terms and compared with the other 2 NSW DNSPs, for publicly available EV charging sites. At the very least, Ausgrid should be required to immediately increase its capacity threshold to 160MWh – in 1 step – in line with the other NSW DNSPs.

However Evie again notes that, as set out in its accompanying submission, tariff structures with Demand Charges are not appropriate for publicly available EV charging sites at this point in its development cycle and because of the industry's special characteristics. Evie therefore does not support the application of Demand Charges to publicly available EV charging sites at this point in time.

Evie therefore does not support the tariff changes presented by Ausgrid as they would apply to publicly available EV charging sites (including sites that would be affected by Ausgrid's proposed changes to Embedded Networks), and requests that the AER reject them.

Evie also draws the AER's attention to the MJA analysis which clearly demonstrates that Ausgrid is out of step with the other 2 NSW DNSPs and, most importantly, is delivering extremely high charges to publicly available EV charging sites that must challenge the prospect of this nascent industry - that is so critical to Governments achieving their Emission Reduction Objectives and associated policies - establishing a commercially viable business model in its network areas covering Greater Sydney, the Central Coast and the Hunter.

ENDS

MARSDEN JACOB ASSOCIATES

economics
public policy
markets
strategy

NSW distribution network tariff proposals; impacts for public electric vehicle charging

Report for Evie Networks

15 May 2023

A Marsden Jacob Report

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MARSDEN JACOB ASSOCIATES

Contents

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Glossary and abbreviations

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Augmentation	Expansion of network capacity to support new connections or existing connection demand growth
CER	consumer energy resources
Cost reflective network prices	Outcomes from tariff designs where the marginal revenue corresponds to marginal expenditure
DAPR	Distribution Annual Planning Report
Demand profile	See load duration curve
Demand diversity factor	A measure of variations in maximum demand between one asset or customer group and another. A customer whose maximum demand diverges from maximum demand at a network asset has a higher diversity factor
DNSP	Distribution Network Service Provider
EV	Electric vehicle
Firm capacity	Network capacity inclusive of reserves necessary to maintain reliability performance
Infra-marginal demand	Demand that uses sunk or existing capacity
Infra-marginal capacity	Existing or sunk capacity
Interval data	Measurements of power/energy at half or quarter hourly intervals
kW	Kilowatt
kWh	Kilowatt hour
LDC	Load duration curve – a customer or retail segment demand profile for a given period (not daily)
LF	Load factor – the ratio of energy consumed over a period to maximum demand
LRMC	Long run marginal cost recoverable over a period in which all factors of production can be varied
Marginal demand	Demand that approaches or exceeds existing sunk capacity
MD	Maximum demand (power)
Marginal expenditure (cost)	Avoidable portion of regulated revenues for the regulatory period to which the TSS applies
Marginal revenue	Incremental revenue from premium components of network charges
NEO	National Electricity Objective
MVA	mega Volt-Ampere
NEL	National Electricity Law
NER (Rules)	National Electricity Rules
Peak demand	Demand within around 5 per cent of annual maximum demand, typically corresponding to less than 2 per cent of a year
Premium price	Refers to tariff components, such as peak energy, demand and capacity charges, that increase average unit prices

PTRM	Post-Tax Revenue Model that among other things converts avoidable network costs incurred over up to 10 regulatory periods into avoidable costs recoverable under the Rules within the period to which a TSS applies
Residual cost	Refers to the difference between LRMC and the total revenue requirement for the relevant period
Standard (tariff component)	Refers to tariff components intended to recover the residual cost
SRMC	Short run marginal cost – unlike thermal generation, a relatively small component of total network costs
Sunk cost	Refers to the portion of the total revenue requirement that relates to existing or sunk assets.
TSS	Tariff Structure Statement for a given regulatory control period (typically 5 years)
WACC	weighted average cost of capital
ZS	zone substation – along with associated feeders ('poles and wires'), typically the largest capital component of network capacity at a given location

Executive summary

Introduction

Marsden Jacob Associates (Marsden Jacob) has been retained by Evie Networks to prepare a report to assist it in presenting a submission to the Australian Energy Regulator (AER) on electricity distribution revenue proposals for 2024-2029 submitted by the NSW DNSPs: Ausgrid, Endeavour Energy ("Endeavour") and Essential Energy ("Essential").

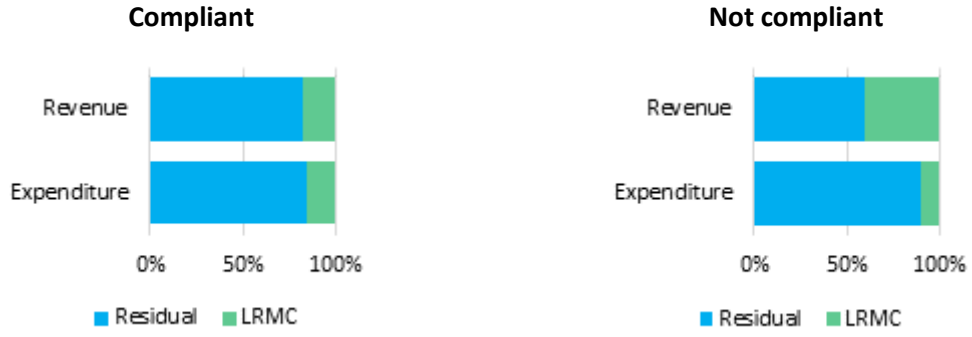
A particular focus of this report is whether the TSS of the three NSW DNSPs are consistent with the relevant national electricity rules ("Rules"), as well as the impact of their proposed tariffs for publicly available fast, and ultra-fast, EV charging sites. In addition, the report makes some specific comments on Ausgrid's tariff structures, which are markedly out of step with those of Endeavour and Essential.

Current Evie network bills are not cost-reflective

The report combines an analysis of Evie network billing and demand data as well as network demand and capacity data. The analysis shows that total network charges applied to Evie sites are substantially higher than efficient network costs. The effective network prices applied to Evie under existing and proposed network tariffs do not correspond to efficient network costs for the location and demand profiles of Evie's charging sites, for which data is currently available.

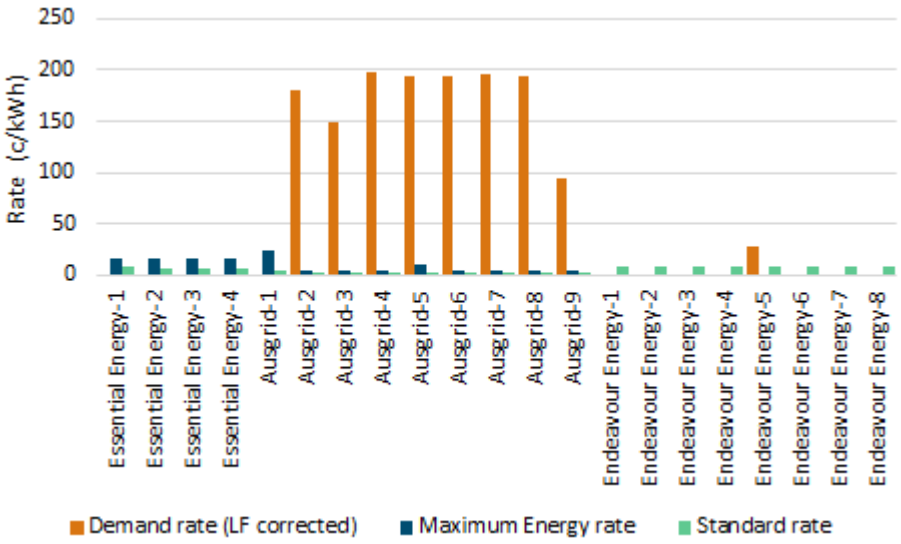
This means that TSS proposals applicable to the Evie sites reviewed are not compliant with the requirements under the Rules, as illustrated on the right in Figure 1 below.

Figure 1 Compliant and non-compliant revenue structures



The mismatch between price and cost is caused by premium tariff charges that lift average unit prices. The unitised premium above standard rates is most extreme for Ausgrid but is also notable for Essential Energy, as shown in Figure 2 below.

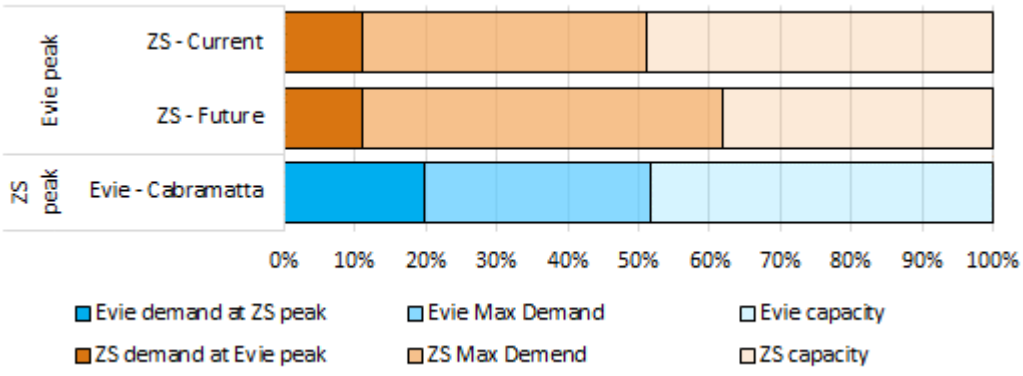
Figure 2 Structure of Evie network bills (tariff structure)



The figure highlights that Ausgrid premium charges are many times higher than the premium prices for the other two networks. The Ausgrid premium charges do not reflect demand diversity and are not cost-based.

The application of high premium prices to Evie sites is not consistent with the Rules because of the diversity between demand peaks at Evie sites versus DNSP Zone Substations (ZS). This is shown in Figure 3.

Figure 3 Example of peak demand diversity between Evie charging site and its Zone Substation



The diversity between the ZS and Evie site demand profiles mean that the Evie site only uses existing ZS capacity. Capacity and demand charges applied to Evie's maximum demand make no sense given Evie's maximum demand diverges from ZS maximum demand. As such, premium pricing of energy used at this site deters otherwise economically productive network asset utilisation.

In all the 10 Evie sites for which data are available, there is a high level of diversity between Evie site maximum demand and ZS maximum demand. Therefore, there is no network cost basis for applying premium tariff components (especially those relating to Evie site maximum demand) for any of the 10 sites.

TSS proposals do not correct errors in current TSS

Tariffs that apply to maximum Evie demand, irrespective of when that occurs, are not consistent with the Rules. None of the three DNSP TSS proposals suggest tariff parameter changes sufficient to address the current inconsistencies between Evie billing outcomes and the relevant Rules.

The current mismatch between price and cost is expected to become more problematic over the TSS period for Evie's Essential Energy sites as Evie's demand grows and it is automatically reassigned to tariffs that apply higher premium rates and/or a higher proportion of premium rates to volumes consumed. This is especially problematic under tariff designs that charge for Evie's maximum demand during a period, without adjusting for Evie's demand diversity compared with other demand on the relevant network assets.

While Ausgrid's unit LRMC estimate for the TSS period is lower than at present, Ausgrid's TSS retains the excessive capacity premium parameter which for Evie is between 10 and 100 times more than the standard tariff parameters or the premium tariff parameters used by the other NSW DNSPs.

Causes – DNSP over-estimation of LRMC

NSW DNSPs are over-estimating LRMC in their TSS proposals in one or more of the following aspects.

a. Failing to adjust LRMC to reflect existing surplus capacity from previous over-investment. NSW DNSP LRMC models are incorrectly treating existing sunk capacity as if it were avoidable and charging premium rates instead of standard rates, raising average prices for some customers including Evie. This ignores the 2018 ACCC recommendation that NSW network assets should be optimised (written down) for price setting purposes, to reflect past over-investment in capacity. DNSPs are proposing to charge consumers for future capacity expansion that already exists.

b. Charging existing customers for network augmentations to increase capacity for new connections growth. Network augmentation requirements in growth areas are driven by new connections growth, not changes in demand behaviour by existing customers. Recovery of augmentation costs to cater for new connections from standard control tariffs is inconsistent with the pricing Rules.

c. "LRMC" is mistakenly interpreted as a licence for DNSPs to charge consumers for the full cost of long-life network assets within the first 10 per cent or so of the assets' expected economic life – a single regulatory period. AER's post-tax revenue model (PTRM) incorporates *variations in all factors of production* with respect to new assets or groups of assets and hence calculates the full avoidable cost of these assets in the period to which the TSS applies. The PTRM does not bring forward cost recovery of long-life assets from future regulatory control periods; or pre-empt future regulatory determinations regarding future cost building blocks or the level of premium revenue in future TSS. That would not be 'cost reflective' because the assets' full marginal costs are not incurred within the first five-year period of the assets' life.

d. Similarly, the PTRM does not include future augmentations that may be required in regulatory periods following the 2024-2029 period. DNPSs do not have a licence to charge consumers for future augmentation requirements beyond the horizon of the TSS in question. This is not cost-

reflective and would pre-empt the AER determination of efficient network costs and revenue recovery structures for the following regulatory period.

e. Applying premium charges to sunk assets due to poorly targeted tariff parameters. Additional to the points above, DNSPs may apply premium charges to energy volumes well outside the 2 per cent or so of energy that is actually marginal. This arises due to tariff designs focused on daily peak demand instead of annual peak demand, or customer monthly maximum capacity and demand charges where customer maximum demand diverges from network maximum demand.

f. Charging "stand alone" costs for a given class of retail customers. While this is the upper bound in the pricing principles, when read alongside the following principles, it is clear DNSPs from inspecting PTRMs that are not permitted to charge consumers at "stand alone" costs without regard to the economies of scope and scale enjoyed by networks offering capacity to multiple customer classes.

Available DNSP disclosures on revenue structures for the year ending June 2024 reveal an implausible level of variability between NSW DNSP revenue structures ranging between 12.2 per cent (Essential), 25.5 per cent (Ausgrid) and 48.9 per cent (Endeavour). When compared with PTRM disclosures of cost building blocks, and the modest impact of standard control network augmentation, avoidable network costs are a relatively small proportion of total standard control expenditure. Both Endeavour and Ausgrid are substantially over-estimating the LRMC component of their revenue requirements.

Essential is the only NSW DNSP to disclose the revenue structures in its TSS and this is welcome. However, the avoidable or LRMC component of total revenue is forecast to increase from 12.2 per cent in FY2024 to 26.4 percent in FY 2025. This change appears to reflect a shift in the definition of LRMC cost (reflecting one or more points 1-5 above), rather than a shift in LRMC between the two periods.

It follows that proposed tariff structures and ensuing prices and bills are not cost based and therefore contradict Section 6.18.5(a). Costs that should be recovered under Section 6.18.5(g)(1) – "residual" – are instead recovered under Section 6.18.5(f) – "LRMC". It also appears that augmentation costs that should be recovered from connection charges and capital contributions are instead being recovered from standard control charges.

Conclusions valid despite limited DNSP energy demand data

The current analysis is based on limited DNSP and Evie energy demand data for 10 Evie EV charging sites. While it is possible that demand profiles at other sites could differ from those analysed for this report, this is considered unlikely. This is because the key drivers for demand at Evie's sites determining their demand profiles (EV population and travel times) are not related to the key drivers of the energy use of the communities connected to those Zone Substations, that is very high cooling or heating demand (i.e., peak demand days) and the traditional evening peak.

The Evie sites analysed so far were selected based on data availability, not other criteria. Twenty-one sites have sufficient billing data to undertake the tariff side of the analysis. Ten sites currently

have sufficient interval data to be appropriate aligned with local zone substations (ZS) interval data.[1] ZS demand data was not available at the time of preparation to allow the analysis to be extended to all NSW Evie sites receiving network bills.[2] On receipt of this additional data, it is anticipated that a supplementary report will be prepared for Evie.

Insufficient TSS data disclosure to verify compliance or non-compliance

The data necessary to assess whether existing and proposed TSS are compliant with the rules are not available and have not been sought by the AER. The absence of the relevant tariff structure data means the AER is not in a position to make evidence-based decisions under Section 6.18.8(a)(1). The absence of the required verification data also means that consumers and other stakeholders are unable to undertake meaningful engagement, as expected under the AER's Better Regulation Handbook. Essential is the only NSW DNSP that supplied revenue structure data. While welcome, the Essential workbook and accompanying material did not provide sufficient information to enable consumers to understand and make informed comments on the basis for various proposals regarding the scope and level of premium tariff components.

AER should require amendments to TSS proposals

In its forthcoming draft decisions, AER should conclude that the pricing proposals are deficient and require necessary amendments (Section 6.18.8(b)(1)), or itself make amendments necessary to correct the deficiencies (Section 6.18.8.b(2)). Possible amendments to TSS include changing tariff allocation rules, creating new tariff classes, or changing tariff charging parameters.

Amendments to TSS required to ensure conformity with the relevant Rules include the following:

- The AER should amend the relevant guidelines so that DNSPs are required to provide data necessary to verify whether revenue structures reflect expenditure structures.
- DNSPs should be required to detail the premium component of proposed aggregate and individual tariff revenue compared with the avoidable cost of their total regulated expenditure both in aggregate and for each tariff class. At present only one of the three NSW DNSPs disclosed revenue structures (Essential). However, Essential did not provide sufficient information to verify whether revenue structures align with expenditure structures.
- DNSPs should be required to ensure that proposed demand and capacity tariffs are readily comprehensible by customers assigned to these tariffs (Section 6.18(5)(i)(1)). There should be improved disclosure of the extent demand and capacity tariff parameters apply to sunk assets during periods and in places where there is no network congestion.
- Given the diversity between Evie site demand and associated DNSP capacity, premium tariff elements should not be applied to existing Evie sites until it can be demonstrated by the relevant DNSP that Evie site maximum demand corresponds with DNSP maximum demand periods and locations. Pending this, Evie sites should only be charged at standard tariff rates (fixed connection plus non-premium volumetric charges). To be clear, Evie sites should have

[1] While networks are required to publish ZS interval data annually in the regulated planning process, the data is historic at the time of publication and in one case not up to date with the regulation requirement.

[2] Some sites operate within embedded networks such as shopping centres and do not receive separate network bills.

lower network bills than is currently the case, especially for Ausgrid but also in the future for Essential.

- Estimates of avoidable expenditure for tariff design purposes should:
    - Not be applied at all to customers and locations where customer maximum demand is forecast only to use sunk capacity – that is it is not associated with any avoidable network expenditure over the period to which the TSS applies. Take into account existing capacity rather than assuming incorrectly that any increasing in maximum demand at a given location triggers a need to augment capacity (Section 6.18.5(f)(2);
    - Exclude network augmentation expenditure that is not recoverable from standard control tariffs (Clause 6.21.2(3)). DNSP connection policies may need to be reviewed to address the deep connection augmentation costs associated with greenfields and brownfields residential, industrial and other development driving large volumes of new or expanded network connections.
- At locations where customer demand is marginal, premium tariff parameters (both rates and volume to which premium rates apply) may need to be adjusted downward to reflect sunk capacity and augmentation related capacity.
- Similarly, as a result of reduced revenue from premium tariff rates, it is possible that standard rates may need to be adjusted upward so that total smoothed revenue forecasts are achievable.

1. Introduction

Marsden Jacob Associates (Marsden Jacob) has been retained by Evie Networks to prepare a report to assist it in presenting a submission to the Australian Energy Regulator (AER) on electricity distribution revenue proposals for 2024-2029 submitted by the NSW DNSPs: Ausgrid, Endeavour and Essential Energy.

In January 2023, the three NSW DNSPs submitted their revenue and pricing proposals, and supporting documents, including Tariff Structure Statements (TSS). The AER is responsible for reviewing NSW DNSP revenue and pricing proposals for 2024-29. The AER published Issues Papers for each DNSP revenue and pricing proposal in March 2023. AER indicated that, based on its initial review, the three NSW network draft TSS met its expectations (Section 6.18.18.8(a)(3)).

The AER also stated it would review the TSSs more thoroughly. It could be expected that this more fulsome review would be informed by submissions from stakeholders.

If the AER finds in its draft determination that proposed TSS are not consistent with the relevant National Electricity Rules (Rules), it can require that networks amend their TSS before the AER's final decision is due. It can also make amendments to TSS as it sees fit.

A particular focus of this report is whether the TSS of the three NSW DNSPs are consistent with the relevant Rules, as well as the impact of their proposed tariffs for publicly available fast, and ultra-fast, EV charging sites. In addition, the report makes some specific comments on Ausgrid's tariff structures, which are markedly out of step with those of Endeavour and Essential.

2. Economic regulation of network prices

2.1 The Rules; what they require

The AER is obliged under the National Electricity Rules (NER) to assess whether DNSP tariff proposals submitted under Sections 6.8.2 and 6.18.1A are compliant with the relevant requirements set out in Section 6.18.8(a)(1). The relevant NER require that network tariffs for standard control services should reflect the DNSPs' efficient costs of providing network services to the relevant retail customer (Section 6.18.5(a)).

Retail customers should be assigned to tariff classes on the basis of one or more of the following factors: the nature and extent of their usage or intended usage of distribution services; the nature of their connection; and whether interval metering technology is used (Section 6.18.4). Retail customers with similar connection and demand profiles should be treated on an equal basis (Section 6.18.4 (a)(2)). Tariff classes are defined as a class of retail customers for one or more direct control services who are subject to a particular tariff or tariffs. Tariff assignment decisions to assign or re-assign a customer from one tariff class to another should be subject to an effective system of assessment and review (Section 6.18.4(4). If the charging parameters for a particular tariff result in a basis of charge that varies according to the customer's usage profile, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which the customer is charged (Section 6.18.4(b)).

For each tariff class, (Clause 6.18.5(e)), the revenue expected to be recovered must lie on or between:

- An upper bound, representing the stand alone cost of the retail customers who belong to that class
- A lower bound representing the avoidable cost of not serving those retail customers.

Each tariff must be based on the long run marginal cost (LRMC) of providing the service to the retail customer group (Section 6.18.5(f)), reflecting, where efficient (Section 6.18.5(f)(1)):

- Additional costs likely to be associated with meeting demand from retail customers assigned to that tariff at *times of greatest utilisation* of the relevant service (Section 6.18.5(f)(2)).
- The *location* of retail customers, and the extent to which costs vary by location (Section 6.18.5(f)(3)).

The residual of DNSPs smoothed revenue requirements (i.e., total allowed expenditure minus LRMC) may be recovered under Section 6.18.5(g)(2).

The structure of each tariffs must be reasonably capable of being understood by retail customers assigned to these tariffs (Section 6.18(5)(i)(1)) and being incorporated into contract terms offered to these customers in contract terms offered by retailers or Market Small Generation Aggregators (Section 6.18(5)(i)(2)).

After the AER has made its determination regarding DNSP's regulated revenue and TSS proposals, DNSPs are required to submit pricing proposals (Section 6.18.2(a)) for submission to the AER at least 3 months before the commencement of the relevant regulatory year. For each proposed tariffs, DNSPs must set out the charging parameters and the elements of service to which each charging parameter relates (Section 6.18.2(b)(3)). For each tariff class, pricing proposals should set out the expected average revenue for the relevant regulatory year and also for the current regulatory year (Section 6.18.2 (b) (4). The term 'tariff class' refers to a class of retail customers for one or more direct control services who are subject to a particular tariff of particular tariffs.

Schedule 6.1 to the Rules sets out the contents of cost building block proposals under the Post Tax Revenue Model (PTRM). This schedule does not require disclosure of the LRMC component of total cost building blocks.

DNSPs may receive a capital contribution, prepayment and/or financial guarantee up to the provider's future revenue related to the provision of direct control services for any new assets installed as part of a new connection or modification to an existing connection, including any augmentation to the distribution network (Clause 6.21.2(3)). However, DNSPs are not entitled to recover, under any mechanism for the economic regulation of direct control services, any component representing asset related costs for assets provided by DNSP users (Clause 6.21.2(3)).

2.2 The economic logic of the Rules

The NER require that, where customer demand profiles correspond to periods of greatest utilisation, in locations where network augmentation may be required, then tariff structures should reflect the additional cost of prudent future network capacity augmentation. This can be achieved using various tariff designs to differentiate demand profiles that trigger future (marginal) network expenditure (LRMC) at certain locations, on the one hand, from demand profiles that do not trigger future network expenditure. The latter demand profiles have low demand and/or high diversity factors, while the former demand profiles have a diversity factor approaching zero and significant demand at network demand peaks.[3]

[3] Diversity factors are a key analytical tool in network planning and reflect variation in maximum demand across different network assets – for example assets with peaking winter rather than peaking summer demand. The concept can equally be applied to compare maximum demand between different customer segments, in this case EV sites and other demand using the same ZS capacity.

Terminology

Discussions on network tariff design and pricing usually get derailed by confusion over terminology used in the National Electricity Rules and the associated economic concepts. The NER use the term "LRMC" in the pricing rules to refer to premium components in tariffs (*revenue*) that correspond to the marginal component of network *expenditure*. "LRMC" is confusingly used to refer to *revenue* corresponding to incremental *costs* – a component of total expenditure. In describing revenue structure, the term "premium" is preferable to "LRMC", because it refers to tariff components that lift average unit prices to recover marginal expenditure (LRMC), where efficient. Marginal expenditure for pricing purposes is avoidable depending on electricity consumption behaviour. The term "avoidable" is used in the pricing Rules (section 6.18.(e)(2), but unlike LRMC is not defined.

For the purposes of this report, all the terms within the left and right columns below are interchangeable. The terms in the left column refer to marginal demand that triggers avoidable cost. The terms in the right column refer to infra-marginal demand because the associated cost is sunk or unavoidable.[4]

NER pricing rules	*LRMC* (6.18.5(f))	Residual (6.18.5(g))
Economics	Long run m*arginal (avoidable)*[5]	Infra-marginal (sunk)
Tariff rate (price)	*Premium*	Standard

Under efficient pricing structures, customers with *marginal* demand profiles in a given location are charged premium (higher) unit rates through a variety of tariff mechanisms, including:

- multi-part tariff components that include peak energy, demand, and capacity charges applying to customer demand at defined *times* (temporal pricing); or
- multi-part tariff components that are targeted at marginal demand at network *locations* where congestion occurs (locational pricing); or
- applying higher average unit rates for tariffs with just one charging parameter (e.g. consumption volume) to encourage customers to switch to multi-part tariffs.

Customers with demand profiles in locations that do not trigger future additional costs – customers with *infra-marginal* demand profiles – pay lower standard unit rates because they are using sunk network capacity. Customers with demand profiles and in locations that do trigger marginal costs – customers with marginal demand profiles – pay premium unit rates because they are using avoidable network capacity.

This distinction is illustrated in Figure 4 below.

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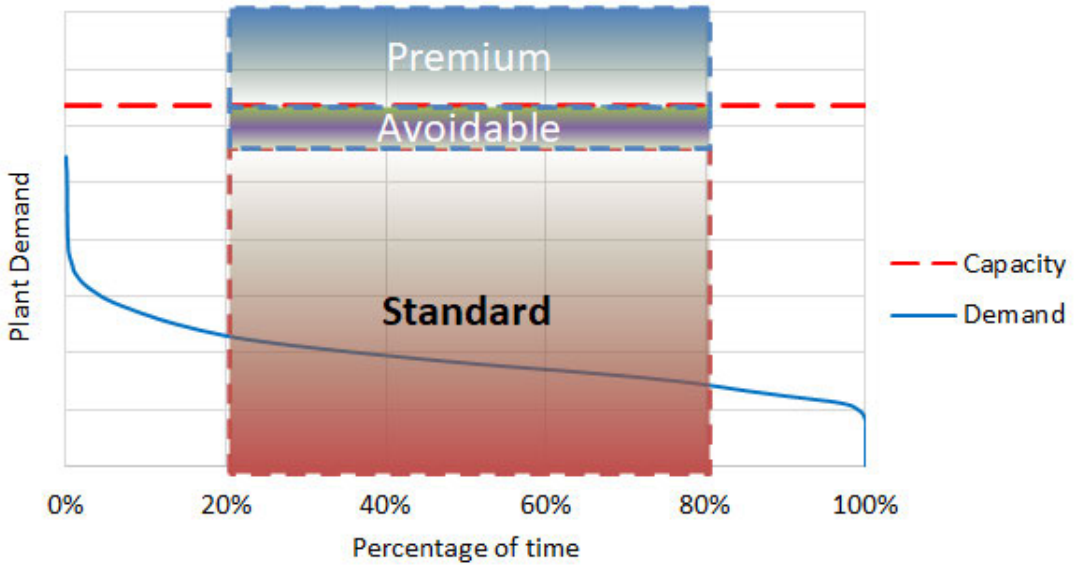
[4] Note that sunk costs can nevertheless be optimised, as recommended by the ACCC in its Retail electricity price review. See discussion in section 3.4.1 below.

[5] The term "marginal" includes both LRMC and Short Run Marginal Cost (SRMC). SRMC is a relatively small portion of total network expenditure and if operating expenditure is efficient, any decreases in SRMC are likely to result in declining network performance and reliability outcomes – such as expenditure to respond to network outages.

Figure 4 Economic logic of premium network pricing



The intent of premium price structures is to influence avoidable (marginal) demand during periods of maximum utilisation of the network to avoid triggering future network augmentation costs in locations where maximum utilisation is approaching maximum firm capacity (the red horizontal line). The associated demand response reduces *congestion* across the network and incremental capacity augmentation above the horizontal red line is avoided. This efficiently reduces the future revenue requirement of the network.

The blue line is a typical customer demand profile over a year. A key feature of typical demand profiles is that a substantial portion of network capacity (represented by the vertical axis) is only used for a very small percentage of the time.[6] Efficient tariff structures target marginal demand on the left-hand side of the chart within the avoidable zone, below existing maximum firm capacity at the relevant network location. This also highlights that efficient tariff structures may apply premium marginal pricing in locations where network congestion is a problem while applying discount marginal pricing in locations and at times when network congestion is not a problem, to increase utilisation of available network capacity.[7]

[6] Demand profiles are often represented as daily average profiles, either annually or quarterly. In either case, daily average profiles are likely to over-state marginal demand and are therefore misleading for the purposes of tariff design decisions.

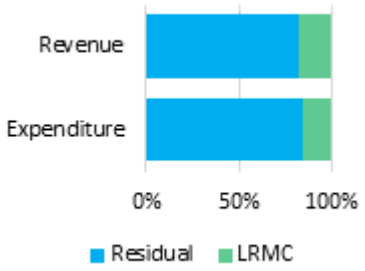
[7] Due to falling minimum demand during high periods of rooftop PV output, several DNSPs have introduced network tariffs that offer discounts during periods of low utilisation.

Applying LRMC to cost building blocks and premium tariffs for five-year regulatory period

As defined in the Rules, "LRMC" refers to "additional" costs from a change in demand over a period in which all factors of production may be varied. "LRMC" as defined for tariff setting purposes reflects the marginal cost of any new long-life assets committed over the regulatory control period on the total revenue requirement for that control period, taking into account variations in all factors of production with respect to that asset of group of assets for the period.[8] "LRMC" is often mistakenly interpreted as a licence for DNSPs to charge consumers for the full cost of long-life network assets within the first 10 per cent or so of the assets' expected economic life – a single regulatory period. AER's post-tax revenue model (PTRM) incorporates *variations in all factors of production with respect to new assets or groups of assets and hence calculates the avoidable cost of these assets in the same period to which the TSS applies*. The PTRM does not bring forward cost recovery of long-life assets from future regulatory control periods or pre-empt future regulatory determinations regarding future cost building blocks or on the level of premium revenue in future TSS. That would not be 'cost reflective' because the asset's full marginal costs are not incurred within the first five-year period of the assets' life. Similarly, DNPSs do not have a licence to charge consumers for future augmentations in regulatory periods following the TSS/PTRM in question. The impact of avoidable network augmentation and replacement on the PTRM revenue requirement for the period in question is therefore the only sound basis for identifying "LRMC" for the purpose of tariff design.

A cost-reflective tariff structure is illustrated in Figure 5 below.

Figure 5 Cost reflective tariff (revenue) structure



Under a cost reflective tariff structure, the premium tariff revenue received from a given customer group, or for the entire network, corresponds to the marginal (avoidable) component of expenditure. This is consistent with the network pricing objective.

Since the demand response arising from the use of premium tariff designs is price related, the economic cost of the avoided demand is less than the avoided cost of increasing the network capacity to reduce congestion. The outcome is therefore consistent with both the pricing rules and the wider National Electricity Objective (NEO); it is efficient.

[8] "LRMC" contrasts with the SRMC of sunk assets where only some factors of production may be varied – e.g., operating and maintenance expenditure and financing costs.

The intended effect of tariff design is not to discourage demand outside periods of maximum utilisation, and in locations where current and future maximum demand is well within maximum firm capacity. Where there is no congestion, there is no avoidable network cost and no congestion reduction benefit.

With declining minimum demand from the majority of existing connections, due to the uptake of consumer energy resources (CER) and improved appliance and building energy efficiency standards, alongside the introduction of export tariffs, efficient tariff design should encourage consumers to increase their demand outside peak demand periods. This avoids the marginal cost of increasing network capacity to absorb electricity exported from CER.

If, however, a DNSP applies premium prices to demand at times and locations where there is no congestion, this will result in:

- A reduction in economic benefit (consumer surplus) due to avoided consumption, to the extent there is a demand response, or
- A wealth transfer to other customers – a cross subsidy – where there is no demand response.

Either outcome is inconsistent with both the network pricing Rules and the wider NEO.

Network congestion and associated augmentation costs associated with new connections – as distinct from changes in demand for standard control services – are not relevant to efficient tariff design for standard control services.

Network augmentation costs are not regulated as standard control services. Networks are not entitled to recover marginal network costs associated with network augmentation to support new and modified connections, as opposed to changes in demand from existing (unmodified) connections, from direct control regulated revenues. Network augmentation costs are recovered from capital charges under Part D of chapter 6 (negotiated distribution services).

2.3 Role of economic regulator

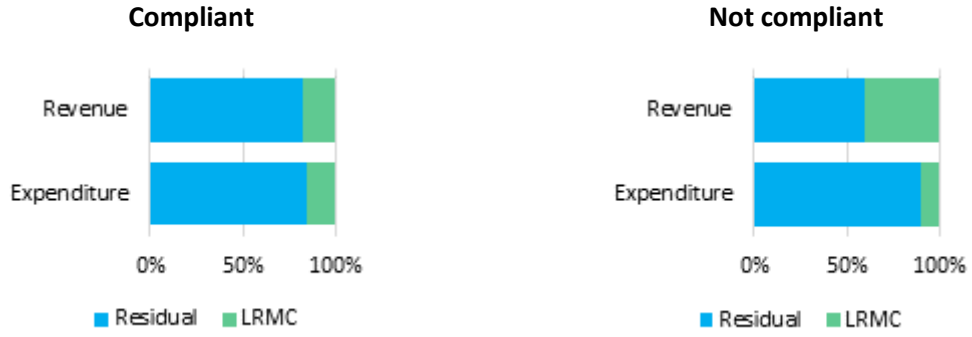
Electricity network distribution is statutory monopoly and networks have an opportunity to exercise market power in setting prices. The AER's stated objective regarding monopoly electricity network regulation is 'to ensure consumers pay no more than necessary for safe and reliable electricity'.[9]

The AER's role under the NER (Section 6.18.8) is to assess whether network tariff proposals are compliant with the rules. This implies that, for each network in aggregate, and for each major customer segment, the AER needs to satisfy itself that the structure of revenues (premium and standard) corresponds to the structure of expenditures (marginal and infra-marginal). Where premium revenues substantially exceed marginal expenditure, as illustrated on the right-hand side of

[9] Page 16, AER Strategic Plan 2020-2025.

Figure 6, the AER should conclude that the proposed TSS is not compliant and needs to be amended.[10]

Figure 6 Compliant and non-compliant revenue structures



3. Tariff impacts for Evie

3.1 Analytical approach and data

An analysis of Evie's current electricity network bills compared with its demand profiles for its NSW sites was undertaken to assess whether Evie's current NSW electricity network bills are cost reflective in accordance with the Rules. This analysis compares the premium charges for Evie sites in the structures of their network tariffs compared with the demand profiles of those sites indicating the potential contribution of Evie sites to customer behaviour driven network augmentation.

The analysis in this report is based on Evie's consumption and billing data as available from a total of 30 sites across the three networks. The sites were selected based on data availability, not other criteria. Where available, Evie's retailer provided consumption data and a breakdown of the network component of retail bills. Twenty-one sites have sufficient billing data to undertake the analysis. Other Evie sites operate within embedded networks such as shopping centres and do not receive separate network bills. Ten sites currently have sufficient interval data for local zone substations (ZS) that match the Evie site.[11][12][13] The data and methodology are detailed in Appendix 1.

Evie demand profiles were generated for each of the 10 sites and these were compared with the corresponding demand profiles for the ZS supplying each Evie site. The interval data is analysed to understand the maximum demand diversity between Evie and DNSP assets, that is the different timing of peak demand at each asset and the potential contribution of Evie sites to ZS augmentation. ZS profiles were selected because augmenting ZS and associated feeders typically represents the

[10] Of course, some discrepancies between revenue and expenditure structures are to be expected and is efficient, because this avoids the excessive transaction costs of high resolution (individual) tariff assignment and associated tariff structures. However, discrepancies should be consistent with the pricing principles.

[11] Interval data are measurements of power/energy consumption at half or quarter hourly intervals

[12] While networks are required to publish ZS interval data annually in the regulated planning process, the data is historic at the time of publication and in one case may not be up to date with the regulation requirement.

[13] Some sites operate within embedded networks such as shopping centres and do not receive separate network bills.

most significant component of network augmentation (or replacement) expenditure when forecast future demand exceeds the firm capacity of the ZS (and associated feeders). This aligns with industry practice as documented in Distribution Annual Planning Reports (DAPR).

While it is possible that these comparisons at other Evie sites could differ from the 10 analysed so far for this report, this is considered unlikely. This is because Evie's demand profiles are not related to periods of very high cooling or heating demand (i.e., peak demand days in summer and winter) and the daily evening peak.

Overall, the analysis shows a significant discrepancy between the way Evie is charged for network capacity and Evie's actual utilisation of the network. The implications are discussed further below.

3.2 Do Evie's current bills reflect efficient network costs?

The analysis shows that total network charges applied to Evie sites are substantially higher than efficient network costs, having regard to the location and demand profiles of Evie's sites. As a result, Evie is being charged higher prices than permitted under the relevant sections of the NER. Evie's network bills are not cost-reflective.

3.2.1 Evie network bills incorporate substantial premium charges

Network charges being incurred by Evie incorporate substantial premium charging components under Section 6.18.5(f), for more than half its NSW sites. This is shown in Figure 7 below which compares the structures of network tariffs across the three networks. Table 1 details the rates for these network tariffs.

Figure 7 compares premium pricing components of tariffs with standard rates in each network tariff shown in green (Standard rate is a volume weighted mix of should and off peak rates, see Appendix 1). Currently this is primary for Essential Energy and Ausgrid as the Endeavour Energy tariffs include and anytime energy rate. The maximum energy rates, shown in dark blue, already exhibit a significant premium over the standard rate (green bars).

What stands out is the order of magnitude price premium in the Ausgrid demand rate. This tariff component has been converted from power (kW) to energy (kWh) for comparison, to account for variations in Evie site load factors compared to the zone substations (see Appendix 1). When applied to the billing quantities for Evie sites, this translates into the very high marginal charge components of Evie's actual bills as a proportion of total charges, as shown in the right-hand columns of Table 1 below.

Figure 7 Structure of Evie network bills (tariff structure)

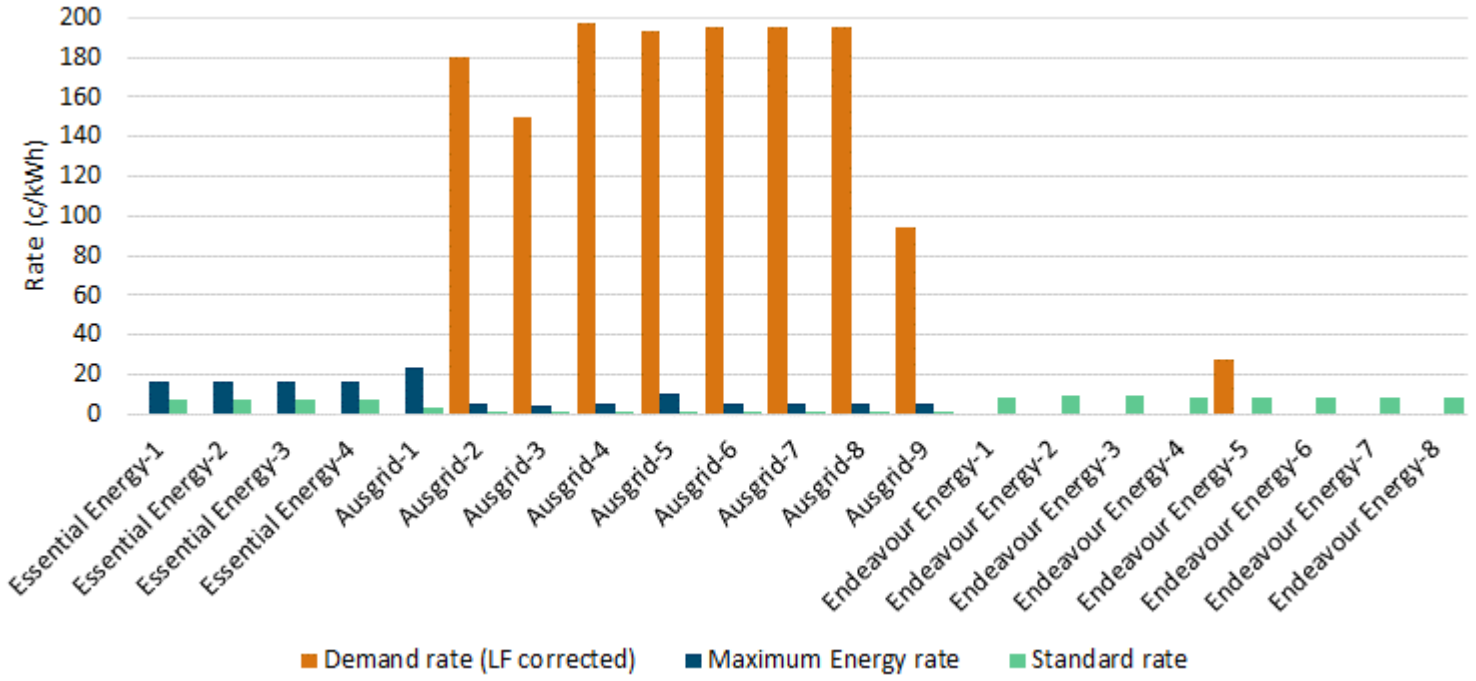


Table 1 Rates in Evie's network tariffs

	Demand[14] c/kW/mth	Peak Energy c/kWh	Shoulder Energy c/kWh	Off Peak Energy c/kWh	Anytime Energy c/kWh	Standard Rate c/kWh	Estimated standard bill component	Estimate premium bill component
Essential Energy-1	0.00	16.90	12.95	6.86	0.00	7.73	84%	16%
Essential Energy-2	0.00	16.99	12.95	6.86	0.00	7.53	86%	14%
Essential Energy-3	0.00	16.85	12.94	6.85	0.00	7.15	86%	14%
Essential Energy-4	0.00	16.93	12.95	6.85	0.00	7.32	88%	12%
Ausgrid-1		23.42	6.42	2.81		3.75	57%	***43%***
Ausgrid-2	1051.03	5.38	1.82	0.75		1.38	16%	***84%***
Ausgrid-3	819.08	4.09	2.18	1.59		1.60	42%	***58%***
Ausgrid-4	1026.31	5.42	1.76	0.71		1.32	16%	***84%***
Ausgrid-5	1009.76	10.60	2.36	1.06		1.68	52%	***48%***
Ausgrid-6	1015.28	5.42	1.76	0.71		1.37	16%	***84%***
Ausgrid-7	1016.09	5.42	1.76	0.71		1.38	20%	***80%***
Ausgrid-8	1015.21	5.42	1.76	0.71		1.43	16%	***84%***
Ausgrid-9	819.98	5.42	1.76	0.71		1.33	18%	***82%***
Endeavour Energy-1					8.87	8.87	100%	0%
Endeavour Energy-2					9.23	9.23	100%	0%
Endeavour Energy-3					8.98	8.98	100%	0%
Endeavour Energy-4					8.75	8.75	100%	0%
Endeavour Energy-5	233.60				8.63	8.63	90%	10%
Endeavour Energy-6					8.87	8.87	100%	0%
Endeavour Energy-7					8.87	8.87	100%	0%
Endeavour Energy-8					8.87	8.87	100%	0%

[14] The naming of tariff components is variable and can be confusing. All Evie "demand" tariff components are measured as a site's maximum demand in the billing month and priced at a rate $/kW/month. These components are variously called "demand", peak demand and capacity tariffs.

3.2.2 Demand data show Evie network demand does not contribute to network congestion

An analysis of available Evie site consumption data compared with each local ZS demand data clearly shows very high levels of diversity between Evie site maximum demand and ZS maximum demand for all 10 sites.[15] The demand data show that Evie network demand does not trigger any requirement for network augmentation related costs (LRMC). There is therefore no basis for applying charges to Evie site demand under Section 6.18.5(f) of the NER.

First, maximum demand of Evie sites is compared with the total capacity of its zone substation in Figure 8 below. This indicates the potential that consumer behaviour for power demand at Evie sties might influence a future need to increase the ZS capacity. A hypothetical future utilisation three times current utilisation is modelled assuming Evie increases its site capacity to respond to growing EV demand.

Figure 8 indicates that only in small, regional locations does this potential arise. Tarcutta and Taree are regional towns providing highway EV charging on a major transport corridor. It is natural that both the current network infrastructure is relatively smaller than larger urban areas and that more future travelling public will demand highway charging.

Figure 8 does not account for the timing of consumer behaviour that may drive a need for future network augmentation. It does matter whether and how consumers use energy when the network infrastructure is, in the language of the Rules, at the time of greatest utilisation. The purpose of cost reflective pricing is to signal to consumers to defer their power use at these times or in these places. In order to understand this better, we compare the maximum demand diversity, that is the ZS demand at the time of Evie peak demand and particularly the Evie site demand at the time of ZS peak demand.

Figure 9 below shows an example of these relationships between an Evie site and the (Endeavour) Zone Substation serving that Evie site (see methods Appendix 1).

In this example, there is a strong difference between the maximum demand of each asset. At the time of Evie peak demand the Zone Substation demand is just over 10 percent of its capacity as shown in the top orange bar. Conversely, Evie demand at the time of the ZS peak is around 20% of Evie's maximum demand as shown in the blue bar.

There is a significant demand diversity between the two assets, and it is unlikely that the power demand from the Evie site will be marginal, that is economically 'at the edge' of existing infrastructure. Premium pricing of energy used at this site is likely to deter otherwise economically productive energy use by EV owners.

[15] Zone substation data concurrent with data for Evie sites is not publicly available and has not yet been supplied in response to requests made to the networks. This comparison assumes that each data set is reasonably typical of the seasonal and monthly variation in plant utilisation.

Figure 8 Evie site MD compared to Zone substation capacity

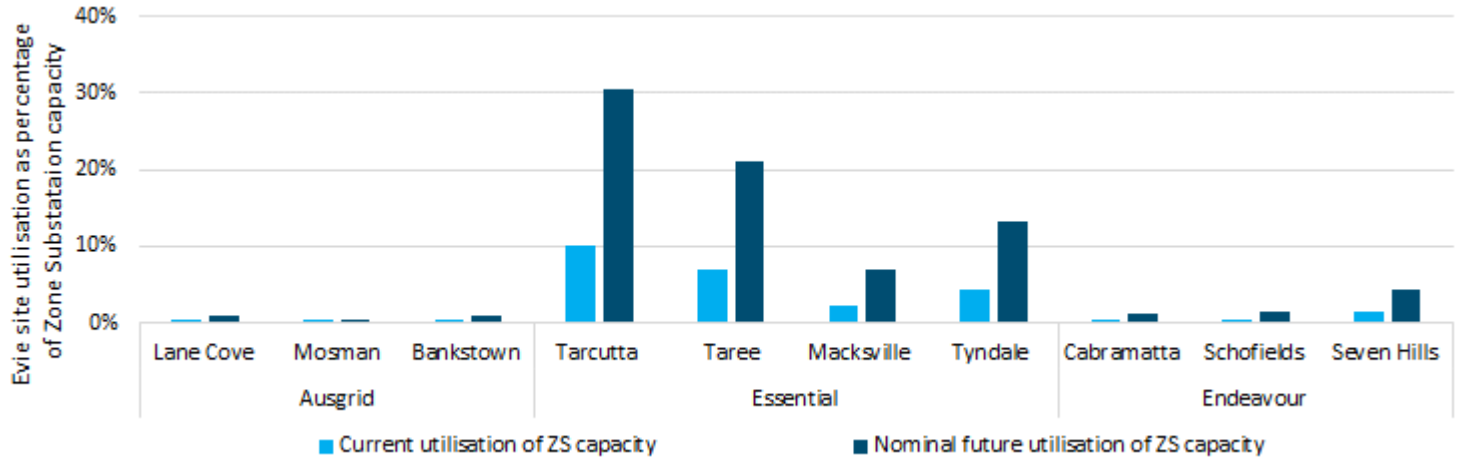
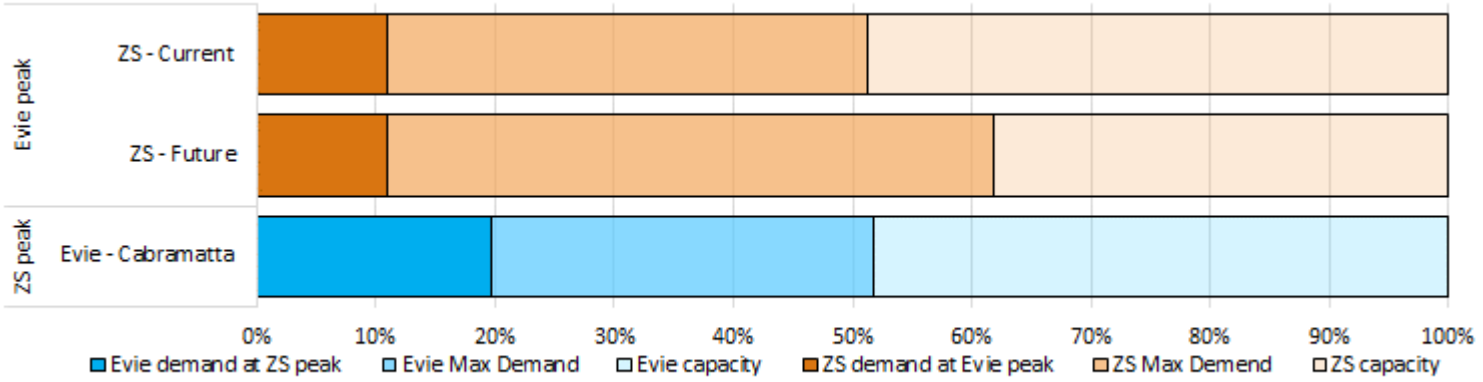


Figure 9 An example of peak demand diversity between Evie charging site and its Zone Substation



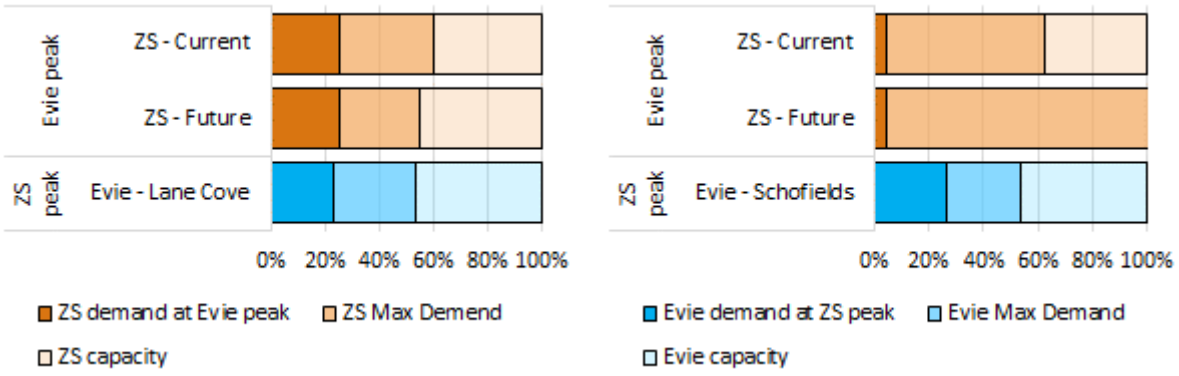
Moreover, the zone substation at this location is significantly underutilised - current maximum demand on this ZS is around half its capacity and is forecast to grow to just over 60% of its capacity in 5 years time, as shown in the lower orange bar. According to the DNSP's own demand forecast, there is no requirement for augmentation from either customer behaviour (such as EV charging) or from new connections as the will still be sufficient capacity at this ZS.

Even if there were less demand diversity between the two assets, it is still not clear that maximum demand from the Evie site will correspond to ZS congestion. The full power capacity is presumably already accounted for in Evie connection charges and appears not to have resulted in a DNSP decision to augment the ZS capacity. Even if demand diversity decreases, it would not follow that the proposed continuation of very high premium pricing is economically efficient.

Figure 10 provides examples of two other planning circumstances in network demand at zone substations to which Evie sites are connected. Like in Figure 9, there is significant demand diversity as neither asset is close to maximum utilisation at the peak use of the other. Once again, there is no case for applying premium network charges.

The difference between the current and future ZS maximum demand is the network forecast for each ZS. In the Lane Cove case (on the left), energy demand is shrinking – while MD is 34% of capacity now it is expected to be 29% of capacity in 5 years. At this site there is no evidence that there is any need for a time-based premium price signal to consumers. In these circumstances premium pricing (overcharging) can only deter economically efficient energy use.

Figure 10 Peak demand diversity between Evie charging sites and two Zone Substations



In the Schofields case (on the right), energy demand is rapidly growing beyond current capacity, requiring augmentation within the 5 year time frame. However, the rate of growth is so rapid it demands examination to distinguish consumer behaviour and connection growth, further discussed below.

The data for all available sites is in Table 2 below. For each Evie site the corresponding network and ZS maximum demands are identified. The ZS data including current capacity, maximum demand and forecast 5 year demand is taken from the networks' planning reports. The capacity for each Evie site is presented, as well as the data for the diversity comparison such as in Figure 10 above – the demand of Evie's sites and corresponding ZS at each other's peak demand.

Table 2 Evie and ZS utilisation and diversity data

Site characteristics			Network DAPR data			combined with Evie data		
Evie site	DNSP	Zone substation	Capacity MVA	Current ZS peak demand	Future ZS peak demand	Evie capacity kW	ZS at Evie peak	Evie at ZS peak
Zone substation demand is shrinking and well within existing capacity								
Lane Cove	Ausgrid	Chatswood	67.14	60%	55%	200	26%	23%
Mosman	Ausgrid	Mosman	89.05	90%	85%	100	33%	43%
Bankstown	Ausgrid	Bankstown	63.52	86%	71%	200	30%	27%
Seven Hills	Endeavour	Seven Hills	50	51%	44%	700	12%	6%
Zone substation demand is increasing but remains within existing capacity								
Macksville	Essential	Macksville	30	31%	35%	700	23%	6%
Tyndale	Essential	MacLean	16	40%	64%	700	15%	0%
Cabramatta	Endeavour	Canley Vale	50	51%	62%	200	11%	20%
Zone substation needs augmentation – probably for new residential and commercial connections								
Schofields	Endeavour	Schofields	45	62%	162%	200	4%	26%
Tarcutta	Essential	Oura	6.9	12%	109%	700	4%	19%
Taree	Essential	Whitbread St	20	84%	101%	1400	70%	0%

In all cases, Evie's maximum demand does not correspond to ZS maximum demand; Evie's maximum demand occurs at times when maximum ZS demand is light. There is therefore no basis for applying premium components (particularly demand chargers) of network tariff structures for any of the 10 sites across the three NSW networks for which data is currently available.

In the case of the subset where ZS augmentation is required, as noted above, the drivers of demand growth are specific to each site.

Schofields is a growing residential and commercial area near Rouse Hill in outer Sydney – much of the 100% demand growth is likely to be from new connections.

As noted, Tarcutta and Taree are small towns on a major transport corridor, and in the case of Tarcutta, the smallest ZS capacity in this sample. From this small size the forecast percentage growth in Tarcutta is large, but this growth may be from new connections flowing from growth in the wider Albury-Wodonga region.

It is possible EV charging could be significant at the time of ZS maximum demand, as in Taree where the largest Evie site is located. However, the maximum demand for EV charging is only 11% of the Evie site capacity – which capacity is presumably account for in connection fees and network planning. Where the highway charging station is a driver of network asset utilisation growth, this should under the Rules be addressed through connection charges.

3.3 Will Evie network bills be consistent with the Rules in the future?

None of the DNSP TSS proposals make changes to tariff assignment and design necessary to address the current inconsistencies between Evie billing outcomes and the network pricing Rules. Estimated import LRMC values are forecast by the DNSPs in their revenue proposals to decrease significantly, reflecting updated demand forecasts.

A significant risk remains that, under proposed tariff designs, divergences between Evie bills and efficient prices could in many cases increase. This is especially so for sites in Essential Energy where Evie is likely to be reassigned to tariffs with substantially higher premium charges.

This reflects Evie's expectation that its electricity demand (energy) will increase along with increased EV market penetration. As this occurs sites will be reassigned from small and medium business tariffs to commercial and industrial tariffs, with a higher exposure to excessive premium pricing components, especially for Essential Energy.

The analysis above relies on existing data for Evie bills, and demand profiles. Forecast Evie demand profiles and the network costs from the proposed tariff parameters over the forthcoming regulatory period are challenging to construct and not currently available. At sites where maximum demand increases to the limit of charging site capacity, it is expected that Evie will increase the number of charging facilities at that site and or/or place new sites in nearby locations.

Similarly, DNSP forecast data is limited – current interval data is already outdated and no forecast interval data or even annual data is available, the DNSP's expectations of future energy demand are provided only as the point value of maximum demand in 5 years' time.

It is therefore reasonable to assume that MD diversity between Evie sites and DNSP infrastructure illustrated in Figure 10 will continue. This can be shown by analysis of current load duration curves (LDC) compared with forecast maximum demand.

Figure 11 and Figure 12 show the LDCs (blue lines) for Cabramatta and Mosman zone substations, compared to their current and forecast MD and current capacity. The LDCs demonstrate that this plant approaches its current maximum demand for only a small proportion of the time.

The fact that some locations have ample capacity even beyond forecast periods suggests that temporal premium pricing in those locations is not efficient. Where demand is approaching current capacity and forecast to increase, the fact that average utilisation is well below capacity and peak demand occurs in a small number of periods.

This highlights that temporal premium pricing must be accurately targeted – where augmentation is driven by customer behaviours rather than increasing customer connections. Demand and capacity charges based on MD at any time during a billing period are clearly not cost-reflective.

Evie applies its own pricing structures and demand management solutions that can support curtailment of Evie site demand where network congestion occurs at certain times and places. This means that Evie can respond to critical peak pricing or other efficient network pricing structures.

Any application of demand discouragement or curtailment in the absence of congestion would not be efficient or consistent with the network pricing rules or NEO. This is because there would be no avoidable cost associated with avoided Evie site demand. There would, however, be an economic cost to the extent Evie customers were required to modify their demand, charging time, and travel time decisions.

Figure 11 Cabramatta Zone Substations

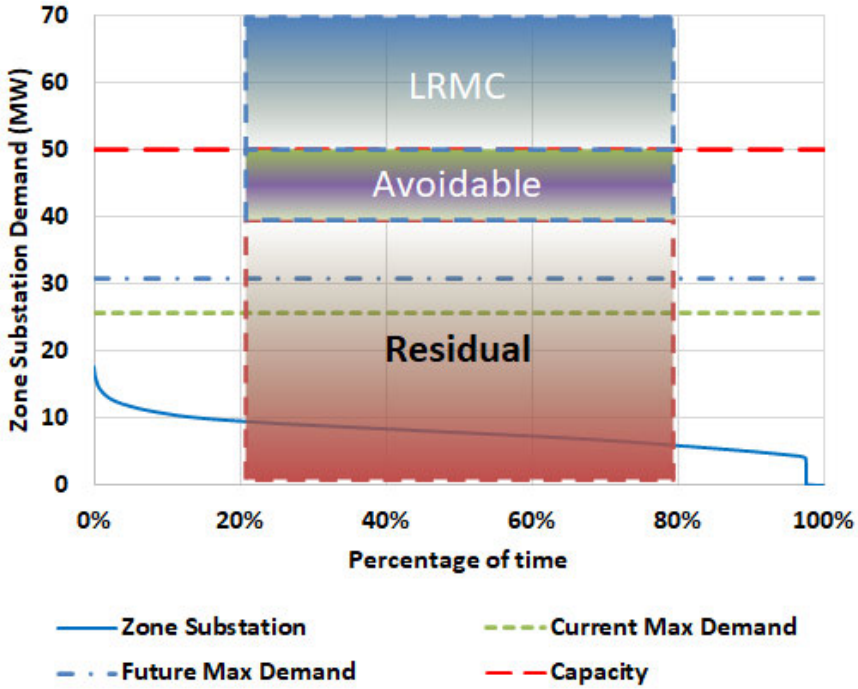
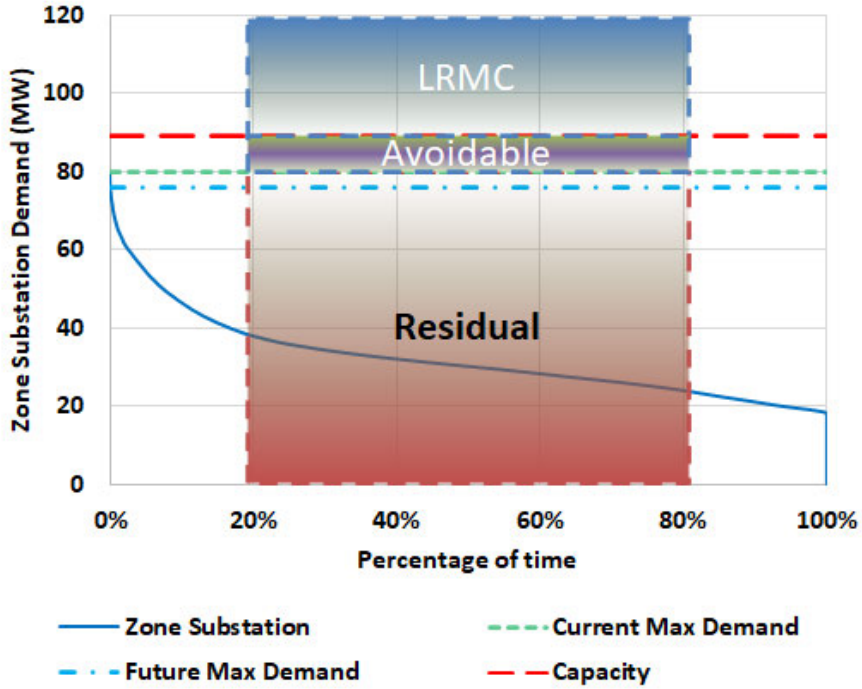


Figure 12 Mosman Zone Substation



3.4 DNSPs are over-estimating LRMC generally

Over-estimation of LRMC by all three DNSPs would appear to be a substantial cause of divergence between efficient prices and Evie network bills. This section briefly comments on the mis-estimation of LRMC in DNSP proposals. This was not identified in any of the AER's Issues Papers.

NSW DNSPs are over-estimating LRMC in their TSS proposals in one or more of the following aspects.

a. Failing to adjust LRMC to reflect existing surplus capacity from previous over-investment. NSW DNSP LRMC models are incorrectly treating existing sunk capacity as if it were avoidable and charging premium rates instead of standard rates, raising average prices for some customers including Evie. This ignores the 2018 ACCC recommendation that NSW network assets should be optimised (written down) for price setting purposes, to reflect past over-investment in capacity. DNSPs are proposing to charge consumers for future capacity expansion that already exists.

b. Charging existing customers for network augmentations to increase capacity for new connections growth. Network augmentation requirements in growth areas are driven by new connections growth, not changes in demand behaviour by existing customers. Recovery of augmentation costs to cater for new connections from standard control tariffs is inconsistent with the pricing Rules.

c. "LRMC" is mistakenly interpreted as a licence for DNSPs to charge consumers for the full cost of long-life network assets within the first 10 per cent or so of the assets' expected economic life – a single regulatory period. AER's post-tax revenue model (PTRM) incorporates *variations in all factors of production* with respect to new assets or groups of assets and hence calculates the full avoidable cost of these assets in the period to which the TSS applies. The PTRM does not bring forward cost recovery of long-life assets from future regulatory control periods; or pre-empt future regulatory determinations regarding future cost building blocks or the level of premium revenue in future TSS. That would not be 'cost reflective' because the assets' full marginal costs are not incurred within the first five-year period of the assets' life.

d. Similarly, the PTRM does not include future augmentations that may be required in regulatory periods following the 2024-2029 period. DNPSs do not have a licence to charge consumers for future augmentation requirements beyond the horizon of the TSS in question. This is not cost-reflective and would pre-empt the AER determination of efficient network costs and revenue recovery structures for the following regulatory period.

e. Applying premium charges to sunk assets due to poorly targeted tariff parameters. Additional to the points above, DNSPs may apply premium charges to energy volumes well outside the 2 per cent or so of energy that is actually marginal. This arises due to tariff designs focused on daily peak demand instead of annual peak demand, or customer monthly maximum capacity and demand charges where customer maximum demand diverges from network maximum demand.

f. Charging "stand alone" costs for a given class of retail customers. While this is the upper bound in the pricing principles, when read alongside the following principles, it is clear DNSPs from inspecting PTRMs that are not permitted to charge consumers at "stand alone" costs without regard to the economies of scope and scale enjoyed by networks offering capacity to multiple customer classes.

3.4.1 Excess capacity excluded from LRMC estimations

It appears that none of the DNSP TSS proposals and supporting analysis take into account existing excess sunk capacity in their estimates of future LRMC and the associated tariff design parameters. Instead, for tariff design purposes, all three DNSPs incorrectly assume that any increase in maximum demand triggers marginal network costs.[16]

For example, in the LRMC analysis supporting Ausgrid's proposal, it is noted that 75 per cent of Ausgrid's demand (MWh) will occur in areas where maximum demand is also growing.[17] However, the paper and supporting spreadsheet model do not differentiate between marginal demand and marginal demand triggering network augmentation.

Similarly, the AER Issues Papers do not identify DNSP TSS proposals do not differentiate between maximum demand and marginal demand that exceeds sunk network capacity.

This contrasts with the ACCC recommendation in 2018 that network asset values should be written down in Queensland, NSW and Tasmania to reflect excess capacity, as shown in Figure 13.[18]

Figure 13 ACCC retail price review recommendation

Recommendation 11

The governments of Queensland, NSW and Tasmania should take immediate steps to remedy the past over-investment of their network businesses in order to improve affordability of the network. With appropriate assistance from the Australian Government, this can be done:

- in Queensland, Tasmania and for Essential Energy in NSW, through a voluntary government write-down of the regulatory asset base
- in NSW, where the assets have since been fully or partially privatised, through the use of rebates on network charges (paid to the distribution company to be passed on to consumers) that offset the impact of over-investment in those states.

Such write-downs would enhance economic efficiency by reducing current distorting price signals. The amount of the write-downs and rebates should be made by reference to the estimates of over-investment by the Grattan Institute, and should result in at least $100 a year in savings for average residential customers in those states.

This recommendation has not been adopted by NSW or other jurisdictions. As a result, excess sunk capacity continues to be relevant to the design of efficient network pricing because it defines the efficient boundary between marginal and infra-marginal demand and the efficient application and rate of premium pricing components.

3.4.2 Marginal demand from new connections, not changed consumer behaviour

LRMC estimation methodologies used by the networks sometimes may not fully differentiate between marginal demand from existing connections and marginal demand from new connections.

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[16] By contrast, in their distribution annual planning reports and forecasts of capital expenditure requirements accompanying revenue proposals, DNSPs do take into account existing capacity. At least one of the three NSW DNSPs is also exploring opportunities for the application of new technology to expand the capacity of existing network assets by a significant amount: https://www.afr.com/companies/energy/how-ai-unlocked-capacity-across-nsw-s-energy-grid-20230222-p5cmkj .

[17] See page 5, Attachment 8.6 *Long run marginal cost import methodology report; Ausgrid's 2024-29 regulatory proposal* memo by Houston Kemp dated 14 July 2022.

[18] See Recommendation 11 of *Retail electricity pricing inquiry – final report, ACCC, June 2018*

For example, LRMC analysis supporting the Ausgrid's TSS proposal finds positive LRMC values only in areas where maximum demand is growing.[19]

A review of recent DAPR published by the DNSPs indicates that demand growth across all three networks is driven by new or expanded connections, not increased demand from existing connections (consumer behaviour). Indeed, demand from existing connections is forecast to remain flat or decrease. This is consistent with AEMO demand forecasts and the impact of different scenarios including population and economic growth on future demand.

With respect to Ausgrid, Houston Kemp noted that, in locations where demand is falling, downsizing assets upon replacement is not efficient. As a result, the most likely response is to defer asset replacement.[20] For parts of the network where demand is forecast to decline, Houston Kemp considered applying the perturbation approach in place of the average incremental cost approach to estimating LRMC. However, for areas where demand is forecast to decline over the period to 2029, the perturbation method requires extending the forecast period beyond 2029 to 2032 when per average connection demand is expected to increase. Houston Kemp therefore does not propose using the perturbation approach.

Houston Kemp recommended that LRMC charges are applied on a postage stamp basis to areas where demand is growing.[21] This reflects the fact that the estimated LRMC for low demand growth areas appeared to be insignificant within the period to which the TSS applies, even before excess existing capacity is taken into account.

Ausgrid's LRMC analysis implies that cost reflective tariff structures and associated network bills should be locationally based under 6.18.5(f)(3), rather than temporally based under 6.18.5(f)(2)). In contrast Ausgrid is proposing a continuation of exclusively temporally based tariff structures – e.g. peak demand, or capacity charges.[22]

The efficiency case under the Rules for applying locationally based premium charges is problematic under actual market conditions. This is because the overwhelming cause of demand growth is increased connections – that is, from future population growth. There is no obvious efficiency gain from charging higher prices for existing customers to augment network capacity to meet demand from new connections. To the extent customers with existing connections reduce demand, there is a net economic cost. To the extent they pay higher bills, that is a wealth transfer to other customers.

[19] See Table 1.1 Ibid.
[20] Ibid. page 3.
[21] Ibid, page 3 and Table 1.2.
[22] See Attachment 8.3: Network bill impacts, Ausgrid's 2024-29 Regulatory Proposal, 31 January 2023.

4. Data required for verification that proposed TSS comply

4.1 Need to compare marginal revenue and marginal expenditure

The AER is required by the NER to review TSS proposals to assess whether proposed TSS comply with the NER. It follows that, in order to make evidence-based decisions, AER needs to be able to access data on DNSP tariff revenue structures to verify that revenue structures correspond to expenditure structures – i.e. that tariffs are based on or reflect efficient cost (Section 6.18.5(a)).

Expenditure structure estimates can be derived via checking the marginal impact of network augmentation on aggregate proposed revenue over the regulatory control period, using the Post-Tax Revenue Model (PTRM) supplied by each DNSP with its regulatory proposal. The difference in the aggregate revenue requirement estimated by the PTRM with and without regulated capacity augmentation capital and associated marginal operating expenditure represents total marginal expenditure – additional or avoidable LRMC for the regulatory control period 2024-2029.

Revenue structure information could also be derived from PTRM input sheet data in the forecast revenues worksheet (prices from row 44, revenues from row 77). This data would allow a comparison between revenue from premium tariff components on the one hand, with additional or avoidable LRMC on the other.

4.2 Verification data not provided, or required

None of the NSW DNSPs have provided data on forecast revenue structures under their proposed TSS. Similarly, none of the NSW DNSPs have provided data on current revenue structures under their current approved TSS.

Revenue structure data in PTRMs is not required by the AER under the revenue cap form of regulation, as opposed to weighted average price cap (WAPC) regulation.[23] Similarly, revenue structure data is not required by the AER to accompany TSS proposals.[24] Similarly, DNSPs are not required to provide the LRMC component of total cost building blocks under Schedule 6.1 of the NER.

Information on revenue structures does not appear to be included in DNSP's TSS explanatory statements and supporting information and spreadsheets. There is extensive material on network bill impacts, but this material does not provide any information on revenue structures and whether revenue structures correspond to expenditure structures.

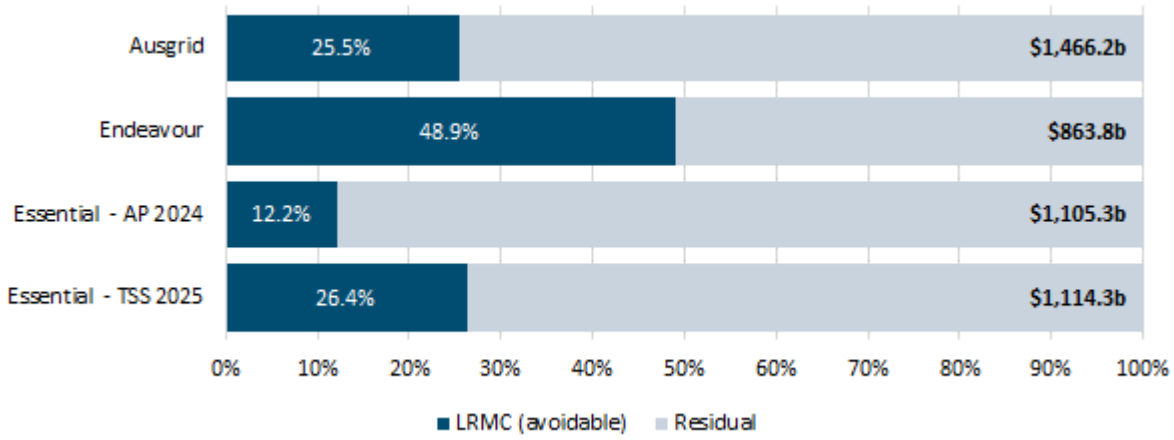
Consultant reports and associated spreadsheet models attached to TSS develop estimates of unit LRMC that could be applied in the form of premium charges for different types of customer demand at different connection levels (temporally or locationally defined). However, the relationships

[23] See page 35 of *Post-tax revenue model handbook: Electricity distribution network service providers*, January 2019, AER.
[24] See chapter 7 of *Better Resets Handbook – Towards Consumer Centric Network Proposals*, December 2021, AER.

between unit LRMC estimates for tariff setting purposes and tariff structures, as well as PTRM inputs (and outputs) are not provided or explained. Unit LRMC estimates cannot be reconciled with PTRM sensitivity analysis for marginal capital and operating expenditure. The impact of unit LRMC estimates on tariff design decisions (the extent premium rates exceed standard rates and the volume of demand to which premium rates apply) are not explained or disclosed.

Figure 14 below shows the limited tariff structure data available, from DNSPs' pricing proposals for the year ending June 2024 (the final year of the current regulatory period) relative to the estimated total revenue requirement (expenditure) for standard control services.

Figure 14 DNSP revenue structure disclosures for year to June 2024



Only in the case of Essential Energy does similar data appear to be available for the period covered by TSS proposals (2024-2029).[25] The other pricing proposal data are highly aggregated and refer not to published tariffs for retail customers (tariff classes) but instead to major network elements – apparently connection capacity and voltage level – to which multiple tariff classes apply. This means it is not possible to identify the extent LRMC allocations may vary between published tariff classes within a connection level, as required under Section 6.18.4.[26] It also means that it is not possible on the public data for the AER to undertake any meaningful assessment of tariff class allocation or reallocation decisions.

The variability in the LRMC ratio is highlighted by Endeavour's disclosure that nearly half of its total revenue requirement is LRMC, while Essential's is only 12.2 per cent in the same year. Most importantly, the ratio of LRMC to the total standard control revenue requirement (excluding jurisdictional scheme and other non-Distribution Use of Service (DUOS) charges) appears both highly variable between DNSPs and for two of the three highly implausible compared with the structure of DNSP expenditures as disclosed in PTRM and Regulatory Information Notice (RIN) returns.

Connections growth is likely to be very significant for Endeavour, as disclosed in its 2022 DAPR. However, augmentations for connections growth should under the Rules be recovered from user

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[25] Essential Energy - 12.01.01 Standard Control Long Run Marginal Cost (LRMC) Model - 21Feb23 - Public_0.xlsm available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/essential-energy-determination-2024%E2%80%9329/proposal

[26] The disclosures use the term "avoidable" not LRMC, as they appear to be referring to Clause 6.18.5(e), not to clause 6.18.5.(f).

charges, not premium components in standard control bills for existing customers. PTRM coding excludes non-standard control augmentation expenditure.

The improved information on allocation of LRMC and residual costs available in Essential Energy's TSS is welcome and provides insights not previously available. It does introduce the potential for analysis of LRMC revenue against the PTRM. But it does throw up challenges to consumer comprehensibility.

The first is the variability in the LRMC methods as shown in Figure 14, more than doubling of the LRMC ratio between 2024 and 2025 while the required revenue increases by just $50 million. This raises a question of how, without comprehensive AER guidelines, can DNSPs calculated and allocate LRMC in consistent and comprehensible ways?

The model report[27] describes complex mapping of estimated LRMC values to actual tariffs such that, for example, the LRMC component of the fixed daily charge varies between -1% and 78% for ten residential and small business tariffs. While the model report is more transparent about these final allocations, the calculations of aggregate revenue from cost allocation in tariff rates are not visible, and based on the visible values is not consistent. Hence these allocations and the implied cross subsidies are not comprehensible.

4.3 Meaningful consumer input not possible

The absence of the required verification data means that consumers and other stakeholders are unable to undertake meaningful engagement on TSS. This appears to be contrary to the purpose of the Issues Papers and expectations of DNSP proposals under the AER's Better Regulation Handbook (December 2023).

4.4 Evidence based decisions by AER on TSS not possible

The data required by the AER to be supplied by NSW DNSPs to support TSS proposals, and provided in January 2023, does not appear sufficient to enable the AER to verify whether proposed TSS are compliant with the relevant NER. This is because the various pricing and revenue model data provided do not connect with or cross reference expenditure model data, as previously applied to DNSPs operating under weighted average price cap regulation. If so, this means the AER cannot make evidence-based decisions under Section 6.18.8(a)(1). For the same reason, the AER's statements in all three NSW DNSP Issues Papers that on an initial review TSS meet the AER's expectations do not appear capable of being evidence-based.

[27] Values in the Excel model are hardcoded, that is formulae are replaced by values so it is not possible to trace the assumptions of calculations.

Appendix 1. Data methods

A1.1. Billing data analysis

Evie billing data by component including network charges and tariff component (Network Access Charge, Peak Energy, Shoulder Energy, Off Peak Energy, Demand) was accessed supplied from the data portal of Evie's retailer. The network component were categorised as Premium and Standard usage rates and the fixed charge:

- Premium charges are identified as tariff rates intended to signal to the customer a need to reduce consumer demand. These included Peak Energy and Demand rates (named variously Demand, Peak Demand and Capacity, although these are all measured by the same metric, that is maximum consumer demand at any time in the billing month).
- Standard charges included Anytime, Off peak and Shoulder rates. For the purpose of comparison with Premium rates, the single Standard rate in TOU tariff structures was calculated as the volume weighted average of these rates ($V_{Off\ peak} \times \$_{Off\ peak} + V_{Shoulder} \times \$_{Shoulder}$).

Commonly consumers compare their energy costs in terms of a energy unitised rate (c/kWh), and find it difficult to understand or compare a power unitised rate (c/kW) of a demand tariff. Energy unitised demand/ tariffs are difficult as the largest determinant will be the plant load factor or utilisation across a period. Variations in load factor have been normalised for comparison purposes by adjusting for the ratio of the Evie site load factor against the Zone Substation load factor, using a site's data where available, or otherwise the average for the Ausgrid network.

Public EV charging site load factor

Each site's maximum demand for each billing period (month) reflects the capacity and number of installed EV charging units. A public EV charging facility operates at maximum capacity when all individual charging units are used by rapid charge capable EVs at the same time. Aside from a small constant electricity demand for the onsite equipment, demand during periods when the charging units are not being used is close to zero.

Capacity utilisation and energy used (the load factor) is currently low for all sites reviewed. This means that network and overall retail bills for EV charging facilities are sensitive to any excess component in capacity or demand charges.

As EVs become more common, energy use per charger and per site will increase and load factors will improve, resulting in lower unit energy costs. To avoid EV charging congestion, additional chargers may be added at each site, increasing maximum demand and limiting improvements to load factors. Additionally, the charging site operator will be required to pay for any increases in current capacity, either through an upfront payment or higher ongoing connection charges.

A1.2. Interval data

Evie load data was accessed supplied from the data portal of Evie's retailer. This included data identifying the Evie site and site characteristics together with interval data.

The basic method seeks to identify the demand of each asset in the same time intervals. By focusing on the relative timing of peak demand at each asset, the demand diversity can be explored. At least one year of data is required to ensure that the identified periods of peak demand account for all monthly and seasonal variation.

The installation of Evie sites is rolling out across NSW. Consequently only 10 Evie sites have a full annual period of interval data, and this is the basis for the sites selected for analysis.

The zone substation for each Evie was identified using the energy infrastructure data sets in the Australian Government National Map[28]. This map includes data for each Zone Substation from the latest published regulatory DAPRs including capacity, current and forecast loads. Historical load interval data is published by networks under NER 5.13A, made available through their websites, under certain caveats including that data is raw and unchecked.

The data is made available under various interpretations of Rule 5.13A, as discussed further below. The significant fact is that public data is only available up to the latest date of publication. This both a) is not current and b) varies by DNSP. Evie requested up to date data from the DNSPs, but was referred to the publicly available data. Consequently, it is not possible to align coincident data between the Evie charging sites and the zone substations serving them energy.

In order to perform the analysis we have aligned the Evie interval data with the corresponding day and time from the year available in the DNSP public data. This makes an assumption that the seasonal and monthly variation of demand at the Zone Substation does not substantially vary from year to year. While this is strictly not true (the day of the week inches forward so that a weekday may become a weekend day), the assumption is generally viable as the key drivers of demand at each asset are substantially different..

The key drivers of demand at Zone Substations are summer cooling and winter heating and the daily duck curve of dinner time demand, so that one pattern is common while the other is intensely seasonal with extreme heating/cooling demand. Conversely the key drivers of demand at electric vehicle charging stations are the population of electric vehicles and travel times. We are more interested in the relative timing of asset demand rather than the absolute quantum of demand

Once that data sets are aligned, the data is analysed to identify the timing of peaks and adjacent intervals, and the magnitude of demand at these times.

[28] https://nationalmap.gov.au/renewables/

Interpretation of NER 5.13A Distribution zone substation information

Rule 5.13A provides for DNSPs to make available zone substation information for all zone substations where information is available, and data is not confidential or commercially sensitive. They include identifying information and interval load data.

The Rule was made in 13 March 2014.[29] The Rule required DNSPs to produce

2. a ***ten year zone substation report*** means a report containing historical information that is available for the ***ten reporting years prior*** to the commencement of this rule 5.13A (i.e.. from 2004), and
3. an ***annual zone substation*** report for each subsequent reporting year.

The ***reporting year*** is a requirement for data covering a period of one year ending on the same date in each reporting year – that is subsequent information files should be contiguous. There is no definition of the ending date, which is left to DNSPs.

After these definitions, the Rule is mostly about obligations of DNSPs and persons requesting information, in particular (f)(1) that a DNSP "*must provide the report(s) requested as soon as practicable but, in any event, within 30 business days of the date of the request*".

There is some variation in interpretation of this Rule. All DNSPs now provide the data through their websites so that no request and response of a DNSP officer is required.

Ausgrid provides csv files on its website[30] from 2005 to 2022, most recently published 21 December 2022 for data ending 30 April 2022.

Essential Energy provides csv files on its website[31] from 1 October 2012 to 30 September 2022.

Endeavour Energy provides csv files on its website.[32] Eleven files of annual data are available, including the latest 2020-21 year for data ending 29 June 2021, and preceding ten years from 2010-11 to 2020-21.

> *In accordance with Rule 5.13A of the National Electricity Rules, Endeavour Energy has made available historical interval demand data (in kilowatts or megawatts) for all its zone substations not subject to third party privacy concerns. Within 30 business days of the publication of our Distribution and Transmission Annual Planning Report, we will provide 12 months' worth of interval data based on a financial reporting year. Please refer to the Australian Energy Market Commission for further information on this rule.*

The DAPR website is not dated. The 2022 DAPR Systems Limitations Template and current Systems Limitations Data and have ZS forecasts for 2024-2028. It would seem the timing of the DAPR publication enables a 18-24 month obscure period in ZS load data/forecasts.

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[29] AEMC 2014, Publication of zone substation data, Rule Determination, 13 March 2014, Sydney
[30] https://www.ausgrid.com.au/Industry/Our-Research/Data-to-share/Distribution-zone-substation-data
[31] https://www.essentialenergy.com.au/our-network/network-projects/zone-substation-reports
[32] https://www.endeavourenergy.com.au/modern-grid/creating-the-modern-grid/network-planning/distribution-annual-planning-report

Appendix 2. History of network tariff reforms

Network tariff reform was part of a broader response to runaway regulated network prices following the move to economic regulation by the AER under the National Electricity Rules from 2006-2007. The Productivity Commission undertook a review in 2012, the AEMC undertook a review of NSW DNSP reliability standards, and a significant set of changes were made to the rules for economic regulation, marketed as "Better Regulation".

Network tariff reform followed a review by the AEMC – the Power of choice. New rules were put in place in 2014 and DNSPs published their first TSS in 2015 with implementation from 2016. Implementation was fast tracked which among other things meant that the AER did not issue any guidance to DNSPs on methodologies for estimating marginal expenditure for the purpose of designing tariffs and setting tariff parameters.

Network tariff reform explicitly assumed that the very high rate of network augmentation over the period 2007-2012 would continue to 2022/23.[33] As a consequence of this assumption, it was further assumed that peak demand growth in Queensland, NSW and Victoria could be reduced by between 400 and 1300MW by 2020 by the introduction of a suite of demand side measures.

AEMC accepted advice from Frontier Economics that cost savings from peak demand reduction in the NEM was likely to be between 2012 $4.3 billion and $11.8billion by 2020. This equates to between 2 and 9 per cent of forecast expenditure on the supply side (both generation and network). Most of these cost savings were assumed to occur in the network sector, given the then over-supply of wholesale generation and relatively conservative assumption of baseline demand growth.

DNSP capacity augmentation expenditure has, however, trended significantly down since 2012. This reflects a series of changes to the regulatory framework, including the AER's Better Regulation reform[34] and changes to DNSP planning (reliability) standards in NSW and Queensland.

In Queensland, NSW and Tasmania the economics of future capacity augmentation have also been affected by significant excess capacity due to previous over-investment. According to the ACCC, this over-investment was driven by excessive reliability standards and a regulatory regime tilted in favour of network owners at the expense of electricity users.[35] The ACCC recommended that network asset values should be written down in Queensland, NSW and Tasmania to reflect excess capacity.[36]

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[33] See page vi of *Power of Choice – Stage 3 demand side participation review, AEMC, 2012*, available at https://www.aemc.gov.au/rule-changes/distribution-network-pricing-arrangements

[34] See for example *Overview of the Better Regulation reform package, AER, April 2014*

[35] See page ix of *Retail electricity pricing inquiry – final report, ACCC, June 2018*

[36] See page xxx of *Retail electricity pricing inquiry – final report, ACCC, June 2018*

Recommendation 11

The governments of Queensland, NSW and Tasmania should take immediate steps to remedy the past over-investment of their network businesses in order to improve affordability of the network. With appropriate assistance from the Australian Government, this can be done:

- in Queensland, Tasmania and for Essential Energy in NSW, through a voluntary government write-down of the regulatory asset base
- in NSW, where the assets have since been fully or partially privatised, through the use of rebates on network charges (paid to the distribution company to be passed on to consumers) that offset the impact of over-investment in those states.

Such write-downs would enhance economic efficiency by reducing current distorting price signals. The amount of the write-downs and rebates should be made by reference to the estimates of over-investment by the Grattan Institute, and should result in at least $100 a year in savings for average residential customers in those states.

Growth in demand from existing connections has been reduced due to a combination of demand response to substantial rises in retail electricity prices, as well as technology, market and regulatory change, for example associated with the introduction of carbon pricing before its repeal. These trends resulted in widespread adoption of consumer energy resources (CER), with very high levels of consumer investment in embedded rooftop solar photovoltaic generation.[37]

In addition to the assumed very high levels of potentially avoidable network augmentation expenditure, pricing reforms assumed that inefficient tariff structures were resulting in runaway demand growth due cross subsidies in favour of a subset of customers with demand profiles that triggered a requirement for network capacity augmentations. The new network pricing rules required network tariffs to be split into premium and standard components.

The intention was to create variation in total network prices between customers that drove capacity augmentations (premium network prices) and those that did not (standard or even discount network prices). The key assumption is that a significant portion of the total network revenue requirement would be driven by marginal demand, and this would be recovered from the premium component of network prices.

This assumption has turned out to be false. The total network revenue requirement associated with marginal demand is small. This reflects the combination of low or negative maximum demand growth alongside ample excess capacity due to previous overbuilding.

The relatively modest extent network costs are avoidable can be revealed by using DNSP populated PTRM to test the sensitivity of the total revenue requirement to changes in capital expenditure for network capacity augmentation. At the extreme, all capital expenditure recovered from standard control tariffs can be excluded from PTRM inputs. The PTRM carries the reduction in capital expenditure across to the cost building blocks, including not only depreciation, financing and tax costs but also to operating and maintenance expenditure. The change in the resulting revenue

[37] See for example Endeavour Energy's demand forecast for the forward planning period for its 2022 Distribution Annual Planning Report available at Demand Forecasts For The Forward Planning Period | Endeavour Energy

requirement indicates the maximum extent to which all factors of production can be varied within the relevant time frame for each TSS.

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