Reimagining Network Utilisation in the Era of Consumer Energy Resources

Grant funded by Energy Consumers Australia

Institute for Sustainable Futures

Final Report (v1.2), December 2024

isf.uts.edu.au

Research Team

- Dr Ibrahim Ibrahim
- Dr Edward Langham
- Jonathan Rispler
- David Roche

Citation

Langham, E, Ibrahim, I., Rispler, J and Roche, D. (2024). *Reimagining Network Utilisation in the Era of Consumer Energy Resources.* Prepared by UTS with the support of Energy Consumers Australia. Version 1.2, December 2024.

This project was funded by Energy Consumers Australia Limited as part of its grants process for consumer advocacy projects and research projects for the benefit of consumers of electricity and gas. The views expressed in this document do not necessarily reflect the views of Energy Consumers Australia.

CRediT author statement

Edward Langham: Conceptualisation, Methodology, Research supervision, Project administration, Funding acquisition, Writing - Review & Editing, SRG Chair/Facilitation. **Ibrahim Ibrahim:** Conceptualisation, Methodology, Investigation, Formal analysis, Software, Visualisation, Data Curation, Project administration, Project management, Writing - Original Draft. **Jonathan Rispler:** Validation, Writing - Review & Editing. **David Roche:** Validation, Writing - Review & Editing.

Institute for Sustainable Futures
University of Technology Sydney
PO Box 123 Broadway, NSW, 2007
www.isf.uts.edu.au

Acknowledgements

The authors would like to thank the Energy Consumers Australia grants program for their logistical and financial support, and Brian Spak and Ashley Bradshaw for their technical advice and guidance.

The research team would like to acknowledge the Endeavour Energy for access to non-public data sources, and the invaluable contributions of the members of the Industry Reference Group (IRG), who provided critical advice and guidance to shape the metric selection, testing and recommendations:

- Brian Spak and Ashley Bradshaw (ECA)
- Dr John Ward (CSIRO)
- Kieran Anglim and Alex Zeller (AER)
- Justin Robinson (AEMC)
- Jason Hockings (EQL on behalf of Energy Networks Australia)
- Ross de Rango (EV Council)
- Luke Cowen and Debbie Voltz (SAPN)
- Gavin Dufty (St Vincent de Paul)
- Jan Kucic-Riker (Justice and Equity Centre)
- Dr Fred Geth (GridQube)
- Dr Veryan Hann (University of Tasmania)

While the IRG was consulted throughout the project, and feedback directly shaped the proposed metrics, the views expressed in this document do not necessarily reflect a consensus IRG position or represent the views of any participating organisation.

Executive Summary

Background

Network utilisation is a metric used by energy policy and regulatory bodies to assess the efficiency and performance of electricity grid infrastructure, and can also help an expanding range of energy stakeholders understand how the energy system can be developed at least cost. It reflects the loading of network assets by considering how much network capacity is installed to address maximum electricity demand. The metric is of material importance to consumers, as how well energy assets are utilised strongly influences average prices for the provision of electricity network services. As a general trend, the higher the utilisation of distribution and transmission networks, the lower the average price of delivering energy from generators to consumers. In the context of Australia's electricity systems – which cover large areas of relatively sparse population by international standards – this value derived from grid infrastructure assets is particularly important, as the cost of poles and wires make up approximately 40% of customer bills.

However, as distributed solar and other flexible consumer energy resources (CER), such as batteries and electric vehicles (EV), have become more prevalent, the appropriateness of the 'traditional' network utilisation metric has been brought into question. Many customers now require the ability to export energy and connect their CER, which creates two-way flows of energy and represents a different kind of network value: export services. These services are not explicitly considered by the traditional network utilisation metric, nor flow-on effects such as 'minimum demand' or voltage constraints that might also drive network investment. In considering only the peak hour of energy demand and aggregating at the whole network level, the traditional metrics also sheds no light on where and how to obtain more value from the network for the remaining 99.9% of the time.

To address these limitations, this report explores alternative measures of network utilisation (or other metrics clustering around a similar purpose), to better inform network performance assessment and planning in the CER era, and incentivise the adoption of non-network solutions, such as flexible demand. Such measures will be crucial in keeping consumer prices down over the coming decades as consumers continue to adopt solar and increasingly electrify gas and transport energy use.

Approach

The research team developed a database of power, energy, economic, reliability, risk and resilience metrics that had greatest potential to address the observed limitations, to propose a shortlist of metrics to explore further. The shortlisted metrics were refined with guidance from an expert Industry Reference Group established for the project and road-tested to explore data availability and metric behaviour.

Proposed new metrics

To incentivise networks to deliver more customer value from capital-intensive network assets in the CER era, we propose two headline alternatives to traditional network utilisation:

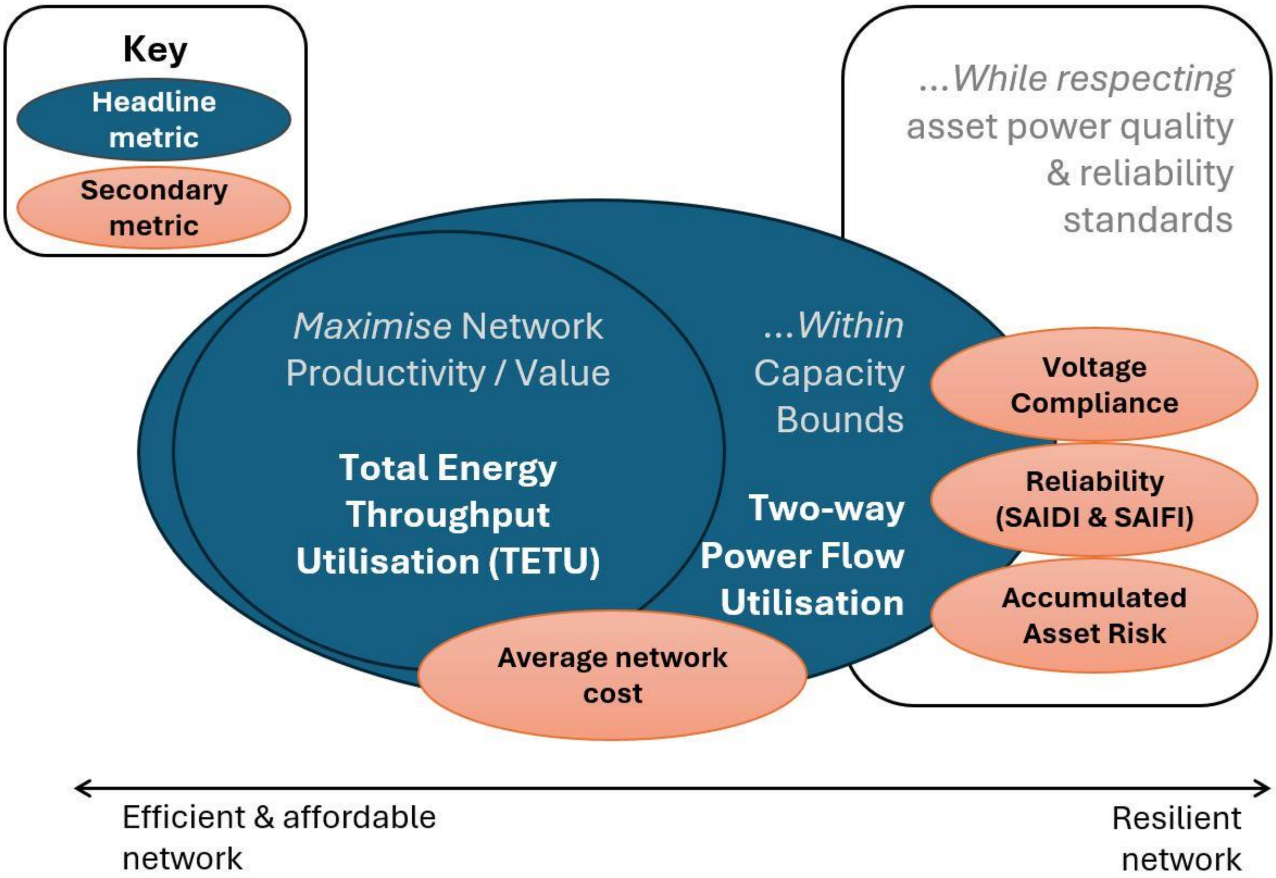
1. *Total Energy Throughput Utilisation (TETU),* which is an energy metric focussed on maximising the customer value that is facilitated by a grid connection, in the form of energy imported from the grid, exported to the grid and self-consumed.[1]
2. *Two-way Power Flow Utilisation,* which is a power metric focussed on understanding and balancing the level of capacity risk accrued to deliver the network productivity represented in the TETU. This provides

[1] While the AER's position is that self-consumption is not a 'network output', the authors suggest that there are also strong arguments for its inclusion in a holistic network utilisation metric – see Section 4.1.1 for discussion. The TETU metric can also be produced without self-consumption if using customer meter data, as discussed in Section 4.1.2.1.

visibility of the critical time-of-day and seasonal variations in two-way grid usage that inform how TETU can be maximised.

As electricity supply has other critical power quality and reliability standards that must be respected and that influence asset capacity, the headline metrics are complemented by three secondary asset-level metrics regarding voltage compliance, reliability (System Average Interruption Duration Index–SAIDI) and System Average Interruption Frequency Index–SAIFI), and risk (accumulated asset risk). Finally, we propose a simple inflation-adjusted average per unit and per customer network cost, to introduce a vital economic dimension that considers all useful customer value derived from the network.

The goals of, and relationships between, these objectives are illustrated in the Figure below. Note, however, that even if these new metrics could ultimately serve as replacements, we recommend that they are produced alongside the traditional utilisation metric for consistency of interpretation over time. Maintaining this continuity ensures that we have a reliable foundation upon which to evaluate long-term trends and the impacts of past decisions.



Relationship between proposed headline and secondary utilisation metrics

The traditional metric is calculated by the regulator at the zone substation level and aggregated across the system. Industry engagement through this project has revealed that other stakeholder use cases of updated utilisation metrics requires data to be made accessible at the *Zone Substation level* (in the immediate term) *and below* (in the longer term). Metric availability at more granular spatial scales or asset-levels can help to manage peak and minimum loads towards improving network productivity during periods of low demand or high rooftop solar supply, in the context of tariff design, demand management, and the strategic location and timing of new loads such as EV charging.

If networks are successfully able to *maximise* Total Energy Throughput Utilisation *within the bounds* of capacity, reliability and quality of supply, this means that there are more units of customer value over which to spread the repayment of network costs. This has substantial potential to lower the average costs of network supply for customers.

Specific actions that network businesses could take to drive increases in a metric like the TETU could include encouraging time of use and 'solar soak' network pricing, realignment of controlled load programming with solar production periods, encouraging customer conversion from gas to (timed/smart) electric hot water, proactive voltage management or flexible exports to reduce curtailment, or partnership programs to open streetside EV charging with solar soak tariffs in strategic network areas. Such measures, in concert with incentives to flatten peaks in areas approaching capacity investment (such as afternoon pre-cooling of homes), could increase the volume of energy flowing through network assets, without additional capacity upgrades.

Example road testing results

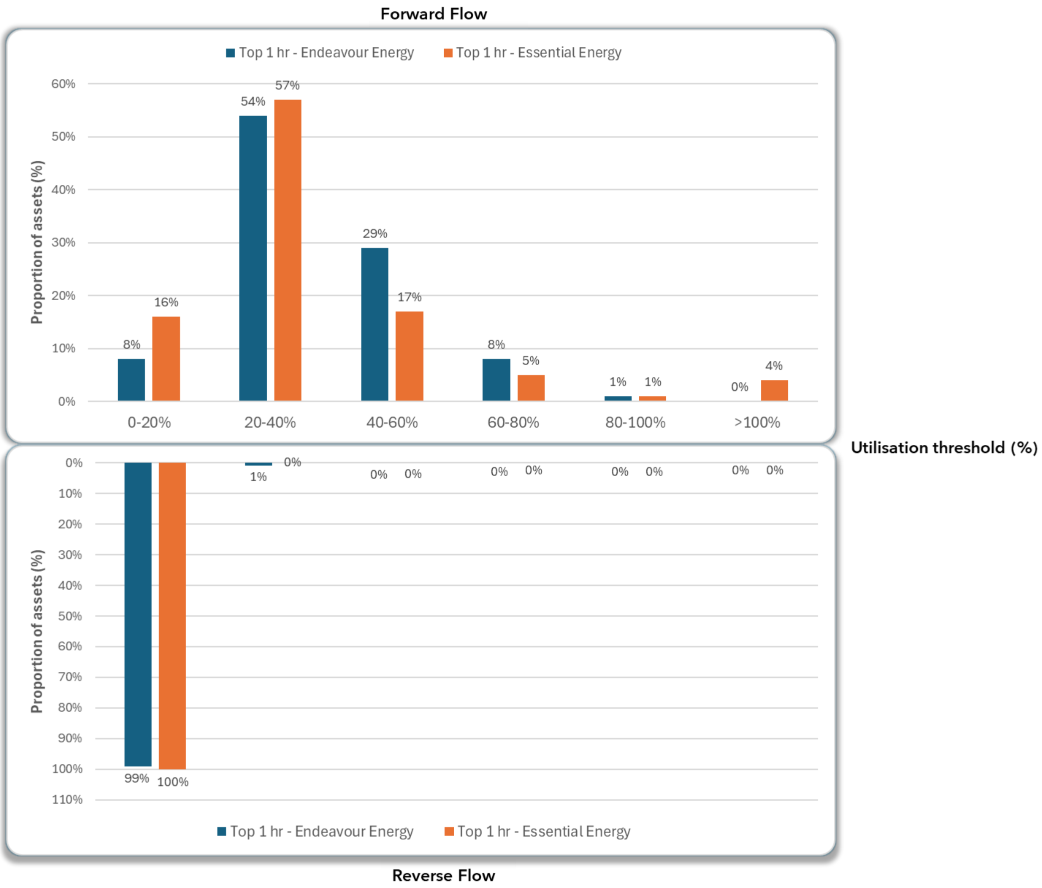
Due to data gaps, the metrics were primarily tested with public and non-public Endeavour Energy data, and public Essential Energy data. The TETU figures calculated are lower than the traditional metric, as shown in the table below. This is neither good nor bad, but is a function of using a different benchmark. It is difficult to interpret the significance of TETU metric behaviour without multiple years of data for multiple networks, but examination of the monthly variations in the TETU and hypothetical scenarios (see Section 5.3.1) reveals that the metric behaves as desired in response to increased solar, battery storage, 'solar soak' load shifting as it increases in value with solar input or other desirable customer actions that reduce curtailment. This contrasts with the traditional utilisation metric which may go down, producing an apparent decline in productivity. However, like most power and energy metrics, the TETU does not reward energy efficiency and thus may benefit from being viewed alongside the *average network cost per customer* metric, which would not decline with improved efficiency.

Annual and seasonal TETU metric vs traditional network utilisation metric

Name	Network level	Traditional metric			TETU metric		
		Yearly	Summer	Winter	Yearly	Summer	Winter
ENDEAVOUR ENERGY	Network (average of zone substations)	37.1%	35.6%	31.8%	15.3%	14.5%	16.1%
9674 - ROBERTSON	Zone substation (higher utilisation; winter peak)	69.9%	51.7%	69.9%	33.8%	29%	37.9%
9654 - DARKES FOREST	Zone substation (lower utilisation; summer peak)	13.2%	2.8%	13.2%	1.1%	1.0%	1.2%
9779 - MARSDEN PARK	Zone substation (very high solar)	38.2%	38.2%	30.3%	13.9%	15.2%	12.0%

The figure below compares whole of network Two-Way Power Flow Utilisation for Endeavour Energy and Essential Energy networks for the top 1-hour. It shows the proportion of assets that fall into different utilisation bands in the maximum hour of forward and reverse energy flows. It reveals that there is slightly lower utilisation in the Essential Energy network (more spare capacity), as indicated by the orange columns being skewed to the lower utilisation categories on the left. Contrary to this trend, there are also some assets in Essential's network that exceed their nameplate capacity.

Essential Energy currently exhibits no reverse flow utilisation at the zone substation level, while some Endeavour assets have reverse flows over 30% of capacity (the magnitude of this trend is elaborated in zone-specific visualisations in Section 5.3.2). This representation, while using the same time period as the traditional metric (top 1-hour of demand) reveals a more nuanced picture about the balance of assets at different risk levels, and includes reverse flows – which were relatively limited in 2023/24. This metric can also be readily produced for other durations, such as the top 100-hours.



Two-way power flow utilisation level comparison between Endeavour Energy (blue) and Essential Energy (orange) assets (Top 1-hour; FY 2023/24; based on nameplate capacity)

A seasonal time-of-use heat map representation of Two-Way Power Flow Utilisation can also be produced, as shown below for Robertson, a winter-peaking zone substation with medium solar penetration. Green areas are lower utilisation and red are highest (on a scale on 0-100%).

This granular data representation clearly shows the variation across the day, and compares between the peak day, average weekday and average weekend days, by season. This is useful identifying opportunities to increase productivity through for load shifting and EV charging. In the case of Robertson, solar hours can be seen to be a better target than overnight, when demand remains moderate. There are no reverse flows in this area.

WINTER (FORWARD FLOW) - 9674 - ROBERTSON																								
Day/Hour	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
Peak day FF	50	48	46	44	44	44	45	45	45	44	40	37	36	40	44	50	56	62	67	70	66	62	59	55
Weekday	43	41	38	36	35	35	36	39	39	33	27	22	20	19	21	25	31	39	45.7	48	48	46	45	44
Weekend	44	42	39	37	35	35	36	38	40	38	33	28	25	24	25	29	35	43	47.4	49	49	47	45	44

(a)

WINTER (REVERSE FLOW) - 9674 - ROBERTSON																								
Day/Hour	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
Peak day RF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

(b)

Two-way Winter Heat Map Power Flow Utilisation (9674 – ROBERTSON ZS Owner: Endeavour Energy; Winter nameplate capacity 7.5 MW]) – (a) Forward flow heat map; and (b) Reverse flow heat map (numbers in percentages)

Recommendations

Utilisation metrics potentially influence several strands of the AER's ongoing work program. We recommend that the AER:

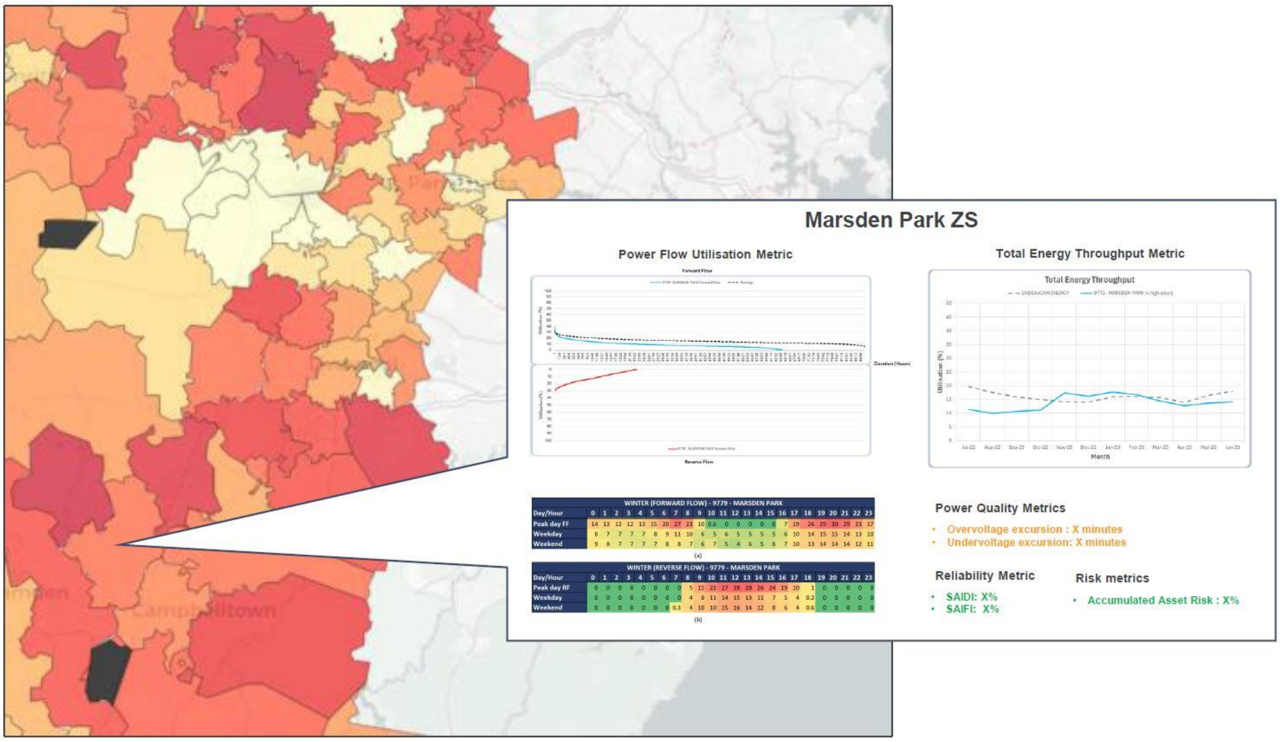
1. Consult on the collection of the disclosure and transparent release of component network data to enable the calculation of the zone substation level proposed metrics in annual performance reporting in 2025 and beyond, alongside the traditional metric. Potential mechanisms for this are:
   - Routine annual review of network performance reporting inclusions, Regulatory Investment Notices (RINs), or Distribution Annual Planning Reports (DAPRs), where appropriate.
   - The scheduled review of how the AER's benchmarking models can be updated to better reflect export services (slated for 2027 or earlier).
2. Establish a plan towards more granular data supply below the Zone Substation level over time, potentially via the AER's ongoing efforts to enhance network data visibility, flowing on from the ESB data strategy. The ultimate goal may be an open access platform for this consistent cross-jurisdictional network data at a granular resolution, similar to the image mock up shown below.
3. Review the need for alignment of network utilisation metrics with benchmarking models in upcoming review, including bringing forward this process prior to 2027.

The road-testing found that the proposed metrics provide a more comprehensive view of network performance and the impact of CER, but gaps in data availability and granularity exist. The power metric (Two-way Power Flow Utilisation) can be calculated at the system and zone substation level with available data, while the energy metric (Total Energy Throughput Utilisation) requires new or more granular data disclosures. The specific data gaps and associated recommendations, including both headline and secondary metrics, can be found in Table 13 in Section 6.2.

Notes on metric usage

Currently network utilisation has no direct financial regulation or incentives associated with it. These new metrics were conceived with this same use in mind, and the AER's primary role with respect to the updated metrics is as a monitor and reporter, rather than a direct regulator. While regulatory incentives for network utilisation could be considered, this would be a distinct use case and may change the desirable metrics. Reporting network utilisation alone may influence network behaviour. But measuring network utilisation is not considered solely (or necessarily primarily) a tool to change network behaviour. Measuring network utilisation helps us to understand how the entire system — including consumer and large-scale generation and storage — can be developed at least cost and the greatest customer value.

The proposed shift towards a more granular, two-way view of utilisation extends the use cases beyond monitoring long-term system trends, towards performance and productivity analysis for specific assets. In this new context, it is important to remember that a low TETU does not inherently equate to a 'poor performing' asset. Low utilisation represents an opportunity for low-cost load growth, while high utilisation represents a challenge to mitigate new costs, while accommodating load growth or changing consumer trends. The TETU should be interpreted within the context of two-way power flow, power quality, reliability, and asset risk thresholds. This why we recommend that the proposed metrics are used as a suite that can be interrogated at the relevant level of the system, as shown in the mock up image below. While the regulatory focus may remain on system-level reporting, such a tool would enable more localised analysis for a wider range of stakeholder use cases, supporting decision-making and improving the ability to identify opportunities to increase utilisation.



Mock up map-based view showing a compilation of asset-specific zone substation level metrics

Furthermore, every asset will have cycles of lower and higher utilisation depending on demand growth, and how recent capacity upgrades have taken place. What matters most is the general trend of continuous improvement as new loads are electrified, to ensure the TETU can be raised as much as possible before new network investments are made, applying downward pressure on average network prices. To this end, it may be useful for DNSPs to specifically monitor and seek to improve the TETU in assets that are over, say, 60% on the Two-way Power Flow Utilisation metric – that is, those that are closer to reaching capacity constraints. From the regulator's perspective, a subset of the TETU could be monitored for assets that have planned investment to overcome constraints in the coming five-year network planning period.

It is beyond the scope of this project to interrogate how these utilisation metrics should influence cost allocation to consumers. There are live debates within the industry as to what 'cost reflectivity' in customer tariffs should look like. It is true that network investment is ultimately tied to large investments in capacity. It is also true that these investments are 'lumpy', and the short-run marginal costs of using more network capacity are small when an investment is distant, and very high when an investment is imminent. But it is also true that to get the best value out of the network in the long term, we must steadily encourage consumers and third-party technology and service providers to actively fill troughs in demand – particularly negative demand (reverse flows) associated with the uptake of solar – and flatten peaks. Therefore, considering the intersection with long-term, sustained consumer behaviour is critical. By better measuring and understanding how value is derived from networks in the CER era, we hope that the metrics considered by this report provide a foundation to inform this debate.

Contents

Abbreviations

AESO	Alberta Electric System Operator
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BTM	Behind-the-Meter
CBD	Central Business District
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CER	Consumer Energy Resources (also known as Distributed Energy Resources)
CMOS	Customer Minutes Off–Supply
DAPR	Distribution Annual Planning Report
DC	Direct Current
DNSP	Distributed Network Service Provider
EV	Electric Vehicles
ECA	Energy Consumers Australia
ENA	Energy Networks Australia
EUSE	Expected Unserved Energy
FiT	Feed-in Tariff
HVAC	Heating, Ventilation, and Air Conditioning
IRG	Industry Reference Group
IEEFA	Institute for Energy Economics and Financial Analysis
kA	Kiloamperes (a measure of current)
kVA	Kilovolt Amperes (a measure of infrastructure capacity or demand)
LV	Low Voltage
MVA	Megavolt Amperes (a measure of infrastructure capacity or demand)
MW	Megawatt (a measure of infrastructure capacity or demand)
MWh	Megawatt hour (a measure of energy)
MTFP	Multilateral Total Factor Productivity
NEM	National Electricity Market
NOM	Network Opportunity Maps
OFGEM	Office of Gas and Electricity Markets
PV	Photovoltaic (Rooftop solar power)
OP HW	Off-Peak Hot Water
RIN	Regulatory Investment Notice
STPIS	Service Target Performance Incentive Scheme
SAIDI	System Average Interruption Duration Index
SAFI	System Average Interruption Frequency Index
TOU	Time of Use
TETU	Total Energy Throughput Utilisation
VCR	Value of Customer Reliability
V2G	Vehicle-to-Grid
ZS	Zone Substation

1 Background

Network utilisation is a metric used by energy policy and regulatory bodies to assess the efficiency and performance of electricity grid infrastructure. It reflects the loading of network assets by considering how much network capacity is installed to address maximum electricity demand. It is applicable to both transmission and distribution infrastructure, but the primary focus of this project is on electricity distribution networks. The metric is of material importance to consumers, as how well energy assets are utilised strongly influences average prices for the provision of electricity network services. As a general trend, the higher the utilisation of distribution and transmission networks, the lower the average price of delivering energy from generators to consumers. In the context of Australia's electricity systems – which cover large areas of relatively sparse population by international standards – this value derived from grid infrastructure assets is particularly important, as the cost of poles and wires make up approximately 40% of customer bills.[2]

However, the relationship between network utilisation and efficiency is not one-dimensional. Higher utilisation generally also reflects less spare capacity in the system, which serves as redundancy to deal with rare events. Thus, there is – at least theoretically – a trade-off between the reliability of supply and cost efficiency. Yet, the Australian Energy Regulator (AER), in its most recent performance reporting, found no clear relationship between high utilisation and better or worse reliability. This lack of correlation is not unintuitive, as performance degradation in reliability metrics (such as SAIDI and SAIFI) is often influenced by factors beyond capacity-related outages such as deteriorating asset condition or external impacts like weather or vegetation.[3] So, what is the current trend in distribution network utilisation, and what does it tell us?

The AER reports network utilisation figures for distribution networks in the National Electricity Market (NEM) from 2006. The AER's metric shows a slow but steady decline until 2015 as shown in Figure 1, suggesting a deteriorating average trend in network productivity. This declining trend related to factors such as the tightening of reliability targets, which prompted additional network investment to handle peak demand, that was then (incorrectly) forecast to continue its steady rise.[4]

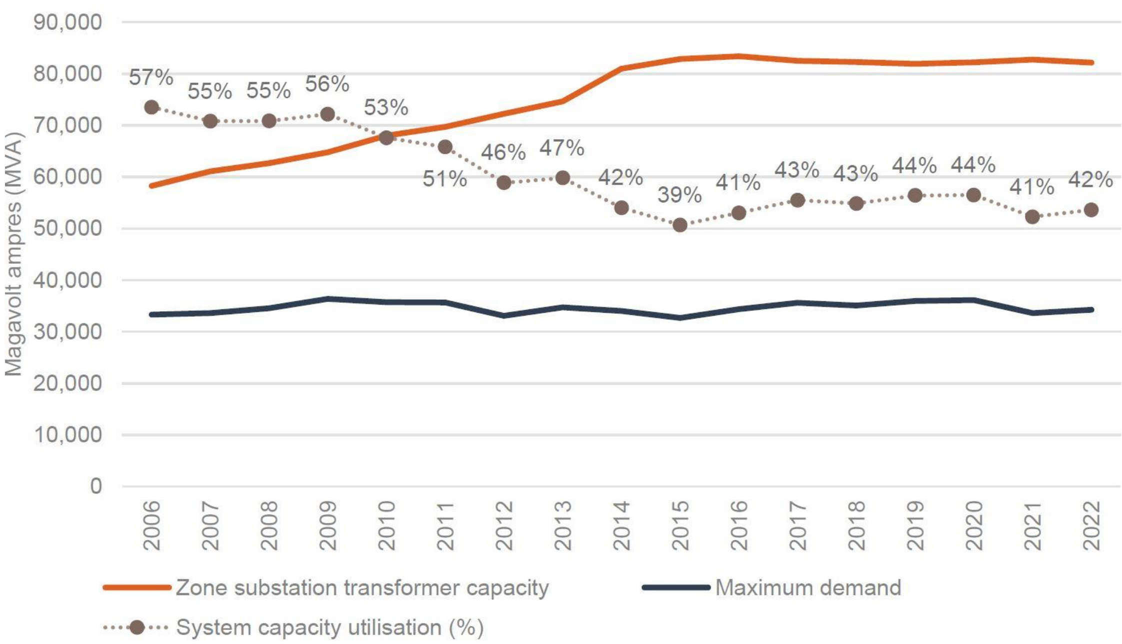


Figure 1: Average distribution network utilisation across all NEM networks, 2006-2022 (Source: AER)[5]

---

[2] AER, Default market offer prices 2024–25, June 2024.
[3] AER, Electricity Network Performance Report 2020, Australian Energy Regulator, September 2020.
[4] Kate Griffiths, You're paying too much for electricity, but here's what the states can do about it, Grattan Institute, March 2018. Accessed on Mar. 01, 2024.
[5] AER, Electricity Network Performance Report 2023, Australian Energy Regulator, July 2023.

This period of declining utilisation was directly connected to increased consumer bills, driving increases of $100–$200 per annum per residential customer in state-owned networks in NSW, Queensland, and Tasmania.[6] As state-based reliability targets and further network investment were scaled back, this was associated with a period of stabilisation of network utilisation and a tempering of average network prices.

There are no direct performance targets or incentives attached to network utilisation in the Australian context,[7] however, it still serves as an important contextual data point for the AER and consumer advocates. Since 2015, the AER has also calculated the economic productivity of Distributed Network Service Provider (DNSPs) according to an index called multilateral total factor productivity (MTFP), which integrates the 'inputs' of network capital investment with productivity 'outputs' including maximum demand (in megawatts, MW), energy delivered (in megawatt hours, MWh) and reliability (customer minutes-off-supply) relative to the DNSP's geographical coverage and customer numbers. While the data upon which the MTFP is based are broader, the general trend of decline and then stabilisation bears resemblance to that of network utilisation (see Figure 2).

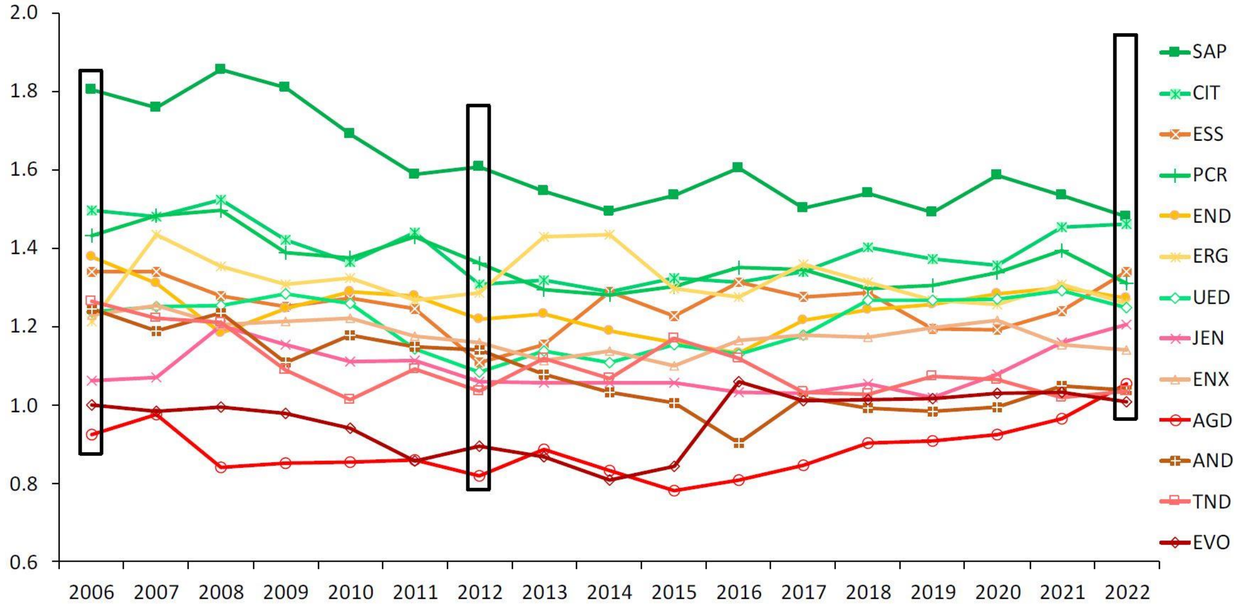


Figure 2: Multilateral total factor productivity (MTFP) trend by DNSP, 2006-2022 (Source: AER)[7]

As noted by the Institute for Energy Economics and Financial Analysis (IEEFA), both network utilisation and the MTFP "give us very little insight into understanding the economic productivity and relative efficiencies of the DNSPs", and that the "measure of MTFP is curious given that productivity should be based on the outputs that consumers value, not what DNSPs value".[8]

This observation is particularly important as distributed solar and other flexible consumer energy resources (CER), such as batteries and electric vehicles (EV), have become more prevalent, leading to legitimate questions over the appropriateness of the network utilisation metric in the CER era. Customers now require the ability to export energy and connect their CER, which creates two-way flows of energy and represents a different kind of network value: export services. These services are not explicitly considered by the current measures of network utilisation. The recognition of 'export services' is reflected in the AER's first annual export services network performance report,[9] which collects new data to understand and standardise how networks monitor and improve the quality of export services. Using current metrics, if a DNSP is effectively able to integrate high proportions of CER, driving a reduction in summer peak demand, its network utilisation figure would decline, reflecting negatively on the DNSP.

---

[6] For a fuller history of these trends including variance across jurisdictions and network business types, see the ACCC's 2018 review of retail electricity: ACCC, Retail Electricity Pricing Inquiry Final Report, Australian Competition & Consumer Commission, June 2018.
[7] AER, 2023 Annual Benchmarking Report – Distribution Network Service Providers, Australian Energy Regulator, November 2023.
[8] Kuiper, G. Reforming the economic regulation of Australian electricity distribution networks, IEEFA Report, May 2024.
[9] AER, 2023 Export services network performance report, Australian Energy Regulator, December 2023.

Alternative measures of network utilisation (or other metrics clustering around a similar purpose) could address the shortcomings of the existing metric, to better inform network performance assessment and planning, highlight stranded asset risks, and incentivise the adoption of non-network solutions, such as flexible demand. Such measures will be crucial in keeping consumer prices down over the coming decades as consumers continue to adopt solar and increasingly electrify gas and transport energy use.

Within this context, the work considers how the traditional network utilisation metric might be reconsidered for the new energy landscape, to more closely reflect the new types of customer value in the CER era.

2 Traditional Network Utilisation

2.1 Australian regulatory definition

The Australian Energy Regulator (AER) defines network utilisation as ***an operational performance metric that estimates the extent to which a DNSP's assets are used to meet the non-coincident maximum demand***.[5] Non-coincident maximum demand calculates the total energy usage at different locations (like connection points or areas) when each location is using its maximum amount of electricity. This is different from coincident maximum demand, which looks at the highest amount of electricity used across the entire network at the same time. Network utilisation is calculated for DNSPs as the ratio of reported non-coincident maximum demand (in megavolt amperes (MVA)) to total zone substation (ZS) transformer capacity (in MVA). We will refer to this definition hereafter in this report as the "**traditional network utilisation"** metric.

The metric is calculated as the summation of the non-coincident maximum demand supplied by all the zone substations in the network within one year over summation of all the capacities of the substations in the network, as per the following formula:

$$Traditional\ network\ utilisation\ = \frac{\sum_{sub=1}^{N} Maximum\ power_{sub}^{\text{non-coincident}}}{\sum_{sub=1}^{N} ZS\ capacity_{sub}} \times 100\%$$

where $Maximum\ power_{sub}^{\text{non-coincident}}$ is the non-coincident maximum demand supplied by zone substation sub during one year (i.e., it is not a function of time t, and it is maximum value in one year), N stands for the total number of the zone substations in the network, and $ZS\ capacity_{sub}$ represents the nameplate capacity of zone substation sub.

2.2 Historical insights

Historically, the network utilisation metric is known as the 'utilisation factor'. The utilisation factor was defined in 1957 by the American Institute of Electrical Engineers in the American Standard Definitions of Electric Terms, as *the ratio of the peak demand of a system to its rated capacity.* This factor can also be determined for a subsystem, which may be similarly defined as the peak demand of the subsystem to the rated capacity of the subsystem under consideration.[10] More recently, William H. Kersting defined the utilisation factor as *an indication of how well the capacity of an electrical equipment is being utilised, which can be calculated as a ration of maximum demand on the transformer (in kilovolt amperes (kVA)) to the transformer rating (in kVA)*.[11] The maximum demand and the rated capacity should be in the same units, so that the utilisation factor is dimensionless.

The Electric Utility Engineers of the Westinghouse Electric Cooperation in 1965 stated that the utilisation factor should include both the interval during which demand is measured and the specific duration that the peak demand covers. Additionally, it should highlight the degree to which a system is being loaded during its peak period, with respect to its capacity. Typically, a system's or a subsystem's rated capacity is defined by its thermal capacity. This early work points out that there may be instances where the actual load is below the system's thermal capacity but exceeds the allowable voltage drop, leading to a situation where the system's thermal capacity is greater than its capacity to handle voltage drops. The authors thus go on to recommend that when determining the utilisation factor, the smaller value between thermal capacity and voltage drop capacity should be used as the benchmark. To provide a comprehensive understanding, any mention of the utilisation factor should specify which of these capacities serves as the foundation for the rated capacity.[12]

---

[10] American Institute of Electrical Engineers. American Standard Definitions of Electric Terms, Group 35, Generation, Transmission and Distribution, ASA C42.35, 1957. *This definition is also used by Electric Utility Engineers of the Westinghouse Electric Cooperation in Pennsylvania, USA, in 1965, in "Electric Utility Engineering Reference Book: Distribution systems" book and by Turan Gonen in "Electric Power Distribution Engineering" book*.
[11] Kersting, W. H. Distribution system modeling and analysis. CRC press, 2001.
[12] Electric Utility Engineers of the Westinghouse Electric Cooperation. Electric Utility Engineering Reference Book: Distribution Systems, 1965.

This early work contains several useful considerations. Firstly, in a distribution system, load is not evenly distributed across all substations according to their capacity: some substations will be newer and have load intentionally shifted to them; and load growth is not uniform across the system, leading to varying degrees of load increase at different substations. This implies that calculations of the utilisation factor carry value when undertaken at the substation or transformer asset level.[12]

Secondly, there are not one-size-fits-all definitions for 'load' and 'capacity'. For instance, load can be defined as the peak monthly demand (in kVA) recorded in 15- or 30-minute intervals, with separate assessments for summer and winter peaks to account for temperature effects and daily usage patterns. Capacity might be determined based on the cooling method of transformers—whether self-cooled, air-forced, or oil-forced—or on an "operational capability" derived from practical experience with similar equipment. Furthermore, the capability of a substation with multiple transformers might be evaluated based on its firm capacity, considering scenarios like having one transformer down and calculating the permissible load on the remaining transformers during peak usage.[12] The implication here, for the purposes of this work, is to ensure that we are sufficiently specific in defining how the constituent components of the metrics are calculated.

Thus, while the AER, the Australian regulatory, definition is specifically at the system level for non-coincident demand, this is not the only way that network utilisation can or has been calculated. These historical uses highlight the value of a broader, multi-level indication of a distribution network's operational capability, which is:

- calculated as the ratio of peak demand to rated capacity,
- either for the entire system or specific subsystems (i.e., assets),
- measuring demand over specified intervals, and
- considering the impact of non-thermal network constraints (e.g., voltage limits) on asset capacity.

2.3 Applications

The traditional network utilisation metric has been used for understanding the network's design efficiency, current operation and future upgrade needs, which can used in the following three main applications:[5]

- **Network performance analysis and reporting:** Assessing how efficiently the electricity distribution network operates and reporting on network utilisation to regulatory bodies.
- **Infrastructure planning:** Providing a contextual reference point for decisions on network expansion and upgrades to meet future demand (even if not directly used to assess specific investment trigger points).
- **Electricity tariff calculation:** Network utilisation is one of the factors that informing the setting of demand charges based on usage patterns and the network charges based on the network capital and operating expenditure.

2.4 Use in other jurisdictions

The calculation of network utilisation varies slightly in different jurisdictions, and in some cases the prominence of its use has declined. In the UK, for example, the Office of Gas and Electricity Markets (OFGEM) has moved away from the use of network utilisation as a measure of network productivity. Network quality-of-service targets are now set in line with customer priorities, such as the quality of connections, reliability of service, and the environmental impact of operations.[13] However, network utilisation, referred to by OFGEM as the 'duty factor', remains an important factor for cables and substations (i.e., at the asset level). The metric plays a crucial role in estimating the expected lifespan of these assets and is incorporated into assessment, forecasting, and regulatory reporting. This, in turn, is used in the calculation of asset risk metrics.[14]

The Alberta Electric System Operator (AESO) in Canada applies utilisation metrics and related concepts for two reasons. The first is to cultivate a mutual understanding of network loading among interested parties.

---

[13] OFGEM, RIIO-2 Final Determinations - Core Document (REVISED), Office of Gas and Electricity Markets, February 2021.
[14] OFGEM, DNO Common Network Asset Indices Methodology, Office of Gas and Electricity Markets, April 2021.

The second is to communicate about utilisation transparently, addressing both past performance and anticipating future infrastructure needs. Utilisation is defined as the current use of network capacity, while capability refers to the unused capacity reserved for future expansion and demands. Utilisation is quantified by AESO as the highest proportion of capacity that is allocated for power flow and ensuring reliability, in relation to the total facility rating, represented as a percentage. At the asset level, the utilisation is assessed annually for stakeholder transparency, to generate long-term utilisation metrics and to identify trends for the years ahead. High utilisation areas are monitored closely, with the potential to adjust the planning models based on this surveillance. However, it is understood that while supplementary data is beneficial for decision-making, such results by themselves are not enough to justify the expansion of transmission infrastructure. Nonetheless, the AESO approach emphasises that comprehensive and contextual data analysis is essential for informed planning and development of the transmission network.[15]

2.5 Limitations of the traditional metric

In recent years, stakeholders have begun to question the relevance of network utilisation. Network businesses have highlighted that traditional measures of network utilisation no longer fully capture the value of network use as the energy landscape evolves. Energy Networks Australia (ENA) points out that the rise in CER, driven by a demand for more affordable and sustainable energy, is reshaping our understanding of network utilisation. They argue that CER reduces overall demand, which lowers utilisation, but can simultaneously lead to local congestion and may require additional investment in necessitating network upgrades. As utilisation is measured by substation peak demand, which necessarily coincides with periods when CER has a lower contribution,[16] typically in the evenings. Therefore, they argue, that the increasing adoption of CER and the investments required to accommodate this shift could undermine traditional benchmarks of network performance.[17]

The AER itself has signalled that network utilisation, in its current form, is an incomplete measure of the preparedness of network assets to respond to short term changes in demand. The AER is considering expanding its analysis of network utilisation to investigate the changing dynamics of maximum demand per customer,[5] to provide insight into how energy efficiency, demand management, and consumer energy resources can influence maximum demand per customer. This approach indicates an appetite for more detailed and customer-centric analysis of network utilisation and demand patterns.

Energy Consumers Australia (ECA) has argued that the current aggregate form of network utilisation measures fails to guide us towards outcomes that make the most of existing infrastructure, highlight stranded asset risks, adequately encourage beneficial activities like demand response, and more generally keep network prices down in an environment of increasingly dynamic two-way energy flows.[18]

A summary of the limitations of the traditional network utilisation metric can be distilled to five interrelated issues:

1. **Two-way flow:** It does not account for two-way flows on the network. As energy consumers invest in rooftop solar and batteries, distribution networks are being used less for one-way energy transfer and increasingly customers derive value from transferring energy both from and to the grid, which is not captured by the current metric.
2. **Minimum demand:** It does not account for the growing issue of minimum demand, resulting from an abundance of daytime solar, which offsets local loads and can cause constraints resulting from reverse flows.
3. **Time-differentiated utilisation:** Focussing utilisation only on a single peak hour of the peak day in the year limits the ability to provide meaningful information about how to get value out of the network outside of that one period. A broader time-based consideration might even consider the measurement of peak

[15] AESO, Transmission System Utilization Concepts and 2022 Assessment, Alberta Electric System Operator, September 2023.
[16] As when CER has a strong contribution, this lowers network demand, thereby 'shifting' the peak to other times when CER has a lower contribution.
[17] ENA, Is it time to retire network utilisation measures?, Energy Networks Australia, July 2021. Accessed on Feb. 07, 2024.
[18] ECA, Electricity distribution network utilisation – why it's important to consumers, and why we need to update how we measure it, Energy Consumers Australia, 2023. Accessed on Feb. 07, 2024.

loads separately for summer and winter to account for the effects of temperature and daily usage patterns on transformer performance. Generally, utilisation at different times of day or year could highlight when and where demand response or energy storage might be most beneficial. The reliance on non-coincident demand metrics may also overlook the nuances of simultaneous peak demands and their impact on network efficiency. The traditional approach, while providing a snapshot of asset utilisation, may not fully capture the dynamic and interconnected nature of modern distribution networks, potentially leading to inefficiencies in planning and operation.

4. **Asset-specificity:** Utilisation of different asset types/levels (e.g., feeders, street substations, zone substations) – which can vary widely across the network[12] – is not considered in current metric. Calculating utilisation for particular categories of network assets (e.g., substations, transformers, power lines) could provide insights into performance patterns across specific levels of the network.

5. **Local network issues:** Network utilisation varies significantly at different locations within a network, owing to differences in loads and CER penetration. As local network constraints become more prevalent during the energy transition, a simple, static, aggregated network-wide measure of total demand versus total capacity masks such constraints.

3 Rethinking network utilisation

3.1 Benefits of rethinking network utilisation

Alternative measures of network utilisation (or other metrics clustering around a similar purpose) can address the above limitations to better inform network planning, highlight and address stranded asset risks, and help to incentivise the adoption of non-network solutions, such as flexible demand.

A more granular and nuanced picture of utilisation in time and space could help to both manage peaky loads (areas of high utilisation) and to improve productivity in areas and times of low grid demand (more often associated with lower utilisation).

In the context of peaky loads, such granular measurement could identify where investments in CER could reduce grid demand, particularly in areas with significant potential for deferring capital-intensive grid upgrades.

Conversely, understanding the times and locations in which *more* energy could be pushed through the network can fill ‘troughs’ in demand. This is of relevance in promoting flexible loads to utilise surplus solar generation, and to better target tariffs, consumer education and infrastructure planning for strategically located and timed EV charging. If DNSPs and retailers can offer appealing EV charging rates, this could support revenue growth, better EV charging facilities, and repay network infrastructure over a larger base of energy sales. For EV charging stations, where all costs are predominantly fixed post-construction, achieving high utilisation is crucial for efficiency. Even with a modest utilisation of 20% for stand-alone fast chargers, peak times may see customer queues. Surpassing this threshold often prompts operators to consider expanding or adding new locations to accommodate increasing demand.[19] These opportunities are summarised in Table 1, below.

Table 1: Two means of improving network utilisation for customer benefit

	Flattening Peaks	Raising Troughs
Where	Higher utilisation areas	Lower utilisation areas
When	Higher utilisation duration	Lower utilisation duration
How	Reduce the energy flow through the substation and in the feeders	Incentivise EV charging or other load shifting during low utilisation periods
Why	Defer or avoid grid upgrades and reduce CER curtailment	Increase energy throughput, lowering average network prices

3.2 Assessment criteria for new metrics

To assess the suite of potential new or updated utilisation metrics, three meta-criteria and a series of sub-criteria were used:[20]

1. **Does it overcome one or more of the limitations of the traditional network utilisation metric?**
   a) Does it value or recognise two-way energy flow, acknowledging both traditional grid-to-consumer and consumer-to-grid power flow?
   b) Does it allow for the measurement and management of negative demand, resulting from reverse power flows?
   c) Does it account for time-based variation in demand (across seasons or time of day), or can it be effectively applied across various time scales?
   d) Does it apply to different asset types/levels (e.g., feeders, street substations, zone substations)?

[19] PwC, Electric vehicles and the charging infrastructure: a new mindset?, 2021. Accessed on Feb. 19, 2024.
[20] These criteria were informed by the principles of performance based regulation: see Logan, et al., Next-Generation Performance-Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation, National Renewable Energy Laboratory, September 2017.

    e) Can it be applied to specific grid locations, enabling targeted analysis and interventions?

2. **Is it practical and cost-effective? considering:**
    a) Ease of data access: Data at the appropriate level of temporal and spatial granularity is readily available (now or in the future).
    b) Data quality: Data is sufficiently reliable, accurate, and has good coverage across the relevant levels of the system, assets, or customer types.
    c) Ease of calculation: Metric formula and calculation approach are transparent (can be independently validated) and replicable.
    d) Ease of interpretation: Metric formula, calculation approach and implications are relatively simple to understand and explain.
    e) Consistency over time: The definition and reporting of the metric are well defined and do not depend on factors that are subject to change, such as the timing of tariff peak periods.
3. **Does it consistently drive the right outcomes/behaviour? including:**
    a) Does it encourage reduced customer prices or bills?
    b) Does it support beneficial customer activities in a future energy system, such as self-consumption and continued CER uptake, including EVs and battery storage technologies?
    c) Is it applicable across different network types (such as urban versus rural), with different monitoring/measurement capabilities?
    d) Is it applicable across different customer types and classes?
    e) Can the network business act to positively affect the metric in the long term?
    f) Does it have a low potential for unintended perverse incentives/outcomes?
    g) Does it respect power quality, reliability, and system security standards, ensuring safe and resilient operation?
    h) Does it promote or support equitable cost allocation outcomes?

4 New metrics for consideration

A review of Australian and international scholarly and grey literature was undertaken to examine different approaches to the calculation of network utilisation and alternatives that have been floated to address the emerging limitations of network utilisation in the CER era. A long list of existing and prospective metrics was compiled as the starting point to consider metrics that could eventually replace or complement traditional network utilisation. These were arranged into six categories for consideration: energy, power (the traditional metric falls into this category), economic, power quality, reliability, and risk and resilience metrics. The longlist (refer to Appendices) was reviewed against the assessment criteria (Section 3.2, above) to propose an initial shortlist to the Industry Reference Group (IRG). After refinement based on IRG feedback, a final shortlist of two headline metrics and four complementary metrics was selected. This section outlines the rationale behind and representation options for each of the metrics in the shortlist. Section 5 then presents the results and conclusion of the road-testing of calculation of the headline metrics.

4.1 Energy metrics

The most tangible service that customers derive from the grid is the delivery of energy: this can be in the form of both *imports* to service customer energy demand, and *exports,* to distribute excess CER energy to other users on the network. While the AER's established position on a customer's behind-the-meter *self-consumption* of CER[21] is that it is not considered as a 'network output', there are also strong arguments for including self-consumption in the calculation of customer value and thus as part of network utilisation. These are explored in detail in Section 4.1.1 below.

An alternative way of thinking about network utilisation might even be 'how much energy can be put through a given network asset'. As such, metrics that measure energy throughput relative to capacity may offer a useful framework for measuring the value that customers derive from the modern grid.

4.1.1 To include or exclude CER self-consumption?

Measuring network utilisation is not considered solely (or necessarily primarily) a tool to use to change the behaviour of network businesses. Measuring network utilisation helps us to understand how the *entire system* — including consumer and large-scale generation and storage — can be developed at least cost and the greatest customer value. As such, we want to ensure that the metrics reflect all useful forms of customer value associated with a connection to the network. We suggest that this should include self-consumption for the following reasons:

- Self-consumption requires a network connection and reference voltage to be able to take place in grid-connected PV systems. Self-consumption is part of the same technology that produces exports, which are considered a network output, and it does not make sense to consider one outcome of a technology but not another. Indeed, from a customer value perspective, self-consumption is far more important to customers than exports. A decade ago, customers may have justified investment in solar based substantially on exports. However, without regulated feed-in tariffs (FiTs) and as surplus solar production drives spot prices and associated retailer FiTs down, customers would now largely not adopt rooftop solar in the absence of self-consumption. Therefore, treating self-consumption and exports as disconnected phenomena should be avoided if attempting to taking a systemic and holistic view.
- When a customer self-consumes, the existing network capacity can be used to deliver additional energy to other customers. Essentially this means that the same infrastructure can be 'used more than once', particularly when new energy uses coming online are increasingly flexible, such as smart hot water, air conditioning, or EV charging. This is the reason that a grid with high CER penetration can theoretically achieve more than 100% utilisation of a given asset, because more and more customers can have their energy services met with the same infrastructure. This is *not* the case for an electricity system served only by centralised generation. Therefore, if proactively managed, self-consumption should align with the

[21] For the purposes of this report CER only includes solar PV systems.

least cost customer outcome, as a greater volume of useful energy services can be met with the same sunk infrastructure cost.

- Self-consumption will increasingly not only occur during solar hours: with the uptake of distributed battery storage (both home batteries and EVs), self-consumption will be a steeply increasing phenomenon to mediate peak demand outside solar hours and may thus be undesirable to leave outside the measurement system.
- If self-consumption is *excluded* from the metric, that customer's self-consumed energy services become 'invisible to the network' and would register as a decline in utilisation. *Including* self-consumption seeks to avoid the emergence of a tension between customers being rewarded for self-consumption, but networks only being viewed as having productivity improvement if exports rise.
- The scale of self-consumption is not inconsequential, given it is in the order of 25-75% of total generation, so is roughly of equivalent magnitude to exports. This proportion will increase with battery storage.

Conversely, there are legitimate challenges associated with including self-consumption that must be taken seriously. Most prominently, self-consumption is an action taken by consumers using their own investment, and thus network businesses should not be 'rewarded' for actions taken by others. While we agree with this general principle, the argument carries most weight if there are financial incentives associated with increased utilisation. This is not currently the case, nor is this proposed by the authors or the ECA. Incentive schemes should be considered as a separate use case and may have different associated metrics. Network businesses are not the only actors (or even potentially the most important actors) that can improve network utilisation. In the era of CER, this can and should be a collaborative effort between networks, consumers, retailers, local councils, developers, the CER industry, and others.

Self-consumption is also difficult to measure without access to customer devices, which increases the level of uncertainty in the calculation. This is also of greater concern when financial rewards are associated with the metric.

On balance, the authors take the position that a holistic network utilisation energy metric should include self-consumption, and is therefore included in the below proposed Total Energy Throughput Utilisation metric. Given this uncertainty, this metric was road-tested with an adjustment to the formula to simulate with/without self-consumption, as discussed Section 5.3.1. Using the primary formula based on Zone Substation data, we found that it was not possible to *only* exclude behind-the-meter self-consumption, as CER exports that are locally consumed within the Zone Substation area was also excluded.

In this version (v1.2) of the report, an alternative formula using customer metering data was added that enables self-consumption at individual premises to be isolated (and excluded, should this be required). This can be found in Section 4.1.2.1.

4.1.2 Proposed metric: Total Energy Throughput Utilisation (TETU)

This metric is a productivity indicator that measures the total bi-directional flow of energy as a proportion of total potential energy flow through the asset.

The 'default' scale of application would be to calculate this metric at the zone substation level, as per the traditional network utilisation metric. The metric could then be averaged across the network to a single percentage figure (as per the traditional metric, by summing the numerators for all zone substations within the network over the analysis period (i.e., timeframe) and dividing this by the total capacity of all substations in the network, multiplied by the length of the timeframe.) and could also be calculated other more granular asset levels such as the feeder or street substation. While the default would be annual, the metric could also be calculated on any time horizon based on the application/use case. The general mathematical representation can be formulated as follows:

$$Total\ Energy\ Throughput\ Utilisation\ (\%)^{\S} = \frac{Forward\ Energy\ Flow + |Reverse\ Energy\ Flow| + Locally\ Consumed\ CER\ Energy^{\wedge}}{Seasonal\ Rated\ Capacity \times Time\ Frame^{*}}$$

where,

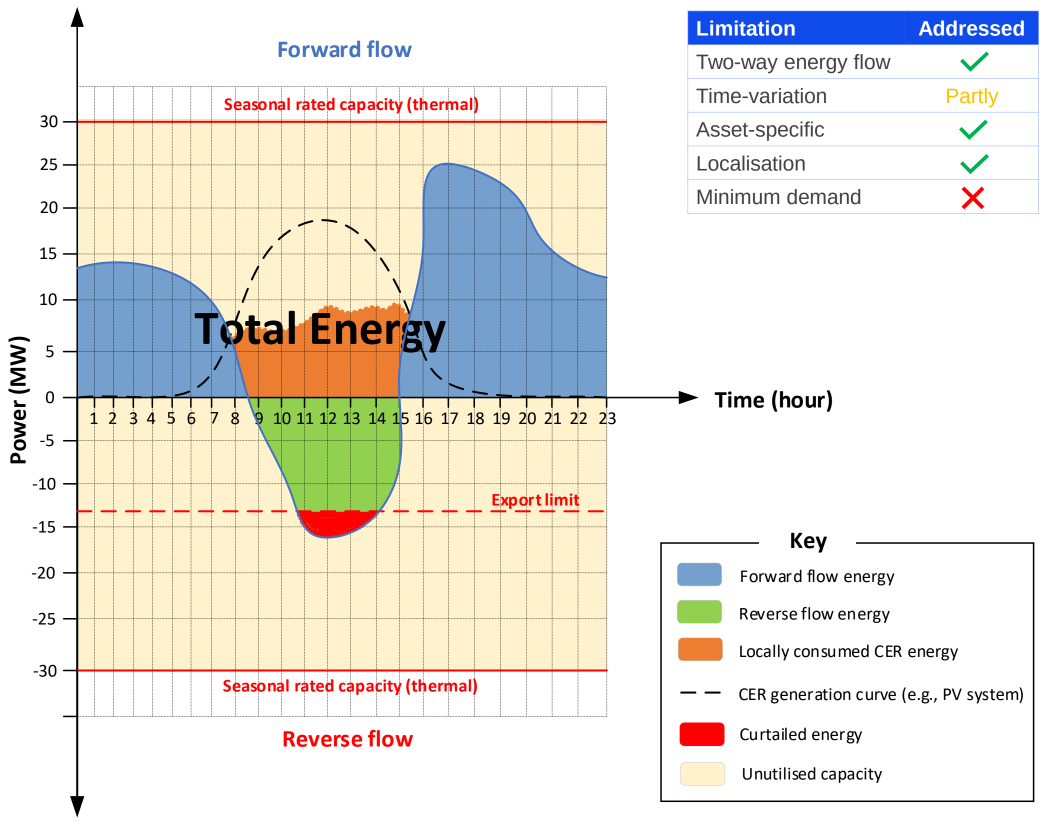
$$^{\wedge}Locally\ Consumed\ CER\ Energy = Expected\ CER\ generation^{\#} - Estimated\ curtailment^{\#} - |Reverse\ Flow\ Energy|$$

* Time frame can be several hours, day, month, season, or the whole year in hourly basis.

\# Curtailment can be quantified as the difference between the amount a customer's CER is allowed to export and the theoretical potential output of the installed CER if no network constraint was present.[9]

§ This metric can be calculated at a range of different network asset levels (e.g. feeder), but the default undertaken in this report is the Zone Substation. If self-consumption is to be excluded, an alternative formula is provided in Section 4.1.2.1.

Figure 3 below visually depicts the metric components in the calculation over a 24-hour period (measured at the zone substation), although the standard metric would be calculated using energy flows over a 12-month period. Only the blue (customer demand) and green (customer exports) are measurable at the zone substation; the yellow (CER energy) needs to be calculated based on the CER capacity reported at zone substation and weather data, while the curtailment amount can be estimated based on the reported curtailment level at the zone substation or customer level if reported; the orange (locally consumed CER) needs to be calculated with installed CER capacity data.



Limitation	Addressed
Two-way energy flow	✓
Time-variation	Partly
Asset-specific	✓
Localisation	✓
Minimum demand	✗

Figure 3: Visualisation of Total Energy Throughput Utilisation (24-hr sample)

The result from this metric is a percentage value that could range from zero to 100% only when locally consumed solar is not included, while it can theoretically exceed 100% when locally consumed solar is included (accounting for both asset capacity and self-consumption). Therefore, the units of energy and capacity should be the same (e.g., kVA or MVA). As this metric has three components (forward energy flow, reverse energy flow and locally consumed solar energy), these should be preserved in recording the calculation to enable other bespoke variants of the metric to be applied to other use cases.

The percentage represented by the TETU metric is calculated by summing the blue, orange, and green areas in the chart (representing forward flow energy, locally consumed CER energy, and reverse flow energy, respectively), subtracting curtailment (in red) and dividing this sum by the total yellow area, which represents the amount of energy that could theoretically pass through the network if was being fully utilised all of the time. Essentially, the metric reflects the portion of the network's capacity that is utilised by the energy flows, either forward or reverse, accounting for locally consumed CER energy.

The TETU was designed as a metric that networks can more clearly seek to increase over time, providing other performance targets on power quality and reliability are met. It is not yet clear what 'target' TETU benchmarks are desirable. We expect that such questions will begin to resolve themselves as the metric is implemented over time. Patterns will emerge across different network types or regions, climate zones, or in jurisdictions with different reliability standards.

We anticipate that a thorough understanding of the metric's performance across diverse networks may take several years and should be interpreted alongside calculation of the traditional utilisation metric for consistency of interpretation.

There is always the potential for perverse incentives or unintended consequences resulting from the establishment of new performance metrics. The TETU metric appears to offer a significant improvement over the traditional metric in terms of network productivity assessment, and we have uncovered relatively few potential conflicts with what would generally be considered desirable system outcomes on a pathway to low cost, high reliability, cleaner energy provision. The main issue flagged is where the same customer outcome is successfully delivered through better efficiency. While misreporting could theoretically occur, it would not necessarily benefit network businesses. For example, if a network reports an artificially lower transformer capacity to increase the TET, it may face difficulties later when justifying the need for network upgrades.

While challenges are inevitable with any metric, the issues posed by the TETU metric do not seem to exceed the difficulties present in the traditional metric, nor are they insurmountable. Nonetheless, it will be important for the AER, in its consideration of alternative network utilisation metrics to consult on potential perverse incentives, including to misreport and on the advantages or disadvantages of including self-consumption in the TETU formula.

4.1.2.1 Alternative formula: TETU based on customer data

An alternative approach to calculating the TETU metric uses aggregated customer metering data. This formula can be calculated with or without behind-the-meter self-consumption ('Self Consumed Solar Energy'), as follows:

$$TETU\ (\%)^{\S} = \frac{\sum_{c=1}^{C} Import\ Energy_c + \sum_{r=1}^{R} Self\ Consumed\ Solar\ Energy_{\boldsymbol{r}}\,\hat{} + Export\ Energy^{\S}}{Seasonal\ Rated\ Capacity^{\S} \times Time\ Frame^{*}}$$

where $Import\ Energy_c$ stands for the energy imported at the customer c measured at the customer meter, C is the total number of customers within the service area of the asset, $Self\ Consumed\ Solar\ Energy_{\boldsymbol{r}}$ is behind-the-meter consumption for solar customer r, R is the total number of solar customers within the service area of the asset, $Export\ Energy$ is the energy flow exported from the asset service area to neighbouring assets (in the default case, energy exported from one zone substation to neighbouring zone substations).

Self-consumption solar energy may be included or excluded, and can be estimated as:

$$\hat{}Self\ Consumed\ Solar\ Energy = Expected\ Solar\ Generation - Expected\ Solar\ Export - Estimated\ curtailment^{\#}$$

*Time frame can be several hours, day, month, season, or the whole year in hourly basis.
Curtailment can be quantified as the difference between the amount a customer's solar system is allowed to export and the theoretical potential output of the installed solar system if no network constraint was present.
§ Variables with this symbol are measured at the relevant network asset level for the desired calculation. In the default case, the Zone Substation TETU measures exports and rated capacity at the Zone Substation level. The remaining variables involve aggregated customer data with that asset's service region.

This metric can be calculated at a range of network asset levels. Note that to calculate the metric at the whole of network level, this would only include exports that leave the DNSP service territory. Exports from one zone substation to another would be double counted as 'exports' in the originating zone and as 'consumption' in the destination zone.

Also note that the original TETU formula effectively includes losses between the customer and the asset, but this customer metering data-based version effectively excludes these losses, which would result in a slight underestimation of utilisation at the DNSP asset.

4.1.2.2 Load factor type variant

As the TETU metric divides energy throughput by the asset capacity, it focusses attention on assets that are closer to reaching capacity augmentation. This is useful for short-medium term investment planning, but hides variation in lower-utilised assets, which is useful for understanding the long-term desired trend towards filling troughs and lowering peaks across the whole network. Such a metric is and easier to compare across the full range of assets at *different stages* of the investment cycle.

A variant of the TETU formula (shown in the Appendices) replaces **Seasonal Rated Capacity** with **Seasonal Maximum Load** in the denominator, as in a traditional 'load factor' calculation.[22] This shifts the focus to the variation in the 'flatness' of loads across the system, and highlight better or worse performing regions, irrespective of how close impending capacity investments may be. An example calculation of this variant is shown in Figure B-1 in the Appendices.

4.1.2.3 Visual Representation Options

The TETU metric can be represented as an annual figure for the whole network or for specific assets. The yearly figure can be visualised in hourly/daily/weekly/monthly resolutions. However, other visual representations can be considered based on the application, including:

1. **Seasonal Variant:** Rather than an annual view, this variant breaks the calculation down by season, to reveal greater clarity on how productivity changes in summer, winter, and spring/autumn. The road testing shows seasonal variation represented across the months of the year.
2. **Map-based view:** This metric lends itself to map-based polygon representations at the zone substation level, or more granularly, as desired.

4.1.2.4 Pros, Cons and Applications

This section summarises the advantages, disadvantages, and potential applications of the TETU metric as listed in Table 2.

Table 2: Pros, cons and applications of the proposed TETU energy metric

Pros	Cons	Applications
• Reflects all useful customer exchanges from the grid (import, export, local consumption of CER) relative to the 'full potential' of the asset. • Can reflect seasonal rated capacity differences (summer/winter). • Voltage-tripping leading to *lost solar exports is captured.*	• Voltage-tripping leading to *lost self-consumption is not captured* (as this is just seen as a resulting rise in grid imports) • Does not tell us anything about risk or timing of low/high utilisation events so has more value for planning (e.g., optimising assets, tariff design, incentives scheme) than for operational purposes (see power metric – Section 4.2). • CER exports and self-consumption are not currently considered "outputs" in the AER's capital and operating	• Annual, system-wide figure is useful for regulation (alongside power metrics). • Seasonal, asset-specific, or spatially mapped versions could be useful for planning. • Preserving calculation components could increase forward/reverse flow energy to be used in other applications.

[22] This metrics was explored based on feedback regarding the benefits of a traditional load factor approach for comparison of network assets at different stages of the investment cycle, from Heather Smith (pers. comm.).

• Yields single value per asset, which is simple for reporting and benchmarking.	expenditure benchmarking, which may represent a barrier to incorporating utilisation into network performance reporting.

4.2 Power metrics

Power metrics measure operational demand on the network at specific point/s in time relative to the asset capacity. Traditional network utilisation is a power metric for a specific time point (anytime maximum demand). This type of metric is inherently more peak (or negative) demand focused than energy metrics, which measure *throughput*. They are useful for infrastructure planning and risk assessment and offer insights into the network's ability to manage renewable integration and demand-side strategies.

4.2.1 Proposed metric: Two-way power flow utilisation

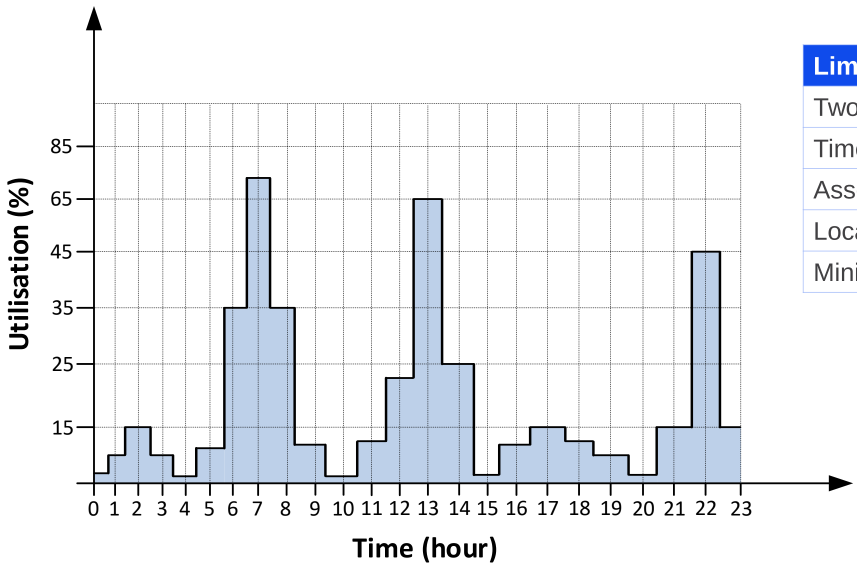
This metric evaluates how intensively the distribution network asset is used (or how "at risk" assets are run) across the year, considering time-varying bi-directional peak or minimum demand. The metric can be binned according to specific time periods (e.g. maximum annual value [i.e. the traditional metric], top 100 hours, 500 hours, etc.) as is considered relevant for strategic decision making.

The two-way power flow utilisation metric can be calculated on the asset level (e.g., feeder, street substation, zone substation) and network level on any time horizon from few hours to seasonal extended to yearly basis (i.e., 8760 hours) based on the application/use case. The general mathematical representation can be formulated as follows:

$$Two\ way\ Power\ Flow\ Utilisation\ (\%)^{\wedge} = \begin{cases} \dfrac{Peak\ forward\ power\ flow\ in\ hour}{Seasonal\ rated\ capacity}, & if\ power\ in\ hour \geq 0 \\ \dfrac{|Peak\ reverse\ power\ flow\ in\ hour|}{Seasonal\ rated\ capacity}, & if\ power\ in\ hour < 0 \end{cases}$$

^ Periods are binned into a few strategic categories. Also, if the asset is a line/cable then the flowing current should be considered instead of power flow in kA and the line/cable ampacity instead of rated capacity in kiloamperes (kA).

The result from this metric is a percentage value that would usually range from zero to 100%, but in some instances could exceed 100% when assets are run at higher levels of risk for short periods (much like the traditional network utilisation metric). The units of power and capacity should be the same (e.g., kVA or MVA). A representation of the raw time-series data is shown in Figure 4, below.



Limitation	Addressed
Two-way energy flow	✗
Time-variation	✓
Asset-specific	✓
Localisation	✓
Minimum demand	✓

Figure 4: Raw time-series two-way power flow utilisation (24-hr conceptual example only)

4.2.1.1 Visual Representation Options

In analysing power flow utilisation data for the network assets, effective visualisation techniques are crucial for revealing patterns and informing decision-making processes. This section explores three different options for visually representing two-way power flow utilisation data, each tailored to provide specific insights. These include “Utilisation Threshold” graphs (explained through the interim calculation steps), the “Two-way Time of Use (TOU) Representation”, and the “Two-way Seasonal Heat Map Representation”. Each visualisation approach serves specific analytical purposes, such as cost allocation, tariff design, demand management incentives, and understanding overall network demand patterns. Each offers different advantages for stakeholders to interpret and manage the power flow and optimise the asset utilisation.

1. Utilisation Thresholds

This option is explained through a set of interim calculation steps. Half hourly two-way power flow utilisation data for a given asset (e.g., zone substation) is first arranged in order of highest to lowest values, to create a “two-way” load duration curve style graph (i.e., representing both forward and reverse flows), as illustrated in Figure 5 below. The steeper the curve, the peakier the demand on the asset. Where reverse flows occur, these can be shown in the ‘mirror’ curve in red.

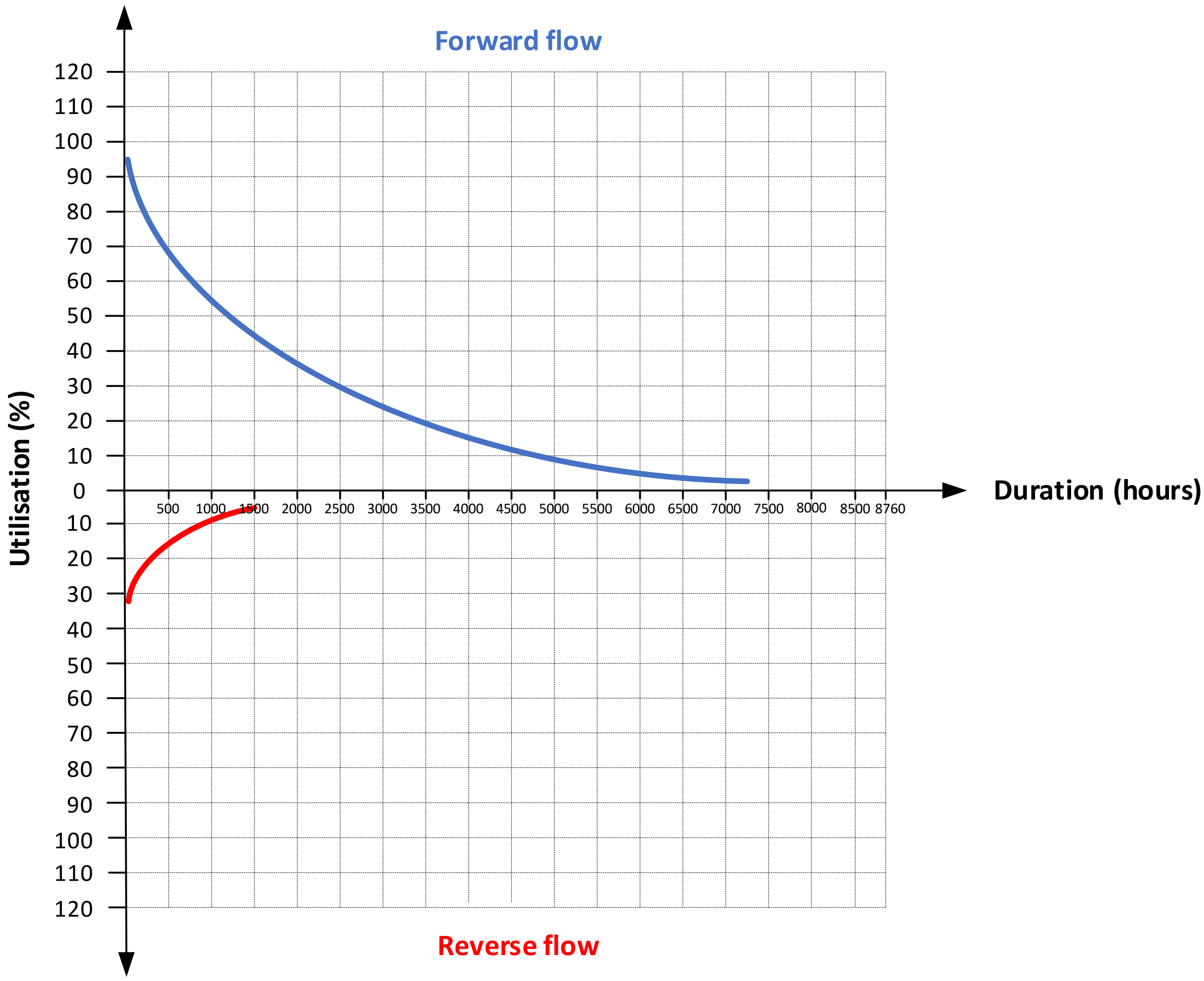


Figure 5: Interim Step 1 – Two-way utilisation duration curve

This allows the user to read off the utilisation level for a given number of hours per year, or vice versa. To **enable comparison between networks**, consistent tables can be created that “bin” the data according to a set of pre-determined data points, such as: Maximum hour, Top 100 hrs, Top 500 hrs, as shown in the top half of Figure 6. When undertaken for all assets at a given level (e.g., zone substation), the percentage of assets that fall into different utilisation bands can be determined, as shown in the bottom half of Figure 6.

Asset **1**

Hours	Utilisation (%)	
	Forward flow	Reverse flow
Maximum hour	38%	6.6%
Top 100 hrs	23%	2.9%
Top 500 hrs	18%	0%

Asset **2**

Hours	Utilisation (%)	
	Forward flow	Reverse flow
Maximum hour	69%	0%
Top 100 hrs	56%	0%
Top 500 hrs	49%	0%

— — —

Asset **N**

Hours	Utilisation (%)	
	Forward flow	Reverse flow
Maximum hour	48%	8.7%
Top 100 hrs	33%	4.5%
Top 500 hrs	27%	0%

DNSP **A** – Max. 1 hr

Utilisation threshold (%)	Proportion of assets (%)	
	Forward flow	Reverse flow
0-20%	8%	99%
20-40%	54%	1%
40-60%	29%	0%
60-80%	8%	0%
80-100%	1%	0%
>100%	0%	0%

DNSP **A** – Top 100 hrs

Utilisation threshold (%)	Proportion of assets (%)	
	Forward flow	Reverse flow
0-20%	15%	99%
20-40%	71%	1%
40-60%	12%	0%
60-80%	3%	0%
80-100%	0%	0%
>100%	0%	0%

DNSP **A** – Top 500 hrs

Utilisation threshould (%)	Proportion of assets (%)	
	Forward flow	Reverse flow
0-20%	33%	100%
20-40%	60%	0%
40-60%	7%	0%
60-80%	0%	0%
80-100%	0%	0%
>100%	0%	0%

Figure 6: Interim Step 2 – Two-way utilisation asset tables for zone substations (top) & whole network (bottom)

These tables showing the proportion of DNSP assets that are utilised in the forward and reverse flows at different utilisation thresholds (i.e., 20% bands) are what is displayed in the third step in Figure 7 below. This can be shown for different peak durations. The top 1 hour might be of most relevance if interested in traditional deterministic investment triggers or demand response, the top 100 hours might be relevant if interested in demand management in sustained high utilisation zones, or the top 500 hours might be relevant if interested in assets that may be targets for broad-based load shifting programs.

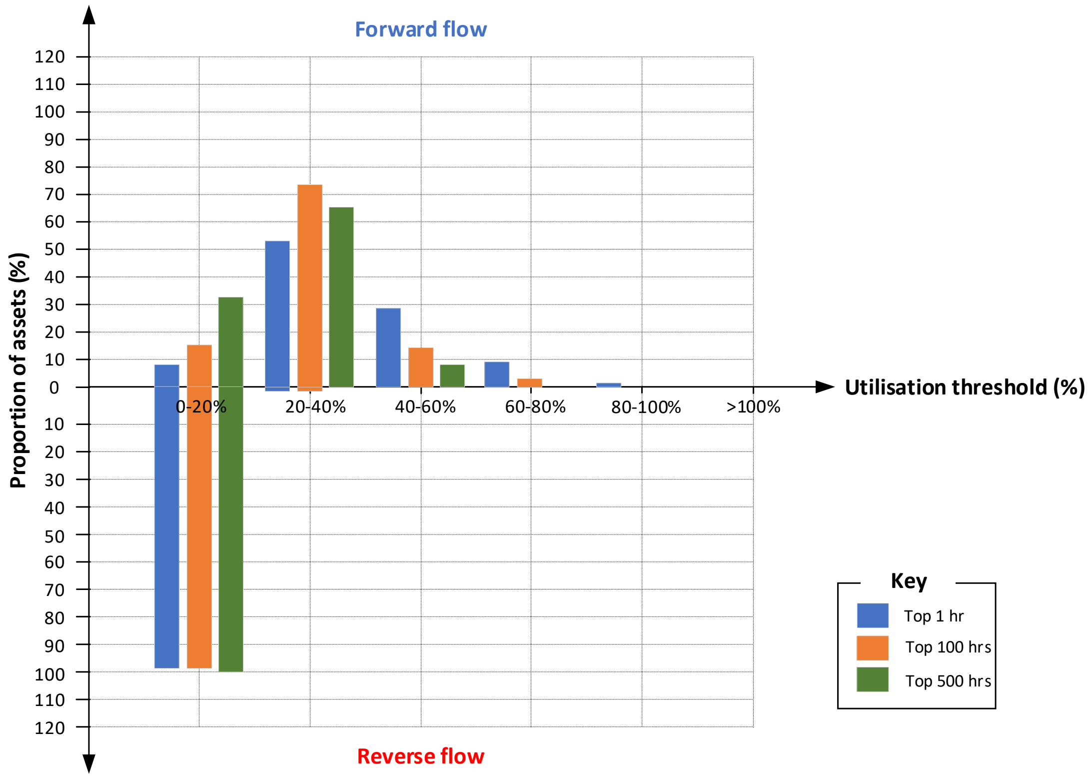


Figure 7: Interim Step 3 – Proportion of assets at different two-way power flow utilisation levels for a given DNSP (Top ~1 hour, 100 hours, and 500 hours durations shown)

With this data in hand, networks can be compared by the proportion of assets at each utilisation threshold, as shown in the example below (see Figure 8). This data could be considered alongside the Total Energy Throughput Utilisation (TETU) energy metric, to contextualise the capacity margins that different networks are using to achieve their energy throughput productivity.

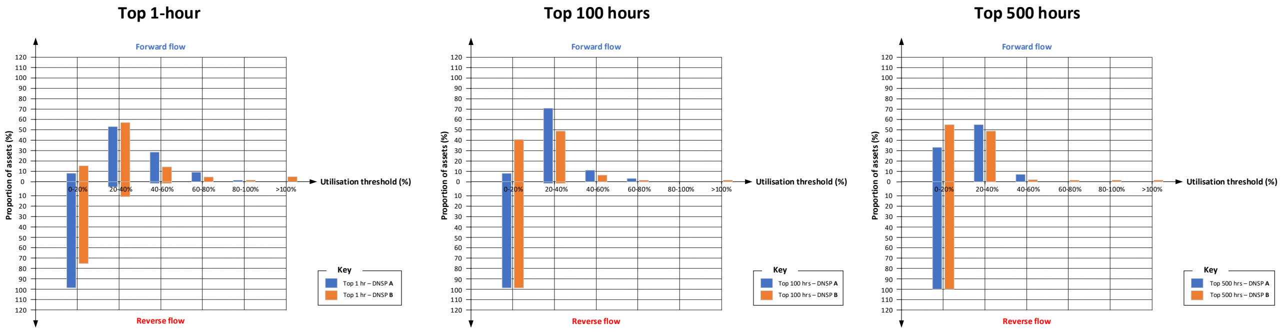


Figure 8: DNSP comparison of proportion of assets at different two-way power flow utilisation levels (Top ~1 hour, 100 hours, and 500 hours durations shown)

2. Two-way Time of Use (TOU) Representation

This version bins the power flow utilisation data into TOU periods, to represent average power flow utilisation on an hourly basis during peak, shoulder, solar soak, and off-peak periods for specific assets. This representation provides a direct link between the time of day/season and utilisation, which may inform cost allocation, tariff design and demand management incentives. A system-level version averaged across all zone substations – while less useful for the above purposes – may also provide an interesting comparison of network demand patterns.

The two sub figures in Figure 9 illustrate the hourly utilisation of specific assets (not the system as a whole), focusing on forward and reverse flow patterns. The figure on the left-hand side depicts the hourly forward flow utilisation. The black area represents the average hourly forward flow utilisation across a 24-hour period based on the selected season—summer, winter, (or other seasons) or annual. The lower the utilisation, the closer the black area is to the centre of the circle for that hour. Utilisation is calculated as the ratio of power flow over a given period (e.g., hourly) to the asset's capacity. The red line highlights the peak forward flow day, identified as the day with the highest positive utilisation. Any negative values on this peak day are converted to zero, so the figure only reflects forward flows.

On the right-hand side, the figure presents the reverse flow utilisation, which captures the values where the power flow is negative. The light blue area represents the average reverse flow utilisation, calculated by averaging the absolute values of the negative utilisation over the selected season or annually. Similar to the forward flow figure, the red dashed line indicates the peak reverse flow day, where the highest negative utilisation occurs. On this peak day, any positive values (forward flows) are converted to zero so that only reverse flows are represented.

Together, these figures show the difference between the average and peak utilisation in both directions. The zone substation represented shows low average forward utilisation across most of the day, peaking in the evening, which is strongly accentuated on the peak day. Average reverse flows are substantial during solar hours.

A limitation of this representation is that while a standardised scale is preferable to better compare assets, many assets in the network have low utilisation, so appear as very small circles on this image. Rescaling is needed to interrogate the utilisation profile of lower demand assets.

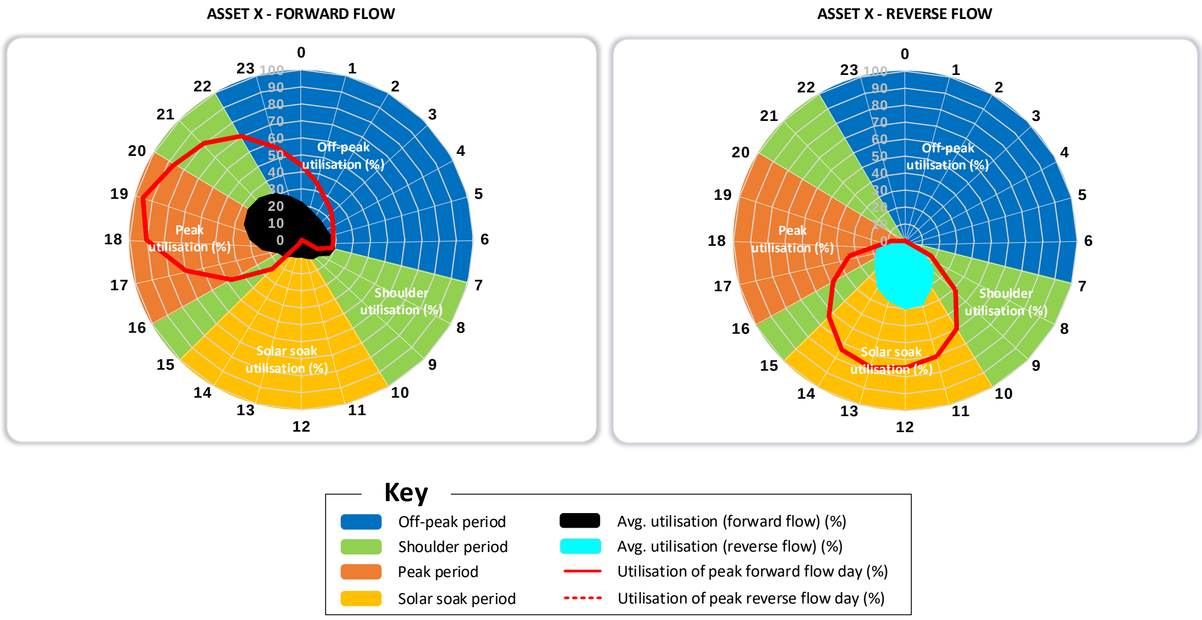


Figure 9: Visualisation options: Two-way TOU power flow utilisation (residential TOU periods example, for summer) – Internal circles represent the utilisation in %, out numbers on the edges (0-23) represent the 24-hours

3. Two-way Seasonal Heat Map Representation

Some readers may find the above clock representation difficult to interpret. An alternative version represents power flow utilisation data as a heat map, which shows hourly utilisation for the peak day, average weekdays and average weekend days. The heat map uses colour coding to indicate utilisation levels for specific assets, clearly showing periods of high, medium, and low utilisation. This approach facilitates a similar TOU analysis, offering a percentage-based view of utilisation and its correlation with specific times of the day/week/season for each asset. This information can be valuable for cost allocation, tariff design, and demand management incentives. Like the clock representation, a system-wide version averaged across all zone substations can provide an interesting comparison of overall network utilisation patterns. This version bins the power flow utilisation data into seasonal TOU periods to represent average power flow utilisation on an hourly basis during peak, shoulder, solar soak, and off-peak periods for specific assets. This representation provides a direct link between the time of day/season and utilisation, which may inform cost allocation, tariff design and demand management incentives. A system-level version averaged across all zone substations – while less useful for the above purposes – may also provide an interesting comparison of network demand patterns.

The two sub figures in Figure 9 illustrate the hourly utilisation of specific assets (not the system as a whole), focusing on forward and reverse flow patterns. The figure on the left-hand side depicts the hourly forward flow utilisation. The black area represents the average hourly forward flow utilisation across a 24-hour period based on the selected season—summer, winter, (or other seasons) or annual. The lower the utilisation, the closer the black area is to the centre of the circle for that hour. Utilisation is calculated as the ratio of power flow over a given period (e.g., hourly) to the asset's capacity. The red line highlights the peak forward flow day, identified as the day with the highest positive utilisation. Any negative values on this peak day are converted to zero, so the figure only reflects forward flows.

On the right-hand side, the figure presents the reverse flow utilisation, which captures the values where the power flow is negative. The light blue area represents the average reverse flow utilisation, calculated by averaging the absolute values of the negative utilisation over the selected season or annually. Similar to the forward flow figure, the red dashed line indicates the peak reverse flow day, where the highest negative utilisation occurs. On this peak day, any positive values (forward flows) are converted to zero so that only reverse flows are represented.

Together, these figures show the difference between the average and peak utilisation in both directions. The zone substation represented shows low average forward utilisation across most of the day, peaking in the evening, which is strongly accentuated on the peak day. Average reverse flows are substantial during solar hours.

A limitation of this representation is that while a standardised scale is preferable to better compare assets, many assets in the network have low utilisation, so appear as very small circles on this image. Rescaling is needed to interrogate the utilisation profile of lower demand assets.

Figure 10 illustrates the two-way heat map power flow utilisation representation in summer (both seasons are shown in the road-testing section).

(a) FORWARD FLOW - Asset X																								
Day/Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Peak day FF	36	28	22	20	16	14	14	14	8	0	0	0	0	0	2	20	38	56	72	76	70	64	56	44
Weekday	18	16	12	12	12	12	12	10	8	8	8	6	6	4	6	18	12	14	20	26	28	28	26	22
Weekend	20	16	14	12	12	10	10	8	8	6	6	6	8	4	6	14	18	20	22	28	30	30	28	24

(b) REVERSE FLOW - Asset X																								
Day/Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Peak day RF	0	0	0	0	0	0	0	0	14	32	48	56	60	62	60	50	38	28	6	0	0	0	0	0
Weekday	0	0	0	0	0	0	0	0.8	8	20	30	34	36	32	30	26	20	14	2	0	0	0	0	0
Weekend	0	0	0	0	0	0	0	1.6	8	20	28	34	32	30	25	22	22	14	4	0	0	0	0	0

Figure 10: Visualisation options: Two-way seasonal heat map power flow utilisation (example, summer) – (a) Forward flow heat map; and (b) Reverse flow heat map (numbers in percentages)

4. Map-based view

If applied at the zone substation or lower asset level, either of the above data representations would lend themselves to being presented in map form to show specific asset utilisation. Canada's Alberta Electric System Operator provides an example of a map showing traditional network utilisation (based on a single peak hour calculation) but applying a reliability standard margin (e.g., n-1) onto the rated capacity.[23]

A mock-up of a map-based representation with multiple complementary metrics is shown in Figure 11 below.

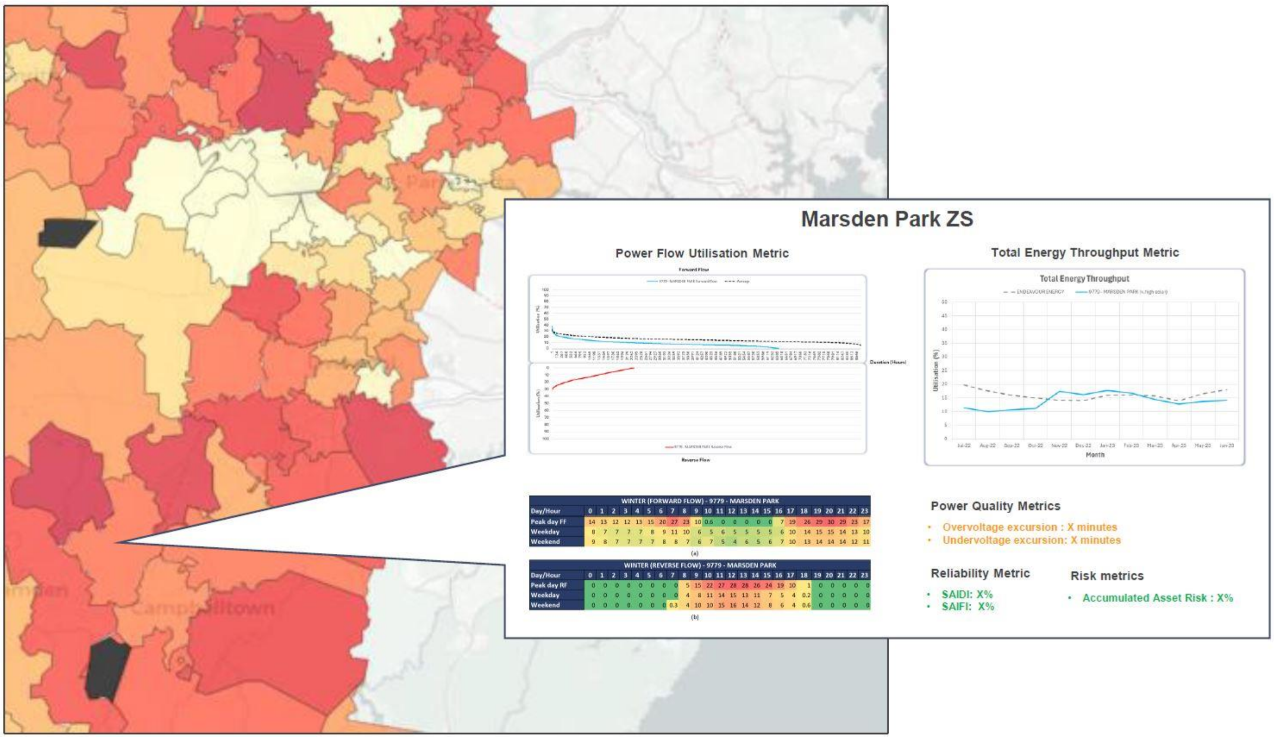


Figure 11: Mock up map-based view showing a compilation of asset-specific metrics

---

[23] AESO, Transmission Utilization Map, Alberta Electric System Operator. Accessed on July 1, 2024.

4.2.1.2 Pros, Cons and Applications

This section summarises the advantages, disadvantages, and potential applications of the power metric as listed in Table 3.

Table 3: Pros, cons and applications of the proposed power metric

Pros	Cons	Applications
• Reflects peakiness of import & export energy. • Reflects the seasonal rated capacity (summer/winter). • Allows visibility of utilisation level and duration associated with high and low demand events.	• Not a single value: requires several data points to be represented effectively, making ease of interpretation challenging. • As per the traditional metric, there is no 'target value' – higher or lower is not necessarily desirable.	• A system-wide version could be considered an 'update' of the traditional metric. • Asset-specific seasonal, TOU, or mapped versions useful for planning or operational purposes (e.g., non-network solutions).

4.3 Economic metrics

At the core of the concept of network utilisation is understanding the value that networks are delivering for customers, which is inherently an economic question. This surfaced as a core concern for some consumer representatives in the industry reference group. Recent consultation with Ausgrid also identified that adding larger capacities of network infrastructure, which would inherently lower utilisation (by most measures), could plausibly deliver the best customer value. For example, a 20MVA substation may only be a small amount more expensive than a 10MVA substation, as industry-standard capacities are more cost-effective, preventing the need to re-invest in a short period. Conversely, if that future demand was never reached, this would change the perception of whether good value for customers was achieved. This illustrates the value of integrating economic investment data into utilisation metrics.

Economic productivity metrics usually involve determining a level of output per unit of economic input. As such, the proposed new energy and power output measures could also be represented through an economic value lens, such as on a per unit of investment or collected revenue basis.

However, some important challenges exist. Firstly, such economic metrics are often complex, weighted multi-factor representations with substantial data inputs that are difficult to for anyone other than the regulator or their consultants to reproduce. In response to this challenge and to ensure a robust and defensible cost calculation, we propose a simple average network cost metric that utilises network costs that are already calculated by DNSPs in annual RINs. This could be divided by the total energy throughput, consistent with the TETU energy metric, described earlier. The formula for this proposed metric is as follows:

$$\boldsymbol{Average\ Network\ Cost\ (c/kWh\ version)} = \frac{\boldsymbol{Total\ Annual\ Network\ Cost\ (\$m\ real)\ \times\ 100}}{\boldsymbol{Total\ Energy\ Throughput\ (GWh)^{\wedge}}}$$

^ Includes grid imports + CER exports + locally consumed CER, as per TETU metric

As total network costs are not easily broken down by network area, this metric is restricted to being reported at the system level. The formula uses real (inflation-adjusted) costs to ensure that inflation is not falsely interpreted as a declining utilisation trend.

We also propose that Average Network Cost be calculated in a per customer ($/customer/yr) format, as follows:

$$\boldsymbol{Average\ Network\ Cost\ (\$/customer\ version)} = \frac{\boldsymbol{Total\ Annual\ Network\ Cost\ (\$m\ real)}}{\boldsymbol{Total\ Number\ of\ Customers}}$$

The per customer version provides the ability to identify customer energy efficiency/productivity improvements that might otherwise appear as a reduction in the TETU. For example, the widespread uptake of heat pump hot water in place of electric resistance systems would both reduce both electricity network and generation capacity requirements, but also substantially reduce the energy consumption for water heating by around 70%. This positive social outcome would see a decline in the TETU, and potentially even a slight increase in c/kWh average network cost. But the *average network cost per customer* would go down, thus helping stakeholders to identify an actual underlying improvement in customer outcomes. See Section 5.3.1.4 for further discussion.

Care should be taken in the communication of both forms of this simple, averaged metric. The metric merges the cost and energy delivered of different customer classes, meaning that figures will not resemble what a specific residential, commercial or industrial customer might recognise to be representative of their average cost of network services. Residential customer classes have lower energy consumption volumes per unit of network cost than high voltage (HV) connected commercial and industrial customers that only use parts of the network infrastructure and have large volumes of consumption. Therefore, the overall *average network cost (c/kWh)* would be lower than the actual cost paid by residential customers, and higher than that paid by HV customers. While this could theoretically be corrected by reporting figures by customer class, it is very challenging to break many network costs down according to customer class. The purpose of this metric is to understand the direction and magnitude of the trend, rather than to compare between networks.

When considering metrics more designed for comparing *between* networks (benchmarking) such as the AER's Multifactor Total Factor Productivity (MTFP), an additional challenge is that CER exports are not fully integrated as legitimate network outputs.[24] Self-consumption is also not currently considered by the AER as a valid network output in the MTFP. As such, issues associated with divergence between the energy throughput inclusions of the TETU (and the average network cost) and the MTFP or other performance metrics may need to be reviewed in the AER’s slated 2027 export services review (see recommendations in Section 6.1).

4.4 Power quality metrics

Power quality metrics are important for the health and stability of the network, ensuring that the electricity supplied meets certain standards necessary for the proper operation of the assets and for the protection of customer equipment. These include voltage stability, frequency stability, and the presence of harmonics or other distortions. They are relevant to utilisation as the capacity of electrical assets is not only limited by thermal constraints (breached by high levels of demand), but is also limited by voltage constraints, which are increasingly prevalent in high CER areas. It is thus important to ensure that recommended operating bounds are not breached. However, power quality metrics require high resolution and granularity data to model the low voltage (LV) networks to be able to run unbalanced power flow to understand power quality, especially voltage constraints. While modelling unbalanced power flow is outside the reach of this project and of DNSPs in the short- to medium-term, there may be some less complex ways of incorporating voltage (as perhaps the most pertinent CER power quality issue) into or alongside utilisation metrics.

Voltage issues, to the extent that they present constraints for solar generation, are considered in the proposed *Total Energy Throughput Utilisation*, as the curtailment of exports caused by voltage tripping results in a lower utilisation. Thus, there is an inherent incentive to manage solar curtailment within that metric.

In the same context, a more explicit option is to document voltage ‘excursions’, by capturing the frequency that voltage levels reach or exceed recommended maximum or minimum operating bounds. Such indicators could include those required by the Victorian Essential Services Commission:[25]

- Number/percentage of assets above the maximum voltage limit.
- Number/percentage of assets below the minimum voltage limit.

---

[24] Exports measured at the customer meter are effectively considered in indices such as the MTFP, but a review of further integration of export services is planned by the AER in 2027.

[25] Essential Services Commission, Compliance and Performance Reporting Guideline - Version 7, February 2022.

In both cases, functional compliance is met when no more than 1% of readings fall outside 10% of the nominal voltage, for at least 95% of assets.[26] Such metrics could be calculated either by voltage monitoring or by simulation.

For assets for which voltage **monitoring data** is available, this can be reported easily, although voltage monitoring at a zone substation level will fail to capture most voltage excursions occurring downstream in local feeders. Other sources of voltage monitoring closer to the customer, such as smart meters (as is the case in Victoria), telemetry data, inverters, or customer energy monitoring devices, will likely fill this void over time. The recommendation from our related previous work was that the “lack of availability of voltage data from existing smart meters [outside Victoria] is a key impediment arising from the contestable metering framework and must be addressed by the Australian Energy Market Commission’s (AEMC) ongoing review.”[27] The AEMC has since drafted recommendations that “DNSPs be given a provision to procure power quality data (voltage, current, and power factor) from [metering companies] at commercially determined prices.”[28] Thus, it appears that voltage monitoring is in train but is still some time away from being routinely reportable.

In the (most common) case where low penetration of voltage monitoring devices prevents the above option, it is possible to **simulate this data** using unbalanced power flow/state estimation analysis, which would allow voltage constraint levels to be identified for relevant assets. Full unbalanced power flow/state estimation analysis involves detailed consideration of hundreds of assets under thousands of different scenarios, and numerous contingencies, generating an overwhelming number of data points. A more streamlined approach could be to employ an automated process towards a system-level unbalanced power flow model for best- and worst-case scenarios *only*,[29] to calculate asset capacity under voltage constraints. This approach still requires a detailed network model, which is currently a work in progress for many DNSPs. Improving this DNSP capability is the focus of a proposed collaboration between Commonwealth Scientific and Industrial Research Organisation (CSIRO), University of Technology Sydney (UTS) and other research partners.

Given the above, the position of the authors, based on IRG advice, is that when available, **monitored** aggregated feeder or customer-level voltage compliance data should be viewed alongside zone substation level utilisation data. In the long-term, asset capacities in the proposed utilisation formulas data should use the minimum of the voltage and the thermal limit.

4.5 Reliability metrics

Reliability metrics in power systems are used to quantify and assess grid performance and reliability. These metrics help in evaluating how well the power system can meet the demand for electricity under both normal and adverse conditions. Understanding these metrics is crucial for planning, operating, and improving power systems to ensure that they can deliver electricity reliably and efficiently to consumers. Regulatory incentive schemes for reliability already exist in the NEM, through the Service Target Performance Incentive Scheme (STPIS). For DNSPs, these focus on the frequency and duration of interruptions to supply measured for each part of the network (urban, rural, central business district (CBD)) through measures such as:

- System Average Interruption Duration Index (SAIDI)
- System Average Interruption Frequency Index (SAIFI)

SAIDI and SAIFI are reported for different asset types, such as distribution substations and medium voltage feeders.[30]

---

[26] Captured at the asset level, this would be the percentage of readings falling outside 10% of nominal voltage.
[27] Langham, E.L., Guerrero, J., Nagrath, K. and Roche, D. (2022). Measuring and communicating network export service quality. Prepared for RACE for 2030.
[28] AER, Energy Security Board (ESB): Benefits of increased visibility of networks - Consultation paper, Australian Energy Regulator, July 2023.
[29] This should be followed by a detailed power flow analysis for the assets that are found to breach their voltage limit in this simplified approach.
[30] Energy Security Board, Benefits of increased visibility of networks: consultation paper, July 2023.

It is not within the scope of this project to reconceive these metrics. The question to consider is whether the existing measures adequately address reliability in the context of increasing CER, to ensure that pursuing the goal of increasing utilisation with new CER-based measures does not negatively affect reliability.

SAIDI and SAIFI are adequate reliability metrics, but we recommend that they add the most value in contextualising utilisation if reported at the zone substation level[31] and are viewed alongside asset-level power and energy metrics. The authors' understanding is that this data is captured and calculated at the asset level, and could be summed at the required spatial resolution. Currently it is only reported to the AER according to feeder type.

4.6 Risk and resilience metrics

Resilience metrics quantify a system's capability to prepare for, endure, and swiftly recover from disruptions like natural disasters, equipment failures, and cyber-attacks. These metrics guide utilities in fortifying the grid's robustness and recovery speed, ensuring uninterrupted service. Focusing on resilience enhances infrastructure planning, operational reliability, and customer satisfaction in the face of adverse conditions.[32]

Risk metrics quantify the probability of undesirable consequences, generally relating to reliability, such as load or capacity at risk. Many jurisdictions already apply risk-based assessment methods to investment planning decisions, whereby the volume of Expected Unserved Energy (EUSE) is calculated and converted to financial units according to the customer Value of Customer Reliability (VCR), published by the AER. The AER's multi-factor benchmarking of networks incorporates a similar approach using reliability performance data (i.e. outages, represented as Customer Minutes Off–supply (CMOS)) valued at the VCR.[33]

Reviewing a suite of risk and resilience measures, our position is that resilience measures, while useful, are not central to the scope of this project. Risk metrics, on the other hand, relate closely given that reliability risk and efficiency are core trade-offs in the concept of asset utilisation.

4.6.1 Accumulated Asset Risk

Given the above, we suggest that there is potential to incorporate risk accumulation into a suite of asset-level utilisation-related metrics. While reliability metrics show *actual* and *historical* performance, risk can provide a *forward-looking* view pertaining to the current management of utilisation. An option that aligns with current risk-based asset investment decisions, is as follows:

$$\begin{aligned}&Accumulated\ Asset\ Risk\ (\%)\\&\qquad = \frac{Expected\ Unserved\ Energy\ (MWh) \times Value\ of\ Customer\ Reliability\ (\$/MWh)^{\wedge}}{Annualised\ Network\ Investment\ (\$)}\end{aligned}$$

^ Asset weighted average according to the connected customers.

This would provide a percentage that represents how close the asset it to the DNSP investment trigger (the DNSP invests when this figure reaches 100%).

The challenge with risk metrics is that they require the computation of different contingency-based scenarios, often within a Monte Carlo simulation framework.[34] This makes it prohibitive to calculate across an entire network and is why the calculation of Expected Unserved Energy is generally only done as investment is approaching. Therefore, to reduce the computation burden, we suggest that such metrics should only be calculated for assets that pass a certain *Two-way Power Flow Utilisation* or other investment planning threshold. For example, assets for which the utilisation breaches 60% in the forward or the reverse direction within the forecast planning period.

[31] Or other asset level at which the suite of energy and power metrics are reported.
[32] Raoufi, H., Vahidinasab, V., & Mehran, K. (2020). Power Systems Resilience Metrics: A Comprehensive Review of Challenges and Outlook, Sustainability, 12(22), 9698.
[33] Quantonomics (2023). Economic Benchmarking Results for the Australian Energy Regulator's 2023 DNSP Annual Benchmarking Report, November 2023.
[34] AEMO, Reliability Standard Implementation Guidelines, Australian Energy Market Operator, April 2023.

5 Road-testing results

The proposed primary Energy and Power metrics were taken through a road-testing phase to determine how easily, accurately and granularly they can be calculated with publicly available data, and to highlight any data availability or quality issues that arise. The secondary economic, power quality, reliability and risk metrics were cursorily explored to check data availability for display alongside the primary metrics, which is covered in Section 5.1 only.

5.1 Data sources and availability

This section highlights the data requirements identified through the road-testing process. Calculating these metrics requires data from various sources, including DNSPs, the AER, Australian Energy Market Operator (AEMO) and additional sources such as weather data service providers.

Some of the required data is not available in the format or resolution needed to conduct road-testing using the proposed metrics. This includes time-series data for expected CER power generation and estimated curtailment power. To address this, we have proposed estimation methodologies (see Section 5.2) based on industry practices and academic/grey literature to fill these data gaps and support road-testing. However, it is important to note that these methodologies are not intended to replace the need for accurate measured data, which remains essential to ensuring robust results.

In this context, we propose a method to estimate the expected hourly CER power generation using available data, despite existing data gaps and the variability in current methodologies. The approach relies on key input factors, such as PV system capacity, hourly solar radiation, hourly ambient temperature, and system losses (DC and inverter losses). These inputs are either directly measured, reliably estimated, or assumed based on industry standards.

The recommendation from *Measuring and communicating network export service quality* study emphasises the need for standardised definitions of curtailment and improved data visibility to effectively estimate voltage-related curtailment events.[27] Challenges include the difficulty in identifying voltage-based curtailment when the voltage data is unavailable, and potential errors due to reliance on methods such as clear-sky normalisation.[35] Curtailment occurs under different reasons, which could be voltage-based responses or export limits (static or dynamic) or inverter responses to prevent excessive voltage rise. However, a consistent definition of curtailment is still lacking within the Australian energy industry, leading to varying interpretations.

Therefore, we propose a method that incorporates the quantification time-series hourly curtailment power as accurately as possible based on the available data, despite the substantial limitations and lack of consistency associated with current methodologies. Network businesses have been required to report and forecast curtailment out to 2040 for the five-year AER regulatory reset periods. This has highlighted the importance of the need to improve the understanding of curtailment and develop more consistent approaches to measurement, as current interpretations vary significantly across different networks. The process has highlighted the need for this data to be made publicly available.

5.1.1 Data inputs for shortlisted metrics

This section maps the shortlisted metrics with the required data inputs needed for their estimation, along with the availability of these inputs. Before delving into the findings, Table 4 provides an overview of the data needs and its availability for shortlisted metrics in general. The required data is categorised using three symbols to indicate availability: ● medium to high accessibility, ○ limited or difficult-to-access data, and ◊ data that can be estimated based on available information. More details about the symbols and the colour coding are provided in the Table 4 key below.

---

[35] Yildiz, B., Adams, S., Samarakoon S., Stringer, N., Bruce, A., and MacGill, I., Curtailment and Network Voltage Analysis Study (CANVAS). Prepared for RACE for 2030.

Table 4: Data requirements and availability for shortlisted metrics

		DNSP data																	BTM data	Others	
ID	**Shortlisted metrics**	**Total energy delivered (MWh)**	**Net metered volume of energy exported (MWh)**	**Active power (MW)**	**Seasonal rated capacity (k/MVA)**	**Current flow (k/A)**	**Seasonal line/cable ampacity (kA)**	**Voltage (k/V)/Voltage variations (%)**	**Voltage limits (%)**	**Cusomrt Import Energy (kWh)**	**SAIDI**	**SAIFI**	**Expected Unserved Energy (MWh)**	**Weighted Avg Value of Customer Reliability ($/MWh)***	**Annualised Network Investment ($)**	**PV installed capacity (k/MW)**	**PV system energy generation (k/MWh)**	**Estimated curtailment (kWh)**	**Behind-the-meter self-consumption consumption (kWh)**	**Solar irradiance data (W/m²)**	**Ambient Temperature (°C)**
1.1	Total Energy Throughput Utilisation (Energy metric)	●	●	●	●											●	◊	◊		●	●
1.2	Total Energy Throughput Utilisation [based on customer data] (Energy metric - *Alternative*)		●		●					○									○		
2	Two-way Power Flow utilisation (Power metric)			●	●	○	○														
3	Number/percentage of assets above/below the max/min voltage limit (Power quality metrics)							○	●									◊			
4	SAIDI and SAIFI (Reliability metrics)										○	○									
5	Accumulated Asset Risk (Risk metric)												●	○	●						

* This term represents the asset weighted average according to the connected customers, which is called the "Value of Customer Reliability" in Accumulated Asset Risk equation.

Key:

Operations and planning data
Reliability and resilience data
Financial data
CER data
External source data
● Required data (med-high accessibility)
○ Required data (limited or difficult-to-access data)
◊ Required data (data that can be estimated based on available information)

As shown in the table, several required data inputs are categorised as "○: limited data available or difficult to process/access." These data might be available at the network level or at some downstream levels, such as zone substation, but not at all levels. The proposed metrics are formulated to be calculated at different system levels from distribution transformers (street substation) up to the network level with the potential to average the results of the assets (zone substations or feeders). However, the data required to estimate all the metrics are not currently available at all system levels, as shown in Table 5.

Table 5: Data required and its availability for shortlisted metrics at asset level

	Data	**State**	**Network/DNSP**	**Zone substation**	**Feeder**	**Cable/line**	**Distribution transformer**	**Customer**	**Other**
DNSP data	**Total energy delivered (MWh)**	◊	●[36]	◊	◊	◊	○	○	
	Net metered volume of energy exported (MWh)	◊	●[36]	◊	◊	◊	○	○	
	Active power (k/MW)	◊	◊	●[37,38]	○[37, 39]	○	○	○	
	Seasonal rated capacity (k/MVA)	◊	◊	●[37]	○[37, 39]	○	○		
	Current flow (k/A)	◊	◊	○	○	○	○	○	
	Seasonal line/cable ampacity (kA)					○			
	Voltage (k/V)/Voltage variations (%)			○[40]	○[40]		○	○	
	Voltage limits (%)								●[41, 25]
	Customer Import Energy (kWh)							○	
	SAIDI	◊	●[36, 40, 42]	○	○[36, 40, 42]	○	○		
	SAIFI	◊	●[36, 40, 42]	○	○[36, 40, 42]	○	○		
	Customer minutes of supply			○	●[40]	●[40]			
	Expected Unserved Energy (MWh)	◊	●	●[38]	○[36]	○	○		
	Weighted Average Value of Customer Reliability ($/MWh)*		○	○	○	○	○	○	
	Annualised Network Investment ($)	◊	○	●[38, 43]	●[38]	○	○	○	
	PV installed capacity (kW)	●[43]	●[43]	○	○	○	○	○	
	PV system energy generation (kWh)	◊	◊	◊	◊	◊	◊	○	
	Estimated curtailment (kWh)	○	○	○	○	○	○	○	
BTM data	**Behind-the-meter self-consumption consumption (kWh)**							○	
Others	**Solar irradiance data (W/m²)**								●[44]
	Ambient Temperature (°C)								●[44]

* This term represents the asset weighted average according to the connected customers, which is called the "Value of Customer Reliability" in Accumulated Asset Risk equation.

---

[36] AER, AER - Electricity DNSP - Export services data - 2020–23, Australian Energy Regulator, January 2024. *Available in sheet: 6. Measured export volume.*
[37] ENA, Network Opportunity Maps, Energy Networks Australia, 2024.
[38] Endeavour Energy, System Limitation Templates. Accessed on May 20, 2024.
[39] *Available for some DFs that have constraint/investment.*
[40] AER, Endeavour Energy 2022-23 - Annual reporting RIN – Templates, Australian Energy Regulator, October 2023. *Supposed to be available in sheet 3.6 Quality of services in section 3.6.5 - QUALITY OF SUPPLY METRICS, but it is not reported.*
[41] AS/NZS 4777.2:2020, Grid connection of energy systems via inverters, Part 2: Inverter requirements, Australian Standards, 2020.
[42] *Available as the average minutes of supply per customer, weighted by the number of customers in each network.*
[43] AEMO, AEMO's DER Register, Australian Energy Market Operator, 2024. Available *by suburb and state level.*
[44] BOM, Weather Stations, Bureau of Meteorology, 2024. *Available by weather station.*

Key:

	Operations and planning data
	Reliability and resilience data
	Financial data
	CER data
	External source data
●	Required data (med-high accessibility)
○	Required data (limited or difficult-to-access data)
◊	Required data (data that can be estimated based on available information)

According to the data scanning from the public sources of the DNSP, AER, AEMO, and additional sources and mapping them across the system levels, most of the data is available at the zone substation level. Therefore, we have considered the zone substation level to test the proposed energy and power metrics. The required data to measure each metric, its availability, potential proxies and future resources are listed in Table 6.

Table 6: Data used/proxy for road testing shortlisted metrics

Metric	Required data	Availability	Proxy	Future resources
Energy metric (Total Energy Throughput Utilisation)	Time-series zone substation load trace data (forward and reverse power flows)	Available publicly (half-hourly resolution) for most of zone substations for all DNSPs in the NEM.	Converted the data to hourly resolution to simplify the visualisation.	For downstream assets (e.g., feeders, street zone substation, etc) directly from DNSPs.
	Zone substation nameplate capacity	Available publicly.	N/A	For downstream assets (e.g., kA capacity for feeders, MVA capacity for street zone substation, etc) directly from DNSPs (their portals or DAPRs).
	CER capacity	Not available at each zone substation (only by postcode, which creates substantial inaccuracy).	Matching the postcode with the zone substation polygons.	Directly from DNSPs or included in the AEMO's DER Register by zone substation or downstream assets.
	Time-series CER curtailment	Not available in time-series form. It is available as a single value by DNSP level not by zone substation or some DNSPs (e.g., Endeavour energy) has a single value represents the annual total energy curtailment by zone substation.	Consider the same curtailment level for all zone substation in case of it is available by DNSP level and then estimate the time-series curtailment or calculate the curtailment ratio by dividing the total annual energy curtailment over the estimated expected total annual CER energy generated and then estimate the time-series curtailment.	Should eventually be produced at the zone substation level by DNSPs for AER regulatory reset proposals but would need to be made accessible.
	Weather data (solar radiation	Not publicly available as measured and up to date data (it is available as a	Considered the publicly available simulated solar	BOM or SolCast databases could serve as

Metric	Required data	Availability	Proxy	Future resources
	and ambient temperature)	paid option). Simulated and out date data can be obtained from international/national databases (e.g., PVGIS typical meteorological year (TMY) generator[45], specifically from the "PVGIS-ERA5" database).	radiation and ambient temperature from 2020.	potential paid sources for up-to-date weather data.
	Time-series expected CER energy generated	Not available in time-series form. The CER capacity is available by suburb code not at each zone substation, and weather data (explained in the next row) is publicly available, but it is simulated and not up to date.	Matching the suburb code with the zone substation polygons and then use the zone substation coordinates (obtained from NOM) to collect the simulated weather data, then use a mathematical formula to estimate the time-series expected CER energy generated by zone substation.	From retailers, aggregators or included it in the AEMO's DER Register by zone substation or downstream assets.
Power metric (Two-way power flow utilisation)	Time-series zone substation load trace data (forward and reverse power flows)	Available publicly (half-hourly resolution) for most of zone substations for all DNSPs in the NEM.	Converted the data to hourly resolution to simplify the visualisation.	For downstream assets (e.g., feeders, street zone substation, etc) directly from DNSPs.
	Zone substation nameplate capacity	Available publicly.	N/A	For downstream assets (e.g., kA capacity for feeders, MVA capacity for street zone substation, etc) directly from DNSPs (their portals or DAPRs).
Economic metric (Average network cost)	Total annual network cost	Publicly in AER Partial Performance Indicators for distribution.[46]	N/A	N/A
	Total Energy Throughput	MWh component of energy metric, see above		
Power quality metric (voltage)	Time-series voltage 'excursions'	Not available.	N/A	Directly from DNSPs.
	Voltage limits	Available publicly based on states (e.g., VIC) or country level based on the Australia standards (e.g., AS/NZS 4777[41]).	N/A	N/A

[45] European Commission, PVGIS typical meteorological year (TMY) generator. Accessed on May 20, 2024.
[46] AER, https://www.aer.gov.au/documents/aer-partial-performance-indicators-distribution Accessed on Oct 7, 2024.

Metric	Required data	Availability	Proxy	Future resources
Reliability metrics	SAIDI	Available publicly as the average minutes of supply per customer, weighted by the number of customers in each network. However, it is not provided in the format required to measure the reliability of specific assets.	Cannot be estimated based on the available data.	Directly from DNSPs or included in the AER - Annual reporting RIN.
	SAIFI	Available publicly as the average minutes of supply per customer, weighted by the number of customers in each network. However, it is not provided in the format required to measure the reliability of specific assets.	Cannot be estimated based on the available data.	Directly from DNSPs or included in the AER - Annual reporting RIN.
Risk metric (Accumulated Asset Risk)	Expected Unserved Energy	Available publicly in annual system limitation templates.	Not calculated.	N/A
	Weighted Average Value of Customer Reliability (VCR)^	Not available by zone.	Not calculated.	Directly from DNSPs or included in the AER - Annual reporting RIN or System Limitation Templates.
	Annualised Network Investment	Available publicly in annual system limitation templates.	Not calculated.	N/A

^This term represents the asset weighted average according to the connected customers, which is simply called the "Value of Customer Reliability" in Accumulated Asset Risk equation.

The required measured data is generally available for road-testing the proposed energy and power metrics only. The data needed to test the power quality metric (Number/percentage of assets above/below the max/min voltage limit) is not available at this stage, limiting our ability to test this metric. Similarly, the available SAIDI and SAIFI data are reported as average minutes of supply per customer, weighted by each network's customer numbers, supporting the SAIDI and SAIFI incentive schemes, but not in the format needed to measure the reliability of the assets. Additionally, the accumulated asset risk metric lacks the main input data, expected unserved energy in MWh. Although data is available down to the feeder classification level (e.g., CBD, urban, or rural feeder), it is not collected per individual feeder or higher stream asset and cannot be estimated based on the available data. Finally, the calculation of an economic metric for network utilisation is hindered by data complexity, the exclusion of significant factors in benchmarking, and external influences on revenue and costs. Enhanced data collection, multi-variate analysis, and continued stakeholder collaboration are essential for refining and validating new metrics. Therefore, the proposed energy and power metrics are the only two metrics that have been tested in this document.

5.2 Metric calculation templates

This section presents generic calculations of the components of the proposed energy and power metrics, as simplified diagrammatic representations.

5.2.1 Expected CER power generation

The expected CER power generation data is a key supporting calculation function that estimates the timeseries of locally consumed CER energy, which is a major component in calculating the "Total Energy Throughput Utilisation" metric. In this report, we focus on the photovoltaic (PV) system to calculate the expected CER power generation, as it is the primary source of local energy generation with available actual data at the zone substation level.

The estimated CER power generation data for PV systems is based on the available PV capacity at the asset level (zone substation level in this report) and incorporates the effects of weather parameters (normalised solar radiation and ambient temperature), as well as system losses (including direct current (DC) and inverter losses). A simplified diagrammatic representation of the expected CER power generation calculation is shown in Figure 12 below.

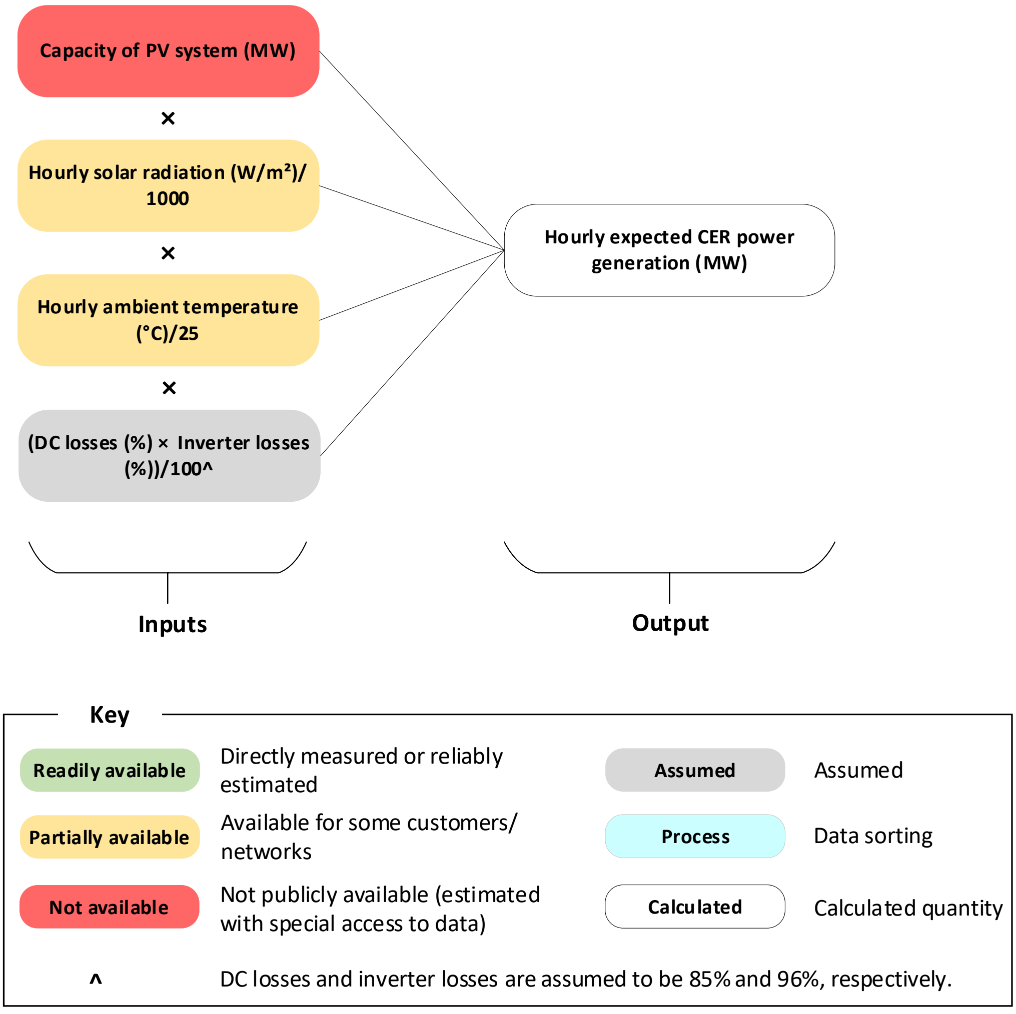


Figure 12: Expected CER power generation calculation

Note the diagram's colour coding: Green elements represent reliable and readily available data sources, either directly measured or reliably estimated. Orange inputs indicate data sources that are available for some customers/networks but need refinement, such as improved estimation techniques or broader network coverage. Red inputs denote data that is currently publicly unavailable. Gray stands for assumed variables or quantities. Cyan indicates a data sorting process used as a data preparation step. Finally, white stands for calculated quantities.

5.2.2 Estimated power curtailment

The amount of curtailment can vary across different system levels and is dependent on time and location, influenced by network constraints such as voltage variations and thermal limits. Several DNSPs enforce curtailment by setting static export limits to prevent breaching voltage limits. Therefore, CER energy curtailment should be estimated for each asset as a timeseries dataset, reflecting the temporal variation of CER behaviour.

In this context, the estimated timeseries hourly power curtailment was calculated based on the estimated curtailment rate, which is determined as a percentage of the annual energy curtailment relative to the annual sum of expected hourly CER power generation (calculated in Figure 12). This percentage is then multiplied by the timeseries expected hourly CER power generation. A simplified diagrammatic representation of the estimated power curtailment calculation is shown in Figure 13 below.

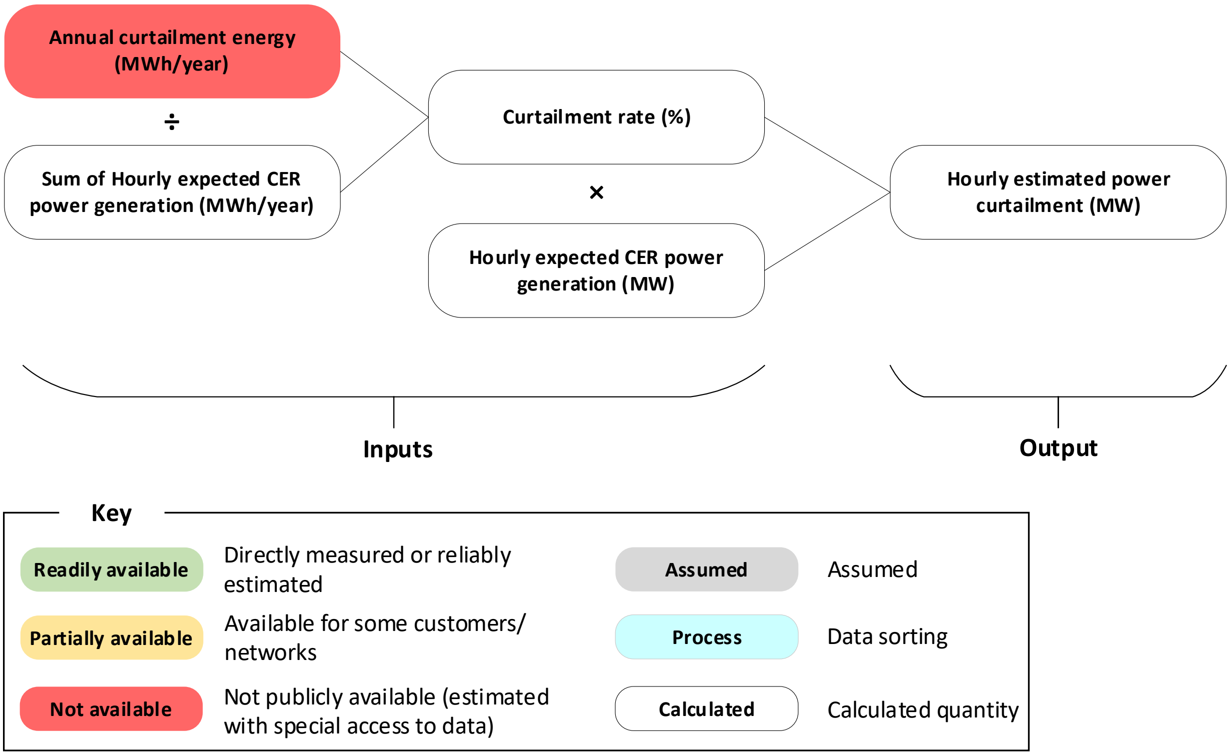


Figure 13: Estimated power curtailment calculation

The estimated curtailment calculation has some limitations and challenges listed as follows:

- Estimating behind-the-meter (BTM) curtailment:
  - More work is needed to accurately estimate the volume of BTM curtailment caused by voltage-based curtailment. Until then, a 'rule of thumb' of doubling the export curtailment is used.
  - This metric requires estimating CER generation to compare actual energy export data with 'expected' generation.
  - Accurate identification of BTM curtailed energy and export-related energy needs local load data.
- Inverter operating settings:
  - The metric assumes inverters are operating at agreed settings. Any unusual behaviour, like exports exceeding the agreed limit, must be identified to avoid misleading results.
- Calculating curtailment volume:
  - When calculating curtailment volume based on customer metering data that shows active power *at the agreed export limit*, it is important to use available data sources to determine whether curtailment is actually occurring.[47]
  - Since the expiry of premium FiTs makes self-consumption more desirable than exporting, theoretical scenarios in which customers seek to export when it is financially disadvantageous to do so are considered unlikely and are thus ignored.

5.2.3 Locally consumed CER power

Locally consumed CER power data is a critical to calculating the CER effects on the proposed "Total Energy Throughput Utilisation" metric. The locally consumed CER energy (sum of locally consumed CER power over

[47] For a customer with PV only, if there is reverse power flow we calculate the "Local PV consumption = Expected PV generation - Reverse flow power". If this value is not zero, the remaining amount is considered curtailed energy. If there is forward power flow, the "Local PV consumption = Expected PV generation", and curtailment is zero.

the period of analysis in hours) represents the CER energy consumed within the system level (zone substation in this report), a factor not captured by traditional network utilisation metrics. The timeseries hourly consumed CER power is calculated by taking the hourly expected CER power generation (calculated in Figure 12), subtracting the hourly estimated power curtailment (calculated in Figure 13), and further subtracting absolute value of the hourly reverse power flow, which can be obtained from the network opportunity maps (NOM)[37] at zone substation level. A simplified diagrammatic representation of the locally consumed CER power calculation is shown in Figure 14 below.

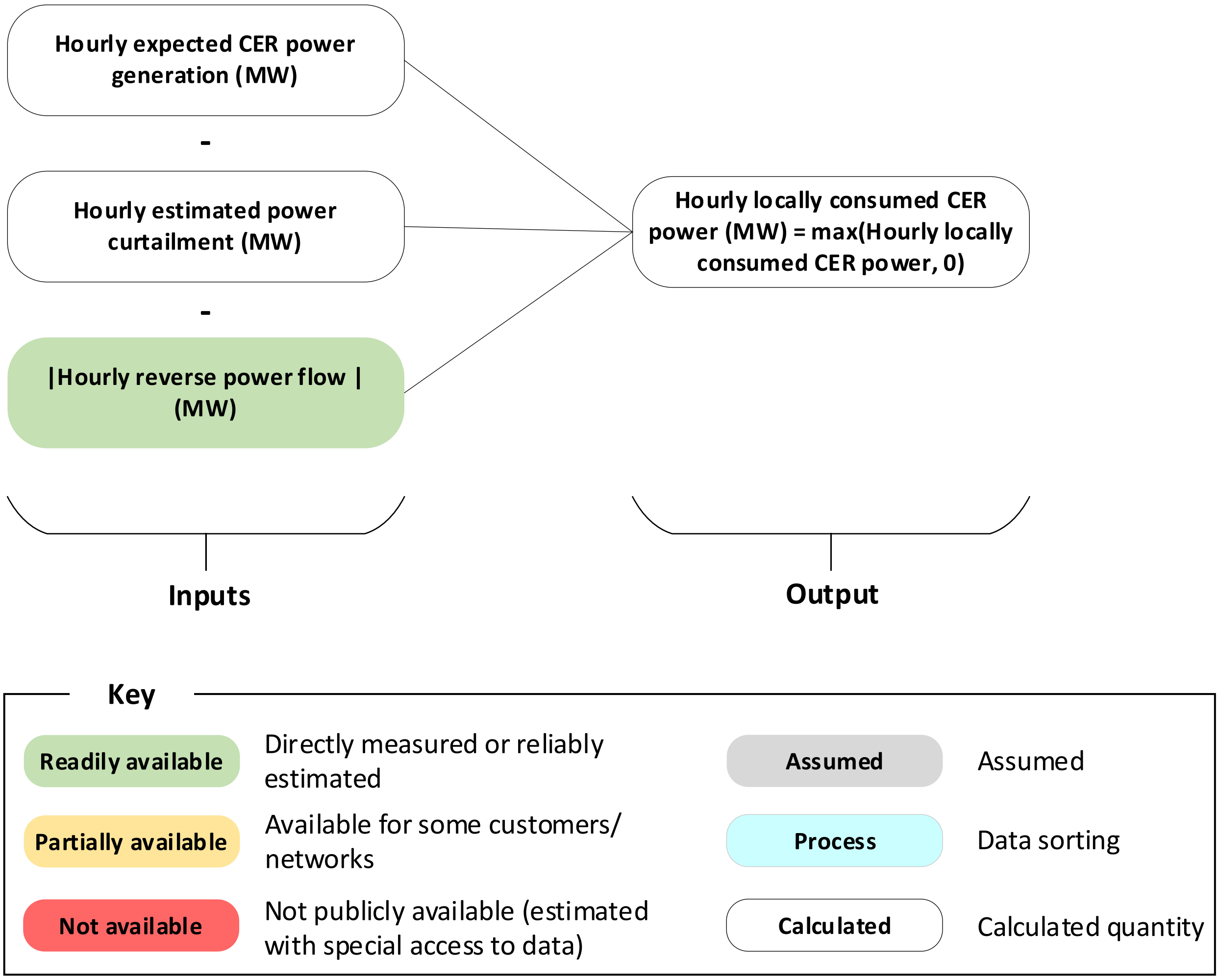


Figure 14: Locally consumed CER power calculation

5.2.4 Total Energy Throughput Utilisation (TETU)

Total Energy Throughput Utilisation (TETU) metric can be calculated as the sum of the forward energy flow (sum of forward power flow over the period of analysis in hours), the absolute value of the reverse energy flow (sum of reverse power flow over the period of analysis in hours) [hourly forward power flow and reverse power flow for zone substation can be obtained from NOM[37]], and the locally consumed CER energy (sum of locally consumed CER power over the period of analysis in hours) [hourly locally consumed CER power can be calculated as shown in Figure 14], divided by the seasonal rated capacity (can be obtained for zone substation from NOM[37]) multiplied by the number of hours in the period of analysis. To exclude BTM CER consumption, the locally consumed CER energy in the numerator should be set to zero. A simplified diagrammatic representation of the "Total Energy Throughput Utilisation" metric calculation templates is shown in Figure 15.

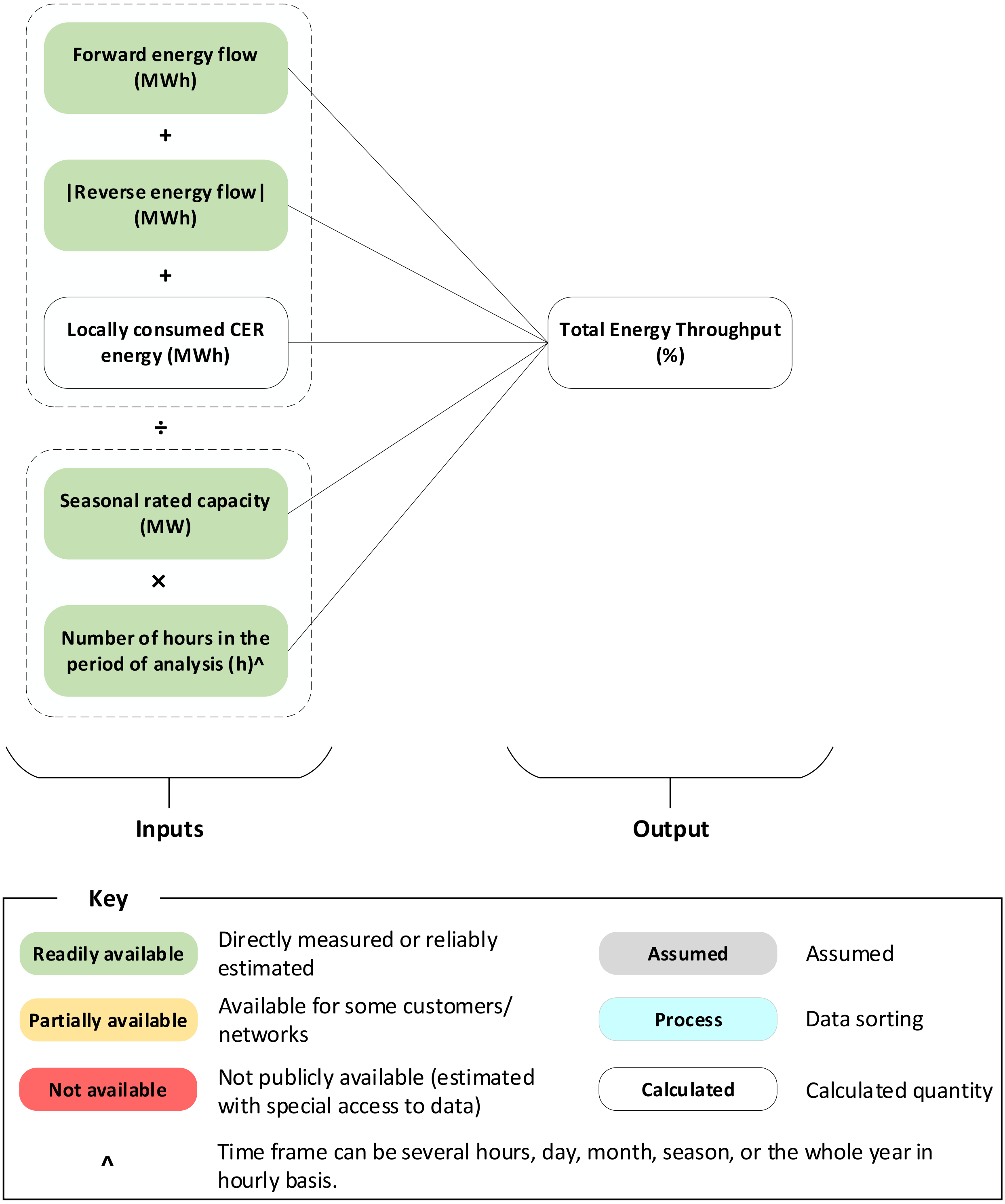


Figure 15: Total Energy Throughput Utilisation calculation (to exclude BTM CER consumption, locally consumed CER energy should be equal to zero)

5.2.5 Two-way Power Flow Utilisation

Two-way power flow utilisation can be determined based on the sign of the hourly power flow value. If the hourly power flow is positive, it indicates a forward flow, while a negative value indicates a reverse flow. By sorting the data to separate forward and reverse power flows, the forward power flow utilisation and the reverse power flow utilisation can be calculated by dividing the hourly forward power flow and the hourly reverse power flow by the seasonal rated capacity, respectively. A simplified diagrammatic representation of the two-way power flow utilisation calculation is shown in Figure 16 below. This metric was able to be readily calculated at the zone substation level based on publicly available load trace and capacity data from the NOM[37], as indicated by the green boxes.

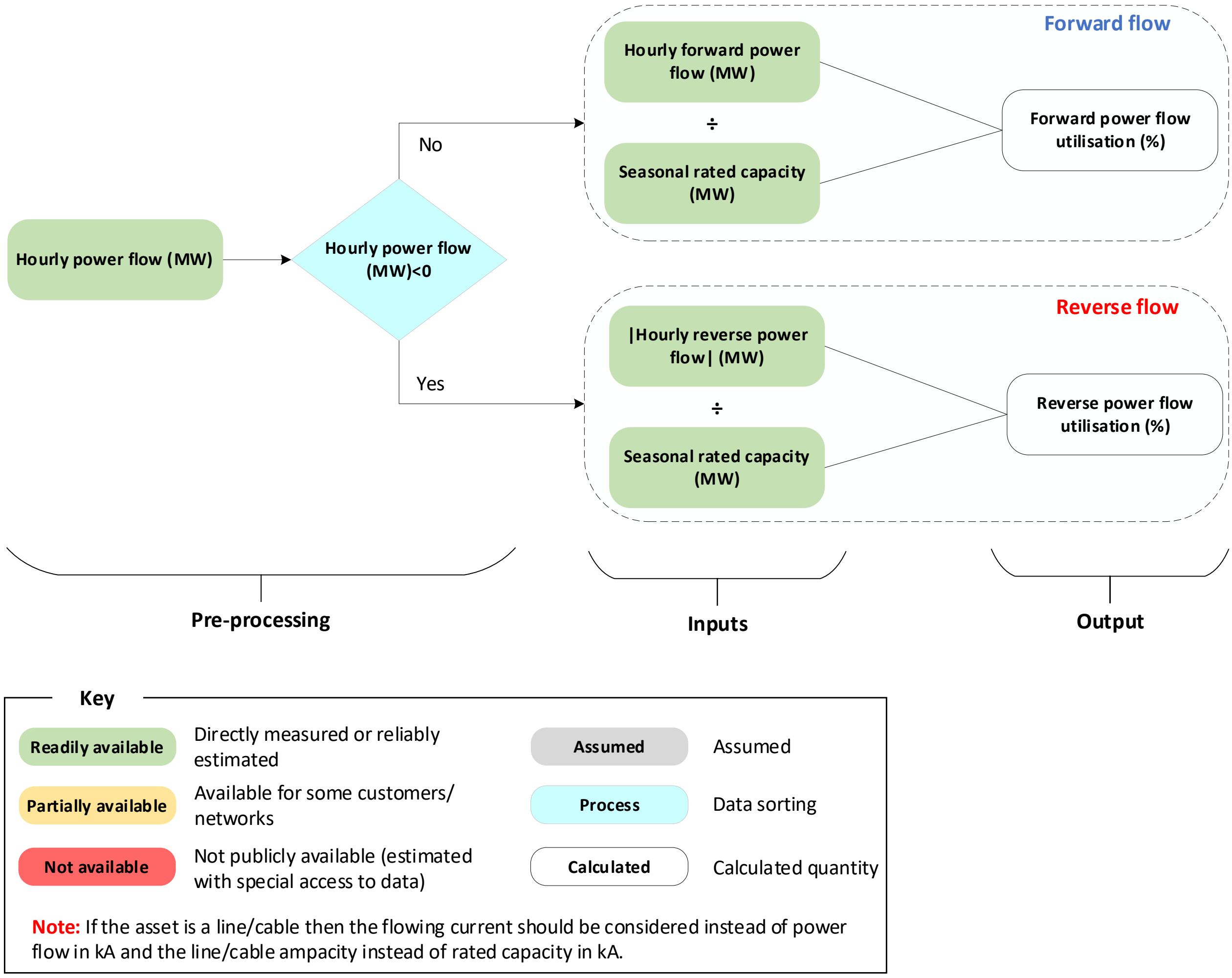


Figure 16: Two-Way Power Flow Utilisation calculation

5.3 Road-testing results

5.3.1 Total Energy Throughput Utilisation (energy metric)

Due to some key data gaps outlined in the Table 6 (CER capacity by zone substation, and curtailment estimates), this metric could only be calculated for networks where additional non-public data sources were available to the research team. This inherently limits the comparisons that can be made between DNSPs or jurisdictions. Historical data or sufficient proxies were even more difficult to access, which also limited the ability to analyse trends in this metric. Therefore this section is structured according to comparisons that were able to be made: between different zone substations in one DNSP across the course of a year (Section 5.3.1.1) and trending over a number of years (Section 0), and between single assets of two different DNSPs (Section 5.3.1.3).

As these comparisons still do not fully elucidate the metric behaviour, we have also qualitatively explored the direction and rate of change of the metric under different scenarios, that are commonly considered to be either desirable or undesirable as part of the energy transition, to clarify what the metric encourages (Section 5.3.1.4).

5.3.1.1 Comparing zone substations in one network

This metric was calculated by zone substation and across the whole network by season and month (accounting for seasonality effects on asset capacity), using Endeavour Energy zone substations load trace data and seasonal nameplate capacities.[37] The proposed metric is also shown alongside a calculation of the traditional network utilisation metric (with added seasonality) for reference.

For this and subsequent metrics, three different representative zones were chosen for their unique characteristics:

- Robertson ZS: Higher utilisation (running at closer to the rated capacity according to the traditional utilisation metric) with a winter peak and moderate solar penetration.
- Darkes Forest ZS: Very low utilisation and summer peaking.
- Marsden Park ZS: Unusually high solar penetration and winter peaking.

The behaviour of the TETU and traditional metric are shown in Table 7. Note that TETU figures are lower than the traditional metric. This is neither good nor bad, but is a function of using a different benchmark. The summer vs winter dominance generally remains the same at the individual zone substation level. That is, zones with higher traditional utilisation in summer are generally still higher in summer with the TETU. At the whole of network level, however, Endeavour is a summer-peaking network on the traditional metric, but has a slightly higher winter TET, suggesting that summer may be peakier season in terms of electricity demand.

Table 7: Annual and seasonal TETU metric vs traditional network utilisation metric

Name	Network level	Traditional metric			TETU metric		
		Yearly	Summer	Winter	Yearly	Summer	Winter
ENDEAVOUR ENERGY	Network (average of zone substation)	37.1%	35.6%	31.8%	15.3%*	14.5%*	16.1%*
9674 - ROBERTSON	Zone substation (higher utilisation; winter peak)	69.9%	51.7%	69.9%	33.8%	29%	37.9%
9654 - DARKES FOREST	Zone substation (lower utilisation; summer peak)	13.2%	2.8%	13.2%	1.1%	1.0%	1.2%
9779 - MARSDEN PARK	Zone substation (very high solar)	38.2%	38.2%	30.3%	13.9%	15.2%	12.0%

* This network-wide calculation excludes exports from the zone substation level to avoid double counting. If this these were included, this would increase each figure by ~0.1%.

To explore the metric behaviour more visually, Figure 17 shows the same zone substations with monthly changes to the TETU metric. Figure 17 also shows a version of the metric with 'Locally consumed CER energy' removed (the dotted lines).[48] This is partly in response to the position that customer self-consumption should not be valued as a full network service like imports or exports (so as a sensitivity test without this factor). But this representation is also useful to better understand what the metric reflects. Note that the differential change in summer is more prominent than winter (the gaps between the solid and dotted lines are greatest in summer), reflecting a greater network 'productivity boost' in summer than winter, due to CER. Even with all CER effects included, however, the variation of the TETU across the year is shaped most dominantly by the scale and seasonality of forward flow demand.

The authors' position is that self-consumption and local consumption of CER within the zone should be given equivalent value within the metric and be included, providing a grid connection is present. If self-consumption was required to be excluded, a more accurate formula is provided in Section 4.1.2.1. This was not able to be calculated by the research team due to a lack of access to customer metering data, aggregated by Zone Substation service region.

[48] Ideally, we wished to remove just customer self-consumption from the TET, but due to the way that the metric is calculated based on currently available data, this could not be separated from energy exported by one customer, and consumed by another within the zone substation area (which of course has a critical reliance on the network for this transfer to occur).

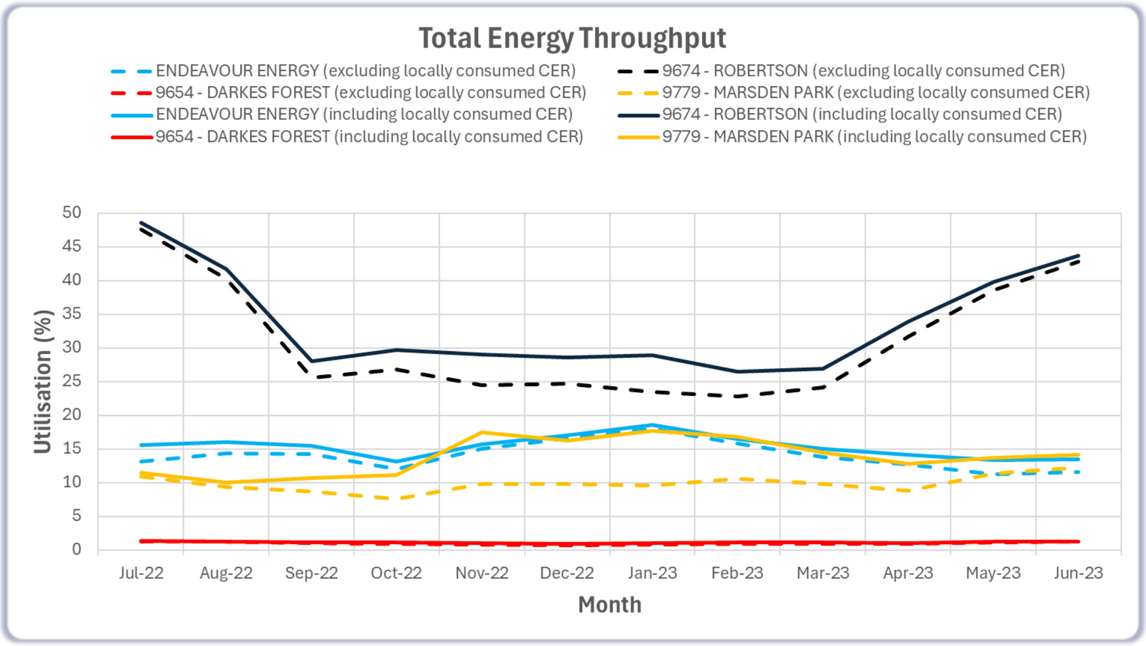


Figure 17: Annual TETU metric including and excluding locally consumed CER energy

The annual statistical figures of the Traditional, TETU (including locally consumed CER) and TETU (excluding locally consumed CER) metrics are also listed in Table 8 for reference.

Table 8: Total Energy Throughput Utilisation (with and without locally consumed CER) metric vs traditional metric

Name	Network level	Traditional metric	TETU (excluding locally-consumed CER)	TETU (including locally-consumed CER)
ENDEAVOUR ENERGY	Network (average of zone substation)	37.1%	14%*	15.3%*
9674 - ROBERTSON	Zone substation (higher utilisation; winter peak)	69.9%	31.1%	33.8%
9654 - DARKES FOREST	Zone substation (lower utilisation; summer peak)	13.2%	1%	1.1 %
9779 - MARSDEN PARK	Zone substation (very high solar)	38.2%	9.9%	13.9%

* This network-wide calculation excludes exports from the zone substation level to avoid double counting. If this these were included, this would increase each figure by ~0.1%.

5.3.1.2 Total Energy Throughput Utilisation Trend

The trend any metric is critical to understanding the behaviour it reflects and what it rewards. If the metric improves year by year, especially with the increase in CER installations, it signifies better performance and higher value delivery to customers. To analyse this, we used historical power flow data from 2020, reducing the solar capacity by 20.9%[49] and the curtailment by 10% to reflect the 2020 scenario. Additionally, we created new data to represent a future scenario with a 5% load growth rate and 20.9% increase in solar capacity from 2023 actual data, considering a 10% increase curtailment scenario. The statistical annual figures of the TETU metric show a gradual increasing/improving trend as shown in Figure 18.

This analysis has substantial limitations, however, as it is based on a combination of real and synthetic adjustments to real data. The only way to know the actual performance over time is to routinely collect and monitor over time.

---

[49] The compound annual growth rate (CAGR) of the PV capacity in Australia from 2020 to 2023 is approximately 20.9% based on the Australian PV Institute (APVI) statistics (calculated rate).

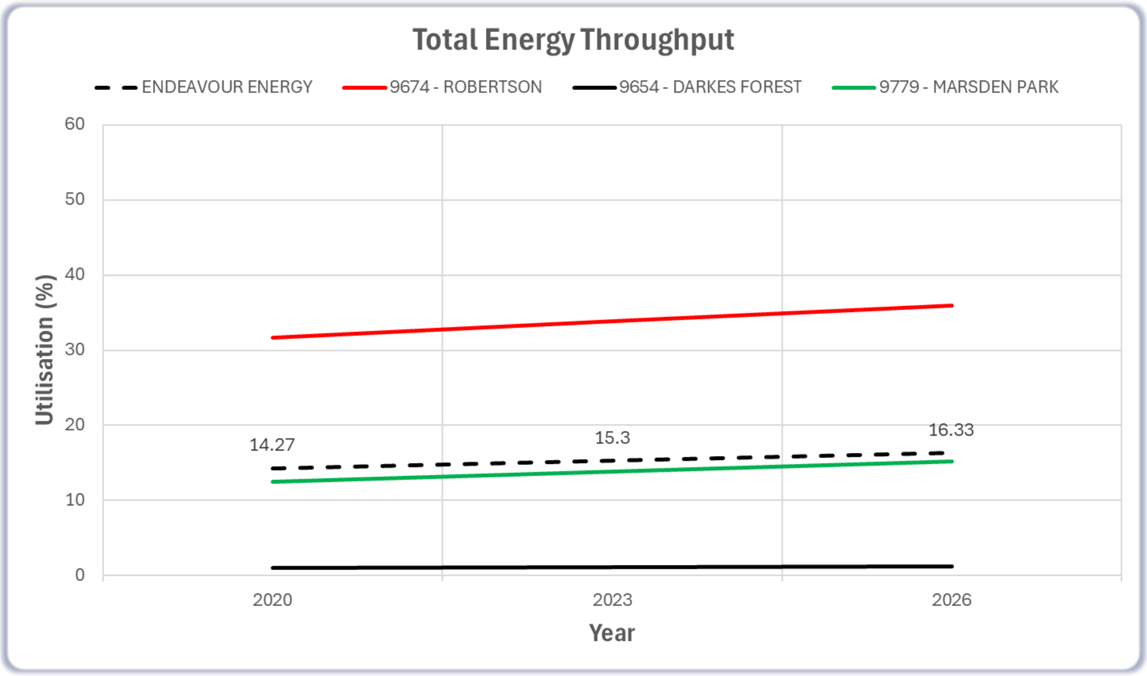


Figure 18: Trend of Total Energy Throughput Utilisation metric

5.3.1.3 Comparing networks

An important function of metrics is benchmarking the relative performance of different networks. Doing so is currently constrained by a lack of universally available data. Therefore, we have calculated the TETU for a single zone substation between two DNSPs in NSW (Endeavour Energy and Essential Energy). The selection of the zone substations for Essential Energy was specifically constrained by the lack of solar PV capacity at Zone Sub Level (only postcode data is publicly available). Therefore, 556 – BBA BARRABA ZS was selected as the zone substation boundary happens to align closely with the postcode boundary, and is shown alongside Endeavour Energy system average and their two zone substations in Figure 19.

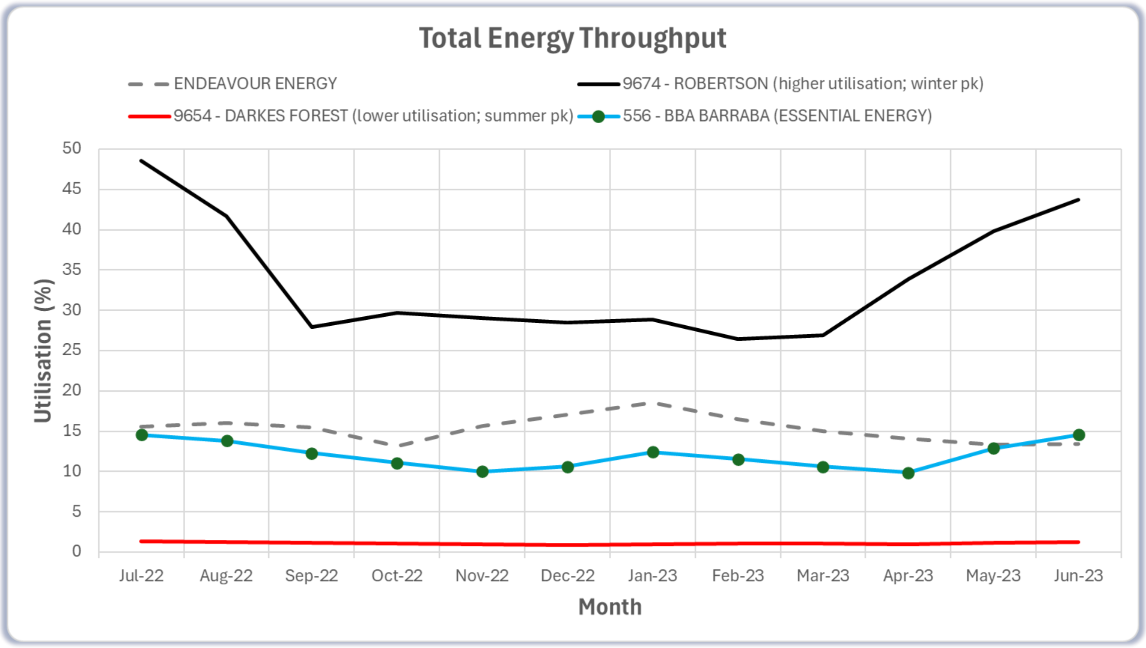


Figure 19: Comparing networks using Total Energy Throughput Utilisation metric

The BARRABA monthly trend is very similar to the Endeavour Energy whole of network curve, however DNSP comparisons are of limited use at the zone substation level, and generally only yield real insight at the whole of network level, once historical trends are available.

5.3.1.4 Customer and Network CER Scenarios

To test the behaviour of the proposed Total Energy Throughput Utilisation metric, we developed several customer-oriented and potential network CER scenarios, evaluating their impacts from both customer and network perspectives. These customer-oriented scenarios included varying percentages of solar PV uptake, self-consumption, curtailment, and reverse power flow. Additionally, we assessed the effects of load shift options, and both controlled and uncontrolled EV charging, as well as vehicle-to-grid (V2G) operations.

On the network side, we focused on implementing network and non-network solutions to enable flexible demand and enhance hosting capacity. This approach aimed to provide a comprehensive understanding of how the proposed metrics perform under different network configurations and conditions.

The primary purpose of these scenarios is to demonstrate how the proposed energy and power metrics respond under different conditions. The data used in this analysis is synthetic due to the lack of load trace data for a zone substation with residential loads and without PV systems, curtailment data, or reverse power flow data. Based on the above assumptions, we applied the below scenarios as listed in Table 9.

Table 9: Customer and network scenarios to test the effectiveness of Total Energy Throughput Utilisation metric

#	Scenario		TETU metric response	Desired effect?
	Baseline	Change		
C1	Res. customer, no solar	Installs 5kW solar (high self-consumption)	Increases	Yes
C2	Res. customer, no solar	Installs 10kW solar (low self-consumption)	Increases, but less than C1 due to some curtailment	Yes
C3	Res. customer, solar	Installs battery storage	Increases only if curtailment is reduced (and some roundtrip losses)	Yes*
C4	Res. customer, off-peak resistance hot water (OP HW)	Load-shifting (OP HW to 10am-3pm)	Increases only if curtailment is reduced	Yes*
C5	Res. customer, solar w/ 5-8pm cooling	Load-shifting (Heating, ventilation, and air conditioning (HVAC) pre-cooling @ 2-5pm)	Increases only if curtailment is reduced	Yes*
C6	Res. customer, OP resistance HW	Engages in energy efficiency + load shifting (OP electric resistance to 10am-3pm heat pump)	Reduces due to lower consumption	No
C7	Res. customer, no EV	Installs EV charger (evening charging)	Increases, irrespective of charging time, unless daytime reduces curtailment	Yes*
C8	Res. customer, no EV	Installs EV charger (overnight charging)		
C9	Res. customer, no EV	Installs EV charger (daytime charging)		
C10	EV charger (daytime charging – C9)	Installs V2G EV charging capability	Increases due to roundtrip losses and if curtailment is reduced	Yes*
N1	N/A	Installs automatic tap-changing equipment to increase hosting capacity (or other voltage management technologies, such as voltage regulators, static synchronous compensator [STATCOM], capacitor banks)	Increases	Yes

* See discussion below for more nuance.

As seen in Table 9, in response to increased solar or battery storage or ‘solar soak’ load shifting (C1-C5), the TETU metric behaves as desired as it is steady or increases in value with solar input or other desirable customer actions that reduce curtailment. This is contrasted with the traditional utilisation metric which may go down, producing an apparent decline in productivity.

Note, however, that the time shifting of load away from peak periods has *no direct effect* on the TETU metric (see cases C3-C5, C7-C10, marked with “**Yes**”). Encouraging load shifting does mean, however, that the network can continue to increase the TETU (and thereby productivity) before investment in new assets takes place. This is how networks can effectively increase the TETU across the system: by filling the troughs (by load shifting or encouraging controlled EV charging) and flatting the peaks in demand. This may also mean that it is useful for DNSPs to monitor and seek to improve the TETU in assets that are over, say, 60% on the Two-way Power Flow Utilisation metric – that is, those that are closer to reaching capacity constraints. From the regulator’s perspective, a subset of the TETU could be monitored for assets that have planned investment to overcome constraints in the coming five-year network planning period. The load factor type variant of the TETU discussed in Section 4.1.2.2 (with example results shown in Figure B-1 in the Appendices) provides a better or more *direct* response to load-shifting changes.

Where network solutions to increasing hosting capacity are used (N1), this also creates the opportunity for higher TETU figures to be realised and is a desirable outcome.

The case where energy efficiency activity is encouraged (C6) is also important to consider, as it does *not* have the desired effect. This case would cause the TETU to decline due to reduced throughput, even though this is arguably one of the most beneficial scenarios. This results from the fact that the TETU – and almost all other network metrics – measure the *input* (MWh of throughput, or kW of capacity), rather than the desired customer *outcome*. That is, meeting customers’ energy needs for warm showers and comfortable premises in an efficient and cost-effective manner. Therefore, it is important to be mindful that other surrounding measures of overarching energy productivity may also be beneficial. To address this, we recommend that the economic metric of Average Network Cost be produced in a *per customer version*, which would not decline with improved energy efficiency (see Section 4.3).

5.3.2 Two-way Power Flow Utilisation (power metric)

This section details two different final visual representations for this metric – seasonal TOU and seasonal heat maps – as well interim calculation steps outlined in Section 4.2.1. Within the constraints of data access, the analysis examines the behaviour of this metric across different zone substations within a single DNSP, compares between DNSPs to the very limited extent possible and explores trends.

Recall that this metric can be binned according to specific time periods (e.g. maximum annual value [i.e. the traditional metric], top 1, 50, 100, 500 of hours) as is considered relevant for strategic decision making. A subset of these time periods is shown in this section, but the most relevant or appropriate periods would ultimately be a decision for the regulator in discussion with stakeholders.

5.3.2.1 Two-way power flow ‘utilisation duration curve’ (Interim Step 1)

This metric was tested using publicly available data sources at the zone substation level, including time-series half hourly power flow data and seasonal zone substation nameplate or firm capacities.

We have calculated this metric for the whole Endeavour Energy territory and selected the same three case study zone substations that have been tested in the TETU (energy) metric: Robertson ZS, representing higher traditional utilisation and winter demand peak; Darkes Forest ZS, representing very low utilisation and a summer demand peak; and Marsden Park ZS, which has very high solar penetration. The two-way power flow utilisation duration curve for the Robertson ZS is shown in Figure 20.

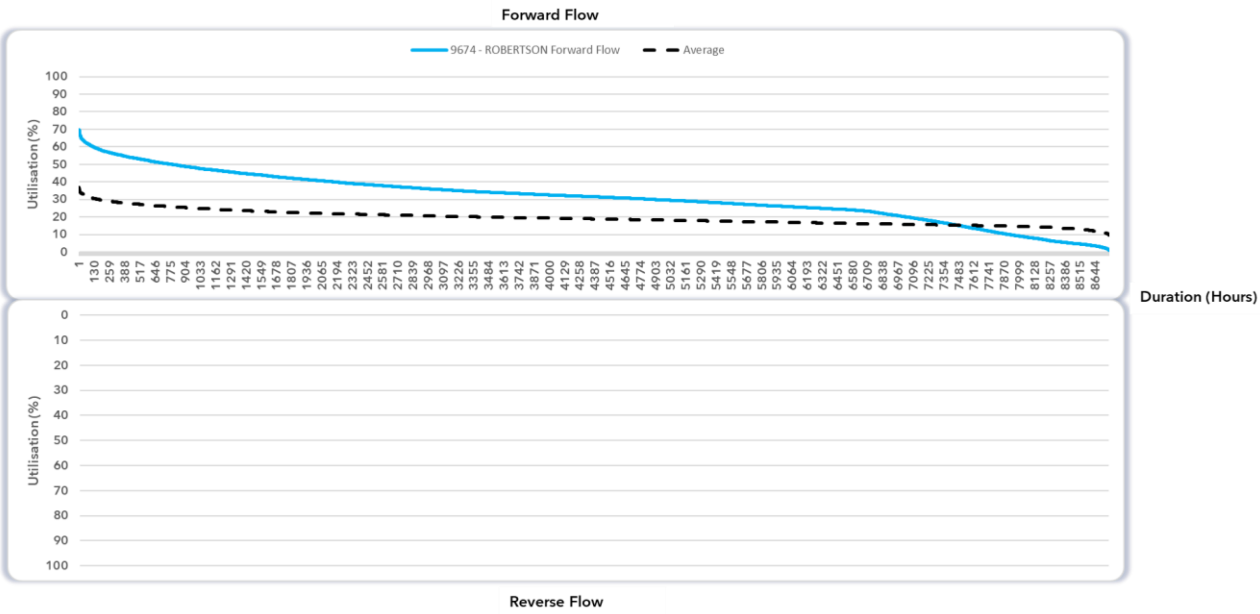


Figure 20: Two-way utilisation duration curve for 9674 – ROBERTSON ZS (Endeavour Energy)

This asset is running at higher utilisation than the system average – at 70% versus 30%. The dip in the right-hand end of the curve for this zone substation indicates shows signs that solar generation has begun to reduce the two-way power flow utilisation, but its impact is not significant enough to actually create reverse flows. This suggests that, despite some reduction in demand due to solar, the zone remains primarily within forward flow conditions, operating near its capacity limits.

From the above curve, the utilisation in both directions can be extracted based on any given number of hours per year. Table 10 shows the utilisation for Robertson ZS at the top 1-hour, top 100 hours and top 500 hours.

Table 10: Two-way utilisation duration curve derivatives for 9674 – ROBERTSON ZS (Endeavour Energy)

Hours	Forward flow utilisation (%)	Reverse flow utilisation (%)
Top 1 hour	69.88%	0%
Top 100 hours	60.78%	0%
Top 500 hours	53.28%	0%

Darkes Forest ZS, shown in Figure 21, is representative of very low utilisation, operating well below its capacity, relative to the system average. The consistent underutilisation suggests ample available capacity with minimal stress on infrastructure. This is how a new zone substation in an area that is yet to be built out might also appear.

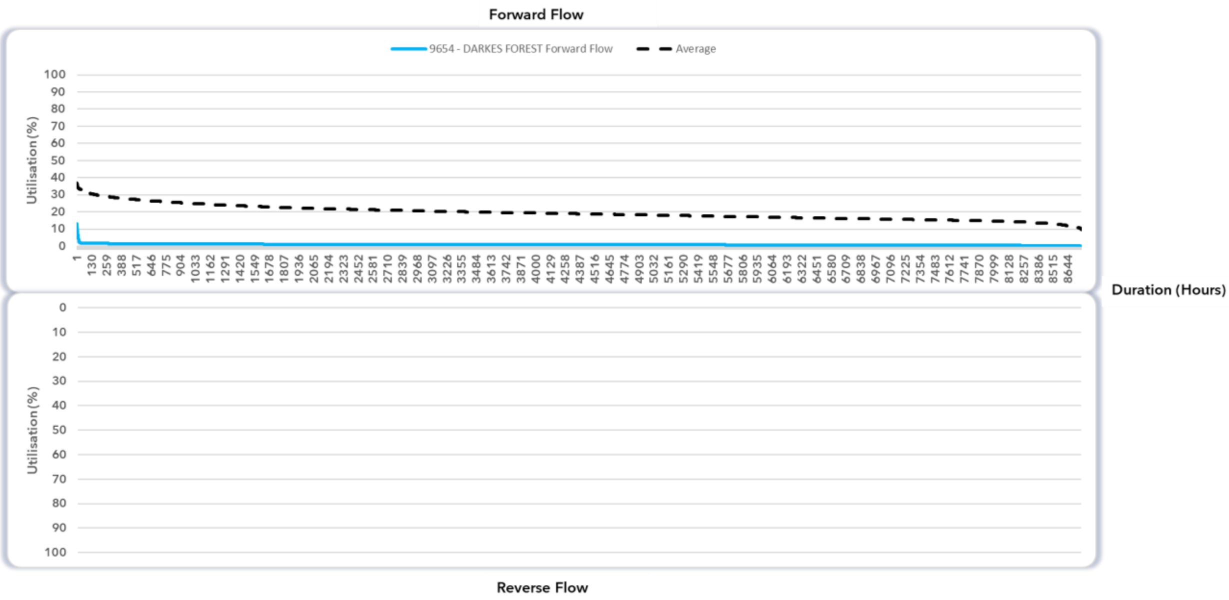


Figure 21: Two-way utilisation duration curve for 9654 - DARKES FOREST ZS (Endeavour Energy)

There are no significant fluctuations or noteworthy factors, making the operational profile relatively uneventful. This indicates stability within the zone substation but also points to potential opportunities for increased usage or optimisation to better leverage the existing infrastructure. The utilisation levels are extracted from the curve in Table 11 below.

Table 11: Two-way utilisation duration curve derivatives for 9654 - DARKES FOREST ZS (Endeavour Energy)

Hours	Forward flow utilisation (%)	Reverse flow utilisation (%)
Top 1 hour	13.25%	0%
Top 100 hours	1.77%	0%
Top 500 hours	1.52%	0%

The curve for Marsden Park ZS is shown in Figure 22, which shows both forward and reverse flow utilisation levels, due to its high penetration of solar.

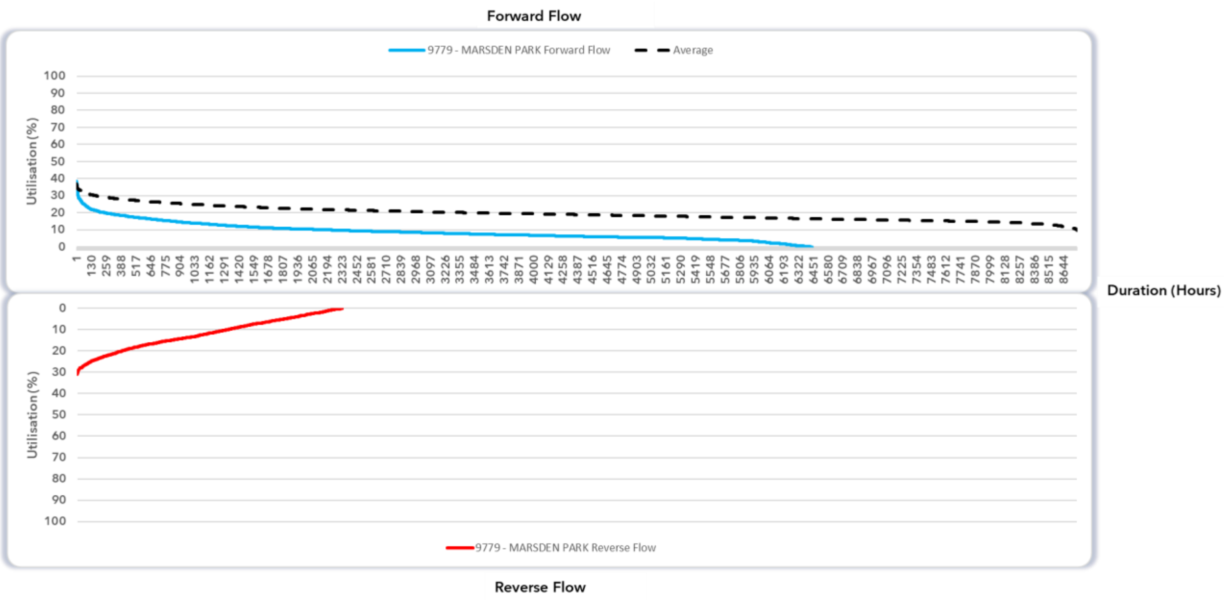


Figure 22: Two-way utilisation duration curve for 9779 - MARSDEN PARK ZS (Endeavour Energy)

The Marsden Park curve is steeper than average in the top hours (potentially influenced by solar reducing the late afternoon but not evening demand), suggesting an opportunity for short duration demand management solutions should it in future approach its capacity, triggering investment. Utilisation in the forward direction can be seen to drop faster than average due to solar, such that for roughly a quarter of all hours the zone substation shows reverse flows. These reverse flows reach 31% of asset capacity, which is similar in magnitude to the forward flow utilisation, at 38% (see Table 12). Neither of these utilisation levels is sufficient to trigger a thermal constraint requiring investment, however there may be voltage issues meaning reverse flow constraints occur at lower utilisation levels. This underscores the importance of integrating voltage considerations into future definitions of asset capacity.

Table 12: Two-way utilisation duration curve derivatives for 9779 - MARSDEN PARK ZS (Endeavour Energy)

Hours	Forward flow utilisation (%)	Reverse flow utilisation (%)
Top 1 hour	38.25%	30.88%
Top 100 hours	23.16%	25.50%
Top 500 hours	17.43%	18.36%

5.3.2.2 Two-way power flow utilisation threshold representation

The above figures and tables represent the two-way power flow utilisation for *individual* zone substations. To get a higher-level view of the two-way power flow utilisation at the *system level,* two approaches can be taken. Firstly, the average utilisation for all the zone substations in the network in both directions can be derived, similar to the traditional metric. However, this obscures the diversity in the data, and we already have the TETU metric for comparing productivity trends between networks at the asset and system level. Therefore, we suggest that a better approach may be to present the proportion of a DNSP's assets over certain operational risk or investment thresholds. Figure 23 below shows the proportion of Endeavour Energy assets running at very low (0-20%), up to very high (>100%) utilisation rates over the top 1-hour.

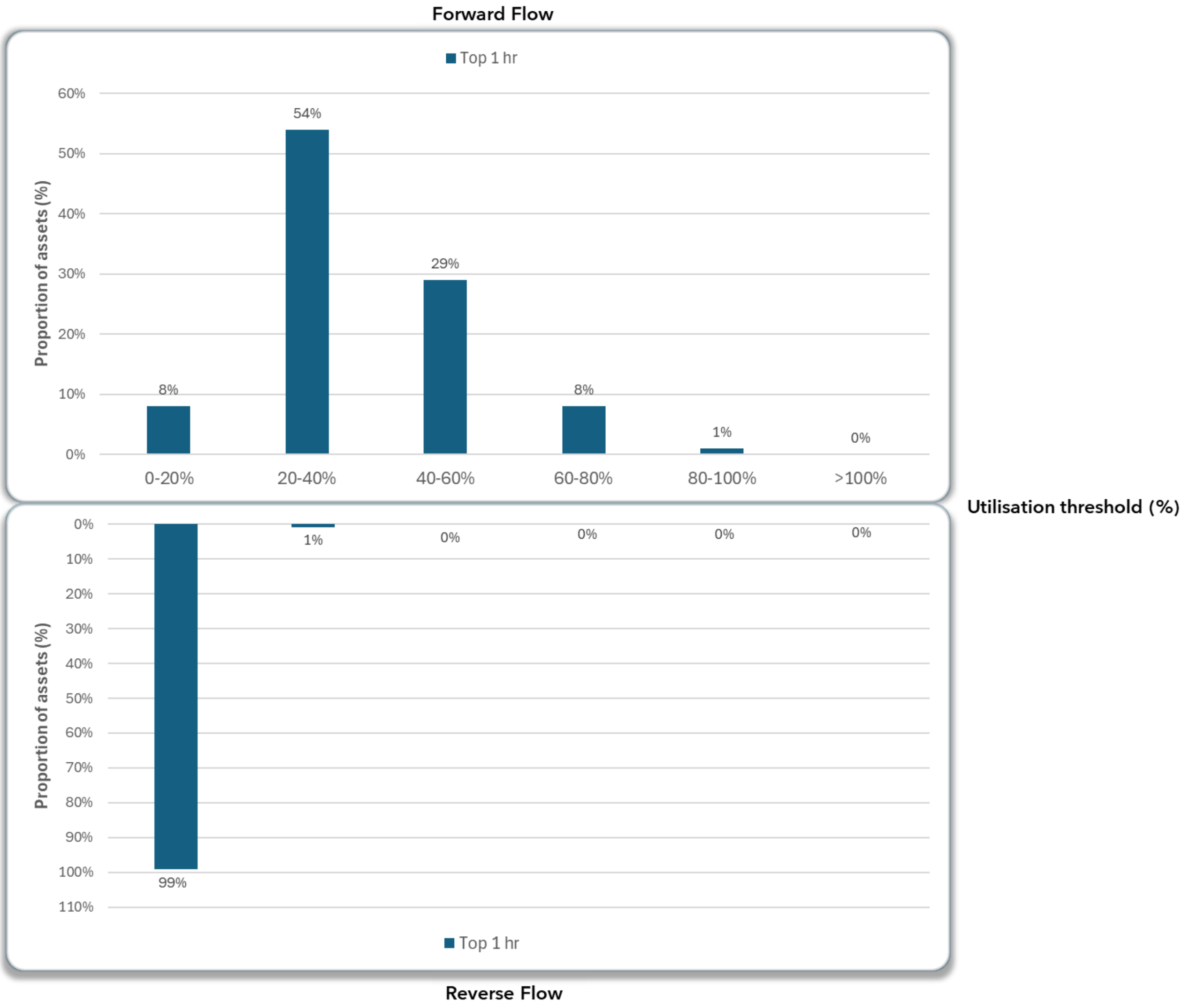


*Figure 23: Two-way power flow utilisation at Endeavour Energy zone substations for top 1-hr (based on FY 2023/24 demand data and **nameplate capacity**)*

This representation provides a detailed view of how heavily assets across the Endeavour Energy network are utilised, particularly under peak demand conditions and based on the zone substation nameplate capacities. It reveals that during the top hour of demand, over 90% of assets operate within a relatively low utilisation range of 20-60%. Only 1% of assets exceed 80% utilisation. Substantial reverse flows are still quite rare, with only 1% of assets experiencing reverse flows at 20-40% of their capacity for the top 1-hr.

This suggests that under the most recent weather conditions (noting that these figures are based on the FY 2023/24 rather than specific demand scenarios for planning), the Endeavour network has a significant amount of spare capacity to handle increases in forward or reverse flows.

Number of peak demand hours considered

One criticism of the traditional utilisation metric is that it only considers one hour of the year – the anytime maximum demand. This road-testing calculated different durations to add nuance to the risk profile regarding the 'peakiness' of asset utilisation. Above, the metric is shown for the top 1-hour, which is commonly used for asset planning. However, depending on the specific use case, other durations might be more appropriate. If considering the viability of demand management in zone substations with sustained high utilisation, or if comparing the conservatism of reliability standards across jurisdictions, examining the top 10 or top 100 hours could be more relevant. Alternatively, the top 500 hours might be more suitable for evaluating broad-based load-shifting programs. However, while these additional durations offer valuable insights, they also introduce significant complexity. Ideally, it would be preferable to select a single duration and allow for the calculation of other durations only when necessary. In this report we have opted to just show the top 1-hour to limit complexity. Refer to Figure C-1 in Appendices if you wish to see a range of durations calculated for

Endeavour Energy zone substations. Taking only the Top 1-hr was considered acceptable, as it is considered alongside the energy (TETU) metric, which accounts for utilisation across all other hours of the year.

Asset capacity definitions

The above metrics are calculated using the nameplate capacity, as this is how traditional network utilisation is calculated by the AER. This makes it easier to standardise comparison across DNSPs. In practice, however, each jurisdiction has different reliability standards that dictate how much spare network capacity should be reserved.

To illustrate the effect of the asset capacity definition, the data underlying Figure 23 is recalculated using the zone substation ‘firm’ capacities,[50] shown in Figure 24, below. For the top 1-hour, the largest proportion of assets fall in the 60-80% utilisation band, and almost a third are over 80%. Comparing Figure 23 and Figure 24 shows the level of conservatism necessarily built into reliability standards, and helps to explain why Figure 23 is skewed towards lower numbers. If, with the two-way power flow utilisation, we are attempting to focus on assets that are nearing investment thresholds (to view alongside the TETU metric) there may be an argument for using the firm capacity version of this metric, as it better differentiates the top few categories.

However, the downside is that firm capacity definitions differ across all DNSPs, which can make it harder to understand what is being compared, when looking across jurisdictions or between urban/rural service territories.

[50] Substation Firm Capacity can refer to either the ultimate transformed load capability with one transformer out of service or the maximum ultimate generation or the maximum ultimate load through-put capability. For transformed load, the Substation Firm Capacity is calculated using the transformer Short Term Maximum Load Limit under an N-1 condition for the substation.

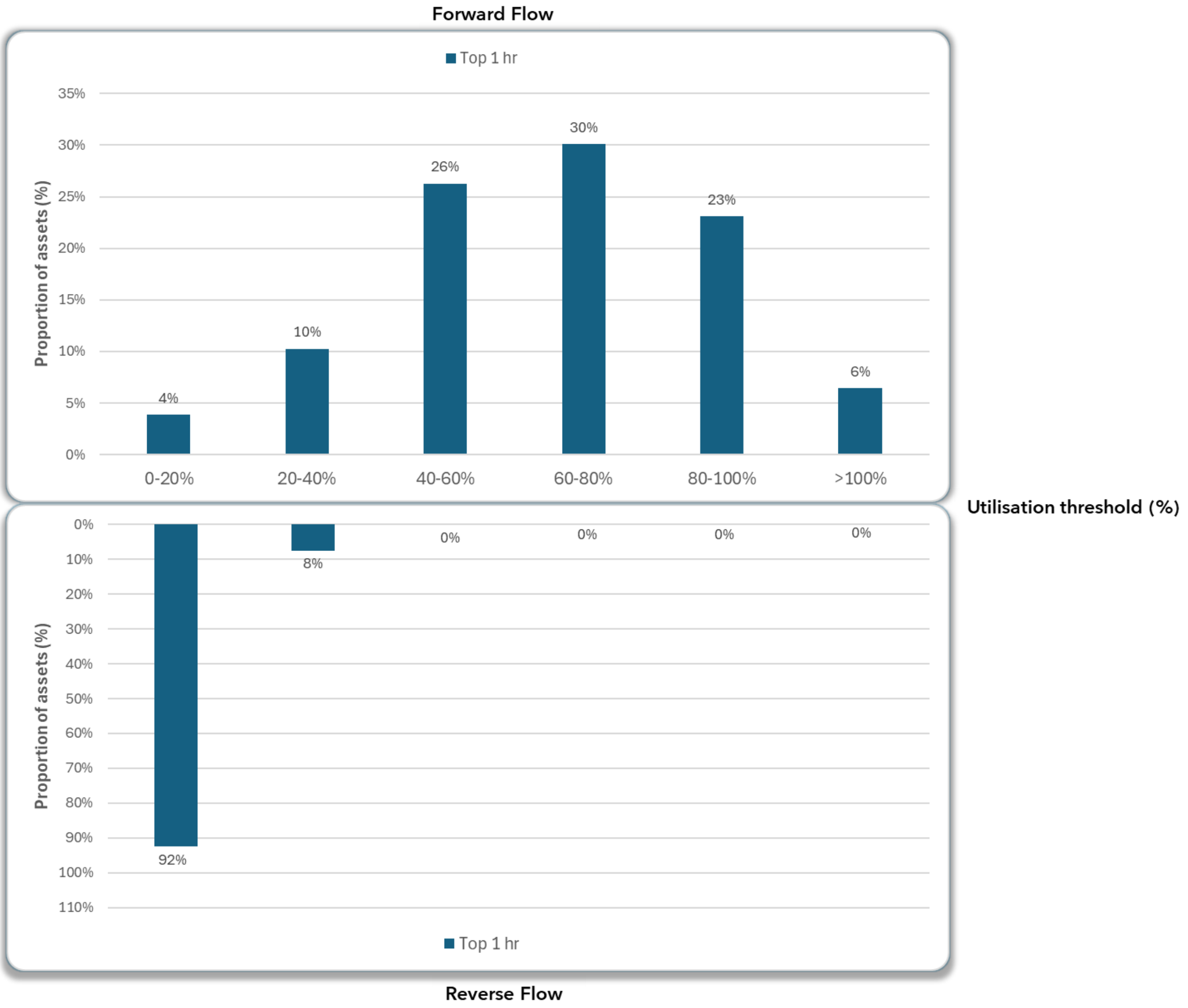


*Figure 24: Two-way power flow utilisation level at Endeavour Energy zone substations for top 1-hr (based on FY 2023/24 demand data and **firm/secure capacity**)*

Comparing networks

The same metric is designed for each comparison of the utilisation profiles of different networks. Figure 25 compares two-way power flow utilisation for Endeavour Energy and Essential Energy networks for the top 1-hour. There is slightly lower utilisation in the Essential Energy network (more spare capacity), as indicated by the orange column being skewed to the lower utilisation categories on the left. Contrary to this trend, there are also some assets in Essential's network (4%) that are exceeding their nameplate capacity.

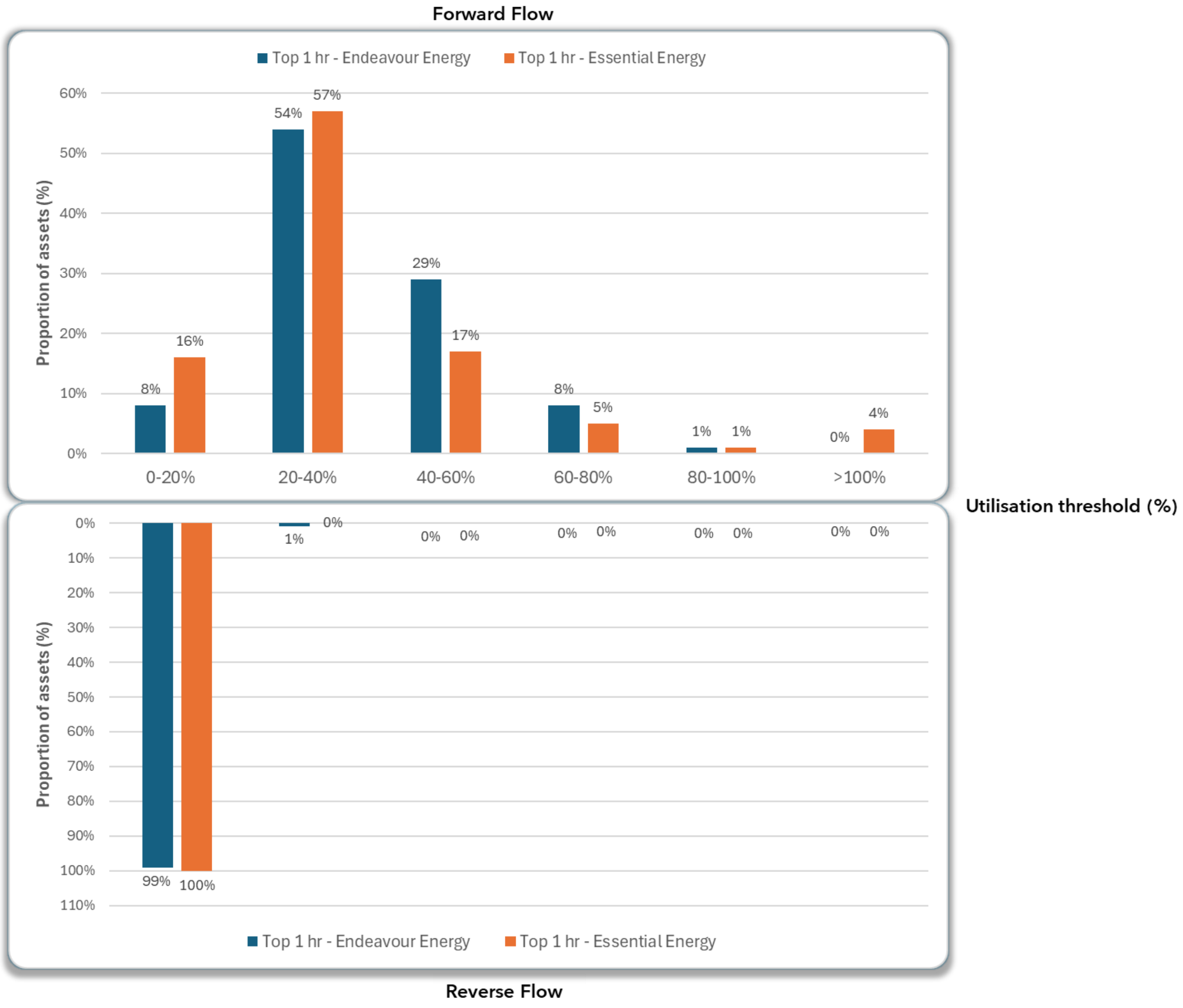


Figure 25: Two-way power flow utilisation level comparison between Endeavour Energy (blue) and Essential Energy (orange) assets (Top 1-hour; FY 2023/24; based on nameplate capacity)

Notably, Essential Energy exhibits no reverse flow utilisation, with 100% of its assets at 0% reverse flow capacity. This absence of reverse flows suggests a more traditional one-way flow of energy across the network. Overall, while both networks maintain a significant level of spare capacity under peak conditions, Endeavour Energy shows a more evenly spread utilisation with minimal reverse flows, whereas Essential Energy demonstrates a slight tendency towards overloading in a few assets without reverse flows, reflecting differences in their operational dynamics and preparedness for demand variations.

Similar comparison graphs can be readily produced for other durations but have not been included here.

5.3.2.3 Two-way Power Flow Utilisation – TOU Clock Representation

The power metric can also be represented according to TOU periods, to show average power flow utilisation on an hourly basis during peak, shoulder, solar soak, and off-peak periods for specific assets. This representation provides a direct link between the time of day/season and utilisation, which may inform cost allocation, tariff design and demand management incentives.

These representations can be produced for each summer/winter season, or just annually (as shown below for simplicity).

While we road-tested all Endeavour Energy zone substations, the results from just two zone substations are presented here:

- Robertson ZS: higher utilisation and winter peak with no reverse flows (Figure 26); and
- Marsden Park ZS: very high solar and significant reverse flows (Figure 27).

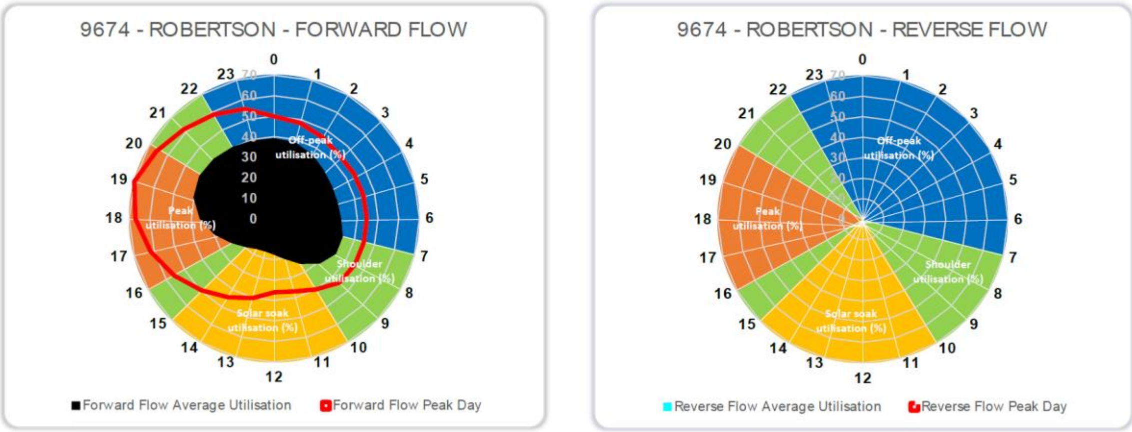


Figure 26: Two-way annual TOU for 9674 – ROBERTSON ZS (Endeavour Energy)

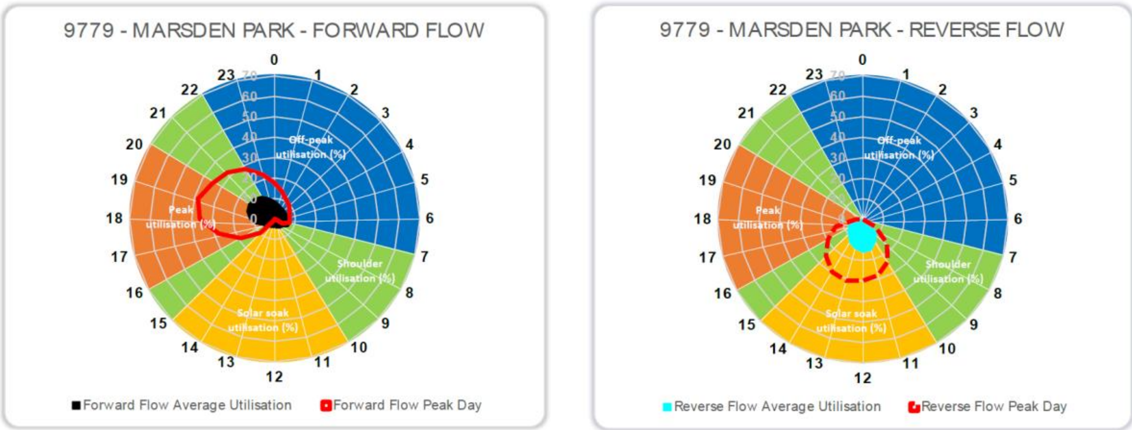


Figure 27: Two-way annual TOU for 9779 - MARSDEN PARK ZS (Endeavour Energy)

This visualisation is designed to represent a clock, with the numbers around the outside showing the hour of the day. The scale of the utilisation is between 0% (at the centre of the clock) to 70% (outer edge of the clock). The black shape indicates the utilisation level for the *average 24-hr day*, while the red line shows the utilisation on the peak demand day. The closer the black or red shape is to the edge of the clock, the higher the utilisation.

In the case of Robertson, the average forward flow demand (black area) is highest from 7-10pm and remains high until 1am. On the peak day (red line), the maximum concentrates at 7pm. The lowest average forward flow demand (black area) is during solar hours (during the yellow solar soak period), but on the peak day the lowest demand is overnight (blue period). This is reflective of a winter-peaking zone as solar is not making as large a contribution as on the average day. This figure helps to illustrate when forward flow demand could safely be increased to improve throughput, but without increasing peak demand, or the period over which demand management would need to be effective. Robertson has no reverse flows, as seen on the right of Figure 26.

Examining Marsden Park ZS in Figure 27, we can see that the utilisation is substantially lower overall, but the average day shape is quite similar to Robertson. The major difference is that forward utilisation drops to zero during solar hours. This trend is then reflected in the reverse flow version on the right, with the average day (blue area) showing 15% utilisation in the reverse direction, and 30% on the peak 'reverse flow' or 'minimum demand' day (red dotted line).

In the case of Robertson, all 8760 hours are forward flows so populate the left-hand image. For Marsden Park, the forward and reverse flows are separately binned before they are averaged to create the left and right-side images, respectively. In this case, 6439 hours of data underpin the forward flow average day shape (the black area), and 2321 hours underpin the reverse flow average day shape (the light blue area).

One notable limitation of the two-way TOU representation is the challenge of maintaining a consistent scale across different zone substations while still preserving the clarity and visibility of the data. When utilising the same scale for comparison, significant variations in utilisation levels between zones can result in less detailed or less discernible information for zone substations with lower or more subtle patterns of utilisation. This can make it difficult to effectively compare zones, as the differences in scale may obscure important details, leading to potential misinterpretations or overlooked trends. Adjusting the scale for each zone solves this problem, but reduces the ability to compare it directly with others, posing a trade-off between comparability and clarity. The scaling limitation in the two-way TOU representation has been solved in the two-way heat map power flow representation as shown in the next section.

A second limitation is that while visually appealing, some people can find the clock representation difficult to quickly interpret.

5.3.2.4 Two-way Power Flow Utilisation – Seasonal Heat Map Representation

To address the limitations of the TOU clock representation, the same data for Robertson and Marsden Park is presented in the form of linear 24-hour heat maps. The peak day, average weekday and average weekend day are all calculated separately for forward flows (a) and reverse flows (b). Summer and winter representations are shown separately to compare seasonality.

Robertson's summer forward flow heat map (Figure 28a) clearly illustrates the effect of solar substantially reducing loading during sunshine hours (green areas), and unusually high utilisation (orange) all the way throughout the night. This nighttime trend is much easier to pick up in the heat map than the TOU clock version. The summer peak is also very late, at 9pm which does not appear in the TOU clock, as a seasonal variant was not shown given the already high complexity of that view. Reverse flows do not yet register, as seen in Figure 28b. The weekday and weekend trends are surprisingly similar, with very limited sign of reduced weekend utilisation.

This suggests that tariffs or other incentives should not overly reward weekend consumption, or overnight EV charging in this area, and the focus should be on solar soak hours.

From the perspective of assessing which assets are approaching their capacity limits, the visualisation could be standardised by setting consistent thresholds—for example, marking values in red only when they exceed 60% of capacity for all zones. However, if this standardised colour scale is applied uniformly, most values in most zones' values would likely appear as green, making it difficult to identify meaningful deviations. To address this issue, we customised the colour scale to highlight utilisation variations more effectively for each individual zone asset.

SUMMER (FORWARD FLOW) - 9674 - ROBERTSON																								
Day/Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Peak day FF	40	38	37	34	33	36	38	41	36	26	17	12	8.5	6	10	12	16	24	32	38	44	47	45	42
Weekday	34	34	33	30	27	26	26	27	28	26	20	15	12	11	10	10	11	15	21	29	32	34	33	33
Weekend	33	35	34	30	28	27	26	26	26	25	22	16	13	10	9	10	11	14	21	29	33	34	33	32

(a)

SUMMER (REVERSE FLOW) - 9674 - ROBERTSON																								
Day/Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Peak day RF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

(b)

Figure 28: Two-way Summer Power Flow Utilisation (9674 – ROBERTSON ZS [Owner: Endeavour Energy; Summer nameplate capacity 7.5 MW]) – (a) Forward flow heat map; and (b) Reverse flow heat map (numbers in percentages)

The equivalent Robertson winter forward flow heat maps (Figure 29a) show a larger difference between peak and average days and a more concentrated 7pm peak. Like summer, there is a substantial off-peak demand during early morning hours, likely due in part to off-peak hot water systems. Again, there is almost no difference between weekdays and weekends.

WINTER (FORWARD FLOW) - 9674 - ROBERTSON																								
Day/Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Peak day FF	50	48	46	44	44	44	45	45	45	44	40	37	36	40	44	50	56	62	67	70	66	62	59	55
Weekday	43	41	38	36	35	35	36	39	39	33	27	22	20	19	21	25	31	39	45.7	48	48	46	45	44
Weekend	44	42	39	37	35	35	36	38	40	38	33	28	25	24	25	29	35	43	47.4	49	49	47	45	44

(a)

WINTER (REVERSE FLOW) - 9674 - ROBERTSON																								
Day/Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Peak day RF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

(b)

Figure 29: Two-way Winter Heat Map Power Flow Utilisation (9674 – ROBERTSON ZS Owner: Endeavour Energy; Winter nameplate capacity 7.5 MW]) – (a) Forward flow heat map; and (b) Reverse flow heat map (numbers in percentages)

The summer heat map for Marsden Park ZS in Figure 30 reveals significant reverse flows occurring during solar hours, starting as early as 7 or 8 am, and a very prominent evening forward flow peak.

SUMMER (FORWARD FLOW) - 9779 - MARSDEN PARK																								
Day/Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Peak day FF	18	14	11	10	8	8	7	7	4	0	0	0	0	0	1	10	19	28	36	38	35	32	28	22
Weekday	9	8	6	6	6	6	6	5	4	4	4	3	3	2	3	9	6	7	10	13	14	14	13	11
Weekend	10	8	7	6	6	5	5	4	4	3	3	3	4	2	3	7	9	10	11	14	15	15	14	12

(a)

SUMMER (REVERSE FLOW) - 9779 - MARSDEN PARK																								
Day/Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Peak day RF	0	0	0	0	0	0	0	0	7	16	24	28	30	31	30	25	19	14	3	0	0	0	0	0
Weekday	0	0	0	0	0	0	0	0.4	4	10	15	17	18	16	15	13	10	7	1	0	0	0	0	0
Weekend	0	0	0	0	0	0	0	0.8	4	10	14	17	16	15	12	11	11	7	2	0	0	0	0	0

(b)

Figure 30: Two-way Summer Heat Map Power Flow Utilisation (9779 - MARSDEN PARK ZS [Owner: Endeavour Energy; Summer nameplate capacity 45 MW]) – (a) Forward flow heat map; and (b) Reverse flow heat map (numbers in percentages)

The winter heat map for Marsden Park (see Figure 31) shows substantial reverse flows even during lower solar production months, highlighting the potential for solar soaking to prevent curtailment and maximise the use of local renewable energy.

WINTER (FORWARD FLOW) - 9779 - MARSDEN PARK																								
Day/Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Peak day FF	14	13	12	12	13	15	20	27	23	10	0.6	0	0	0	0	0	7	19	26	29	30	29	23	17
Weekday	8	7	7	7	7	8	9	11	10	6	5	6	5	5	5	5	6	10	14	15	15	14	13	10
Weekend	9	8	7	7	7	7	8	8	7	6	7	5	4	6	5	6	7	10	13	14	14	14	12	11

(a)

WINTER (REVERSE FLOW) - 9779 - MARSDEN PARK																								
Day/Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Peak day RF	0	0	0	0	0	0	0	0	5	15	22	27	28	28	26	24	19	10	1	0	0	0	0	0
Weekday	0	0	0	0	0	0	0	0	4	8	11	14	15	13	11	7	5	4	0.2	0	0	0	0	0
Weekend	0	0	0	0	0	0	0	0.3	4	10	10	15	16	14	12	8	6	4	0.6	0	0	0	0	0

(b)

Figure 31: Two-way Winter Heat Map Power Flow Utilisation (9779 - MARSDEN PARK ZS [Owner: Endeavour Energy; Winter nameplate capacity 45 MW]) – (a) Forward flow heat map; and (b) Reverse flow heat map (numbers in percentages)

Our conclusion is that the trends noted above are easier to discern in the heat maps (as compared to the TOU clock) for three main reasons:

- The linear format and colour scale requires less cognitive effort to interpret.
- The utilisation in each hour is clearly stated.
- The lower cognitive burden means that more versions can be shown (seasonal, weekday/weekend/peak), which revealed additional useful insights.

Not dissimilar to the TOU clock's scaling issue, the heat maps still require a colour scale that is individually calibrated to each zone to adequately show the trend, making comparisons between zones more difficult. This is considered acceptable as the utilisation figure can easily be read from the map.

The road testing leads us to the conclusion that the power metric can easily calculated from public data and would ultimately provide a versatile replacement for the traditional utilisation metric, addressing the identified limitations of accounting for minimum demand and providing temporal insights beyond a single peak demand hour. Nonetheless, we recommend that even if these new metrics can ultimately serve as replacements, that they be produced alongside the traditional utilisation metric for consistency of interpretation. Maintaining this continuity ensures that we have a reliable foundation upon which to evaluate long-term trends and the impacts of past decisions.

5.3.3 Secondary metrics

Secondary metrics were not calculated in the road testing due to incomplete data availability, but were further interrogated to inform the data status and recommendation in Section 5.1. The road-testing analysis of the primary metrics did reveal, however, that there is no single metric that provides a full picture of network productivity and the associated technical and economic considerations. We therefore suggest that the goal should be for networks to *maximise* Total Energy Throughput Utilisation *within the bounds* of capacity, reliability and quality of supply – which includes these secondary metrics. This why we recommend that the proposed metrics are viewed as a suite that can be interpreted together.

This should lead to having more units of customer value over which to spread the repayment of network costs. The economic dimensions of this improvement should be reflected in the per unit and per customer Average Network Cost.

6 Conclusions and Recommendations

Network utilisation has historically been used as an indirect indicator of electricity grid infrastructure productivity, and to frame the contextual understanding of the value that monopoly network infrastructure providers are delivering on behalf of customers. This report develops the case for why the 'traditional' network utilisation metric is no longer fit-for-purpose, given the evolving needs of distribution networks with substantial proportions of solar PV, batteries, EVs and other forms of CER. Customers now do not *only* obtain value from importing power for their energy needs. Distribution networks provide customers with export services and the ability for customers to meet their energy needs on-site and locally, in a more cost-effective and environmentally friendly manner.

To recognise these new services and to incentivise networks to deliver more customer value from capital-intensive network assets in the CER era, we propose two headline alternatives to the traditional network utilisation metric:

1. *Total Energy Throughput Utilisation (TETU),* which is an energy metric focussed on maximising the customer value that is facilitated by a grid connection, in the form of energy imported from the grid, exported to the grid and self-consumed.[51]
2. *Two-way Power Flow Utilisation,* which is a power metric focussed on understanding and balancing the level of capacity risk accrued to deliver the network productivity represented in the TETU. This provides visibility of the critical time-of-day and seasonal variations in two-way grid usage that inform how TETU can be maximised.

As electricity supply has other critical power quality and reliability standards that must be respected and that influence asset capacity, this is complemented by three secondary asset-level metrics regarding voltage compliance, reliability (SAIDI and SAIFI), and risk (accumulated asset risk). Finally, we propose a simple, inflation-adjusted average per unit and per customer network cost, to introduce a vital economic dimension that considers all useful customer value derived from the network.

The goals of, and relationships between, these objectives are illustrated in Figure 32 below. Note, however, that even if these new metrics can ultimately serve as replacements, they should be produced alongside the traditional utilisation metric for consistency of interpretation over time. Maintaining this continuity ensures that we have a reliable foundation upon which to evaluate long-term trends and the impacts of past decisions.

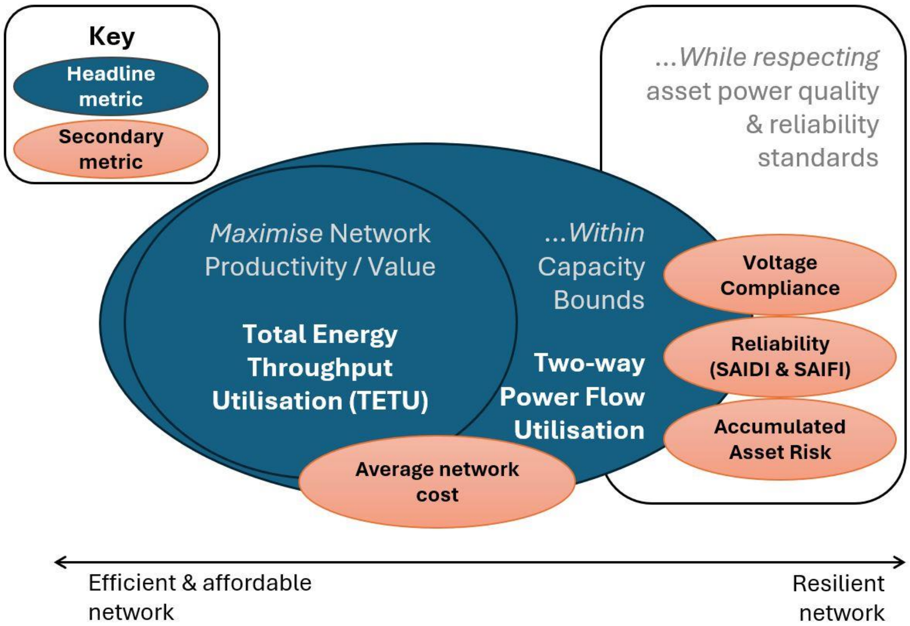


Figure 32: Relationship between proposed headline and secondary utilisation metrics

[51] While the AER's position is that self-consumption is not a 'network output', the authors suggest that there are also strong arguments for its inclusion in a holistic network utilisation metric – see Section 4.1.1 for discussion.

The traditional metric is calculated by the regulator at the zone substation level and aggregated across the system. Industry engagement through this project has revealed that other stakeholder use cases of updated utilisation metrics requires data to be made accessible at the *Zone Substation level* (in the immediate term) *and below* (in the longer term).[52] Metric availability at more granular spatial scales or asset-levels can help to manage peak and minimum loads towards improving network productivity during periods of low demand or high rooftop solar supply, in the context of tariff design, demand management, and the strategic location and timing of new loads such as EV charging.

If networks are successfully able to *maximise* Total Energy Throughput Utilisation *within the bounds* of capacity, reliability and quality of supply, this means that there are more units of customer value over which to spread the repayment of network costs. This has substantial potential to lower the average costs of network supply for customers.

Specific actions that network businesses could take to drive increases in a metric like the TETU could include encouraging time of use and 'solar soak' network pricing, realignment of controlled load programming with solar production periods, encouraging customer conversion from gas to (timed/smart) electric hot water, proactive voltage management or flexible exports to reduce curtailment, or partnership programs to open streetside EV charging with solar soak tariffs in strategic network areas. Such measures, in concert with incentives to flatten peaks in areas approaching capacity investment (such as afternoon pre-cooling of homes), could increase the volume of energy flowing through network assets, without additional capacity upgrades.

6.1 Regulatory process recommendations

Utilisation metrics potentially influence several strands of the AER's ongoing work program. We recommend that the AER:

1. Consult on the collection of the disclosure and transparent release of component network data to enable the calculation of the zone substation level proposed metrics in annual performance reporting in 2025 and beyond, alongside the traditional metric. The main changes to network data supply are elaborated in Section 6.2 below. Potential mechanisms for this are:
   - Routine annual review of network performance reporting inclusions, Regulatory Investment Notices (RINs), or Distribution Annual Planning Reports (DAPRs), where appropriate.
   - The scheduled review of how the AER's benchmarking models can be updated to better reflect export services (slated for 2027 or earlier).
2. Establish a plan towards more granular data supply below the Zone Substation level over time, potentially via the AER's ongoing efforts to enhance network data visibility, flowing on from the ESB data strategy. We suggest that the ultimate goal should be an open access platform for this cross-jurisdictional network data at granular resolution, similar to the image shown in Figure 11.
3. Review the need for alignment of network utilisation metrics with benchmarking models in upcoming review, including bringing forward this process prior to 2027.

6.2 Data conclusions and recommendations

Not all the required data are readily available, limiting the ability to comprehensively calculate and benchmark new metrics. One of the primary challenges identified is the lack of granular data at the necessary asset levels, such as substations or specific feeders. Specific data conclusions and recommendations to facilitate metric calculation are capture in Table 13 below.

[52] This excludes Average Network Cost, which can only be readily calculated and the system level.

Table 13: Data conclusions and recommendations to produce proposed suite of metrics

Metric	Data Conclusion	Recommendation
Power (Two-Way Power Flow Utilisation)	The calculation of zone substation and system-level power metrics is currently possible using existing load profile data but requires the disclosure of more granular asset-level load profile data for these metrics to be extended to meet other stakeholder use cases.	The **AER**, in its continued consideration of network data visibility, should review the spatial/asset granularity of data needs outlined in Section 5.1 of this report.
Energy (Total Energy Throughput Utilisation, TETU)	To be accurately calculated, the following data is required:	
	Installed solar PV capacity by zone substation (and below if calculated more granularly): All DNSPs should have ready access to this simple data input with limited to no overheads, but it is not currently disclosed.	The **AER** should request this data through one of the available annual disclosures (annual performance reporting, DAPRs, or RINs)
	CER curtailment figures: these are currently scarcely available and inaccurate. Most DNSPs have recently produced curtailment modelling for AER regulatory resets, but this is not publicly available. In the near-term, system average curtailment can be used where available, but curtailment varies substantially in different parts of the network due to differential CER uptake and demand profiles of connected customers.[53] Refer to Langham et al. (2022)[27] for recommendations on curtailment calculation.	Greater collaboration between the **AER, AEMO** and **DNSPs** is required to improve industry standardisation of CER curtailment calculation methods and reporting. The **AER** should ensure that this data is calculated under a consistent framework and uniformly presented across networks, fostering transparency and supporting more informed decision-making within the sector. This may align with broader work in facilitating improved standardisation of network models, LV data visibility and hosting capacity calculation.
	Actual weather data: while 'typical meteorological year' simplifications can be used as a proxy, actual solar insolation data enables accurate estimates of operational solar production to increase the accuracy of self-consumption calculations.	This data is accessible through subscription services. While we expect that **AEMO** has routine access to these services, making them consistently available to DNSPs and the AER would improve consistency and accuracy of metric calculation.
Economic (Average network cost)	Can be calculated with publicly disclosed AER Partial Performance Indicator data, providing TETU recommendations are adopted above.	No additional recommendations beyond TETU metric.
Power Quality (Voltage)	**Voltage data for substations and current flow data for feeders** are also key gaps to measure other factors that can meaningfully influence the effective asset capacity or utilisation level. While smart meters provide power quality data at the customer, their limitations—such as the inability to detect high-order harmonics, transients, and rapid voltage fluctuations—highlight the need for additional monitoring devices at upstream asset levels.	As **DNSPs** clarify standardisation of access to power quality data from smart meters in response to the AEMC Metering Services Review,[54] DNSPs should extend consideration to developing a consistent framework for capturing, analysing and reporting power quality data, *including substations and feeders*. The **AER** should guide the standardisation of power quality data capture, analysis, and reporting.
Reliability (SAIDI, SAIFI)	**More granular SAIDI and SAIFI:** these reliability performance data are generally	The **AER** should request SAIDI and SAIFI be reported at zone substation level (and below,

[53] For example: For Endeavour Energy the zone substation average is 5% curtailment but ranges from 0% to 17%, with some even higher outliers.
[54] AEMC, Review of the regulatory framework for metering services, Australian Energy Market Commission, 2024.

	captured by DNSPs at the asset level but are only reported to the AER by feeder classification type.	over time). Annual RINs – where these metrics are already disclosed – are likely to be the most appropriate mechanism.
Risk (Accumulated Asset Risk)	**Weighted Average Value of Customer Reliability:** should be reported at the at the same level of spatial granularity as the energy/power metrics (zone substation and below), for assets with proposed investment (only).	The **AER** should request this disclosure at zone substation level (and below, over time). Annual DAPRs may be the most appropriate mechanism.

6.3 Notes on metric usage

Currently network utilisation has no direct financial regulation or incentives associated with it. These new metrics were conceived with this same use in mind, and the AER's primary role with respect to the updated metrics is as a monitor and reporter, rather than a direct regulator. While regulatory incentives for network utilisation could be considered, this would be a distinct use case and may change the desirable metrics. Reporting network utilisation alone may influence network behaviour. But measuring network utilisation is not considered solely (or necessarily primarily) a tool to change network behaviour. Measuring network utilisation helps us to understand how the entire system — including consumer and large-scale generation and storage — can be developed at least cost and the greatest customer value.

The proposed shift towards a more granular, two-way view of utilisation extends the use cases beyond monitoring long-term system trends, towards performance and productivity analysis for specific assets. This can inform active interventions such as pricing and demand side or other CER activity, to add to the value extracted from our public network assets. In this new context, it is important to remember that a low TETU does not inherently equate to a 'poor performing' asset. Low utilisation represents an opportunity for low-cost load growth, while high utilisation represents a challenge to mitigate new costs, while accommodating load growth or changing consumer trends. The TETU should be interpreted within the context of two-way power flow, power quality, reliability, and asset risk thresholds. This why we recommend that the proposed metrics are used as a suite that can be interrogated at the relevant level of the system.

Furthermore, every asset will have cycles of lower and higher utilisation depending on demand growth, and how recent capacity upgrades have taken place. What matters most is the general trend of continuous improvement as new loads are electrified, to ensure the TETU can be raised as much as possible before new network investments are made, applying downward pressure on average network prices. To this end, it may be useful for DNSPs to specifically monitor and seek to improve the TETU in assets that are over, say, 60% on the Two-way Power Flow Utilisation metric – that is, those that are closer to reaching capacity constraints. From the regulator's perspective, a subset of the TETU could be monitored for assets that have planned investment to overcome constraints in the coming five-year network planning period.

It is beyond the scope of this project to interrogate how these utilisation metrics should influence cost allocation to consumers. There are live debates within the industry as to what 'cost reflectivity' in customer tariffs should look like. It is true that network investment is ultimately tied to large investments in capacity. It is also true that these investments are 'lumpy', and the short-run marginal costs of using more network capacity are small when an investment is distant, and very high when an investment is imminent. But it is also true that to get the best value out of the network in the long term, we must steadily encourage consumers and third-party technology and service providers to actively fill troughs in demand – particularly negative demand (reverse flows) being created by the uptake of solar – and flatten peaks. Therefore, considering the intersection with long-term, sustained consumer behaviour is critical. By better measuring and understanding how value is derived from networks in the CER era, we hope that the metrics considered by this report provide a foundation to inform this debate.

7 Appendices

Appendix A. Long-list Metrics and Assessment

Type	Metric	Source	Assessment
Energy	**E.1. Total Energy Throughput Utilisation**	Research team	**Proposed** – it represents a holistic metric to cover customer values based on two-way energy flow and self-consumption.
	E.1.1. Volume of energy curtailed	RACE/SAPN export service quality[27]	**Adequately covered** – within reverse energy flow component of E.1.
	E.1.2. Total Utilised CER Generation	RACE/SAPN export service quality[27]	**Adequately covered** – within reverse energy flow and self-consumption components of E.1.
	E.1.3. Total EV charging station utilisation	Research team, inspired by metric E.1.2	**Not considered** – too narrow, and positive EV charging behaviour is adequately represented in E.1. Load factor (P.3) might be more relevant for charging stations.
	E.2. Carbon Footprint Reduction	RACE/SAPN export service quality[27]	**Not considered** – adds value, but not considered core to the network utilisation issue.
Power	**P.1. Two-way Power Flow Utilisation**	Research team	**Proposed** – could be a valid update for traditional metric at the system level, and very versatile for application to asset type or locations.
	P.1.1. Asset-specific network utilisation	Electric Utility Engineers of the Westinghouse Electric Cooperation[12]	**Adequately covered** – rolled into P.1 representation/s.
	P.1.2. Time-varying network utilisation	Electric Utility Engineers of the Westinghouse Electric Cooperation[12]	**Adequately covered** – rolled into P.1 representation/s.
	P.1.3. Minimum Demand volume/duration	Research team	**Adequately covered** – rolled into P.1 representation/s.
	P.2. Percentage of Peak Demand Reduction	Research team	**Not considered** – cannot be calculated in a reliable way.
	P.3. Load Factor/Load Factor Improvement	U.S. Department of Energy[55]	**Not considered** – only relates energy and peak demand, but ignores capacity. May be useful for customer-level metrics, noting that there would be a need to develop standard approaches for the

[55] Energetics Incorporated, Metrics for Measuring Progress Toward Implementation of the Smart Grid, July 2008.

			level of detail and time period for comparing load factors on a consistent basis.
	P.4. Periods of CER energy curtailment	RACE/SAPN export service quality[27]	**Adequately covered** – covered in the calculation of curtailment in metric E.1 and bears some similarities TOU representation of P.1.
	P.5. Duration of Full Export Access	RACE/SAPN export service quality[27]	**Not considered** – Too narrow, and AER is calculating this in the Export Service Network Performance.[9]
Power quality	**PQ.1. Voltage variation**		
	PQ.1.1. Voltage Sags (Dips) and Swells (magnitude of symmetric event)	AS/NZS 61000.4.30:2001[56]	**Not considered** – requires detailed model and unbalanced power flow (feasibility).
	PQ.1.2. Voltage limits hit time, frequency, and duration	Research team, inspired by AS/NZS 4777.2[41]	
	PQ.1.3. Number/percentage of assets above the maximum voltage limit	Essential Services Commission[25]	**Proposed as secondary metric** – can be used based on best and worst scenarios as an indicator for individual assets, followed by a detailed power flow analysis for the assets that their voltage level breaches the voltage limit.
	PQ.1.4. Number/percentage of assets below the minimum voltage limit	Essential Services Commission[25]	
	PQ.1.5. Voltage fluctuation	AS/NZS 61000.3.7:2001[57]	**Not considered** – requires detailed model and unbalanced power flow. Given the scale of variables involved hundreds of assets, thousands of hours, and numerous contingencies, calculating the for every asset is not feasible.
	PQ.1.6. Voltage Unbalance Factor (VUF)	NEMA Standard[58] and IEC 60034-26:2006/COR1:2014[59]	
	PQ.2. Harmonics - Total Harmonic Distortion (THD)	TR IEC 61000.3.6:2012[60] under the National Electricity Rules, S5.1a.6	

[56] AS/NZS IEC 61000.4.30:2023, Electromagnetic compatibility (EMC), Part 4.30: Testing and measurement techniques — Power quality measurement methods, Australian Standards, 2023.
[57] AS/NZS 61000.3.7:2001, Electromagnetic compatibility (EMC) Part 3.7: Limits – Assessment of emission limits for fluctuating loads in MV and HV power systems, Australian Standards, 2001.
[58] Motors and Generators, NEMA Standard Publication MG 1-1993, 1993.
[59] IEC 60034-26:2006/COR1:2014, Corrigendum 1 - Rotating electrical machines - Part 26: Effects of unbalanced voltages on the performance of three-phase cage induction motors, 2006.
[60] TR IEC 61000.3.6:2012, Electromagnetic compatibility (EMC) - Part 3.6: Limits - Assessment of emission limits for the connection of distorting installations to MV, HV and EHV power systems, Australian Standards, 2012.

	PQ.3. Frequency Variations	AEMC Frequency operating standard[61]	
	PQ.4. Power Factor	National Electricity Rules	**Not considered** – adds value to utilisation, where a poor Power Factor indicates ineffective utilisation of electricity, while a good Power Factor indicates effective electricity and asset utilisation. However, it is already provided in the power data measured for all the assets that have monitoring system as well as for customers that have smart meters.
Economic	**EC.1. Average network price**	Research team	**Proposed as secondary metric** – simple option to integrate annual system level costs that are already calculated by the AER, and customer value delivery. Initially ruled out by the IRG due to challenges with arriving at defensible cost estimates, until AER Partial Performance Indicator data was found.
	EC.2. Measurable Customer Energy Savings	U.S. Department of Energy[55]	**Not considered** – has several questions about how to accurately track these data include determining the best unit metric, how best to quantify the benefits of the smart grid versus energy efficiency, and how CER and the benefits of storage are factored into smart grid efforts.
	EC.3. Relative Social Welfare	Project EDGE[62]	**Not considered** – more oriented around dynamic operating envelope (DOE) applications.
	EC.4. Amended Multilateral total factor productivity (MTFP)	Research team	**Proposed in draft report and reverted to average network price for simplicity**.
Reliability	**R.1. Distribution reliability measures for sustained interruptions**		
	R.1.1. Sustained Interruption	AER Distribution Reliability Measures Guideline 2018[63]	**Not considered** – part of SAIDI and SAIFI metrics, which cannot be used as a standalone metric (See the assessment of SAIDI and SAIFI metrics).
	1.2. System Average Interruption Duration Index (SAIDI)	AER Distribution Reliability Measures Guideline 2018[63]	

[61] Australian Energy Market Commission, Frequency operating standard, January 2020.
[62] Australian Energy Market Operator, Fairness in Dynamic Operating Envelope Objective Functions, April 2023.
[63] AER, Distribution Reliability Measures Guideline 2018, Australian Energy Regulator, November 2018.

	R.1.3. System Average Interruption Frequency Index (SAIFI)	AER Distribution Reliability Measures Guideline 2018[63]	**Proposed as secondary metric** – key current regulatory measure. Proposed as a comparator at the Zone Substation or other relevant asset level (rather than whole of system)
	R.2. Distribution reliability measures for momentary interruptions		
	R.2.1. Momentary Interruption	AER Distribution Reliability Measures Guideline 2018[63]	**Not considered** – It is a part of MAIFI and MAIFIe metrics, which cannot be used as a standalone metric (See the assessment of MAIFI and MAIFIe metrics).
	R.2.2. Momentary Interruption Event	AER Distribution Reliability Measures Guideline 2018[63]	
	R.2.3. Momentary Average Interruption Frequency Index (MAIFI)	AER Distribution Reliability Measures Guideline 2018[63]	**Not considered** – Considered an inferior measure and is not supported by AEMC and DNSPs.
	R.2.4. Momentary Average Interruption Frequency Index event (MAIFIe)	AER Distribution Reliability Measures Guideline 2018[63]	**Not considered** – It is widely recognised as a more suitable measure for comparing customer reliability service levels. However, trade-offs of reliability and utilisation using this metric is challenging.
	R.3. Customer-based distribution reliability measures		
	R.3.1. Customer Average Interruption Duration Index (CAIDI)	AER Distribution Reliability Measures Guideline 2018[63]	**Not considered** – Energex notes in the "Response to Draft Report: Distribution Reliability Measures (EPR0041)" that customer-based distribution reliability measures have their limitations and require very careful application. Therefore, it is not recommended to use these measures in the NEM.
	3.2. Customer Average Interruption Frequency Index (CAIFI)	Energex[64]	
	3.3. Customer Total Average Interruption Duration Index (CTAIDI)	Energex[64]	
	3.4. Customers experiencing multiple interruptions (CEMI)	Framework of Resilience Metrics in USA[65]	
	3.5. Average Service Availability Index (ASAI)	Framework of Resilience Metrics in USA[65]	
	R.4. Load based distribution reliability measures		

[64] Energex, Energex Response to Draft Report: Distribution Reliability Measures (EPR0041), July 2014.
[65] Watson, J.P.; Guttromson, R.; Silva-Monroy, C.; Jeffers, R.; Jones, K.; Ellison, J.; Rath, C.; Gearhart, J.; Jones, D.; Corbet, T.; et al. Conceptual Framework for Developing Resilience Metrics for the Electricity, Oil, and Gas Sectors in the United States; Sandia National Laboratories: Albuquerque, NM, USA, 2015.

	R.4.1 Average System Interruption Duration Index (ASIDI)	AER Distribution Reliability Measures Guideline 2018[63]	**Not considered** – Energex notes in the "Response to Draft Report: Distribution Reliability Measures (EPR0041)" that customer-based distribution reliability measures have their limitations and require very careful application. Therefore, it is not recommended to use these measures in the NEM.
	R.4.2 Average System Interruption Frequency Index (ASIFI)	AER Distribution Reliability Measures Guideline 2018[63]	
	R.5. Volume of CER System Services	RACE/SAPN export service quality[27]	**Not considered** – adds value, but AEMO supplied relevant measures of DER market services, such as frequency control ancillary services (FCAS), fast frequency response (FFR), synthetic inertia, wholesale demand response (WDR) and reliability and emergency reserve trader (RERT) services.
Risk and resilience	**RR.1. Accumulated Asset Risk**	Research team	**Proposed as secondary metric**
	RR.2. Severity Risk Index (SRI)	2022 IEEE PES GM conference paper[66]	**Not considered** – It can show the best and poorest performance of the grid over a long period of time. It can also illustrate the trend towards recovery due to a major event. However, it requires several data inputs (e.g., % of Generation Lost per hour/day, % of Transmission Lines Tripped per hour/day, and % of Load Disconnected per hour/day), which could be not available, and assumptions for the weighted indices to be considered. Therefore, it is complex to estimate and cannot be calculated in a reliable way.
	RR.3. Dynamic Resilience Indicator (DRI)	2022 IEEE PES GM conference paper[66]	**Not considered** – suitable for shorter time periods (e.g., minutes to hours), which can be calculated during the disturbance phase, and used to identify precursors to major loss of resilience in grid. It is considered as a post-event forensic metric to identify where additional investments would be most needed. However, it has the same limitations of SRI, which requires several data inputs (e.g., Reactive Reserves, Loadability Limit in p.u., and Frequency Agility), which could be not available, and assumptions for the weighted indices to be considered. Therefore, it is complex to estimate and cannot be calculated in a reliable way.
	RR.4. Estimated time of restoration (ETR)	Consolidated Edison Co. New York and Orange and	**Not considered** – It is difficult to estimate accurately because of the uncertainty and dynamics from nonstationary failure and recovery processes. It requires a complex algorithm that takes into account

[66] Schoenwald, D., and Ojetola, S., Revisiting Resilience Indices. 2022 IEEE Power & Energy Society General Meeting, July 2022. doi:10.2172/2004093.

	Rockland Utilities,[67] and Western Power.[68]	queue time, travel time to reach the site of the fault and begin investigating the issue, and repair time.
RR.5. Percentage of critical load coverage	U.S. Department of Energy[69]	**Not considered** – It requires a complex algorithm to cover three main components, including grid disturbance, system characteristics, and performance measures, which will be resulted in identifying weights to be assigned for measuring the percentage of critical load available to be included in the generic performance measure.
RR.6. Loss of Load Probability (LOLP)	Framework of Resilience Metrics in USA[65]	**Not considered** – It gives no indication as to how severe the condition would be when the load exceeds available generation. Also requires a Monte Carlo simulation to calculate the LOLP of a system.
RR.7. Loss of Load Expectation (LOLE)	Framework of Resilience Metrics in USA[65]	**Not considered** – It has the same weakness as LOLP of providing no information about the severity of the condition. Also requires a Monte Carlo simulation.
RR.8. Expected Unserved Energy (USE) or Loss of Energy Expectation (LOEE)	Framework of Resilience Metrics in USA[65]	**Adequately covered** – in metric R.1. To avoid complexity, the expected USE can be calculated to the assets that only pass a certain Two-way power flow utilisation threshold.

[67] Consolidated Edison Co. New York and Orange and Rockland Utilities "Post Sandy enhancement plan", June 2013.
[68] Western Power, Estimating the time of restoration, December 2022. Accessed on Apr. 4, 2024.
[69] Chalishazar, V., Poudel, S., Hanif, S., Mana, P. T., Power System Resilience Metrics Augmentation for Critical Load Prioritization, December 2020.

Appendix B. TETU Load Factor Type Variant – example results

As discussed in Section 4.1.2.1, Figure B-1 shows a comparison of Endeavour Energy's TETU metric for all zones using the original formula (in red; based on the seasonal rated Zone Substation capacity) with the load factor type variant (in blue; based on the seasonal maximum load at the Zone Substation). With the original version (red), attention is focussed on the higher utilisation zones which are closer to maximum capacity loading. This shows very little correlation with the load factor variant, in blue. These blue columns indicate that there is substantial underlying variation in how 'peaky' or 'flat' underlying substation loads, but these are not necessarily related to how constrained the asset is. Reordering on the blue columns would make it easier to compare across the full range of zones at different stages of the investment cycle. This would enable the identification of model zones of flatter load profiles (with the highest figures), and very peaky zones (lowest figures) to focus time-of-use or dynamic tariffs or to encourage trough filling towards a flatter *long-term* load profile.

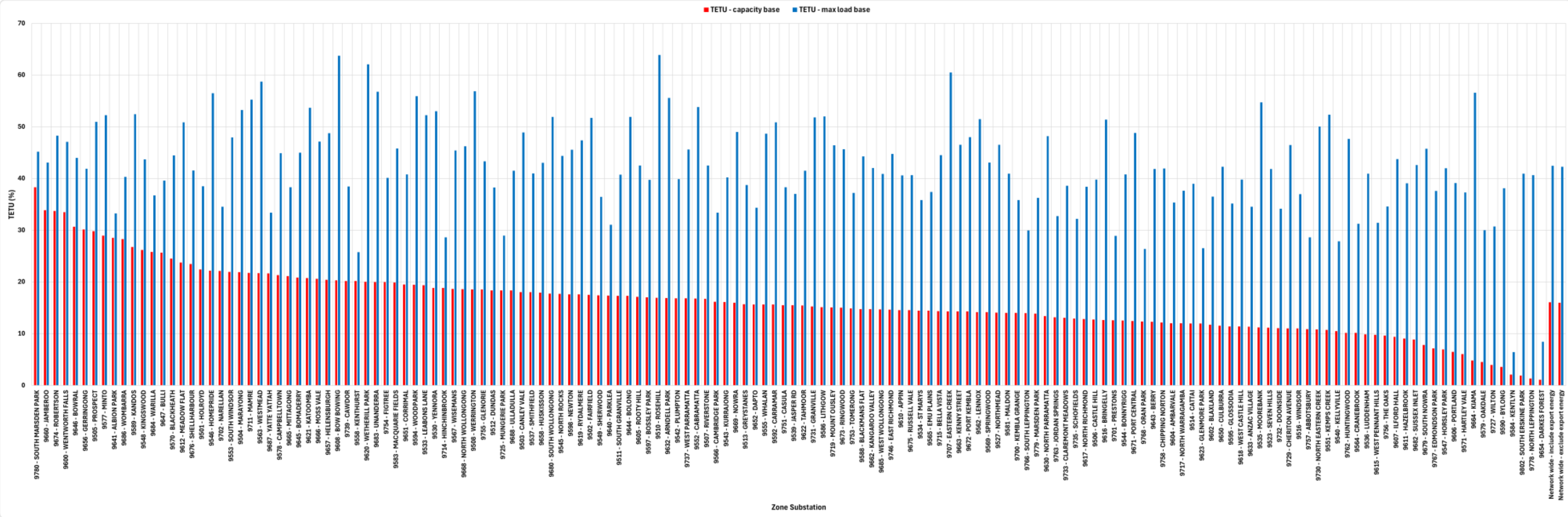


Figure B-1: Comparison of TETU calculated using seasonal rated ZS capacity (red bars) and seasonal maximum load at ZS (blue bars) across Endeavour Energy zone substations

Appendix C. Supplementary Information

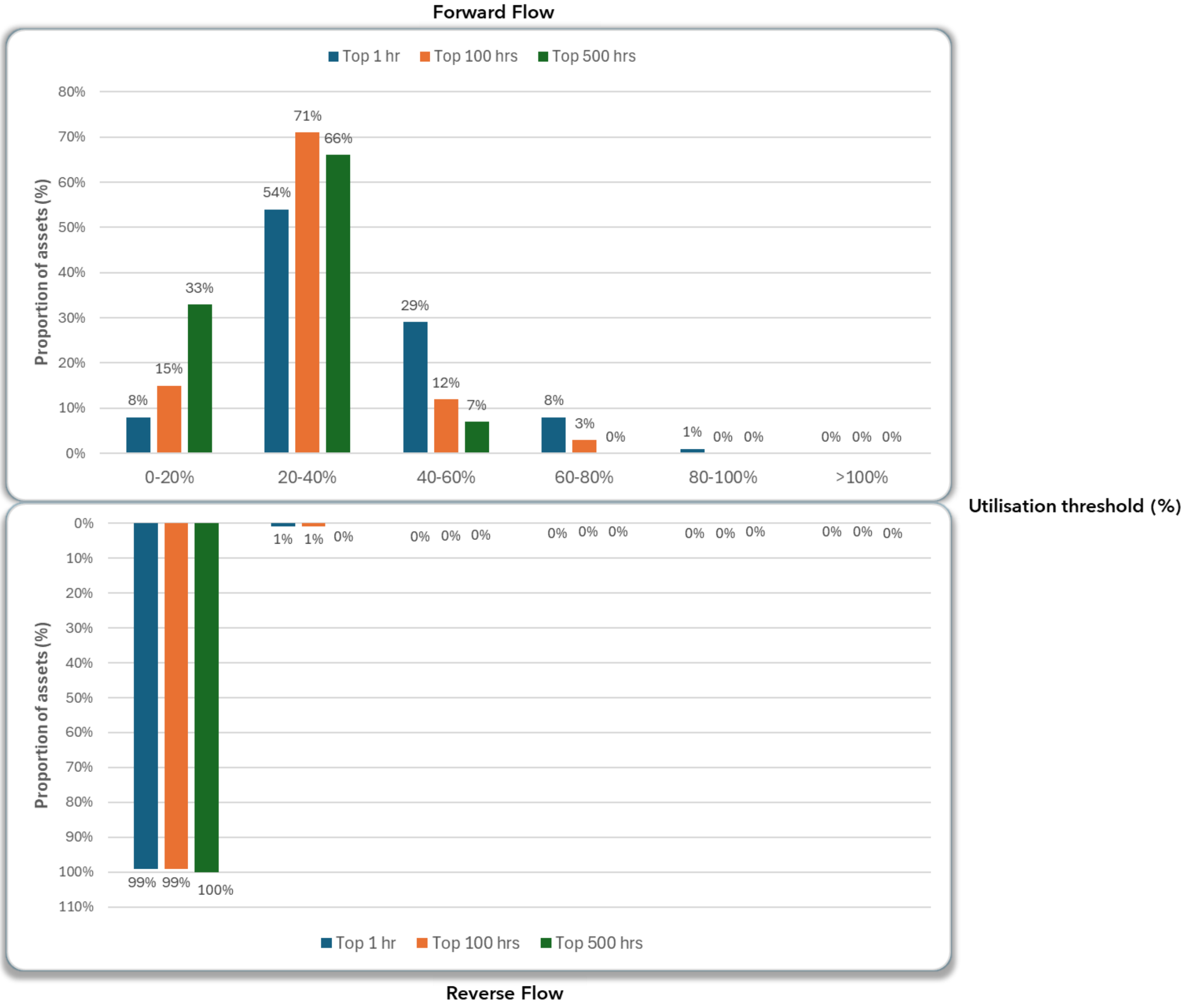


Figure C-1: Two-way power flow utilisation at Endeavour Energy zone substations for top 100 and 500 hours (based on FY 2023/24 demand data and nameplate capacity)

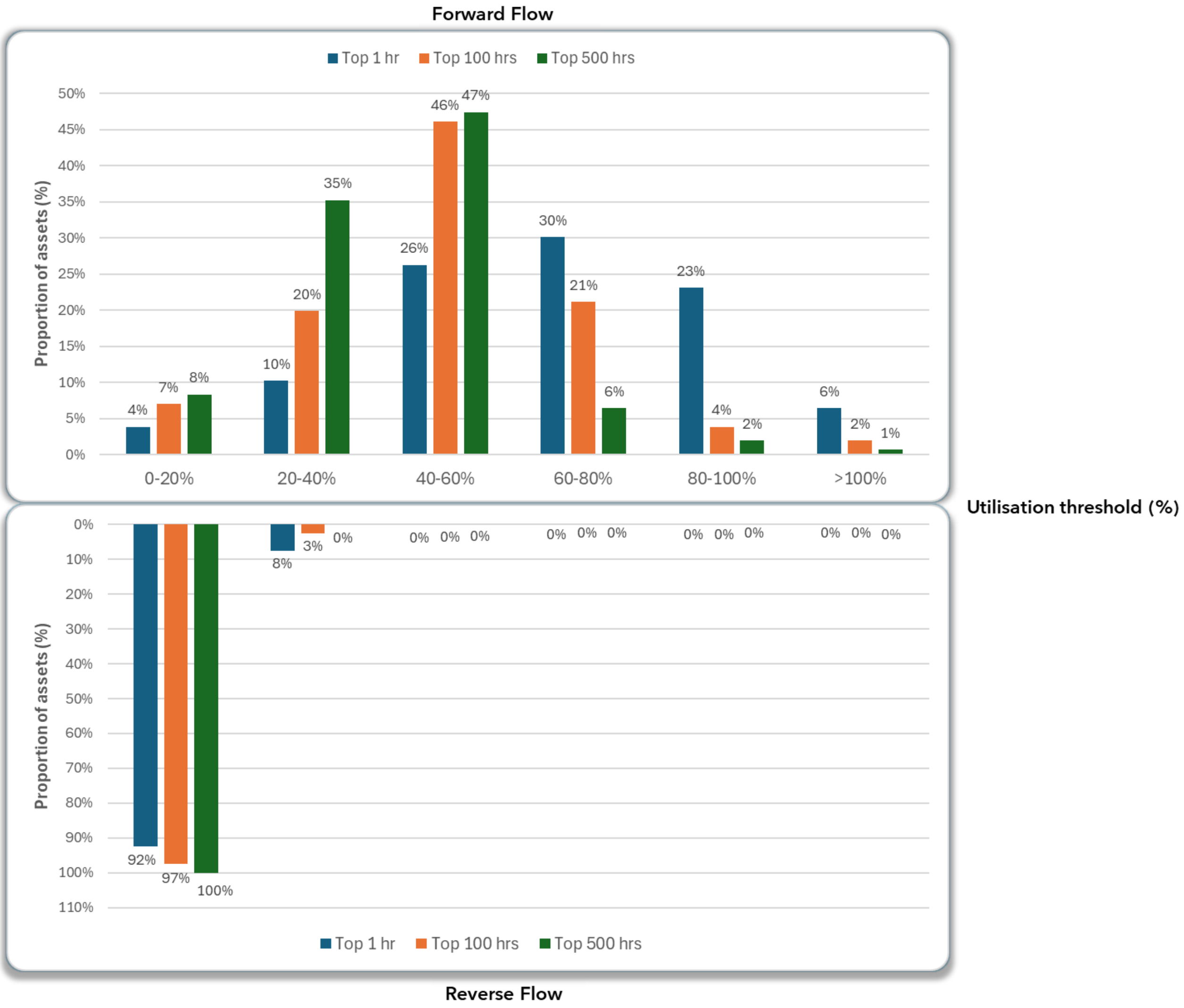


*Figure C-2: Two-way power flow utilisation level at Endeavour Energy zone substations for top 1-hr (based on FY 2023/24 demand data and **firm/secure capacity**)*


UTS
Institute for
Sustainable
Futures