Australia's National Science Agency

Analysis of the VPP dynamic network constraint management

Advanced VPP grid integration project

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Summary

This document is one of the knowledge-sharing deliverables of the Advanced VPP Grid Integration project conducted by SA Power Networks in partnership with Tesla Motors Australia and the CSIRO between January 2019 and December 2020. The project was enabled with funding by ARENA.

The project demonstrated the capability to dynamically set network export limits for a virtual power plant (VPP) coordinating the operation of an array of distributed energy resources (DER) – rooftop PV systems with battery energy storage – allowing them to raise over the normal static export limits during times and in locations where there is sufficient network capacity to do so. This capability was tested on a field trial conducted in South Australia from July 2019 to December 2020, for which SA Power Networks and Tesla co-designed and implemented a network-VPP application programming interface (API), operating procedures and rules to dynamically allocate network capacity to the VPP. The network capacity information provided by the SAPN API was used to coordinate the operation of the PV-battery systems at the first 1,000 customer premises deployed as part of Tesla's VPP rollout in SA.

This report presents research findings regarding the potential to increase DER exports beyond the standard network static export capacity limit, provide flexibility to host increased numbers of DER in the network, and release economic value to VPP aggregators.

Analysis scope and methods

The research was guided by a subset of the research questions formulated in the project research plan [1] (See A.4). Namely,

RQ 1 To what extent can available DER export capacity be increased compared to the maximum capacity available under SA Power Networks' standard connection rules (currently capped at 5kW export per customer) using dynamic network constraint management via the proposed interface between SAPN and the DER aggregator?

RQ 3 To what extent can the proposed interface allow distribution networks to host DER at higher levels of penetration by enabling dynamic, locational export limits compared to standard fixed per-customer export limits?

RQ 5 What are the costs of implementing the proposed dynamic network constraint management assessed against benefits obtained?

RQ 6 What additional economic value can be enabled to DER operators by dynamic network?

Additional analysis addressing the remaining research questions in [1], which deal with management of DER operation within the network technical envelope, DER visibility and customer impacts, will be addressed in a final knowledge sharing report at the end of the project.

The analysis underlying RQ1 and RQ3 was developed using dynamic capacity modelling data provided to CSIRO by SAPN. A suite of metrics was defined to evaluate and compare DER operation limits and export capacity under the dynamic constraint management approach proposed by SAPN. The constraint modelling data provided by SAPN consisted of 25 different scenarios categorised by day-type and month of the year. Each scenario specifies constraints over a 24-hour period produced in half-hourly intervals for workdays and non-workdays for each month of the year. A special profile for a heatwave-day scenario is also included.

This analysis did not study the accuracy or performance of the dynamic capacity models developed by SAPN, which were taken as the source of truth for the analysis, nor did it consider actual VPP utilisation of released capacity during the trial.

For RQ5 and RQ6, a preliminary economic analysis was conducted using simulated data provided by Tesla to produce general estimates on value released by the dynamic network capacity constraints approach implemented in the trial. This analysis focused on estimated wholesale energy arbitrage benefits.

Findings: VPP export capacity under dynamic constraint management

The analysis of the dynamic capacity profiles modelled by SAPN indicates that dynamic constraint management can support significant increases in average DER export capacity as compared to that available under the standard static limit of 5 kW.

The analysis evaluated increases in export capacity averaged over two time periods: over a whole day (daily) and over the portion of the day where PV generation is active (daylight-hours). It was found that dynamic constraint management can support across the year:

- A 60% increase in daily average DER export capacity (up to 8 kW).
- A 20% increase in daylight-hour average DER export capacity (up to 6 kW).

Average available capacity is seasonal and achieves its highest values in the winter months, during which dynamic constraint management can support:

- A 100% increase in daily average DER export capacity (up to 10 kW).
- A 60 % increase in daylight-hour average DER export capacity (up to 8 kW).

Average available capacity is also locational, varying across the transformers connected to the VPP depending on where they are located. The analysis found that:

- All transformers connected to the VPP can be allocated the maximum increases in DER export capacity from May to August.
- Half of the transformers connected to the VPP can be allocated the maximum increases in DER export capacity from March to August.
- Fewer than 20% of the transformers connected to the VPP can be allocated the maximum increases in DER export capacity across the year.

Findings: VPP released energy under dynamic constraint management

The estimated energy that can be released to the VPP through dynamic constraint management follows similar variability across the year to that observed for average available capacity. The analysis found that:

- During June and July, 90% of the VPP transformers are estimated to be able to release an average 32.5 kWh per transformer per day on workdays; and 80% of the transformers on non-workdays.
- The highest potential released energy levels are observed on heatwave days, when 45% of the VPP transformers are estimated to release an average 45 kWh per transformer per day.
- The second highest potential release energy levels are observed from September to February, when 12% of the VPP transformers are estimated to able to release an average 41 kWh per transformer per day.

Findings: Network hosting capacity

The analysis of the network capacity constraint estimates modelled by SAPN reveals that DER hosting capacity could be increased significantly by enabling dynamic, locational export limits rather than standard static constraint limits. As a basis for comparison, the analysis estimated that a regime of *static* locational export limits across the network enables up to 200 MW of DER export capacity, which could be allocated to DER allowed to export the maximum capacity allocated by their static locational limit all the time across the year. This DER export capacity could be increased for dynamically managed DER, which are able to be constrained at periods of high network utilisation – typically during periods of low demand and high PV generation. The analysis shows that by enabling a regime of *dynamic* locational export limits, DER export capacity could be further increased by up to:

- 25% for dynamically managed DER exports that would be unconstrained 90% of the time across the year,
- 55% for dynamically managed DER exports that would be unconstrained 80% of the time across the year,
- 300% for dynamically managed DER exports that would be unconstrained 50% of the time across the year.

Dynamic locational network limits, as implemented in the proposed SAPN API, can thus help unlock otherwise unused network hosting capacity and increase utilisation of existing infrastructure.

Findings: Economics

A preliminary economic analysis of the benefits of the approach was conducted using simulated customer load profiles and solar PV output for 1,000 simulated customer premises, the targeted deployment in Tesla's VPP rollout in SA with the number of premises remaining constant for the analysis period of 10 years.

The estimated benefits were simulated for three cases:

- 2 kW static network export limits,
- 5 kW static network export limits, and
- 10 kW static network export limits.

All three cases analysed used static limits to estimate the upper and lower bounds of potential value in the implementation of an API to exchange real-time and locational data on distribution network constraints between SA Power Networks and the customers' DER aggregator (VPP provider). Further analysis should incorporate the value of dynamic limits between these static limits varying through time based on historic market data and sampled VPP performance.

The present economic modelling analysis found that the estimated wholesale energy arbitrage benefits for each of the twenty participants across the three cases are nonlinear with export limit, increasing the most when the export limit is 5 kW compared to 2 kW. Average energy arbitrage benefits per site equalled $164 in the 2-kW case, $388 in the 5kW case and $423 in the 10kW case.

Increasing dynamic export limit from 2 kW to 5 kW has the potential to create up to $1.7 million additional value to the 1000 participants in the VPP. Increasing the dynamic export limit from 2 kW to 10 kW has the potential to create up to $1.95 million additional value to the 1000 participants in the VPP.

These are preliminary findings based on the data available. A more detailed cost benefit analysis should include dynamic export limits (rather than the static limits assumed here) and FCAS revenues in benefit calculations. An estimate of ongoing costs of VPP implementation will also need to be estimated.

Main conclusion

While further analysis of trial data will be conducted at the end of the field trial to expand on RQ 5 and RQ 6 and address the remaining research questions in [1], the findings of analysis reported at this stage strongly support the main underlying hypotheses of the project.

H 1	Existing limits on the level of network exports from customers' renewable energy systems on the SA distribution network can be increased by as much as two-fold by implementing an API to exchange real-time and locational data on distribution network constraints between SA Power Networks and the customers' DER aggregator (VPP provider).
H 2	Operating a VPP at higher levels of export power than would otherwise be allowed under normal static per-site export limits increases the opportunity for the VPP to provide market and system-wide benefits.

Important caveats

1. **The extent to which DER export capacity can be increased depends on the DER location and the time of the day.** The analysis shows that DER export capacity could indeed reach

at times in some network locations up to 10 kW, which is twice the DER export capacity allowed by the current static export limit of 5 kW in SAPN network. However, this does not imply that the network DER export capacity can be generally doubled by implementing a regime of dynamic export limits.

2. **The way DER export capacity is mapped and communicated is important.** Communicating available DER export capacity as a simple daily average can be misleading, particularly for PV exports, since the data analysis shows that DER export capacity is typically the lowest during daylight hours in networks with high PV penetration. Network capacity available for PV exports is more accurately represented as a daylight average, and even more so if maximum and minimum values are also captured alongside.
3. The findings from the analysis of DER export capacity and network DER hosting capacity take the hosting capacity modelling data provided by SAPN as the source of truth. Hence, the numerical results of the analysis should be taken as more as qualitative indicators of what is possible, rather than as hard estimates. More confident estimates for hosting capacity could be refined and validated with more data and improved modelling. Greater uncertainty in the estimation of hosting capacity leads to more guarded release of value for DER services in VPPs.

Opportunities for further work

Opportunities for additional research can be summarised as technical due diligence and improvement, stakeholder consensus, and economic analysis.

Technical due diligence and improvements

The analysis reported for RQ 1 and RQ 3 was based on dynamic capacity constraint profiles estimated by SAPN constraint engine. At this stage, these profiles provide an average daily capacity curve per month of the year based on approximate hosting capacity estimates extrapolated from calculations from a reduced sample of prototype feeder models and a small number of tuneable parameters (see, e.g., [2]). Access to more DER and network data, such as that provided by a VPP, can help clean network data and validate and refine models that underly the hosting capacity assessment process, increasing confidence and reducing conservativeness in the definition of safe operational envelopes. A combination of data-driven and physics-based state estimation techniques could be considered for sections of the network where more connectivity information, smart meter data, and monitored data become available.

Stakeholder consensus

Regarding stakeholder consensus, there is yet no Australian standard or industry-agreed upon approach for calculating hosting capacity, but much foundational work has been done by EPRI [16], [17], and there is ongoing work led by DEIP [13], [18]. Having one would create a number of benefits, including consistency for VPP developers and clear guidance about how DNSPs should communicate these limits to their customers.

Another opportunity for consensus exists regarding the definition of average available capacity. This report highlighted the ability to describe this capacity on either a 24-hour or daylight-focused basis. Our analysis indicates that, so long as solar energy is a major source of export, the daylight-based metric is significantly more representative of the exploitable capacity, and should therefore be the preferred way of communicating average impacts of dynamic hosting capacity limits. A commonly agreed upon approach for communicating this information would be valuable.

Economic analysis

Finally, there is significant room for follow-up work on economic analysis. The present analysis focused on the increased value to the VPP of implementing hosting capacity estimates at various static levels for DER exports. This analysis is wholly distinct from an economic analysis of the benefit of implementing dynamic constraint limits across SAPN's service area. Indeed, one insight from our analysis is that a large benefit of the introduction of dynamic operating envelopes is that it can potentially optimise utilisation of hosting capacity across the network, enabling additional customers to connect solar to the network. Future economic analysis could analyse this benefit in addition to that released to the existing Tesla VPPs.

A more detailed cost-benefit analysis should include dynamic export limits (rather than static limits assumed in the present report) based on observations collected from the trial and the inclusion of FCAS revenues in benefit calculations (a recent report from AEMO [4] provides some insights on VPP revenue from contingency FCAS markets in current VPP demonstrations, including the present trial). More work is required to determine an accurate cost for the VPP integration process. The PV-battery systems used in the trial were not optimised for dynamic limits, which limited the potential upside versus the 5-kW static limit. As discussed above, consensus on the best data and modelling techniques for adequately determining dynamic capacity limits need to be identified and then the cost of collecting, cleaning, and analysing that data and then communicating it to VPPs (or other DER) can be accurately determined. The economic upside is also heavily dependent on proprietary optimisation algorithms that will vary greatly between VPP operators.

1 Introduction

1.1 The need for dynamic network capacity allocation

Virtual Power Plants (VPPs) that aggregate many customers' individual distributed energy resources (DERs) under central control have great potential as a part of Australia's energy mix. VPPs enable new value streams for individual customers and, having the ability to respond rapidly to export or consume large amounts of power, can potentially play a key role in balancing an energy system dominated by intermittent renewables. However, VPPs also present challenges in grid integration because the physical capacity to accommodate local energy peaks associated with VPP operation in the low voltage network is limited.

In order to protect the integrity of the network for all customers, networks consider worst-case event scenarios and set static export limits at each connection point to ensure that such events will not cause local failures. For a VPP this means that the maximum power that the VPP can manage as a whole is capped. Recent modelling by SA Power Networks suggests that these static limits will likely need to be reduced in some areas to protect the network as DER penetration grows, particularly if there is widespread enrolment of household DER in VPPs.

While AS/NZS4777 standards for inverter-connected DER [3] introduce advanced functionalities to support LV distribution systems, such as Volt-Watt and Volt-VAR control functions, those standards are not a panacea for managing a LV system with high penetrations of DER. One issue with them is that over-voltage protection settings across the network are likely to be inconsistent – in older inverters (installed under AS/NZS4777:2005), it has been observed that over-voltage settings have been overridden by installers in some cases. Furthermore, consumers experience different voltages depending on where they are connected within the network; customers close to transformers are much more likely to have inverters trip than customers at the end of the same line, even if they produce exactly the same amount of solar at the exact same times and their consumption patterns are likewise identical.

If networks had a means to set export limits dynamically, according to the local conditions of the network at a point in time, then greater export capacity could be made available at times when the network assets are lightly loaded, increasing the opportunity of the VPP to be dispatched for market benefits. Such dynamic export limits are a key capability for a Distribution Network Service Provider (DNSP) in an energy system dominated by distributed generation, as it enables better utilisation of the available distribution network capacity for generation without compromising security of supply.

These issues are being tested in SA at an unprecedented scale. Tesla and the SA Government announced plans to roll out battery storage and solar PV to up to 50,000 customers between 2018 and 2022. By 2022, the Tesla VPP could reach up to 500 MW of capacity, making it by far the largest VPP in the world, and a very significant resource in South Australia's energy market. The first phase of this VPP encompassed 100 systems and has been completed. The second phase involves the targeted 1,000 Housing Trust properties that constitute the Tesla VPP trial in the present project. This trial has accelerated the development and real-world implementation of advanced technologies co-designed by SAPN and Tesla to integrate a VPP in a network under dynamic constraint management.

1.2 Scope and research objectives of the project

The Advanced VPP Grid Integration project aimed to demonstrate the capability to dynamically set network export limits for DER, allowing them to raise over the normal static export limits during times and in locations where sufficient network capacity to do so is available.

This capability has been tested on a field trial that operated in SA during one complete season from July 2019 to July 2020, for which SAPN and Tesla co-designed and implemented a digital communications interface – referred to as SAPN API (application programming interface) – to manage the information exchange between the network and the VPP, as well as operating procedures and rules to dynamically allocate network capacity.

The trial had 552 VPP sites registered by September 2019, 783 by December 2019 and 893 by February 2020. The full trial will enable the solution to operate with the first 1,000 VPP sites of the Tesla VPP rollout in SA. The analysis reported in this document is based on data for $N = 584$ VPP sites spread across $T = 425$ transformers. (Three-hundred fourteen (314 or 74% of all analysed) transformers were connected to a single VPP customer.)

The collection and subsequent analysis of data collected during the execution of the project aimed to test the following main underlying hypotheses:

H 1	Existing limits on the level of network exports from customers' renewable energy systems on the SA distribution network can be increased by as much as two-fold by implementing an API to exchange real-time and locational data on distribution network constraints between SA Power Networks and the customers' DER aggregator (VPP provider).
H 2	Operating a VPP at higher levels of export power than would otherwise be allowed under normal static per-site export limits increases the opportunity for the VPP to provide market and system-wide benefits.

Eight research questions were formulated in the project research plan [1] to guide the generation of new knowledge on technical, economic and social aspects of VPP grid integration by the proposed dynamic network capacity management approach:

Management of DER hosting capacity

RQ 1. To what extent can available DER export capacity be increased compared to the maximum capacity available under SA Power Networks' standard connection rules (currently capped at 5kW export per customer) using dynamic network constraint management via the proposed interface between SAPN and the DER aggregator?

RQ 2. To what extent can the proposed interface support maintaining DER operation within the technical envelope of the distribution network during times when network is highly utilised (peak solar PV periods), or during unplanned capacity constraints (e.g. network faults or system-wide contingencies)?

RQ 3. To what extent can the proposed interface allow distribution networks to host DER at higher levels of penetration by enabling dynamic, locational export limits compared to standard fixed per-customer export limits?

Visibility

RQ 4. To what extent can the proposed interface securely increase the visibility and management of DER to network service providers?

Economics

RQ 5. What are the costs of implementing the proposed dynamic network constraint management assessed against benefits obtained?

RQ 6. What additional economic value can be enabled to DER operators by dynamic network constraint management, through enabling higher utilisation of existing network capacity?

Customer impacts

RQ 7. To what extent might the proposed dynamic hosting capacity regime impact on customers and their take-up of demand management and third-party DER control?

RQ 8. What are the customer impacts, if any, of the dynamic network capacity management approach?

1.3 Scope and research objectives of the report

The research presented in this report focused on the following four guiding research questions dealing with management of network DER hosting capacity and economics of DER integration. These four research questions are a subset of the eight guiding research questions for the project. The remaining four research questions, dealing with technical limits of DER operation, DER visibility, and customer impacts will be addressed in the final knowledge sharing report at the conclusion of the project.

Management of DER hosting capacity	
RQ 1	To what extent can available DER export capacity be increased compared to the maximum capacity available under SA Power Networks' standard connection rules (currently capped at 5-kW export per customer) using dynamic network constraint management via the proposed interface between SAPN and the DER aggregator? **Scope:** This research question is addressed by analysing dynamic capacity estimates modelled by SAPN for 425 transformers connected to the VPP. These capacity estimates were considered as the source of truth to evaluate the potential to increase DER export capacity beyond the SAPN's standard static limits. The analysis did not assess the VPP utilisation of released capacity, nor the performance of the capacity estimates provided.

RQ 3	To what extent could the proposed interface allow distribution networks to host DER at higher levels of penetration by enabling dynamic, locational export limits compared to standard static per-customer export limits? **Scope:** This research question is addressed by analysing dynamic capacity estimates modelled by SAPN for 75,530 transformers in their network. The analysis assumes the proposed interface provides a safe and reliable approach for managing the network and DER exports. As for RQ 1, these capacity estimates were considered as the source of truth to evaluate the network potential to increase DER hosting capacity by enabling dynamic, locational export limits. No monitored trial data was used in this analysis.
Economics	
RQ 5	What are the costs of implementing the proposed dynamic network constraint management assessed against benefits obtained?
RQ 6	What additional economic value can be enabled to DER operators by dynamic network constraint management, through enabling higher utilisation of existing network capacity? **Scope:** These research questions are addressed in a preliminary economic analysis conducted using simulated customer load profiles and solar PV output for 1,000 simulated customer premises remaining constant for the analysis period of 10 years. The estimated benefits were simulated for energy market benefits for three cases of static network export limits: 2 kW, 5 kW and 10 kW. No monitored trial data was used in this analysis, and there is no analysis or inclusion of the cost to provide a constraint management technology.

1.4 Organisation of the report

The rest of the report is organised as follows. A description of the dynamic capacity management system implemented to support the integration of the VPP into the SAPN network is presented in Section 2. The section outlines the main functionalities of the SAPN API – the core technical component of the system – and describes the constraint engine that estimates the dynamic network capacity information communicated to the VPP via the SAPN API. The section introduces key concepts and metrics required to represent and analyse dynamic capacity constraints.

Section 3 presents analysis and research findings addressing RQ 1. The analysis explores the potential to increase VPP DER export capacity limits that can be enabled by the proposed dynamic constraint management approach.

Section 4 presents analysis and research findings addressing RQ 3. The analysis explores the potential to increase VPP hosting capacity by the proposed dynamic constraint management approach if implemented across SAPN network.

Section 5 presents a preliminary economic analysis and findings addressing RQ 5 and RQ 6. This section focuses on the benefits of developing and implementing the proposed dynamic network constraint management using the actual costs of implementation, the method used to calculate the wholesale energy market benefits of VPP operation, and the key inputs used in the model adopted. Costs for the analysis are solely based on an audited representation letter provided by SAPN. This cost was assumed to be upfront in the first year of the trial, without ongoing costs.

With the limited data made available at the time for analysis, the findings reported provide only general estimates for the benefits to the VPP operator, net present value and benefit-cost ratio based on energy market benefits obtained in three cases of static –not dynamic – DER export limits. Benefits arising from participation of the VPP in FCAS markets can be found in [4]

Section 6 presents the report conclusions and discusses opportunities for further work.

2 Management and representation of network capacity

2.1 SAPN API system architecture

The architecture of the system that supports the integration of the VPP into the SAPN network is illustrated in Figure 1. The core technical component of the system is the SAPN API, a co-designed communications bridge between SAPN and Tesla backend information systems.

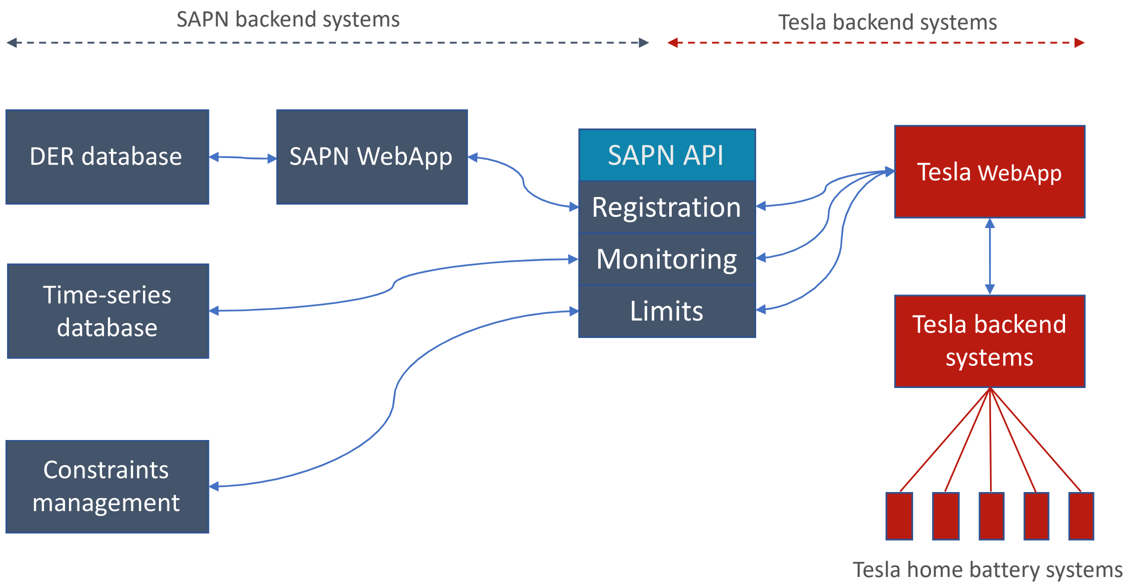


Figure 1. Technical architecture of the system supporting the integration of the VPP into SAPN network

A detailed description of APN API implementation may be found in the report [5]. The main functions of the API are outlined as follows:

- **DER registration**

  All DER devices are registered electronically with SAPN through the Tesla aggregated platform. This registration message must inform SAPN the location, capabilities and control affiliations of the DER, such as its participation in a VPP scheme or responding to any external control signals. The DER registration is expressed with a unique ID assigned to the VPP when they register with SAPN.

- **DER monitoring**

  The API provides a stream of interval DER monitoring data which updates every 5 minutes. This data includes:

  - Site real power – 5-minute average, minimum and maximum
  - Battery terminal voltage – 5-minute average, minimum and maximum
  - Battery State of charge – instantaneous

The API is set up in such a way that if required it could accommodate a range of different data types, which could vary both in sampling interval (e.g. 30 minutes or 5 minutes) and frequency of upload (e.g. once daily, or continuous updates at the sample rate).

- **Constraint management**

  This part of the API provides dynamic network capacity information to the VPP in the form of forecast export capacity limits, which define DER operating envelopes at nodal aggregate level. In the event that the VPP system is unable to communicate with the API, it will revert to a default export limit configuration commensurate with normal static limits.

- **Constraint nodes**

  The concept of constraint nodes is used to manage groups of DER devices that are connected to a common node on the distribution network that may be subject to a capacity constraint, e.g., a distribution transformer. DER devices can be connected from one to many constraint nodes depending on the nature of the section of network to which they are connected. At a minimum, a DER will be mapped to a single constraint node which is the transmission system connection point to which they are connected.

  Aggregators of DER may benefit from understanding network limits at the constraint node, rather than individual site, as it potentially gives greater scope for the aggregator to optimise VPP operation. The intention is that the API will support both site-level and node-level limits. The mapping may be expressed using constraint node IDs that are assigned to DER devices.

  The constraint status of a section of network can change in time and DER devices can be moved to different nodes due to network reconfiguration. A new mapping must be requested at regular intervals to ensure it is up to date.

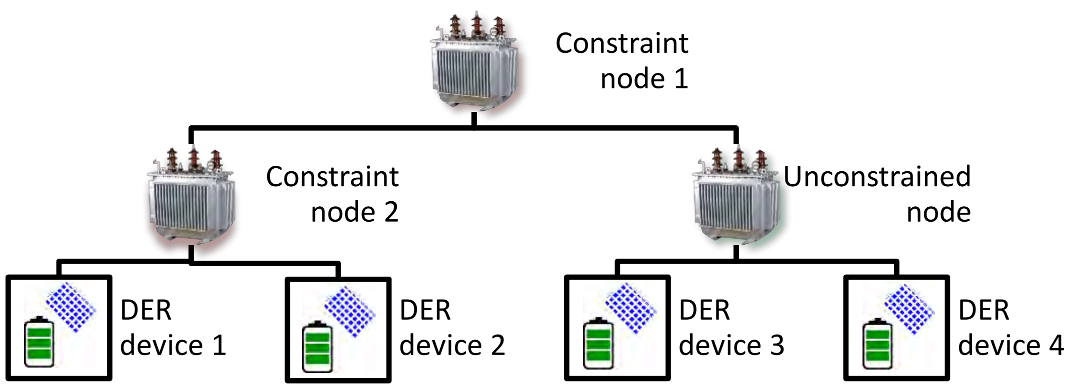


Figure 2. Constraint node mapping example

2.2 The constraint engine

Calculating dynamic site export limits

Identifying and communicating the distribution network constraints is essential to support effective coordination of DER services to the network at large while maintaining the integrity of the distribution network. Network constraints defined by voltage and thermal limits can be used to define permissible DER services within the technical envelope of operation of the distribution network [6].

In order to manage the export capacities made available to the VPP, SAPN have designed a constraint management system (see the schematic in Figure 1), the core component of which is a constraint engine that estimates the latent network capacity that can be made available to each VPP site at any given time. This constraint engine produces a per-customer time series of export constraint limits between 5 kW and 10 kW that are communicated to the VPP via the SAPN API.

The constraint engine is based on a prototypical network modelling approach, where detailed modelling and monitoring of a small subset of representative network sections are used to estimate the hosting capacity of the entire network. Such a prototypical modelling approach has been applied in recent related LV network modelling work [7][2][8][9][10][11][12].

The constraint limits for the VPP trial are calculated for 25 different prototype scenarios categorised by day-type and month of the year, as outlined in Table 1. Each day-type scenario specifies constraints in 5-minute intervals over a 24-hour period for every transformer in SAPN's network. The scenarios specify typical constraints for work and non-workdays for each month of the year, and include an additional scenario for heatwave days (typically characterised by high temperatures and high air conditioning demand).

Table 1. The 25 scenarios modelled by the constraint engine

Month	Workday	Heatwave
Models are produced for each of the 12 months	Each month has both workday and non-workday models	A heatwave scenario is also modelled. This is based on a January non-workday, but could in theory be used for a heatwave at any time of year[1].

Raw capacity constraints

For each of the 25 scenarios specified in Table 1, and for each transformer/network node of interest the constraint engine calculates first a *raw constraint estimate* using the formula

$$C_i(t) = m \times \min\left(P_{V_i}, P_{T_i}\right) - P_i(t), \tag{1}$$

where:

[1] This was a modelling parameter asserted by SAPN.

- i denotes an index that identifies an individual transformer in the set $\{1,2,\ldots,T\}$, where T denotes the total number of distribution transformers in question;
- $C_i(t)$ is the raw constraint limit estimate for the node/transformer i in kilowatts, as a function of time;
- t is a discrete time index, $t = 1, 2, \ldots, 288 = 12 \text{ intervals} \times 24 \text{ hours}$ for 24-hour profiles produced in 5-minute intervals;
- m is a tuneable confidence margin parameter, $0 \leq m \leq 1$, set for example to 0.2 for a conservative estimate of latent capacity, or to 0.8 for a less conservative estimate;
- P_{V_i} is the estimated maximum reverse power flow limit for voltage exceedance at the transformer i, in kilowatts;
- P_{T_i} is the estimated maximum reverse power flow limit for thermal exceedance at the transformer i, in kilowatts; and
- $P_i(t)$ is the reverse power flow modelled at a transformer i in kilowatts – this is the only input value that varies in time. This estimated reverse power flow at the transformer is calculated as the difference between power demand and PV generation based on a set of representative load and generation profiles calculated for the SAPN network for each of the characteristic day-types shown in Table 1. These profiles have been developed by SAPN and are not featured in this report.

The raw constraint limit estimate $C_i(t)$ at a given transformer i is then projected onto the interval $[n_i \times 5\text{kW}, n_i \times 10\text{kW}]$ to produce a *mediated constraint limit* $M_i(t)$, defined below, which is distributed through the VPP API to each VPP site connected to transformer i. To facilitate the analysis in this report, the *allocation approach* [13] adopted is that the capacity limit made available to the transformer i through $M_i(t)$ is distributed in equal ratio to all the VPP sites connected to the transformer. In general, the VPP could allocate capacity in different ratios to VPP sites under the same node.

Two concepts related to $C_i(t)$ that will be used in subsequent analysis are:

- The *average raw capacity constraint per customer connected to transformer* i,

$$B_i(t) = \frac{C_i(t)}{n_i} \tag{2}$$

  Where n_i is the number of VPP sites connected to the node/transformer i, namely, the total number of sites in the VPP is $N = \sum_{i=1}^{T} n_i$. This is shown for nine transformers in Figure 3.

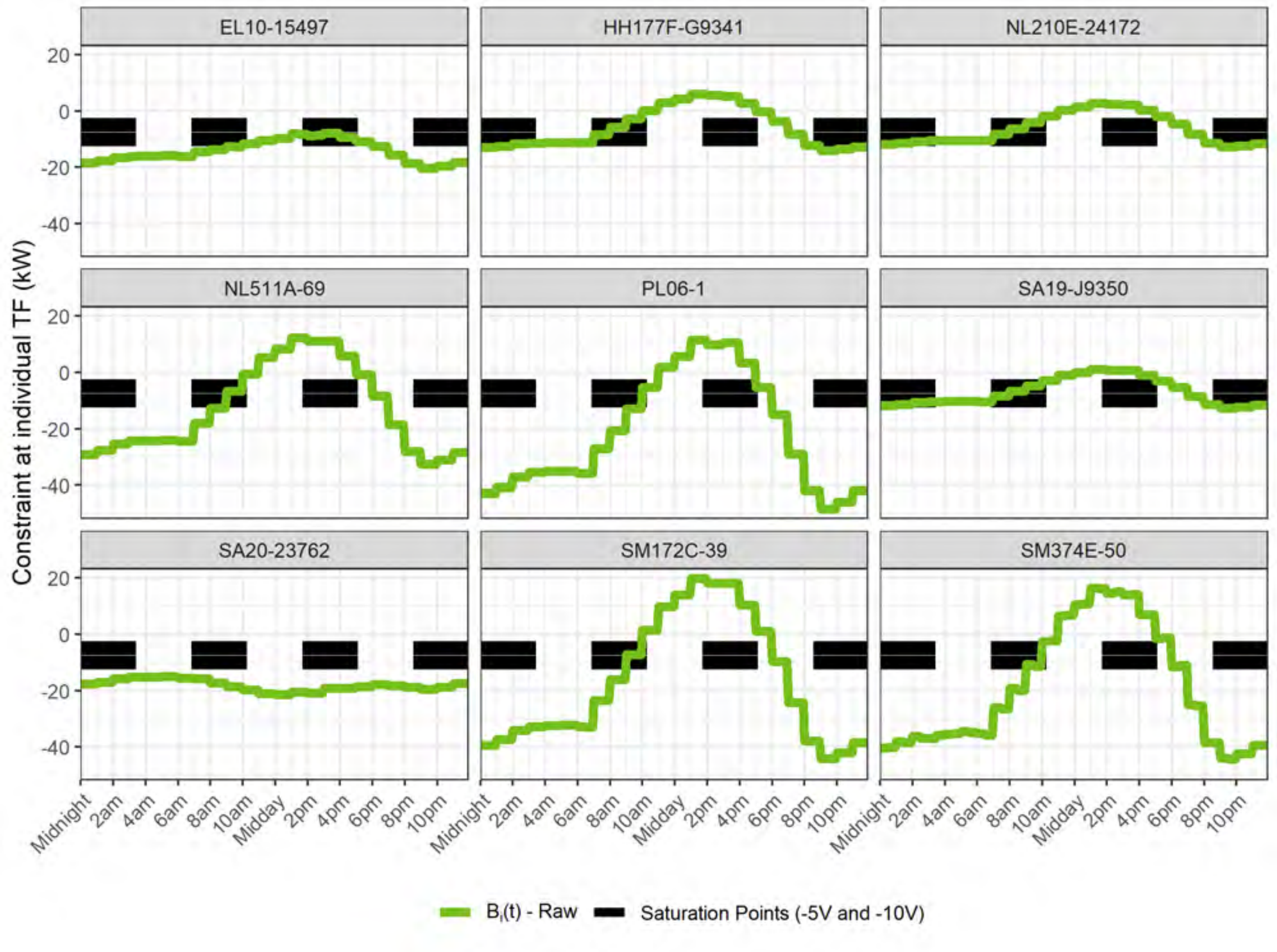


Figure 3 - $B_i(t)$ plotted for a random sample of nine transformers for a January non-workday with a confidence margin m of 80%.

- The *average raw capacity constraint per customer across the entire VPP cohort*

$$B(t) = \frac{1}{N}\sum_{i=1}^{T} C_i(t) = \sum_{i=1}^{T} \frac{n_i}{N} B_i(t) \tag{3}$$

This is shown on aggregate across the 584 VPP sites in Figure 4.

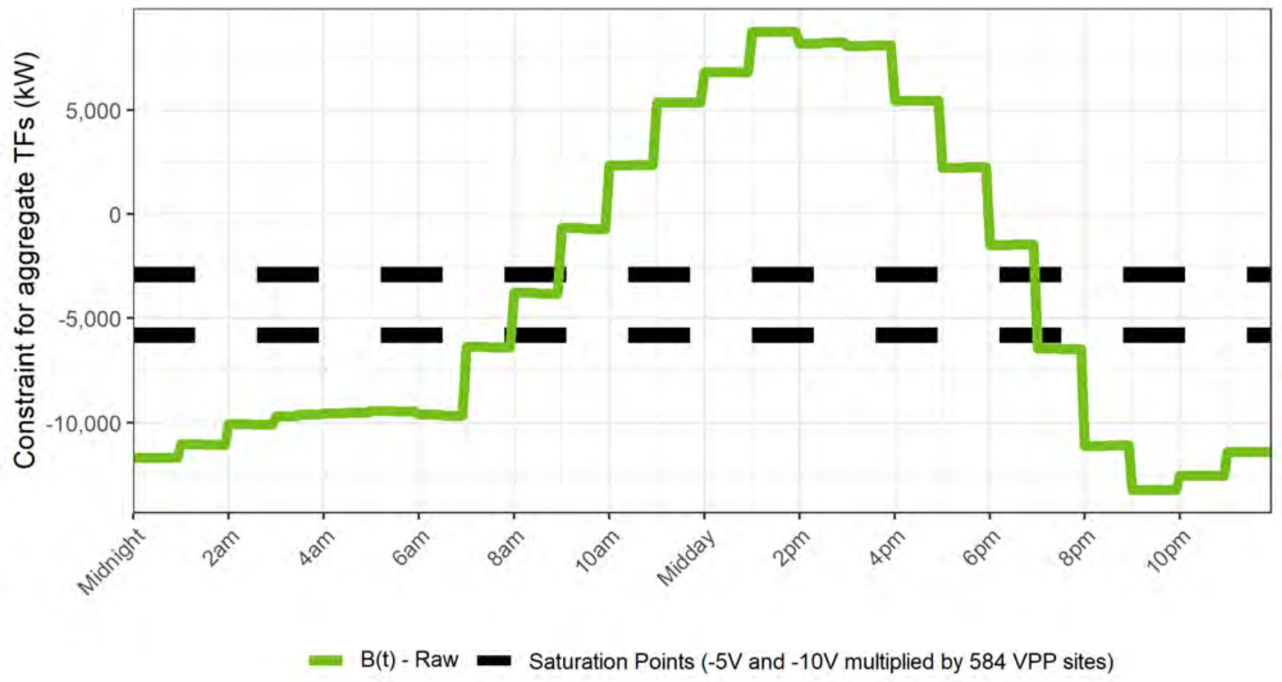


Figure 4 - $B(t)$ plotted for all 584 VPP sites for a January non-workday with a confidence margin m of 80%.

Mediated capacity constraints

For each transformer i, the mediated constraint is calculated using the formula

$$M_i(t) = \mathrm{sat}_{[5\mathrm{n_i},10\mathrm{n_i}]}(C_i(t)) = \min\big(\max\big(5n_i, C_i(t)\big), 10n_i\big), \tag{4}$$

where $\mathrm{sat}_{[5\mathrm{n_i},10\mathrm{n_i}]}(\cdot)$ is a saturation function which takes $C_i(t)$ and restricts it to the interval $[n_i \times 5$ kW, $n_i \times 10$ kW]. As a more straightforward stepwise function it can be equivalently defined as

$$\mathrm{sat}_{[5\mathrm{n_i},10\mathrm{n_i}]}(C_i(t)) = \begin{cases} 5\ n_i, & \text{if } C_i(t) \leq 5\ n_i \text{ (raised to the static limit 5)} \\ 10\ n_i, & \text{if } C_i(t) \geq 10\ n_i \text{ (dynamic limit capped to 10)} \\ C_i(t), & \text{otherwise.} \end{cases} \tag{5}$$

Note that the mediated constraint $M_i(t)$ is indexed per transformer ($i = 1,2, \dots, T$) rather than per VPP site ($k = 1,2, \dots, N = \sum_{i=1}^{T} n_i$). Also, in the subsequent analysis it is assumed that all VPP sites connected to a given transformer are allocated an equal share of its capacity.

When it comes to mediated constraints the below analysis will refer to two concepts:

- The *average mediated capacity constraint per customer connected to transformer i*

$$L_i(t) = \frac{M_i(t)}{n_i} \tag{6}$$

  This is shown for nine transformers in Figure 5.

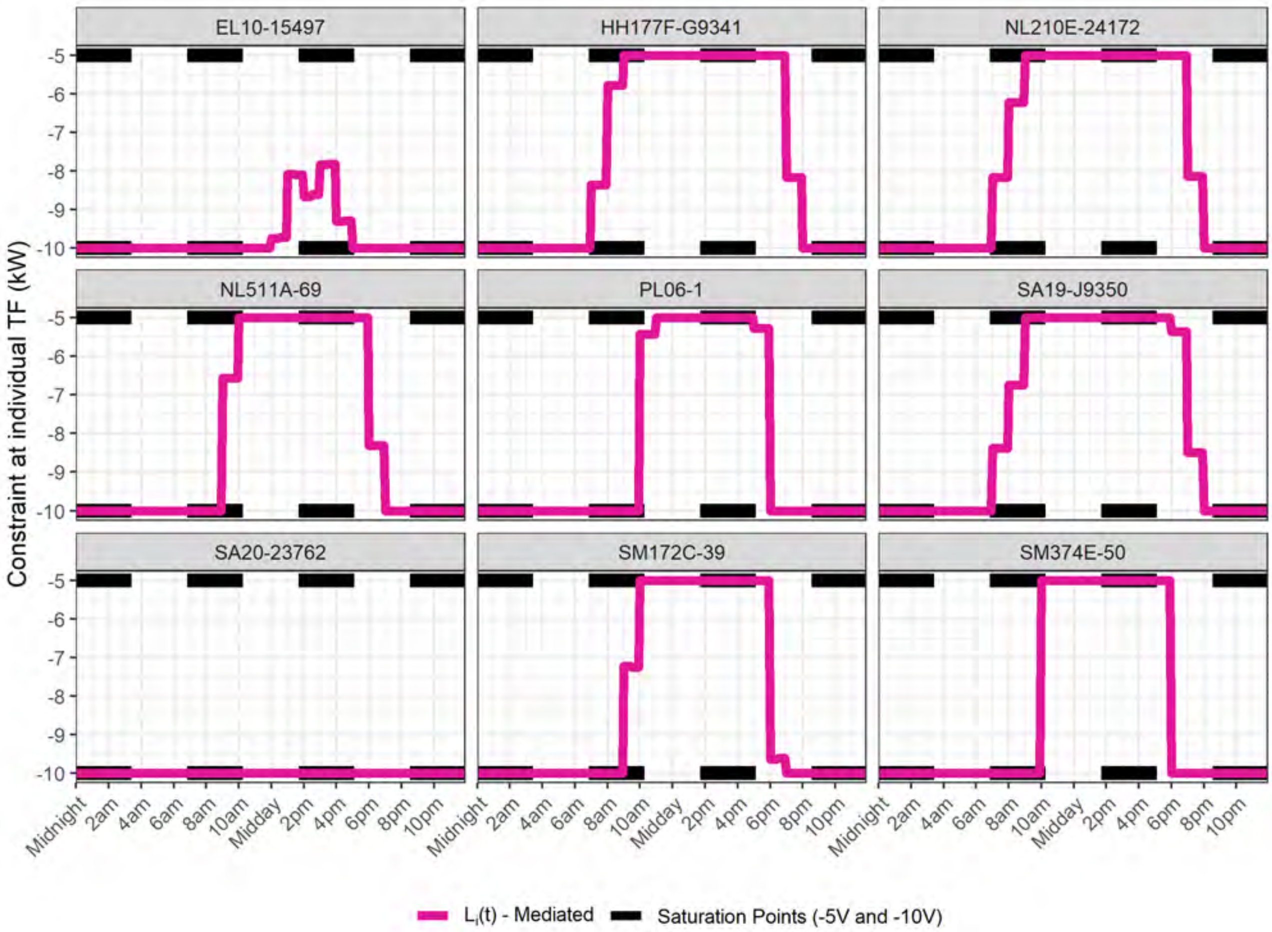


Figure 5 - $L_i(t)$ plotted for a random sample of nine TFs for a January non-workday with a confidence margin m of 80%.

- The *average mediated capacity per customer across the entire VPP cohort*

$$L(t) = \frac{1}{N}\sum_{i=1}^{T} M_i(t) = \sum_{i=1}^{T} \frac{n_i}{N} L_i(t) \tag{7}$$

This is shown on aggregate across the 584 VPP sites in Figure 6.

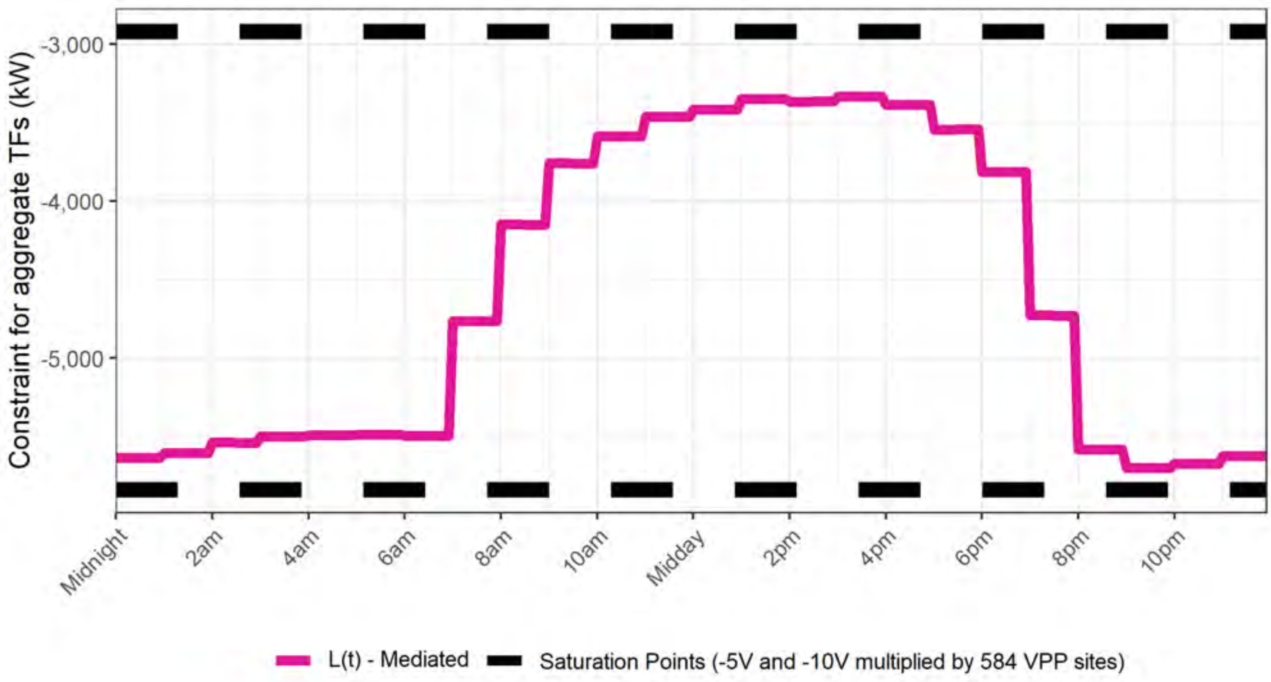


Figure 6 - $L(t)$ plotted for all 584 VPP sites for a January non-workday with a confidence margin m of 80%.

Analysis scope and methods

The analyses of DER export capacity limits made available to the VPP (RQ 1) and VPP hosting capacity (RQ 3) were based on a VPP consisting of 584 sites spread across 425 transformers according to the connection distribution shown in Table 2. Each VPP site is equipped with a 5-kW rooftop PV generation system and a Tesla Powerwall energy storage system. Each of these systems has the capacity to individually export up to 5 kW to the network, adding up to a maximum DER export capacity of 10 kW per VPP site[2].

Table 2 – Distribution of VPP sites across transformers considered for analysis.

Number of VPP sites connected to a common transformer	1	2	3	4	5	6	7	8
Number of occurrences	314	75	29	5	1	0	0	1

The analysis developed to address RQ 1 and RQ 3 consisted of dynamic daily capacity constraint profiles developed by SAPN for 75,530 transformers in their network – 25 day-type scenarios per transformer as specified in Table 1. Input data was also provided by SAPN to independently calculate these profiles using the raw and mediated capacity formulas given in Section 2.2. These data consisted of transformer voltage and thermal limits, representative reverse power flow, PV generation, and load profiles modelled for each VPP transformer.

[2] Though a Tesla Powerwall 2 has a 10 second peak of 7kW and a 5kW PV system could in theory output 6-7kW for a short time, these scenarios are not considered in the analysis.

The capacity constraint profiles and associated transformer data provided by SAPN was considered as the source of truth for analysis, which explored the implications of implementing the proposed dynamic capacity constraint management system based on these profiles. The analysis did not evaluate the accuracy of the capacity estimates produced by SAPN, nor did it evaluate the utilisation by the VPP of additional DER export capacity released during the trial.

2.3 Representation of capacity constraints

Figure 7 shows an example estimated constraint profile aggregated over all VPP sites for a non-workday profile in the month of January; in this case, calculated using a confidence margin $m = 80\%$ in Equation (1) (the least conservative estimate). There are several metrics which will be defined in Section 2.4 using Figure 7 as a reference point. As such, the three key features of the capacity constraint profile in Figure 7 isolated in

Table 3.

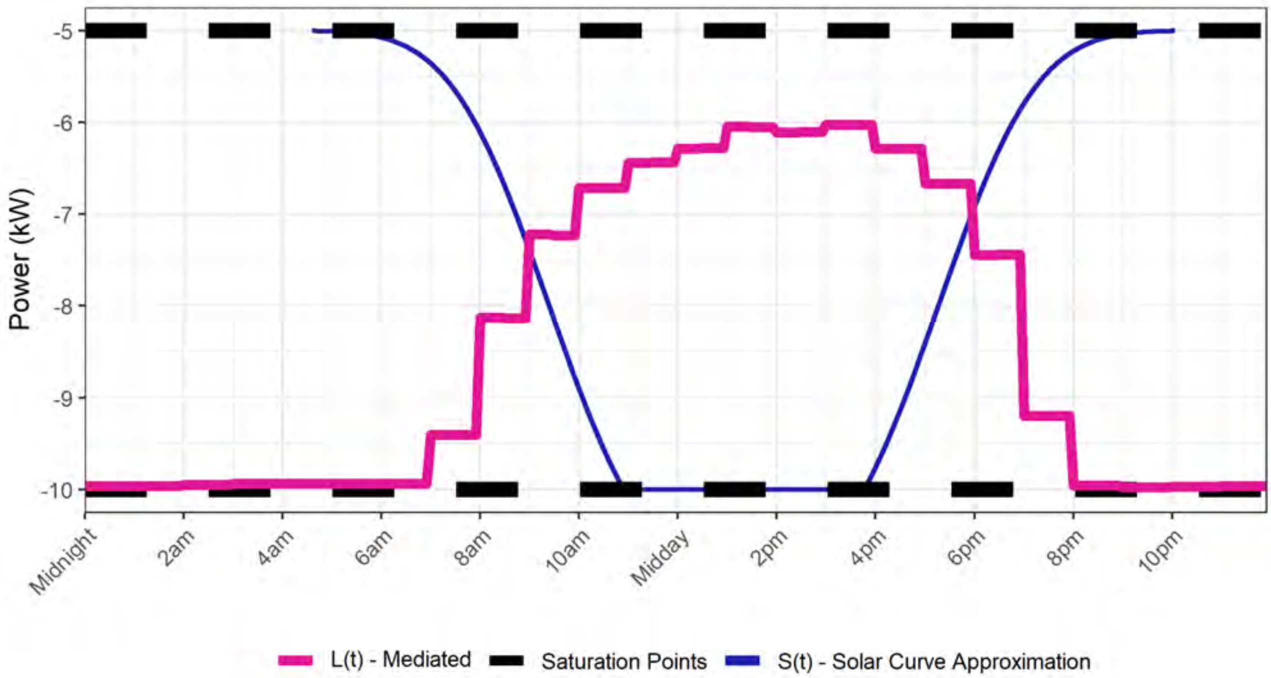
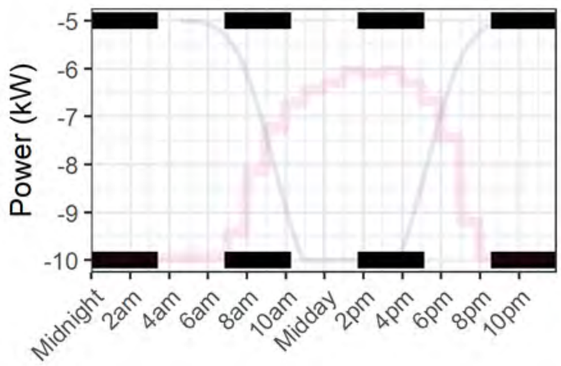
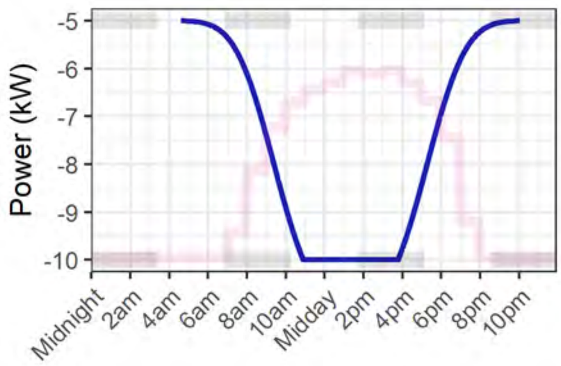
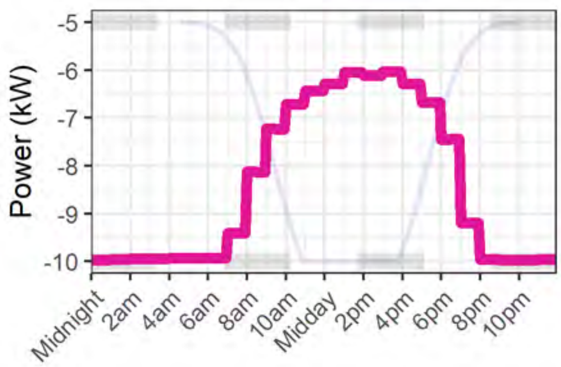


Figure 7 - Trimmed constraints aggregated across all VPP sites (n=584) for a January non-workday with a confidence margin of 80%.

Table 3 - A visual breakdown of each element of the capacity constraint representation in Figure 7.

	**Fixed export limits** • These lines are the 5kW and 10kW export levels per site, for reference. • The 5kW limit is the minimum exports SAPN would like to always allow. • The 10kW limit is the dynamic limit maximum.
	**Solar Curve** • An approximate solar curve profile as defined in Section 2.4 below. • This varies depending on month of the year to centre on daylight hours. • In our calculations this will act as the real-life capacity limit of the battery + PV setup.
	**Mediated Limits** • The average mediated capacity constraint per customer $L(t) = \frac{1}{N}\sum_i M_i(t)$ as introduced in Section 2.2 above. • In our calculations this will act as the theoretical capacity limit of the battery + PV setup.

2.4 Capacity metrics

The following metrics will be used throughout the report to quantify the technical implications of dynamic network constraints in light of the research hypotheses and questions presented in Section 1.2. Note that metrics introduced below and the analysis that results from them should be considered as indicative of available capacity and performance as induced by the constraint engine approximate calculations defined in Section 2.2, based on the prototype modelling developed by SAPN.

Approximate solar curve – $\boldsymbol{S(t)}$

An approximate solar curve profile $\boldsymbol{S(t)}$ will be used in the calculations of capacity and energy metrics to be introduced below. The curve $\boldsymbol{S(t)}$, shown in dark blue line in Figure 7 and Table 3 represents a realistic approximation to the effective export capacity of the VPP systems in the trial, which consist of a battery that can export up to 5 kW and PV panels that could add up to 5 kW, depending on the availability of solar resource. This approximation varies depending on the time of year and uses sunlight times assuming a PV system based in Adelaide, South Australia.

Since the VPP systems can only reach a 10-kW export level during daylight hours (i.e. when the PV panels and the battery at a VPP site are both simultaneously exporting at their 5-kW capacity), the solar curve was introduced to better represent the capacity that can be effectively used by the VPP. This solar curve is incorporated in the metrics introduced below.

Full detail on how $S(t)$ is defined can be found in **Error! Reference source not found.**.

Available Energy – $\boldsymbol{AE}$

The *available energy AE* is defined as the maximum amount of energy in kilowatt-hours that could be released in the export capacity band within 5 kW and 10 kW if no constraints were imposed beyond the availability of solar resource to PV systems. AE represents the area delimited by the solar curve and the 5-kW capacity limit, which can be calculated as

$$AE = \sum_{t \in t_{dl}} (-S(t) - 5\ kW) \times \Delta t,$$

where Δt denotes the sampling period in hours underlying the representation of capacity constraints as a sequence of discrete-time values ($\Delta t = \frac{1}{12}$ for constraints calculated in 5-minute intervals). Note that the period of daylight hours t_{dl} over which AE is evaluated varies through the year across the reference day-type scenarios defined in Table 1.

Released Energy – $\boldsymbol{RE}$

The *released energy RE* is the fraction of the available energy AE that is released to the VPP through a mediated dynamic capacity constraint profile. As an aggregate quantity across the entire VPP, RE is obtained by restricting AE to an area delimited by the mediated constraint curve $L(t)$ and the 5-kW limit, namely,

$$RE = \sum_{t \in t_{dl}} (-\max_{t \in t_{dl}}(S(t), L(t)) - 5\ kW) \times \Delta t.$$

Figure 8 shows an example of RE as the area highlighted in orange over the constraint profile of Figure 7.

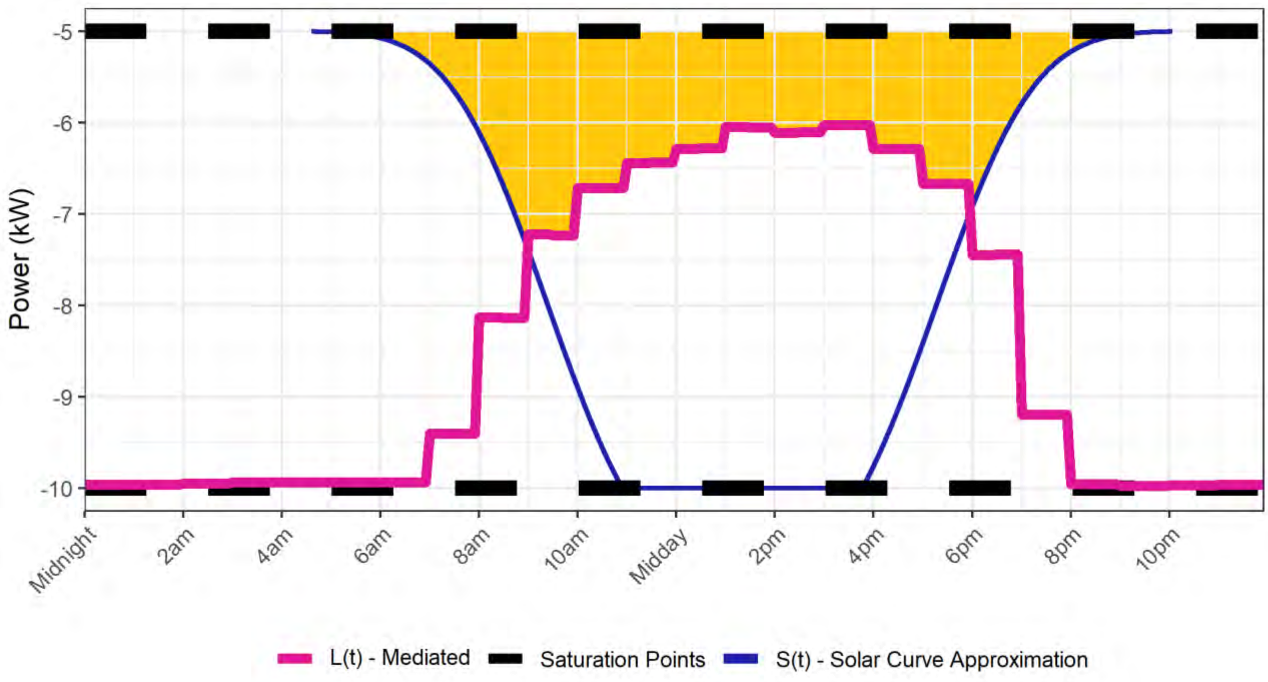


Figure 8 - Released energy shown as the area highlighted in orange on the constraint profile of Figure 7.

It will be useful also to evaluate RE as an *average released energy per customer connected to the transformer i*. In this case we will denote it RE_i and calculate it by using the average mediated capacity constraint per customer $L_i(t)$ as

$$RE_i = \sum_{t \in t_{dl}} (-\max_{t \in t_{dl}}(S(t), L_i(t)) - 5\ kW) \times \Delta t.$$

Note that, in general, RE_i will be different for different transformers, $i = 1,2, \ldots, T$, where T is the number of transformers considered in the VPP.

Average Available Capacity

The average available capacity is the average capacity in kilowatts allowed by the dynamic mediated constraint. The average available capacity is calculated in terms of both the total export capacity made available by the proposed system, and the likely export capacity available when solar irradiance is considered.

The whole day average available capacity AC_{24} is calculated by averaging the mediated constraint $L(t)$, that is

$$AC_{24} = -\overline{L(t)} = -\frac{\sum_{t=1}^{\tau_{24}} L(t)}{\tau_{24}}$$

where τ_{24} is the number of time intervals in the day for which $L(t)$ has been calculated ($\tau_{24} = 288$ for 5-minutely calculated constraints).

The likely average available capacity AC_{dl} due to the limits of solar radiation during daylight hours is calculated by averaging the boundary (that is, minimum) of the mediated constraint $L(t)$ and the solar curve $S(t)$ – this can be seen as the green line in Figure 9. That is

$$AC_{dl} = \frac{\sum_{t \in t_{dl}} \min\big(-L(t), -S(t)\big)}{\tau},$$

where $\tau = \sum_{t \in t_{dl}} t$ is the number of daylight time periods for which the time series $L(t)$ and $S(t)$ have been calculated, which vary through the year according to availability of solar resource, which was accounted for.

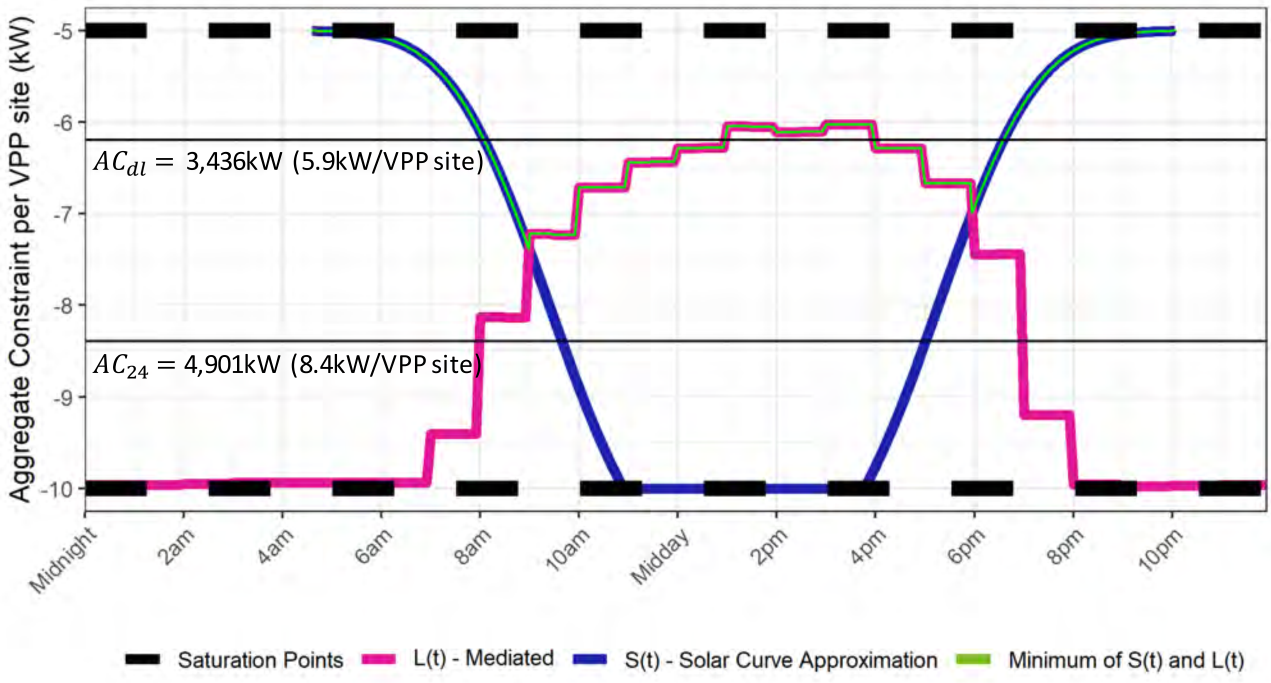


Figure 9 - AC_{24} and AC_{dl} pointed out explicitly for Figure 7 with the minimum of $L(t)$ and $S(t)$ highlighted in green.

AC_{24} and AC_{dl} can also be calculated as per-transformer metrics $AC_{i,24}$ and $AC_{i,dl}$ for a particular transformer i by substituting $L(t)$ with $L_i(t)$ in the respective formulae. Since all VPP sites connected to the same transformer are assumed to be allocated equal capacity, $AC_{i,24}$ and $AC_{i,dl}$ will also be used to characterise available capacity per VPP site.

To give some quantitative grounding to these metrics, the values calculated for the scenario shown in Figure 9 are provided in Table 4.

Table 4. The key metrics for the scenario shown in Figure 1.

January Non-workday Confidence 80%	**Available Energy (AE)**	**Released Energy (RE)**	**Average Available Capacity (AC)**
All Day (24)[3]	25.7MWh (43kWh/VPP)	10.1MWh (39% of AE)	8.4kW
Daylight Hours (dl)			6.2kW

[3] Recall that the 'All Day' estimates are only hypothetical. This considers a scenario where 10kW is exportable for 24 hours and is only affected by the mediated constraints line $L(t)$. In practice we would not expect this to be possible with the current set up.

2.5 Summary of capacity definitions and performance metrics

Table 5 - A summary of the metrics defined throughout Section 2.2 and Section 2.4.

Metric	Notation	Definition	Scope
Raw constraint estimate at transformer i	$C_i(t)$	$C_i(t) = m \times \min\left(P_{V_i}, P_{T_i}\right) - P_i(t)$ Eq. (1)	Distribution transformer kW
Average raw capacity constraint per customer connected to transformer i	$B_i(t)$	$B_i(t) = \frac{C_i(t)}{n_i}$ Eq. (2)	VPP site kW
Average raw capacity constraint per customer across the VPP	$B(t)$	$B(t) = \frac{1}{N}\sum_i C_i(t)$ Eq. (3)	VPP site kW
Mediated constraint estimate at transformer i	$M_i(t)$	$M_i(t) = \min\left(\max\left(5n_i, C_i(t)\right), 10n_i\right)$ Eq. (4)	Distribution transformer kW
Average mediated capacity constraint per customer connected to transformer i	$L_i(t)$	$L_i(t) = \frac{M_i(t)}{n_i}$ Eq. (6)	VPP site kW
Average mediated capacity constraint per customer across the VPP	$L(t)$	$L(t) = \frac{1}{N}\sum_i M_i(t)$ Eq. (7)	VPP site kW
Approximate solar curve	$S(t)$	See **Error! Reference source not found.**	VPP site kW
Average available capacity (whole day and daylight hours)	AC	$AC_{24} = -\frac{\sum_{t=1}^{\tau} L(t)}{\tau}$ $AC_{dl} = \frac{\sum_{t \in t_{dl}} \min\left(-L(t), -S(t)\right)}{\tau}$	VPP site or distribution transformer kW
Available energy	AE	$AE = \sum_{t \in t_{dl}} (-S(t) - 5\ kW) \times \Delta t$	VPP site kWh
Released energy	RE	$RE = \sum_{t \in t_{dl}} (-\max_{t \in t_{dl}}(S(t), L(t)) - 5\ kW) \times \Delta t$	VPP site kWh

3 Analysis of VPP DER export capacity

RQ 1	To what extent can available DER export capacity be increased compared to the maximum capacity available under SA Power Networks' standard connection rules (currently capped at 5-kW export per customer) using dynamic network constraint management via the proposed interface between SAPN and the DER aggregator?

3.1 Context

The export of small (≤30kW) DER on the SAPN network is currently restricted through static export limits per customer. In response to increased solar PV uptake approaching the technical limits of the network at some locations and times, SAPN lowered this export limit in 2017 from 10 kW to 5 kW per customer per phase.

This reduction in static capacity restricts the export capability of today's VPPs. The 'nameplate' peak power rating of Tesla's VPP at the end of its second phase of deployment (1,000 customers) will be 10 MW, as each customer has a 5-kW capacity solar inverter and a 5-kW capacity battery inverter, which would be able to jointly export up to 10 kW. However, under SAPN's present connection rules, the static export limit of 5 kW that applies per household limits the maximum power output of the VPP to 5 MW.

The dynamic constraint management solution developed through the project is intended to enable the VPP to operate at up to its full rated capacity of 10 MW. As the VPP scales to its target size of 50,000 customers, the system has the potential to unlock hundreds of MW of peak export capacity that would otherwise be unusable, significantly increasing the opportunity for the VPP to participate in the SA energy system, and hence the value released from the VPP.

This section analyses the export capacity that can be released to the VPP based on the dynamic capacity estimates modelled by SAPN for 425 transformers connected to the VPP. These capacity estimates were considered as the source of truth to evaluate the potential to increase DER export capacity beyond the static limit available under SAPN connection rules. We quantify this additional export capacity in terms of the metrics introduced in Section 2.4, average available capacity AC and released energy RE. The analysis did not consider utilisation of released capacity, nor the performance of the capacity estimates provided.

Key points from the analysis below indicate that dynamic network constraint management can enable increases in daily average DER export capacity from 5 kW to over 8 kW across the year, and up to 10 kW during winter months. In practice, however, these estimates can be misleading because much of the enabled capacity typically occurs during non-daylight hours, when the PV systems cannot generate or export and therefore the VPP's own capacity is limited to the size of the battery's export inverter. A more accurate average of the exploitable capacity is derived by limiting the analysis to the time of the day when PV generation is active. Using this approach, it is found that the network can still be increased in average during daylight hours from 5 kW to 6 kW across the year, and up to over 8 kW during the winter months.

The analysis of variability of the dynamic capacity estimates indicates that the maximum increases in DER export capacity could be achieved across the VPP from May to August, and for 50% of the network spanned by the VPP from March to August. Less than 20% of the network spanned by the VPP can be allocated the maximum increases in DER export capacity across the year.

3.2 Seasonal variability of average available capacity

We analyse the DER export capacity released to the VPP through the year using the average available capacity metric AC introduced in Section 2.4. This metric represents a daily average capacity in kilowatts made available to the VPP as an aggregate of the 584 VPP sites considered.

We evaluate AC in two distinct ways by averaging the available capacity released to the VPP over the 24 hours of the day, denoted AC_{24}, and over the period of daylight hours, denoted AC_{dl}. Note that the available capacity captured by AC_{dl} is a more realistic representation of the additional capacity over 5 kW that is technically usable by the VPP through simultaneous exports from the battery and PV systems. Both AC_{24} and AC_{dl} are shown normalised by the number of VPP sites $N = 584$ and thus range between 5 kW and 10 kW.

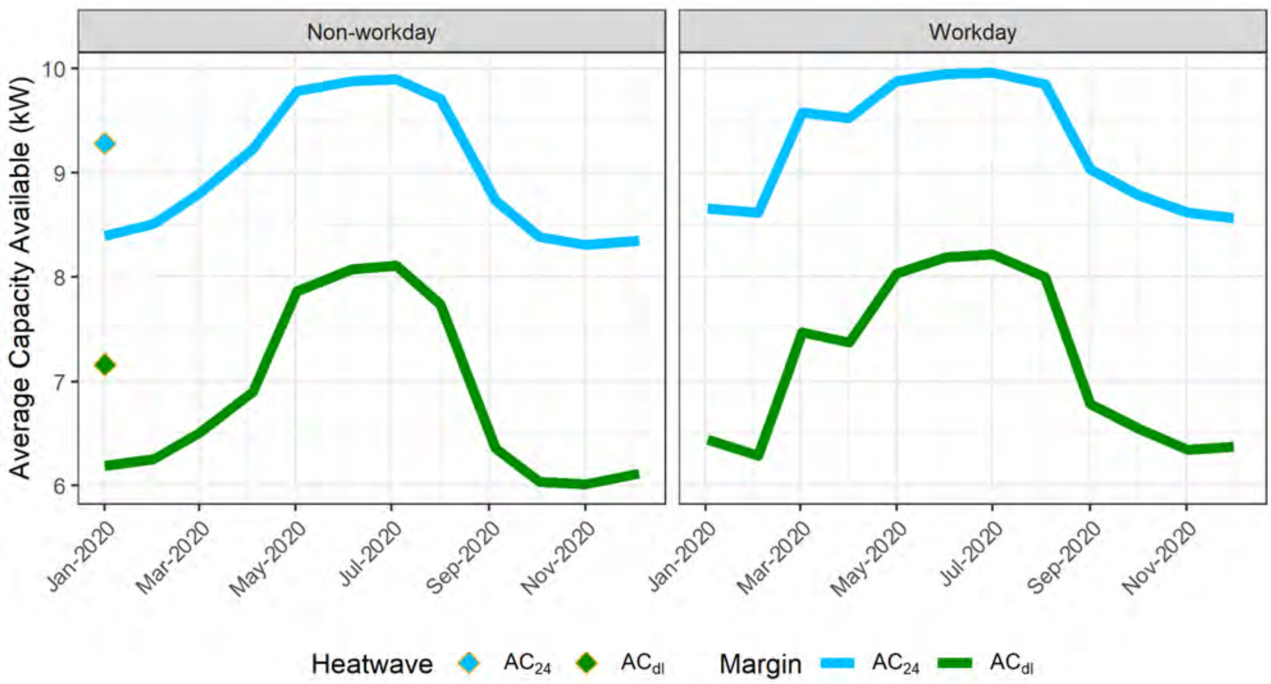


Figure 10 shows how AC_{24} and AC_{dl} vary through the year for the non-workdays, workdays and heatwave dynamic constraint scenarios specified in Table 1. As seen from these plots, the average available capacity that can be released to the VPP by dynamic constraints is generally at a maximum in winter months and at a minimum in Summer months. A large difference can also be appreciated between the average capacity available over the whole day (AC_{24}) and that available only during daylight hours (AC_{dl}), when the network is seen typically more congested.

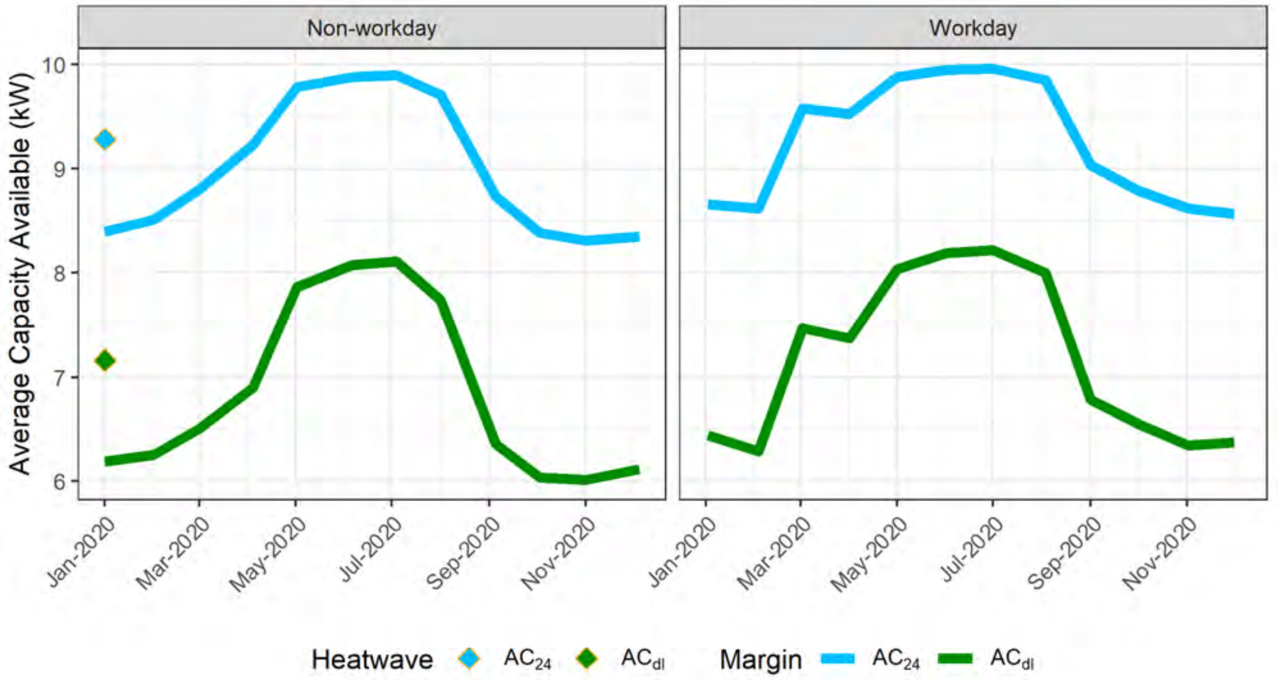


Figure 10 – The average available capacity for the aggregate of 584 VPP sites throughout the year, calculated with confidence margin $m = 80\%$ based on the day-type scenarios defined in Table 1. The heatwave-day scenario is represented together with non-workdays in January without implication that it could not occur at other times.

It follows from the plots of AC_{24} and AC_{dl} in Figure 10 that as a result of the proposed dynamic management of network constraints,

- DER export capacity can be increased in average over the whole day from 5 kW to over 8 kW (a 60% increase in capacity) across the year, and up to 10 kW (a 100% increase in capacity) during Winter months (workdays);
- DER export capacity can be increased in average during daylight hours from 5 kW to over 6 kW (a 20% increase in capacity) across the year, and up to no less that 8 kW (60% increase in capacity) during Winter months;
- Average available capacity for additional DER exports during daylight hours is at its lowest in the year during non-workdays in Spring (October-November), at around 6 kW (20% increase in capacity);
- Very high temperature days (heatwave days) offer opportunities for increased DER export capacity to more than 9 kW (80% increase in capacity) in average over the whole day, and more than 7 kW (40% increase in capacity) in average over daylight hours;
- DER export capacity can generally be increased more during workdays than during non-workdays – up to 1 kW (20% more) during the months of March and April.

This analysis demonstrates the potential advantages of adopting the proposed dynamic constraint management interface to increase DER export capacity. Without dynamic locational constraints, the capacity made available through a static limit is capped at 5kW (or likely lower in the future) at all times. If SAPN's constraint engine correctly estimates the parameters of the network, then even at the times in the year when the network is most congested, an additional 1 kW (20%

increase in DER export capacity) per VPP site can be unlocked by a regime of dynamic constraints. At the times when the network is least congested, an additional 3 kW (60% increase) can be unlocked during daylight hours, and up to 5 kW (100% increase) as a whole day average.

Note that these estimates consider the VPP as an aggregate of 584 sites, and thus do not indicate how capacity could be allocated by accounting for diversity across VPP nodes, which is modelled in the constraint engine calculations. While additional network capacity for DER exports can be unlocked by dynamic constraint management, in reality this capacity is not homogeneously distributed and can only be allocated in certain parts of the network. This brings the discussion to examining how this available capacity is distributed across the network.

3.3 Distribution of available capacity across the VPP

Figure 11 and Figure 12 present boxplots to graphically show how the average available capacities per VPP site, $AC_{i,24}$ and $AC_{i,dl}$, are distributed across the 584 VPP sites considered in the analysis.

The height of the rectangular boxes shown for each month of the year represents the distribution of available capacities for 50% of the sites. The box can collapse to a line in months when the distribution of capacities is very narrowly concentrated around a single capacity value, as is for example the case for the months of June and July in both figures.

The horizontal line inside the box represents the median of the distribution, such that 50% of the data sits above and below this line. For example, in Figure 11 the median line of the distribution of $AC_{i,24}$ for non-workdays in December is at 8 kW, which means that in those days half of the VPP sites can be allocated at least 3 kW additional DER export capacity in average over the day. This additional capacity, however, is mostly available outside daylight hours, as seen from the corresponding box for $AC_{i,dl}$ shown in Figure 12, where the median line sits just above 5 kW.

The lower and upper edges of the box mark the lower and upper quartiles of the data, so that each section of the box subdivided by the median line represents 25% of the sites. For example, the lower quartile line in the distribution of $AC_{i,dl}$ for workdays in April, in Figure 12, sits just above 6 kW, which means that in those days over 75% of the VPP sites can be allocated more than 6 kW DER export capacity.

The boxes may show lines extending from the lower and upper edges (whiskers) that represent variability outside the lower and upper quartiles. Any data which is outside 1.5 times the interquartile range is plotted as a dot and is typically considered an outlier.

The distribution of per-site DER export capacities in Figure 11 and Figure 12 is seen to follow a seasonal variability through the year similar to that seen in Figure 10 for the VPP as an aggregate, as could be expected. The boxplots also depict how these capacities vary across the VPP sites.

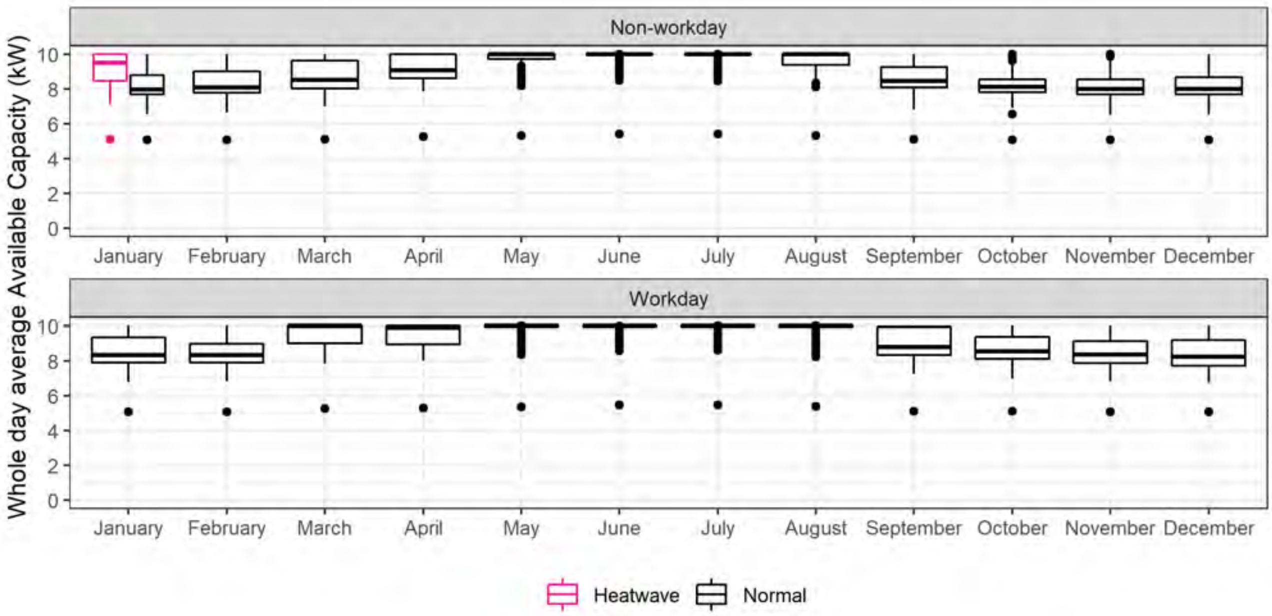


Figure 11 – The distribution whole day average available capacity $AC_{i,24}$ across the ensemble of VPP sites for both workdays and non-workdays during daylight hours with an 80% confidence margin

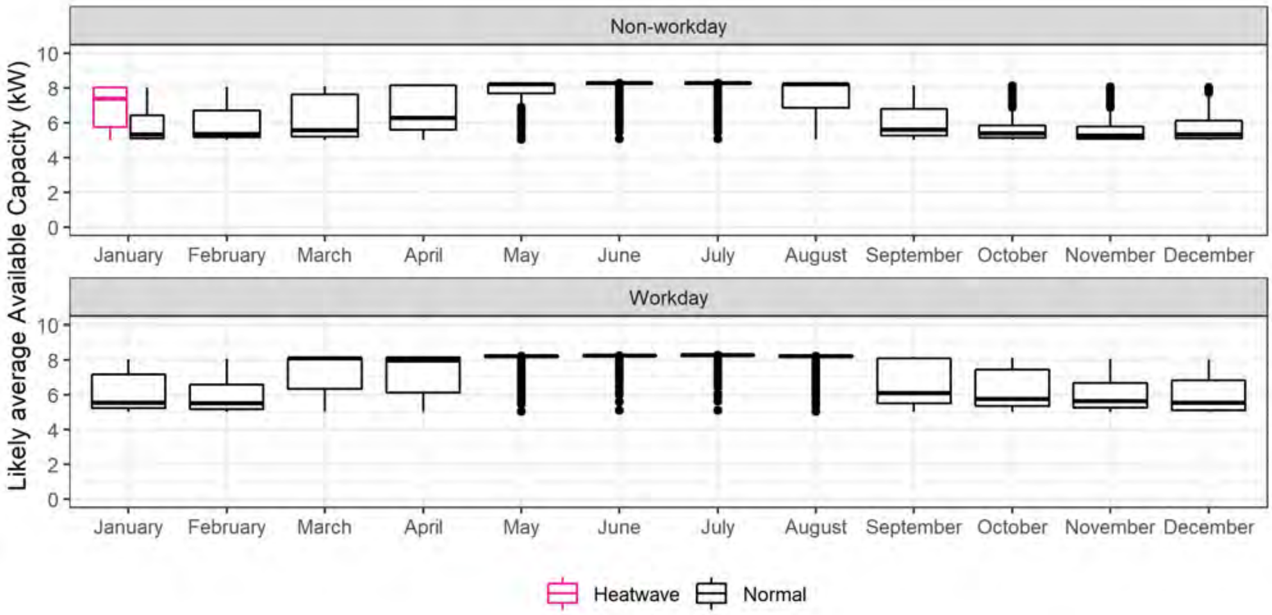


Figure 12 – The distribution likely average available capacity $AC_{i,dl}$ (additional capacity over the 5 kW limit that can be allocated during daylight hours) across the ensemble of VPP sites for both workdays and non-workdays during daylight hours with an 80% confidence margin

These boxplots show that not all VPP sites can be allocated the same levels of DER export capacity through the year. From May through to August the distributions are tight, which indicates that almost all sites are likely to be allocated the highest increases in DER export capacity – 100% increase as an average over the whole day (Figure 11), and 60% increase as an average during daylight hours (Figure 12). Thus, the colder months of the year present opportunity for the most substantial increases in DER export capacity across the VPP, excluding outlier sites.

The rest of the year shows larger spreads in available capacity, which can vary from 1 kW to 2 kW as a whole-day average (Figure 11), excluding an outlier on 5 kW. During daylight hours, there are comparatively many more sites close to the 5 kW lower limit (Figure 12).

These variabilities may be further analysed in four broad seasonal categories according to similarities in median capacity and spread: Autumn (March & April), Shoulder (May and August), Winter (June and July) and Summer (September through February), as shown in Figure 13.

Figure 13 – System capacity constraint seasons

Figure 14 and Figure 15 show for these seasonal categories how the spread of average available capacities across transformers changes when considering average capacities over the whole day as compared to over daylight hours (the most likely usable by the VPP).

While the peak at the highest available capacity stays around the same height between both figures (10 kW in Figure 14 and 8.5 kW in Figure 15), it is reduced by around 1.5 kW over daylight hours. The secondary peaks in available capacity, which are around 7.5 to 8 kW in Figure 14, are reduced to 5 to 5.5 kW in Figure 15. Hence, not only available capacity during daylight hours is reduced for transformers with the highest capacity, but is also relatively further reduced for transformers with the second highest available capacity.

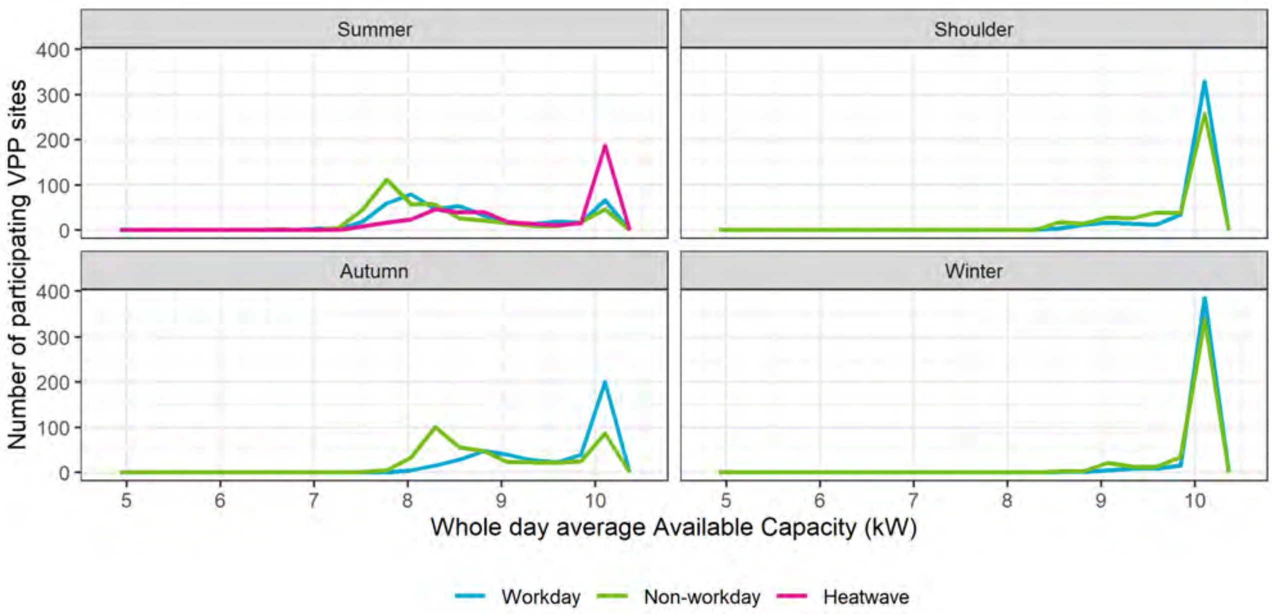


Figure 14 – The density of whole day average available capacity $AC_{i,24}$ across the ensemble of VPP sites for both workdays and non-workdays during daylight hours with an 80% confidence margin

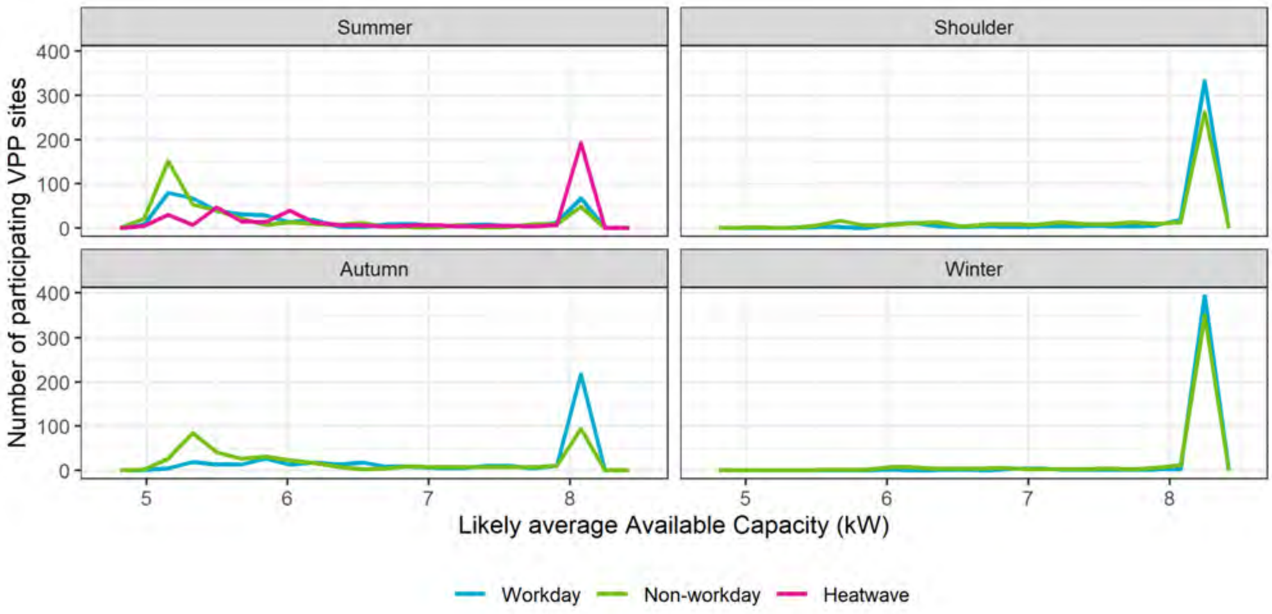


Figure 15 - The density of likely average available capacity AC_(i,dl) (additional capacity over the 5 kW limit that can be allocated during daylight hours) across the ensemble of VPP sites for both workdays and non-workdays during daylight hours with an 80% confidence margin

Figure 16 and Figure 17 present a view on seasonal variability in terms of the percentage of transformers at each available capacity level. Regardless of whether capacity is computed as an average over the day, or during daylight hours, it can be seen in these figures that only around 20% of the transformers reach the maximum capacity available across all seasons, with Summer non-workdays showing the lowest, and Winter workdays showing the highest (around 90% reach maximum capacity available).

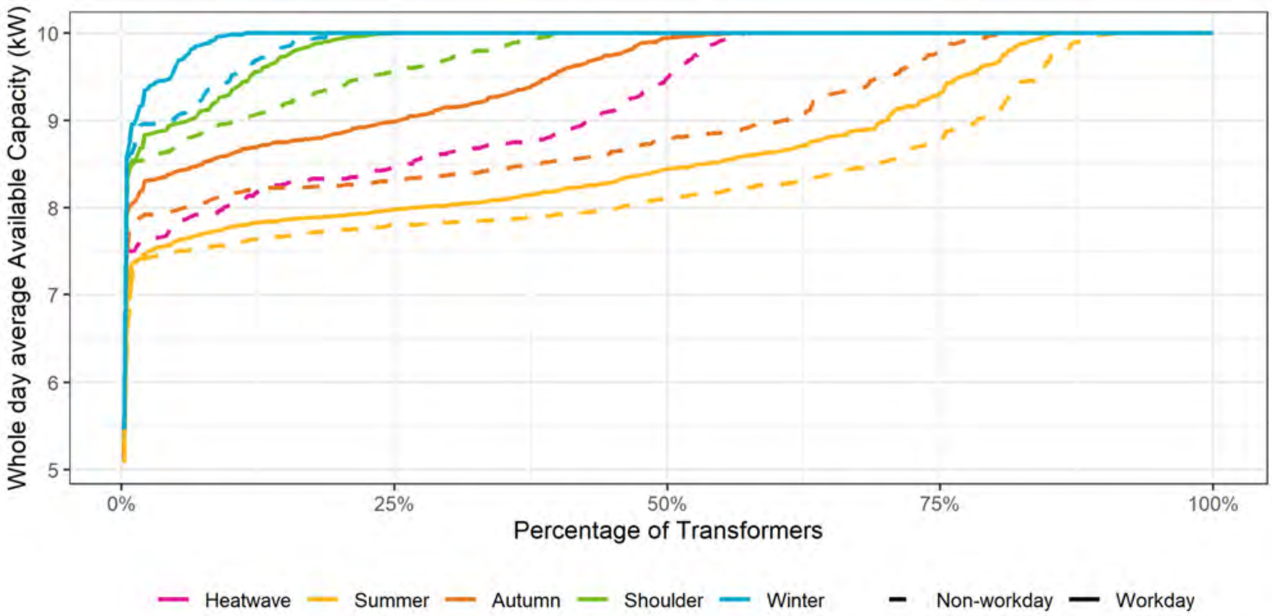


Figure 16 – The percentage distribution of whole day average available capacity $AC_{i,24}$ across the ensemble of VPP transformers for both workdays and non-workdays during daylight hours with an 80% confidence margin

Once again, we see by comparing Figure 16 and Figure 17 that a higher percentage of transformers shows low available capacity during daylight hours. The plots also show that the capacity available during heatwave days is comparable to that available in the Autumn period (March-April, see Figure 13).

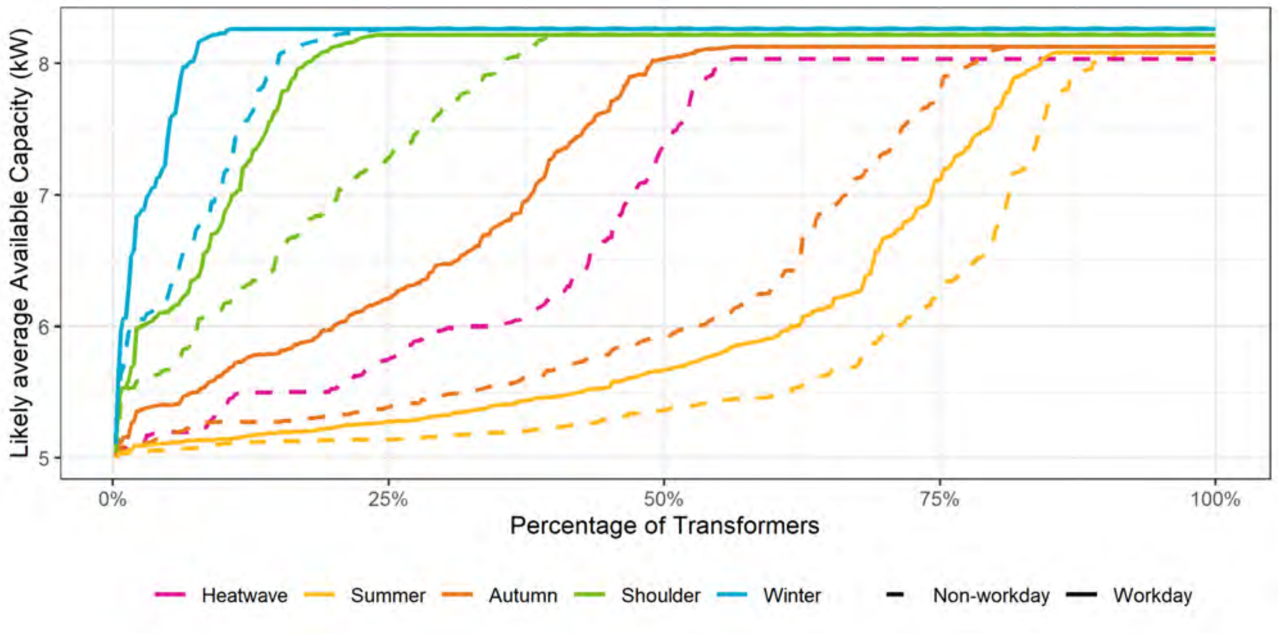


Figure 17 – The percentage distribution of likely average available capacity $AC_{i,dl}$ (additional capacity over the 5 kW limit that can be allocated during daylight hours) across the ensemble of VPP transformers for both workdays and non-workdays during daylight hours with an 80% confidence margin

In summary, the analysis of variability of available capacity across the VPP indicates that

- Maximum increases in available capacity for DER exports could be enabled by dynamic constraints across the VPP during the months of May to August: up to a 100% capacity increase as an average over the whole day (from 5 kW to 10 kW), and a 60% capacity increase during daylight hours (from 5 kW to 8 kW).
- Less than 20% of the transformers connected to the VPP can be allocated the maximum increases in capacity enabled by dynamic constraints across the year.
- More than 30% of the transformers connected to the VPP can be allocated at least a 20% increase in capacity (from 5 kW to 6 kW) in average during daylight hours across the year, and at least a 70% increase in capacity as an average over the whole day across the year.
- Around 50% of the transformers connected to the VPP can be allocated the maximum increases in capacity enabled by dynamic constraints for 6 months of the year from March to August.
- Heatwave days present opportunities to allocate the maximum increases in capacity for around 55% of the transformers connected to the VPP.

3.4 Released energy

We move the focus of the analysis to examine impacts of increasing DER export capacity as measured by DER energy exports. We evaluate and analyse the distribution of the released energy metric RE across the VPP calculated using the formula defined in Section 2.4. Recall that RE quantifies the fraction of available energy that can be exported to the network as capacities greater than 5 kW are allocated by the constraint engine. These capacities are delimited by the mediated constraint limit $L(t)$ and the solar curve $S(t)$, as illustrated in Figure 8.

Figure 18 shows the released energy in kilowatt-hours per day as an aggregate for the VPP across the year. The annual peak in released energy, between 17.5 MWh and 18.5 MWh per day, occurs in the months from May to August, despite the fact that solar resource is more limited in those months of the year. This is a consequence of the additional capacity that can be made available during these months, as discussed in the preceding analysis of potential DER export capacity in Section 3.2. The released energy drops by about 10 MWh in the following months to its lowest values in the year in October and November, following the drop in estimated average available capacity during daylight hours. Note that the released energy metric only integrates available capacity above the 5-kW limit as an average during daylight hours only, because it is shaped by the solar curve, which reduces released energy to zero when PV generation is not active.

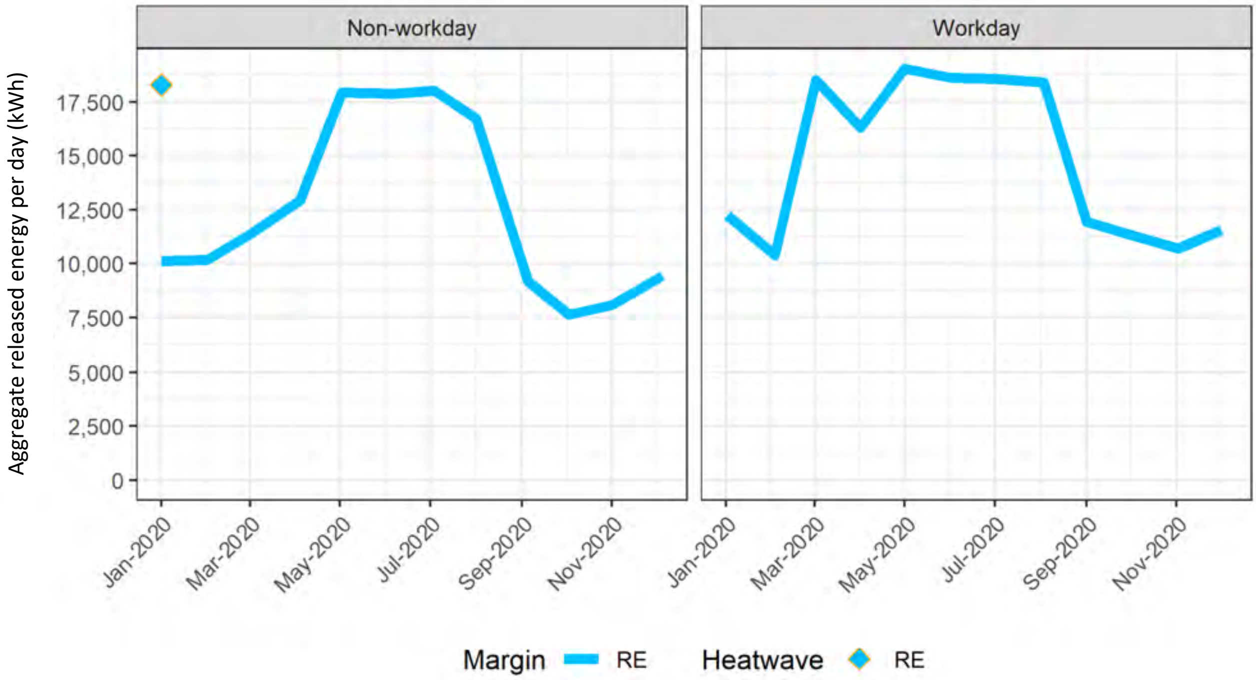


Figure 18. The aggregate Released Energy for confidence margin of 80% for all sites under all scenarios

Figure 19 shows how released energy per VPP site is distributed across the VPP. Figure 20 shows the distribution of released energy across the VPP transformers.

It is interesting to note in Figure 19 that although in the Winter period the released energy estimates are consistently higher than in the Summer period, the peak in the Winter period is lower than in the Summer period. This may be attributed to the increased availability of solar resource in the Summer period. While the network is less constrained in the Winter period, there is also less opportunity to generate high energy exports from solar, which explains why the aggregate released energy output of the network as a whole is lower.

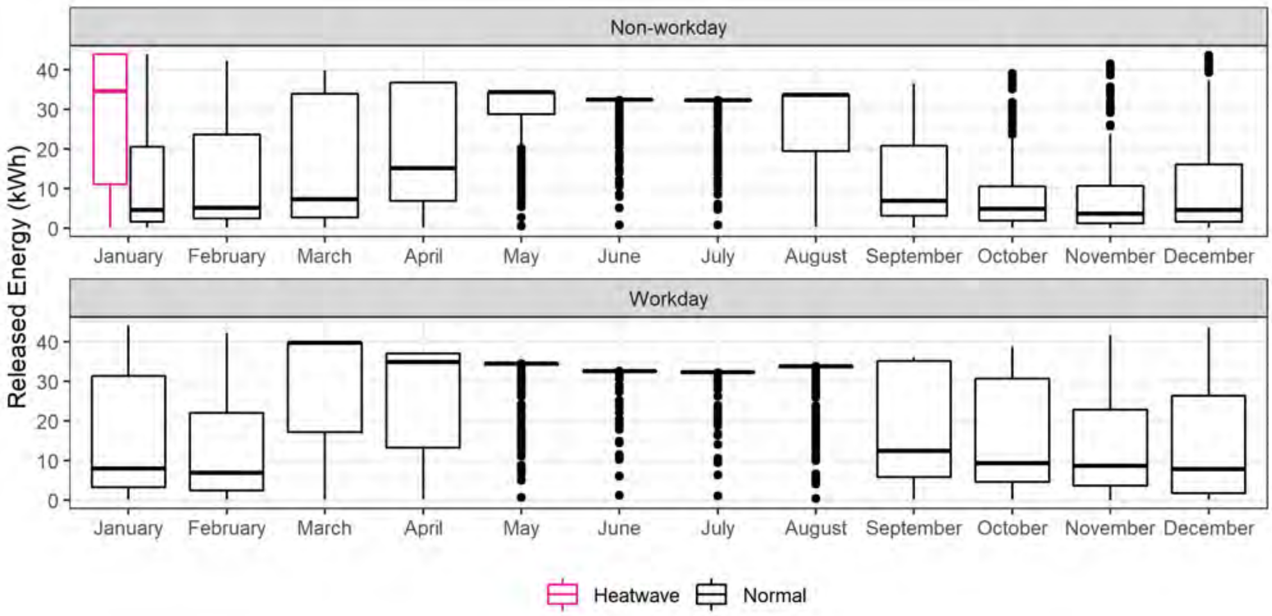


Figure 19 – The distribution of Released Energy RE across the ensemble of VPP sites for both workdays and non-workdays during daylight hours with an 80% confidence margin

This observation can also be made from Figure 20, which shows the variability of potential released energy across the ensemble of VPP transformers. It can be seen that in the Winter workdays, around 90% of transformers could release maximum energy at a level of around 32.5 kWh per transformer, which is lower than the 45 kWh of released energy per transformer seen in the heatwave scenario. In the heatwave scenario, however, only around 45% of transformers reach that level of released energy.

We also observe that most of the released energy is typically associated to a minority of the VPP sites. Observe for example in Figure 20 that released energy levels of around 17 kWh are only typically available to around 25% of VPP sites during non-workdays. For reference, approximately 17 kWh are the released energy share per VPP site resulting from Figure 18 in January, non-workdays (10 MWh divided by 584 VPP sites).

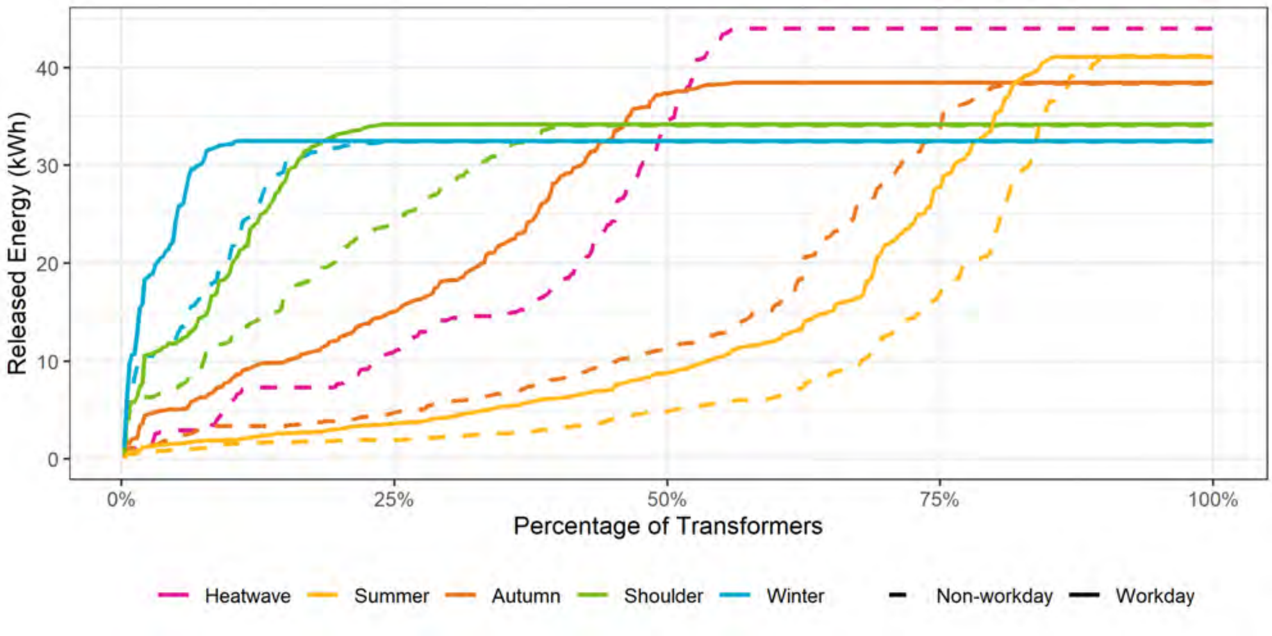


Figure 20 – The percentage distribution of Released Energy RE across the ensemble of VPP sites for both workdays and non-workdays during daylight hours with an 80% confidence margin

3.5 Summary of findings

This section analysed potential DER export capacity that can be allocated to the VPP beyond the capacity allowed by the standard static 5 kW DER export limit. The analysis was based on the evaluation of daily average available capacity and daylight daily average capacity as estimated by the SAPN constraint engine for 425 transformers connected to the VPP. A caveat is in order in regards to the quantification of DER export capacity as a daily average, which can be misleading for PV export capacity. Indeed, since DER export capacity is typically the lowest during daylight hours in feeders with high PV penetration, network capacity available for PV exports is more realistically represented as a *daylight* average.

The analysis found that the dynamic constraint management approach implemented by the proposed SAPN API can increase the DER export capacity that can be allocated to the VPP as a function of the DER location, the type of day (work or non-work) and the month of the year.

The analysis estimates that DER export capacity can be increased as a daily average from 5 kW to over 8 kW across the year, and up to 10 kW during Winter months. During daylight hours, average DER export capacity can be increased from 5 kW to 6 kW across the year, and up to over 8 kW during the Winter months.

Average available capacity achieves maximum values in the Winter months, when dynamic constraint management can allocate DER export capacity to the level of 10 kW daily, and up to 8 kW during daylight hours.

All of the transformers connected to the VPP have potential for the maximum increases in DER export capacity during the months from May to August, while half of the transformers can be allocated the maximum increases in DER export capacity for 6 months of the year from March to

August. Less than 20% of the transformers connected to the VPP show potential for the maximum increases in DER export capacity across the year.

The findings regarding released energy are consistent with those for average available DER export capacity during daylight hours. Similar seasonal variability is observed, with maximum estimated levels of released energy as an aggregate for the VPP occurring during the winter months.

4 Analysis of VPP DER hosting capacity

RQ 3	To what extent can the proposed interface allow distribution networks to host DER at higher levels of penetration by enabling dynamic, locational export limits compared to standard static per-customer export limits?

4.1 Context

In networks with a high penetration of DER such as South Australia, the physical limitations of the distribution network are a potential roadblock to the widespread adoption of VPP technology. This is relevant in the South Australian context, not solely due to the Tesla VPPs target size of 50,000 customers, but also due to State Government subsidy schemes aiming to encourage the installation of another 40,000 VPP-ready batteries. These subsidy schemes have already led to the formation of a VPP ecosystem in South Australia, with new VPPs regularly entering the market.

In the absence of more sophisticated approaches, more widespread aggregation of DER into VPPs could mean that today's static per-household export limits may need to reduce further to protect the integrity of the network. Static per-household export limits likely leave a great deal of available network capacity un-tapped and prevent VPPs from operating at their full potential.

This research question seeks to demonstrate how, as the South Australian VPP ecosystem grows, the proposed approach can remove this roadblock to the greatest extent possible while protecting the safety and security of supply for all customers.

The analysis below shows that DER hosting capacity can be increased significantly by enabling dynamic, locational export limits. The proposed dynamic constraint management solution can support flexible management of available network capacity to host a significantly higher volume of DER than that would be allowed by standard static constraint limits.

The evaluation of available capacity below shows that, compared to standard static per-customer export limits, dynamic export limits enable the network to host

- 25% more DER if their exports are dynamically managed to operate unconstrained 90% of the time,
- 55% more DER if their exports are dynamically managed to operate unconstrained 80% of the time,
- 300% more DER if their exports are dynamically managed to operate unconstrained 50% of the time.

In other words, the network can host more DER if DER exports are constrained some of the time. How much more DER can be hosted depends upon how often exports are constrained: more constraints enable more DER to be hosted.

4.2 Availability of DER export capacity

The availability of DER export capacity across SAPN's network is assessed based on the raw capacity estimate modelled by SAPN (see Section 2.2), which are again considered as the source of truth for network capacity. The distribution of network capacity is calculated across an entire year using the monthly estimated capacity profiles generated by the constraint engine for 75,530 transformers in SAPN's network.

The analysis in Section 3 already shows that dynamic export limits can enable additional DER export capacity over that achievable with the standard static export limits of 5 kW. The time-varying nature of dynamic constraint management captures the variability of network capacity through the hours of the day, the days of the week, and seasonally. With a view to capture maximal network utilisation, available capacity is evaluated with a dependency on the level of network congestion resulting from DER exports if the available capacity were allocated.

Indeed, latent network capacity could be allocated to host a number of DER that could operate without any curtailment of their allowed export capacity. However, a larger number of DER could be hosted if these DER were allowed unconstrained exports except at times of network congestion. In other words, we consider questions such as "What is the capacity available to host DER to operate unconstrained through the entire year?", and "What is the capacity available to host DER to operate unconstrained 90% of the time in the year?"

Consider for example a transformer that is maximally constrained (with minimum share of network capacity) during a few days of highest congestion Spring. Suppose that during those days of highest congestion the constraint engine estimates that there is room for an additional 15 kW of export capacity available for that transformer (indicated by a constraint limit of 15 kW). There is some flexibility in how this available capacity could be used to host new DER:

- Allow 15 kW of new DER export capacity to be connected to the transformer. If the constraint capacity estimates are accurate, these new DER can operate unconstrained 100% of the time and dispatch their full 15 kW export capacity at all times across the year.
- Allow more than 15 kW of new DER export capacity to be connected to the transformer. In this case, the new DER would operate unconstrained at all times their exports are below 15 kW, but would be constrained to 15 kW otherwise.

Thus, export capacity could be overallocated to host more DER in the network under the condition that the DER capacity can be dynamically constrained at times of high network congestion, as determined by the constraint engine estimates.

This example shows that it is possible to *stretch* DER hosting capacity beyond the technical limits of the network as long as the hosted DER can be dynamically managed and constrained at times of network congestion. In this sense, dynamic constraint management can support flexibility in hosting capacity to increase DER numbers and utilisation of common infrastructure.

To illustrate this idea in more concrete terms, we calculated the capacity of DER that could be hosted without constraints. Namely, operating 100% of the time unconstrained. We also calculated how much additional DER capacity could be hosted if the DER were to operate constrained a percentage of the time through the year during periods of high network congestion.

We considered unconstrained operation for 99%, 90%, 80% and 50% of the time in average through the year. The results are shown in Figure 21.

The available capacity of each transformer $i = 1,2, \ldots T$ in the network is evaluated using the raw constraint $C_i(t)$ defined in Section 2.2. Note that $C_i(t)$ is absolute raw capacity that can be allocated to the transformer, rather than additional capacity over the standard static 5-kW constraint limit, as considered in Section 3. If a transformer's capacity falls below 0 kW it is considered caped at 0 kW with no capacity available.

The available capacities calculated for the 75,530 transformers considered are then summed to produce Figure 21, which provides an estimate of DER hosting capacities that would be available as a function of the percentage of time across the year that the network would remain unconstrained once the capacity allowance is utilised.

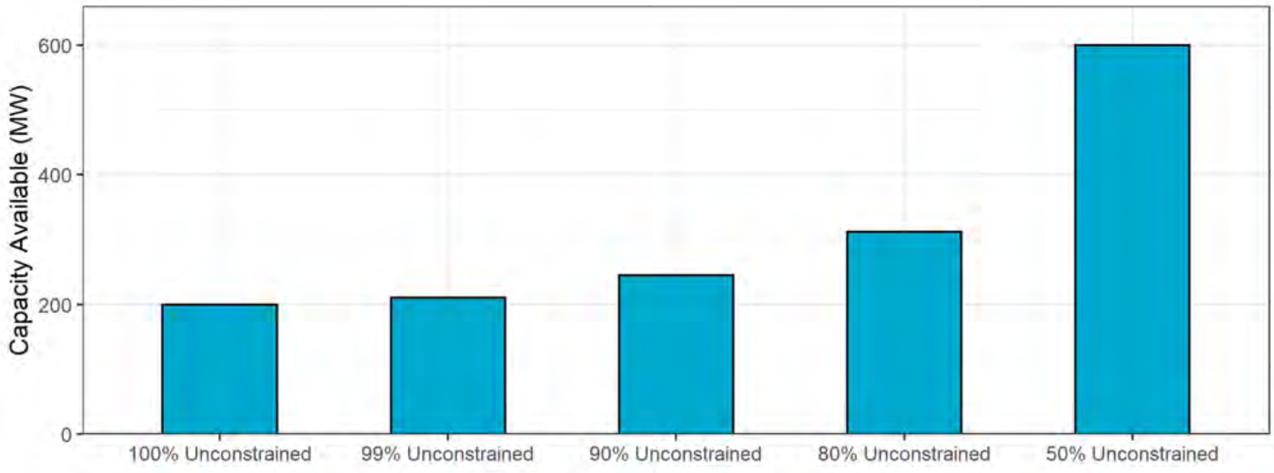


Figure 21 – The summed available capacity across all 75,530 transformers in SAPN's network using a 0kW reference

We observe from Figure 21 that the network could host up to 200 MW of additional export capacity for DER operating 100% of the time unconstrained. In other words, these 200 MW represent the DER hosting capacity of the network to exhaust the latent capacity at all transformers to allow unconstrained DER exports. By enabling dynamic, locational export limits to manage DER exports, the network could alternatively host:

- up to 210 MW of additional export capacity for DER operating unconstrained 99% of the time on average across the year;
- up to 250 MW of additional export capacity for DER operating unconstrained 90% of the time on average across the year;
- up to 310 MW of additional export capacity for DER operating unconstrained 80% of the time on average across the year;
- up to 600 MW of additional export capacity for DER operating unconstrained 50% of the time on average across the year.

Note that the relationship between DER hosting capacity and the percentage of the time DER can operate unconstrained is nonlinear. For example, observe that hosting capacity for DER exports could triple from 200 MW to 600 MW if the hosted DER were to operate unconstrained 50% of the time rather than 100% of the time.

An insight into the current level of congestion of the network may be gained by analysing the distribution of the available capacity across all transformers. Table 6 shows the percentage of transformers clustered according to their available capacity to host DER exports operating 100% of the time unconstrained. In this scenario, 56.1% of the transformers have no capacity available, and even for those transformers with capacity available, an additional 30.7% of transformers have less than 1 kW available.

Table 6 – Percentage of transformers with listed available capacity if they are to remain unconstrained for 100% of the time.

0kW	1kW or less	2kW or less	3kW or less	10kW or less	20kW or less	30kW or less
56.1%	86.8%	90.9%	92.2%	95.4%	97.2%	98.0%

4.3 Summary of findings

The analysis of raw capacity constraints across SAPN's network reveals that DER hosting capacity can be increased significantly by enabling dynamic, locational export limits. The evaluation of DER hosting capacity assumes that DER exports are dynamically managed through the proposed VPP API or an equivalent interface.

The time-varying nature of network capacity captured by dynamic export limits can be exploited to further increase hosting capacity and network utilisation by allowing temporary constraints to DER exports. The evaluation of available capacity shows that, compared to standard static per-customer export limits, dynamic export limits can enable the network to host

- 25% more DER if their exports are dynamically managed to operate unconstrained 90% of the time,
- 55% more DER if their exports are dynamically managed to operate unconstrained 80% of the time,
- 300% more DER if their exports are dynamically managed to operate unconstrained 50% of the time.

While the DER hosting capacity of the network is a limited resource, the proposed dynamic, locational constraint management approach provides flexibility for more efficient utilisation and management of existing infrastructure.

5 Analysis of VPP costs and benefits

RQ 5	What are the costs of implementing the proposed dynamic network constraint management assessed against benefits obtained?
RQ 6	What additional economic value can be enabled to DER operators by dynamic network constraint management, through enabling higher utilisation of existing network capacity?

5.1 Overview

The following sections describe the costs of developing and implementing the proposed dynamic network constraint management using the actual costs of implementation, the method used to calculate the wholesale energy market benefits of VPP operation, and the key inputs used in the model. The analysis provides the estimated benefits to the VPP operator, net present value and benefit cost ratio.

5.2 Methodology

Costs for the analysis are based on an audited representation letter by SAPN. This cost was assumed to be upfront in the first year of the trial, without ongoing costs.

Based on the data made available for the analysis, benefits to the VPP DER operator are estimated in terms of the additional market value of energy able to be dispatched by the VPP under the proposed dynamic limit scheme above what would have been possible under standard static export limits. This analysis builds on the approach undertaken by SAPN in the LV Management Business Case developed as part of its regulatory submission for 2020-25 [14] using as a reference to understand the overall value of the energy released a study commissioned by SAPN with Houston Kemp [15].

Additional wholesale electricity market benefits (spot market revenue streams) that accrue to the VPP provider based on the implementation of dynamic network export limits are estimated for three cases based on static export limits (representing an upper bound on benefits):

- **2 kW Static network export limits** by implementing an API to exchange real-time and locational data on distribution network constraints between SA Power Networks and the customers' DER aggregator (VPP provider).
- **5 kW Static network export limits** by implementing an API to exchange real-time and locational data on distribution network constraints between SA Power Networks and the customers' DER aggregator (VPP provider).
- **10 kW Static network export limits** by implementing an API to exchange real-time and locational data on distribution network constraints between SA Power Networks and the customers' DER aggregator (VPP provider).

The cost-benefit analysis used simulated data in regard to customer load profiles and PV generation output, assuming 1,000 simulated VPP sites – the targeted deployment in Tesla's VPP rollout in SA – with the number of premises remaining constant for the analysis period of 10 years. The simulated data was generated by a linear optimization model with perfect foresight developed by Tesla with the objective of maximizing energy arbitrage and contingency profits earned by a VPP battery energy storage system (BESS), subject to a number of constraints.

5.3 Costs

Based on an audited representation letter by SAPN, the actual costs of implementing the VPP for Tesla was $460,065. This cost was assumed to be upfront in the first year of the trial. No ongoing costs were assumed in future years.

5.4 Benefits

Benefits to the VPP DER operator will be estimated in terms of the additional market value of energy able to be dispatched by the VPP under the dynamic limit scheme above what would have been possible under static export limits. This analysis will build on the approach undertaken by SAPN in the LV Management Business Case developed as part of its regulatory submission for 2020-25 [14] using, as a reference to understand the overall value of the energy released, a study commissioned by SAPN with Houston Kemp [15].

This section will outline the calculation of additional wholesale electricity market benefits (spot market revenue streams) that accrue to the VPP provider based on the implementation of dynamic network export limits. The benefits were calculated for three cases:

- 2 kW static network export limits,
- 5 kW static network export limits, and
- 10 kW static network export limits.

With the data available at this stage of the project, all three cases are using static limits to estimate the upper and lower bounds of potential value.

This cost-benefit analysis used simulated data for both customer load profiles (Section 5.4.2) and solar PV output (Section 5.4.3).

The proposed methodology assumed 1,000 simulated customer premises, the targeted deployment in Tesla's VPP rollout in SA, with the number of premises remaining constant for the analysis period of 10 years.

5.4.1 Model

Tesla have developed a linear optimisation model with perfect foresight with the objective of maximizing energy arbitrage and contingency profits earned by a VPP battery energy storage system (BESS), subject to a number of constraints.

The model has a number of inputs:

- Half-hourly price trajectories for all markets ($/MWh): Energy, 6sec FCAS Raise & Lower, 60sec FCAS Raise & Lower, 5min FCAS Raise & Lower
    - 2019: historical SA price curves for all markets
    - 2021: third-party consultant forecasted SA prices in all markets
- Half-hourly load and PV profiles (kW)
- BESS capacity, duration, roundtrip efficiency, and cycle limit
- Site export limit: 0kW, 2kW, 5kW and 10kW
- Site import limit: none
- SAPN fees: Residential Time of Use tariffs from NUoS (Network Use of System) schedule 2020/21
- Feed-in tariff is set to zero
- Annual cycle limit set to 365 cycles/year.

The model optimises VPP charge and dispatch over time, by seeking to maximise profit from buying and selling into the eight markets. The registered capacity of each BESS (5 kW solar inverter and 5 kW Powerwall 2) is shown in Table 7. The operation of each BESS in the VPP is modelled independently (single site not coordinated optimization).

Table 7: Registered capacities as per AEMO's 0.7 % droop setting for SA VPP

Registered capacity	Load		Generator	
	Lower	Raise	Lower	Raise
Energy	0.005 MW		0.005 MW	
Regulation	0 MW	0 MW	0 MW	0 MW
FCAS 6 s	0.005 MW	0 MW	0 MW	0.005 MW
FCAS 60 s	0.005 MW	0 MW	0 MW	0.005 MW
FCAS 5 min	0.005 MW	0 MW	0 MW	0.005 MW

For the present analysis, the model did not consider export limits for FCAS. Accordingly, the calculation of benefits focussed on energy market arbitrage revenues only.

5.4.2 Customer load profiles

It remains a challenge to access public load profiles due to privacy considerations. For that reason, we used a mixture of synthetic load profiles based on those of real customers. To construct synthetic residential load profiles, we started with around 5,000 New South Wales Ausgrid profiles from the Smart Grid Smart Cities program and found the 5 most representative profiles and their nine nearest neighbours using clustering analysis. We then synthetically created 45 profiles for the SAPN distribution network area by first scaling in each time period in proportion to the relative load profile of SA versus NSW for the sample year, and then scaling so that frequency distribution of the total annual consumption across the 45 profiles approximated that expected for SAPN. This process should adjust for differences in timing (daytime hours) and climate but is probably insufficient to account for all differences in gas versus electricity use, for example, between different states. The SGSC data set did include people with and without gas and with and without hot water control but the proportions will not match other states.

Of these 45 load profiles, twenty SAPN residential customer profiles (SP_ResCust in the figures below) were selected by choosing sites with a total load (excluding controlled load) that were clustered around the average of all sites (approximately +/- 30% of the mean). Controlled loads were included in the final load profiles of the selected sites. Profiles for selected Summer day for three clusters of customers are shown in, respectively, Figure 22, Figure 23 and Figure 24.[4]

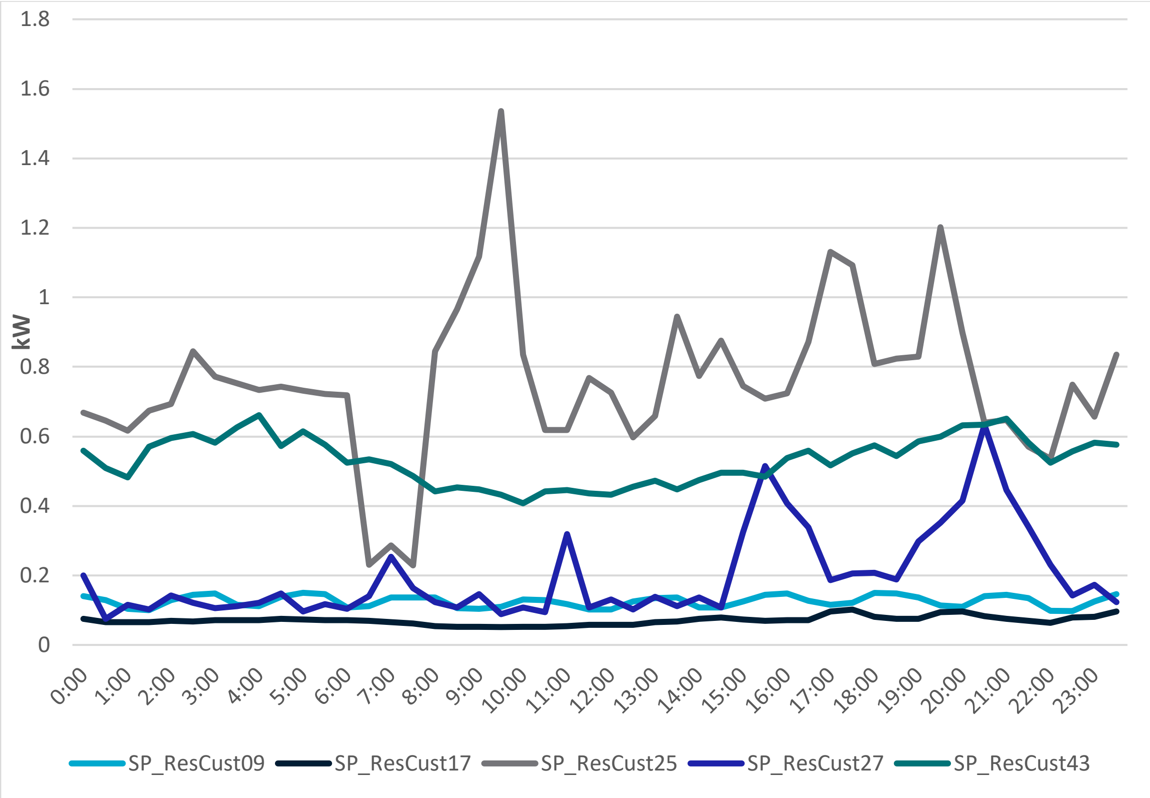


Figure 22: Summer day load profiles for customers in cluster one: SP_ResCust09, SP_ResCust17, SP_ResCust25, SP_ResCust27, SP_ResCust43

[4] The day profile on the day that the aggregate of all customers demand hit its seasonal peak in summer and winter for each site is shown in Appendix A.

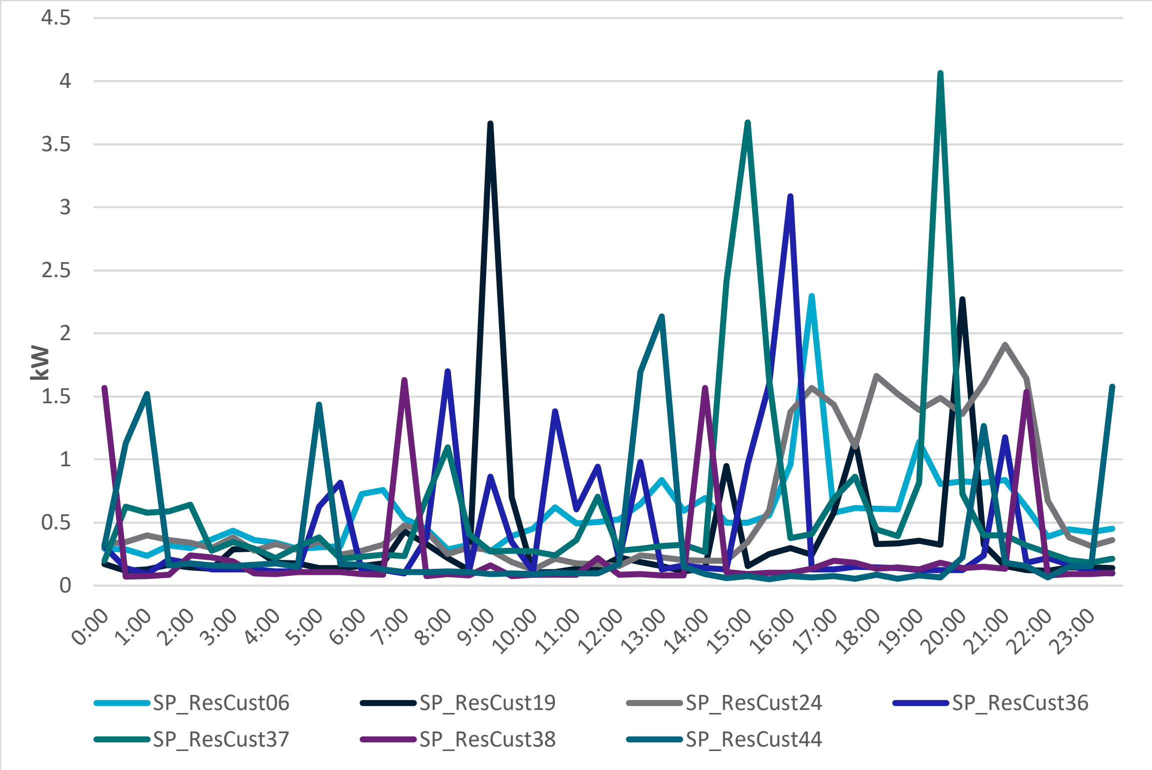


Figure 23: Summer day load profiles for customer in cluster two: SP_ResCust06, SP_ResCust19, SP_ResCust24, SP_ResCust36, SP_ResCust37, SP_ResCust38, SP_ResCust44

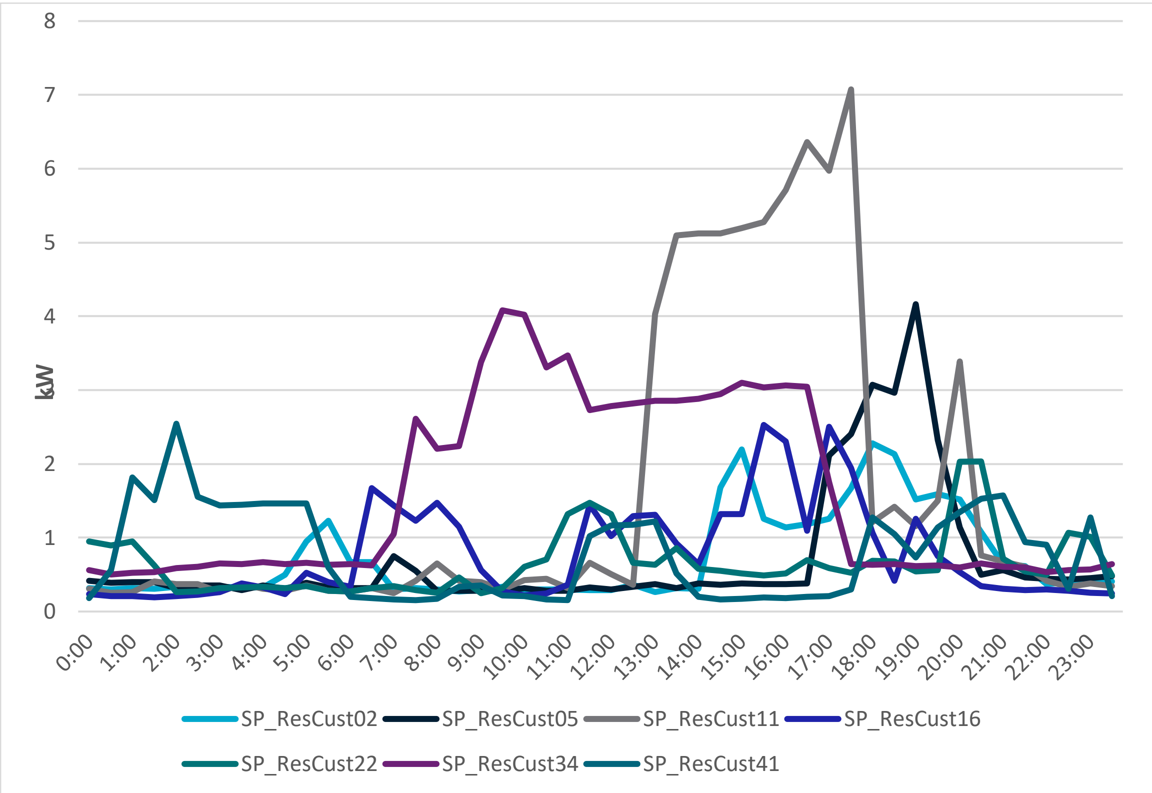


Figure 24: Summer day load profiles for customer in cluster three: SP_ResCust02, SP_ResCust05, SP_ResCust11, SP_ResCust16, SP_ResCust22, SP_ResCust34, SP_ResCust41

It was then assumed that the twenty load profiles were uniformly distributed across the 1,000 VPP (synthetic) participants.

5.4.3 Solar PV output profile

The same solar PV output profile was used in this analysis for each customer. PVWATTS[5] was used to generate a representative solar profile at the following specification drawn from Adelaide-Kent Town, Australia:

- 5 kW dc
- 25-degree azimuth
- 15-degree tilt.

The hourly plot of solar PV output over a year (Figure 25) shows increased solar radiation in the Summer months compared to winter, with monthly statistics shown in Table 8.

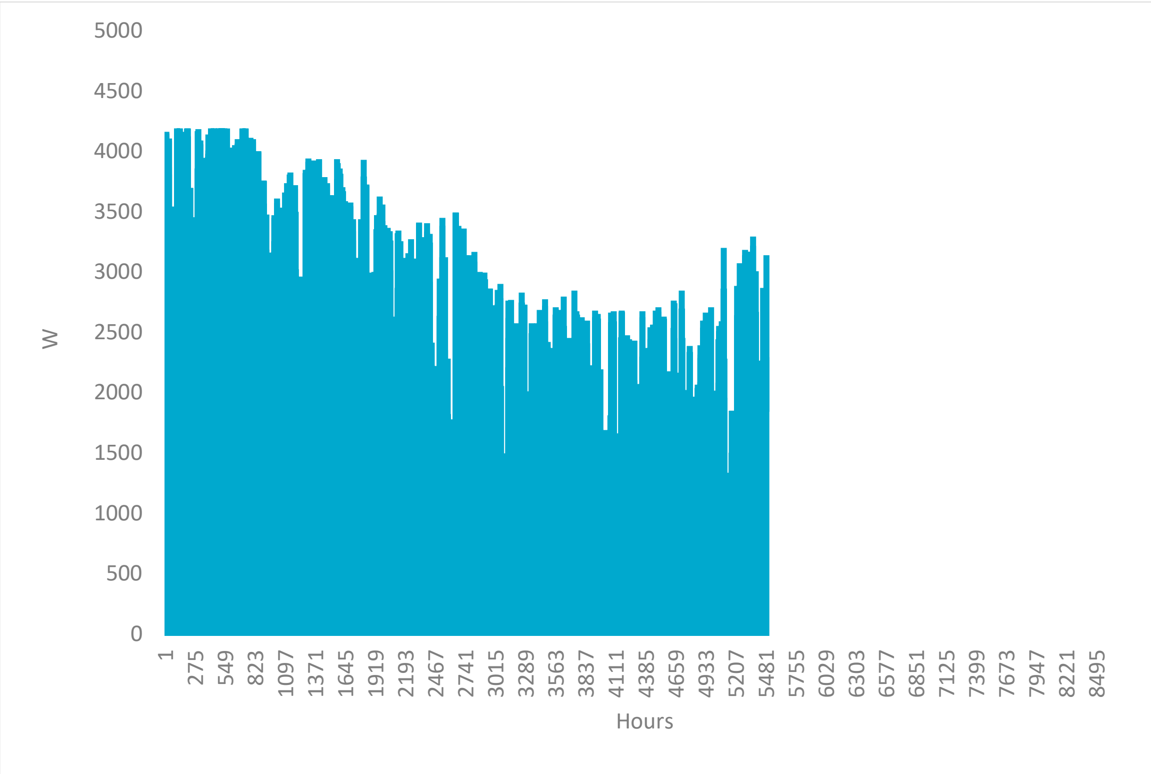


Figure 25: Hourly solar PV output, 5kW system, Kent Town, Adelaide

Table 8: Monthly solar radiation and solar PV power production

Month	Solar Radiation (kWh / m² / day)	Output (kWh)
January	7.98	912
February	7.12	726
March	6.04	700
April	4.51	520
May	3.29	404

[5] https://pvwatts.nrel.gov/pvwatts.php

June	2.66	322
July	2.9	365
August	3.68	462
September	4.79	575
October	6.05	725
November	7.06	809
December	7.54	870
Annual	**5.3**	**7,390**

5.4.4 Estimated benefits

Tesla's optimisation model was used to estimate the wholesale electricity market benefits (spot market) that accrue to the VPP provider based on the implementation of dynamic network export limits. The estimated benefits were simulated for three cases: 2kW, 5kW, 10kW static network export limits by implementing an API to exchange real-time and locational data on distribution network constraints between SA Power Networks and the customers' DER aggregator (VPP provider).

With the data available from the analysis, the dynamic export limit is approximated by a static export limit. That is, each customer's exports are statically limited only by the nominal maximum (2kW, 5kW or 10kW) irrespective of the state of network congestion at each point in time. Under a dynamic export limit, customer's exports may be further limited beyond the nominal threshold to a lower limit that changes depending on local power flows in order to accommodate network constraints.

The estimated wholesale energy arbitrage benefits for each of the twenty participants across the three export limit cases is shown in Figure 26. It shows that the energy arbitrage benefits are nonlinear, increasing the most when the export limit is 5 kW compared to 2 kW. Average energy arbitrage benefits per site are $164 in the 2-kW case, $388 in the 5kW case and $423 in the 10-kW case. Increasing the export limit to 10 kW does result in some additional revenue however it is constrained by the participants ability to discharge at power significantly more than 5 kW. Exports at greater than 5 kW are only possible during daylight hours due to 5 kW solar PV and 5 kW battery system at each site.

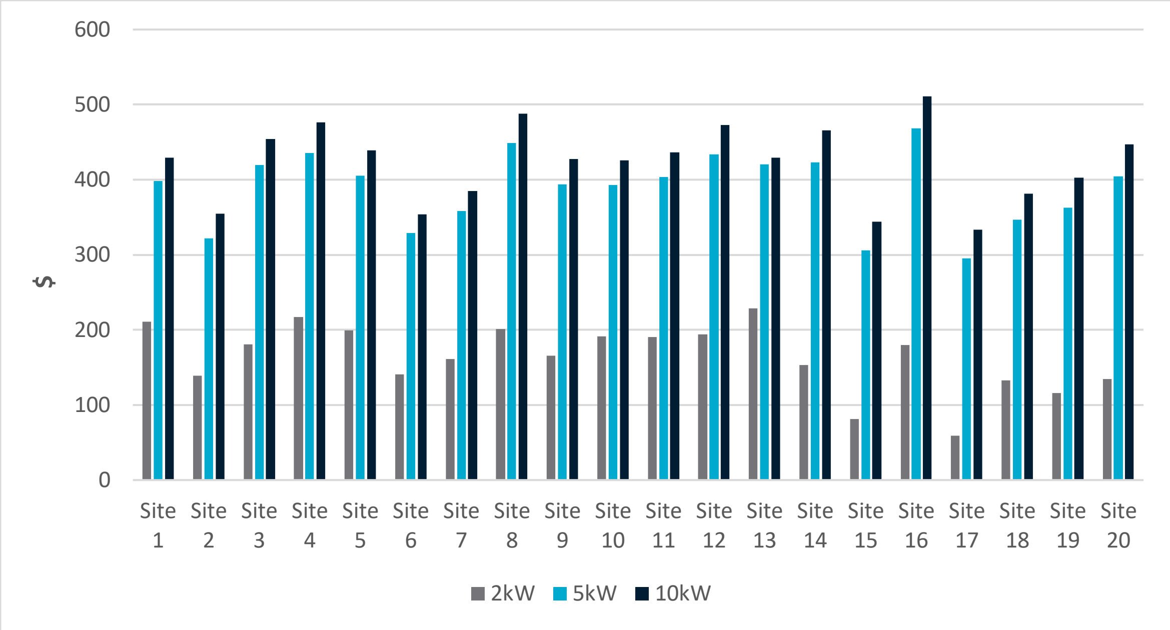


Figure 26: Annual energy arbitrage benefits by participant and export limit case

5.5 Net present value

The net present value (NPV) calculations are summarised in Table 9 with the detailed calculations shown in Table 10, Table 11 and Table 12. A real discount rate of 7% p.a. was used to convert future cash flows to present value terms. As discussed in Section 5.4.1, market prices for two years (2019 historical year and 2021 simulated year) were used for the optimisation model. The NPV calculations used an average of these two years.

Table 9: Net present value (NPV) summary

	2 kW limit	5 kW limit	10 kW limit
Costs (to 2030, $million)	0.46	0.46	0.46
Benefits (to 2030, $million)	1.23	2.92	3.18
NPV (to 2030, $million)	0.77	2.46	2.72

Increasing static export limit from 2kW to 5kW has the potential to create up to $1.7 million additional value to the 1000 participants in the VPP. Increasing the static export limit from 2kW to 10kW has the potential to create up to $1.95 million additional value to the 1000 participants in the VPP.

Table 10: Net present value calculations, 2kW export limit case

				2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Total		($2020)	million	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total (discounted)			million	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Benefits													
no of VPP participants			numbers	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Energy arbitrage													
avg net benefit (2kW)	Tesla model	historical (2019)	million	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
avg net benefit (2kW)	Tesla model	projected (2021)	million	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total (discounted)		historical (2019)	million	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Total (discounted)		projected (2021)	million	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total (discounted)		average	million	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Costs (to 2030)		average	million	0.5									
Benefits (to 2030)		average	million	1.2									
NPV (to 2030)		average	million	0.8									

Table 11: Net present value calculations, 5kW export limit case

				2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Total		($2020)	million	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total (discounted)			million	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Benefits													
no of VPP participants			numbers	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Energy arbitrage													
avg net benefit (5kW)	Tesla model	historical (2019)	million	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
avg net benefit (5kW)	Tesla model	projected (2021)	million	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total (discounted)		historical (2019)	million	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.2	0.2
Total (discounted)		projected (2021)	million	0.4	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Total (discounted)		average	million	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Costs (to 2030)		average	million	0.5									
Benefits (to 2030)		average	million	2.9									
NPV (to 2030)		average	million	2.5									

Table 12: Net present value calculations, 10kW export limit case

				2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Total		($2020)	million	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total (discounted)			million	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Benefits													
no of VPP participants			numbers	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
<u>Energy arbitrage</u>													
avg net benefit (10kW)	Tesla model	historical (2019)	million	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
avg net benefit (10kW)	Tesla model	projected (2021)	million	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total (discounted)		historical (2019)	million	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.2
Total (discounted)		projected (2021)	million	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Total (discounted)		average	million	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.2	0.2
Costs (to 2030)		average	million	0.5									
Benefits (to 2030)		average	million	3.2									
NPV (to 2030)		average	million	2.7									

5.7 Summary of findings

The aim of this analysis was to calculate a preliminary cost-benefit analysis for the following two research questions:

RQ 5. What are the costs of implementing the proposed dynamic network constraint management assessed against benefits obtained?

RQ 6. What additional economic value can be enabled to DER operators by dynamic network constraint management, through enabling higher utilisation of existing network capacity?

This cost-benefit analysis used simulated data in regard to customer load profiles and solar PV output for 1,000 simulated customer premises, the targeted deployment in Tesla's VPP rollout in SA with the number of premises remaining constant for the analysis period of 10 years.

The estimated benefits were simulated for three cases:

- 2 kW static network export limits,
- 5 kW static network export limits, and
- 10 kW static network export limits.

All three cases use static limits to estimate the upper and lower bounds of potential value due to model limitations. Future analysis should consider the value of dynamic limits between these static limits varying through time.

The analysis found that the estimated wholesale energy arbitrage benefits for each of the twenty participants across the three cases are nonlinear with export limit, increasing the most when the export limit is 5kW compared to 2kW. Average energy arbitrage benefits per site equalled $164 in the 2kW case, $388 in the 5kW case and $423 in the 10kW case. It should be noted that the matching between system size and export limits would have considerable impact to benefits. Most benefit would be obtained from export limits that are commensurate with battery output power.

Increasing the static export limit from 2kW to 5kW has the potential to create up to $1.7 million additional value to the 1000 participants in the VPP. Increasing the static export limit from 2 kW to 10 kW has the potential to create up to $1.95 million additional value to the 1000 participants in the VPP.

Follow-up work should include dynamic export limits (rather than static limits assumed here) based on observations collected from the trial and the inclusion of FCAS revenues in benefit calculations. An estimate of ongoing costs of VPP implementation also need to be estimated.

6 Conclusions and opportunities for further work

6.1 Conclusions

This report investigated the potential increases in DER export capacity, increases in network DER hosting capacity, and the release of economic value enabled by dynamic, locational export limits communicated via the SAPN API solution implemented in the project.

The analysis reported focused on the following research questions:

RQ 1	To what extent can available DER export capacity be increased compared to the maximum capacity available under SA Power Networks' standard connection rules (currently capped at 5-kW export per customer) using dynamic network constraint management via the proposed interface between SAPN and the DER aggregator?
RQ 3	To what extent can the proposed interface allow distribution networks to host DER at higher levels of penetration by enabling dynamic, locational export limits compared to standard static per-customer export limits?
RQ 5	What are the costs of implementing the proposed dynamic network constraint management assessed against benefits obtained?
RQ 6	What additional economic value can be enabled to DER operators by dynamic network constraint management, through enabling higher utilisation of existing network capacity?

RQ 1 was investigated by analysing dynamic capacity estimates modelled by SAPN for 425 transformers connected to the VPP. The analysis found that the dynamic constraint management approach implemented through the proposed SAPN API can significantly increase the DER export capacity that can be allocated to the VPP as compared to the maximum capacity available under SAPN standard connection rules.

RQ 3 was investigated by analysing dynamic capacity estimates modelled by SAPN for 75,530 transformers in their network. The analysis shows that DER hosting capacity can be increased significantly by enabling dynamic, locational export limits. The proposed dynamic constraint management solution can support flexible management of available network capacity to host a significantly higher volume of DER than that would be allowed by standard static constraint limits, at the expense of constrained DER exports. The network can host more DER if DER exports can be dynamically constrained some of the time. Much more DER can be hosted if DER exports can be constrained more often.

RQ 5 and RQ 6 were investigated by conducting a preliminary economic analysis of the benefits of the approach using simulated customer load profiles for three static limit cases, 2 kW, 5 kW and 10 kW. These static cases provided upper and lower bounds of potential value in the implementation of an API to exchange real-time and locational data on distribution network constraints between SAPN and the VPP provider.

While further analysis of trial data will be conducted at the end of the field trial to expand on RQ 5 and RQ 6 and address the remaining research questions in [1], the findings of analysis reported at this stage strongly support the main underlying hypotheses of the project.

H 1	Existing limits on the level of network exports from customers' renewable energy systems on the SA distribution network can be increased by as much as two-fold by implementing an API to exchange real-time and locational data on distribution network constraints between SA Power Networks and the customers' DER aggregator (VPP provider).
H 2	Operating a VPP at higher levels of export power than would otherwise be allowed under normal static per-site export limits increases the opportunity for the VPP to provide market and system-wide benefits.

The proposed approach of using dynamic capacity limits to manage hosting capacity appears as a necessary development in efficiently operating a LV network with high penetration of DER for increased network utilisation, and the release of value underpinning emerging markets for energy storage and VPPs.

6.2 Some reflections on further work

This trial is an innovative approach to better managing a network to enable greater adoption and use of VPPs; indeed, it won ENA's 2020 innovation award. As ARENA, the ESB, and other stakeholders increasingly contemplate dynamic operating envelopes as the emerging answer to allow DER to continue playing an increasingly central role in the electricity grid, this report points to the need for additional research and analysis in several areas. In general, these opportunities for additional research can be summarised as technical due diligence and improvement, stakeholder consensus, and economic analysis.

On technical due diligence, the analysis reported for RQ 1 and RQ 3 was based on estimated dynamic capacity constraint profiles generated by SAPN constraint engine. At this stage, these profiles provide an average daily capacity curve per month of the year, and there has been little to no analysis conducted to demonstrate the accuracy or reasonableness of the constraint engine. Indeed, there is limited data to even verify the constraint engine, so a data collection exercise is recommended in addition to additional analysis. As more attention points to dynamic operating envelopes as the approach to managing low-voltage networks, more technical due diligence, research, and development is required to demonstrate that the model used to generate such envelopes or constraints are accurate and reasonable.

While SAPN's approach to calculating constraints is likely reasonable given the data available to them, these estimates could be significantly improved by incorporating real-time weather data and real-time voltage and load data to produce daily forecasts of network capacity.[6] The primary

[6] The constraint modelling has been refined by SAPN since the data was first shared to conduct the analysis reported here.

aim of the present project was to demonstrate the capability, rather than achieving the most accurate hosting capacity engine.

A combination of data-driven and physics-based state estimation techniques could be considered for sections of the network where more connectivity information, smart meter data, and monitored data become available. Commonly agreed upon best practice for data collection, data sharing, and constraint development can ensure that the use of dynamic operating envelopes and similar techniques appropriately reflect the actual conditions of the network. Further work expanding on the SAPN API could also focus on how to communicate and allocate capacity to multiple VPP providers and non-VPP DER, identifying and managing locational variability of network capacity.

Regarding stakeholder consensus, there is yet no Australian standard or industry-agreed upon approach for calculating hosting capacity, but much foundational work has been done by EPRI [16], [17], and there is ongoing work led by DEIP [13], [18]. Having one would create a number of benefits, including consistency for VPP developers and clear guidance about how DNSPs should communicate these limits to their customers. Indeed, developers like Tesla – along with state governments and hundreds of thousands of households in Australia – are investing significantly into solar and storage solutions to reduce electricity bills and carbon emissions. The present report and many others highlight that to enable these customer energy resources to provide the value these stakeholders anticipate, the network must be planned and operated differently. Consensus on how precisely that different management might take place – and on how to communicate network limits to customers, DER aggregators and others – would provide transparency and lower the overall cost of DER integration.

Another opportunity for consensus exists regarding the definition of average available capacity. This report highlighted the ability to describe this capacity on either a 24-hour or daylight-focused basis. Our analysis indicates that, so long as solar energy is a major source of export, the daylight-based metric is significantly more representative of the exploitable capacity, and should therefore be the preferred way of communicating average impacts of dynamic hosting capacity limits. A commonly agreed upon approach for communicating this information would be valuable.

Finally, there is significant room for follow-up work on economic analysis. Our analysis focused on the increased value to the VPP of implementing hosting capacity analysis. This analysis is wholly distinct from an economic analysis of the benefit of implementing dynamic constraint limits across SAPN's service area. Indeed, one insight from our analysis is that a large benefit of the introduction of dynamic operating envelopes is that it enables optimised utilisation of hosting capacity across the network, locationally and in time, enabling additional customers to connect solar to the network. Future economic analysis could analyse this benefit in addition to that released to the existing Tesla VPPs.

Furthermore, a more detailed cost-benefit analysis should include dynamic export limits (rather than static limits assumed in the present report) based on observations collected from the trial and the inclusion of FCAS revenues in benefit calculations (a recent report from AEMO [4] provides some insights on VPP revenue from contingency FCAS markets in current VPP demonstrations, including the present trial). More work is required to determine an accurate cost for developing and operating a constraints engine. The default cost assumption used in this report -- $460,000 – is uncertain at best. As discussed above, consensus on the best data and modelling techniques for adequately determining dynamic capacity limits need to be identified and then the cost of collecting, cleaning, and analysing that data and then communicating it to VPPs (or other DER) can be accurately determined.

Appendix A

A.1 The Solar Curve

The solar curve for this work has been approximated by a $\sinh(\cdot)$ - $\sinh^{-1}(\cdot)$ (hyperbolic sine and inverse-hyperbolic sine) function using the *dSHASHo* function from R's *gamlss.dist* library [19]. This is essentially a four-parameter function which produces a modified normal distribution. In this case it has been used to modify the kurtosis of the normal distribution to produce a distribution with wider shoulders – similar to that of a solar curve.

The base for the solar curve has therefore been generated as:

$$s(t) = dSHASHo(\hat{d}, \mu_d, \sigma_d, \tau)$$

where $\hat{d}$ is a vector of date times between the sunrise and sunset times for a given day at a resolution of 1s, μ_d is the mean of those date times in Unix time, σ_d is the standard deviation of those date times in Unix time, and τ has been chosen as 1.6 as this was a good approximation for the kurtosis of a solar curve.

The curve $s(t)$ was then converted to between the range of 0kW and 5kW to produce the normalised and scaled $\bar{s_5}(t)$. Finally, this was multiplied by 1.2 and capped at 5kW, to extend the maximum solar period in the middle of the day. This means that $S(t)$ was then finally derived as:

$$S(t) = \min\,(5, \bar{s_5}(t) \times 1.2)$$

The curve $S(t)$ can be seen in Figure 27. The sunrise and sunset times have also been included in this plot for reference, represented in light blue (sunrise) and orange (sunset) vertical dashed lines, which are based off the Sun's position for Adelaide's longitude and latitude and account for the progressive daily variation through the year. These lines identify the period of daylight hours and provide an indication as to whether the 10-kW limits that may be allowed by the constraint engine are likely to be realisable by simultaneous export of battery and solar generation output. As such the solar curve $S(t)$ is centred on these times.

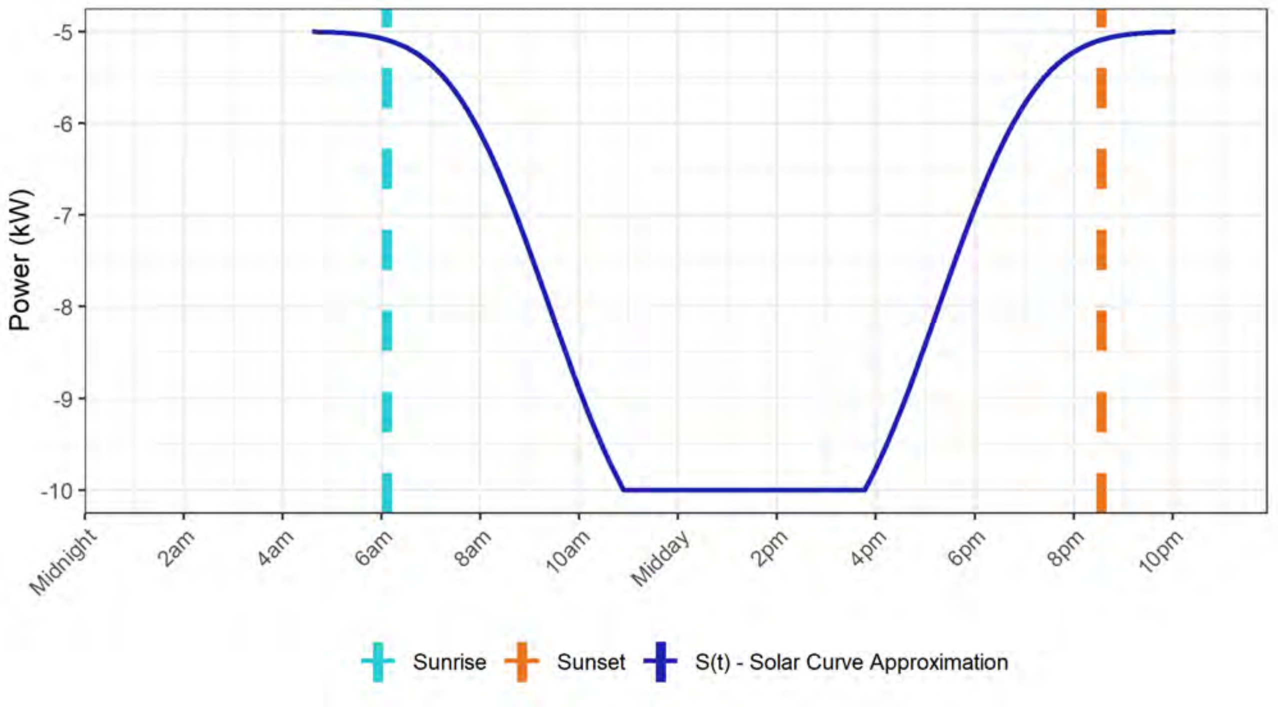


Figure 27 - The solar curve defined based on Sunrise and Sunset times for a January non-workday.

A.2 Site load profiles used in the benefit analysis Analysis of VPP costs and benefits

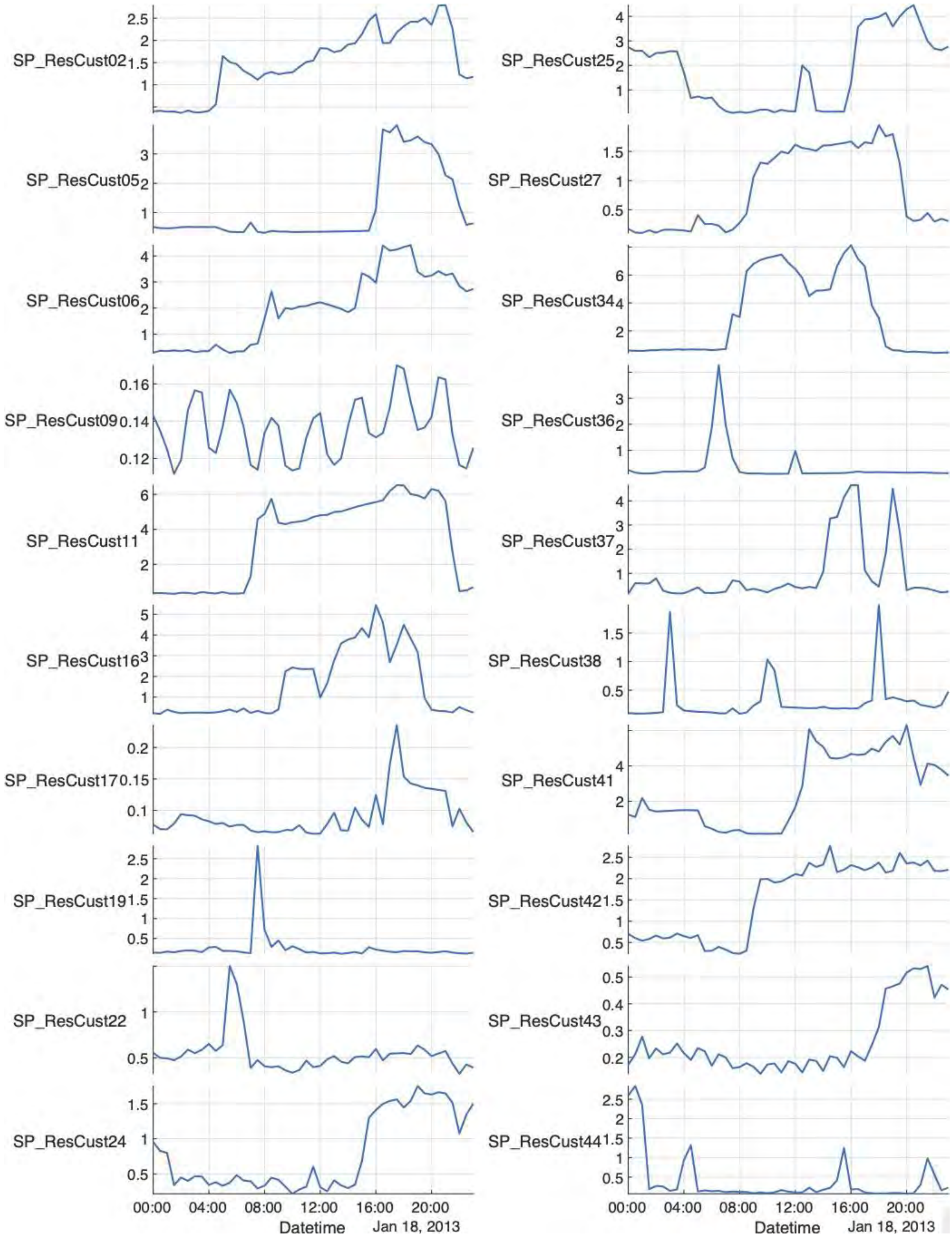


Figure 28 – Site load profiles, peak Summer day

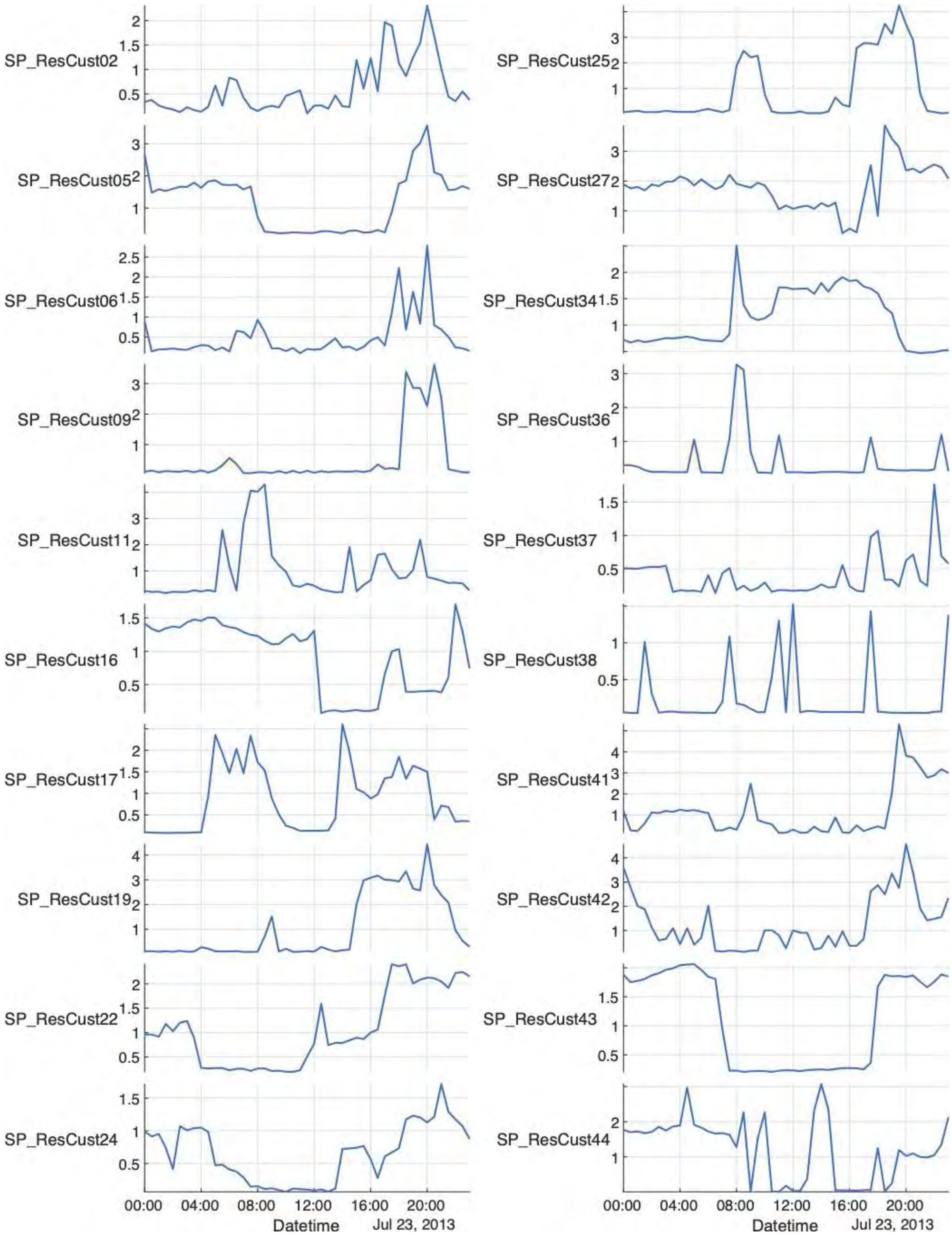


Figure 29 – Site load profiles, peak winter day

A.3 Shortened forms

Abbreviation	Meaning
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
API	Application Programming Interface
ARENA	Australian Renewable Energy Agency
BAU	Business as usual
BESS	Battery Energy Storage System
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DEIP	ARENA's Distributed Energy Integration Program
DER	Distributed energy resources
DNSP	Distribution network service provider
EPRI	Electric Power Research Institute
FCAS	Frequency Control Ancillary Services
ISP	Integrated System Plan
kW	Kilowatt
LV	Low Voltage
MW	Megawatt
NUoS	Network Use of System
PV	Photovoltaic
SA	South Australia
SAPN	SA Power Networks
VPP	Virtual Power Plant

A.4 Research hypotheses and questions

The project aims to test the following main underlying research hypotheses:

H 1. Existing limits on the level of network exports from customers' renewable energy systems on the SA distribution network can be increased by as much as two-fold by implementing an API to exchange real-time and locational data on distribution network constraints between SA Power Networks and the customers' DER aggregator (VPP provider).

H 2. Operating a VPP at higher levels of export power than would otherwise be allowed under normal fixed per-site export limits increases the opportunity for the VPP to provide market and system-wide benefits.

These hypotheses will be tested by analysing data collected during the life of the project to answer the following research questions:

Managing hosting capacity

RQ 1. To what extent can available DER export capacity be increased compared to the maximum capacity available under SA Power Networks' standard connection rules (currently capped at 5kW export per customer) using dynamic network constraint management via the proposed interface between SAPN and the DER aggregator?

RQ 2. To what extent can the proposed interface support maintaining DER operation within the technical envelope of the distribution network during times when network is highly utilised (peak solar PV periods), or during unplanned capacity constraints (e.g. network faults or system-wide contingencies)?

RQ 3. To what extent can the proposed interface allow distribution networks to host DER at higher levels of penetration by enabling dynamic, locational export limits compared to standard fixed per-customer export limits?

Visibility

RQ 4. To what extent can the proposed interface securely increase the visibility and management of DER to network service providers?

Economics

RQ 5. What are the costs of implementing the proposed dynamic network constraint management assessed against benefits obtained?

RQ 6. What additional economic value can be enabled to DER operators by dynamic network constraint management, through enabling higher utilisation of existing network capacity?

Customer impacts

RQ 7. To what extent might the proposed dynamic hosting capacity regime impact on customers and their take-up of demand management and third-party DER control?

RQ 8. What are the customer impacts, if any, of the dynamic network capacity management approach?

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