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Dynamic Operating Envelope Calculation Methodology

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Approver	Tim Lewsey Manager Grid Control	
If RPEQ Sign-off required insert details below.		
Certified Person Name and Position Title	Registration Number	
Alex Guinman Principal Grid Enablement Engineer	20068	

Abstract: This document outlines the philosophy used to calculate Dynamic Operating Envelopes (DOE) for customers on dynamic connection contracts.

Keywords: Dynamic Connection, DOE, Flexible Import Limits, Flexible Export Limits

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1 Overview

1.1 Purpose

This document provides a high-level overview of the philosophy used to determine how a Dynamic Operating Envelope (DOE) is calculated for a customer site. The actual implementation details may vary slightly to this philosophy in specific implementations of systems. For example, operators may change configuration settings from the defaults recommend in this document in response to specific network issues, or to trial future improvements to the philosophy.

It is intended as a guide to inform customers, installers and regulatory bodies about the methodology used when calculating DOE and the reasons behind this methodology. As described throughout the document, the specific methodology utilised for a particular customer site will vary depending on which part of the network they are connected to, and what data is available for that part of the network.

Dynamic Connections (sites that can receive and respond to a DOE) have been introduced to facilitate the two-way energy flows which are now prevalent on the network as part of the energy transition. Network capacity is finite, and dynamic connections provide a mechanism to utilise the available capacity more equitably in comparison to a continuation of fixed export and import limits - which essentially 'reserve' capacity on the network which may prevent successive connections from accessing available capacity. Subsequently, augmentation or paid flexible services would be required to accommodate more Distributed Energy Resources (DER)[1], would increase the costs to consumers overall.

1.2 Scope

Whilst the focus of this document is primarily LV connections, the philosophy has been designed such that it can also be applied to MV and HV connections. It is intended to be equally applicable to all customer connections, and inclusive of small residential connection to large business connections.

A DOE always applies to a connection point and not to any individual device or energy resource. Whilst a DOE applies to a connection point, for some examples in this document downstream energy resources that make up the connection point may be referred to.

[1] The terminology "DER" is referred to in this document, rather than the subset of small customer DER, often referred to as a Consumer Energy Resource (CER). As CER is a subset of DER, and this document is intended to also be inclusive of large connections, the more encompassing term DER has been used.

2 References

2.1 Controlled Documents

Document	Alternative Doc ID
SEP2 Client Handbook - 13436740	
Standard for Plant Rating Manual - 4179110	
Standard for Sub-transmission and Distribution Planning - 11539388	

3 Definitions and Abbreviations

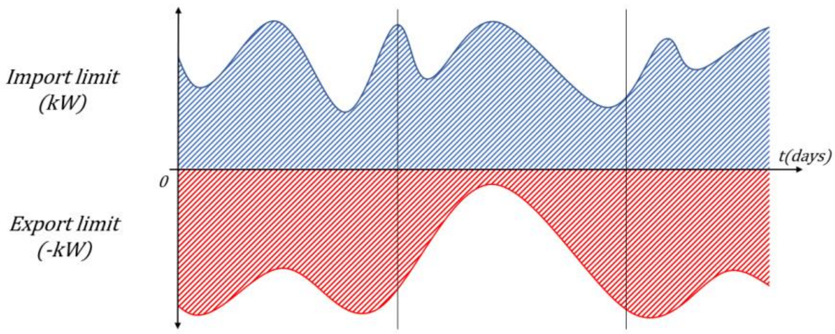
3.1 Abbreviations

BESS	Battery Energy Storage System
CSIP	Common Smart Inverter Profile
CSIP-AUS	Common Smart Inverter Profile Australia
DER	Distributed Energy Resource
DOE	Dynamic Operating Envelope
EMS	Energy Management System
EVSE	Electric Vehicle Supply Equipment
LFDI	Long Form Device Identifier
PV	Solar Photovoltaic
SEP2	Smart Energy Profile 2.0 (IEEE 2030.5)
ADMD	After Diversity Maximum Demand
LV	Low Voltage
MV	Medium Voltage
HV	High Voltage
CER	Consumer Energy Resources (a subset of DER)
NMI	National Metering Identifier
TNI	Transmission Node Identifier
SWER	Single Wire Earth Return
TMU	Target Maximum Utilisation
TTL	Time To Live
DSSE	Distribution System State Estimation
NRT	Near Real Time

4 Operating Envelopes

Operating envelopes are the limits within which an electricity customer can import and export to the electricity grid. These limits are agreed between networks, customers, and regulators as part of the customer connection or regulatory process. Historically, operating envelopes were mostly fixed at conservative levels regardless of the capacity of the network because they are static and need to account for 'worst case scenario' conditions.

Dynamic operating envelopes (DOE) allow import and export limits to vary over time and by location. Dynamic (or flexible) rather than fixed export limits can enable higher levels of energy exports from customers' solar and battery systems by allowing higher export limits when there is more hosting capacity on the local network at a point in time. Dynamic (or flexible) import limits allow customers to install significant additional loads to the network (such as EVSE and BESS) in such a way as they can avoid increasing peak demand and therefore avoiding (or at least deferring) unnecessary network augmentation.



Operating limits can be hard, soft or conditional as outlined in Table 1. Note the terms hard and soft may have a different meaning in other contexts or standards.

Table 1: Limit categories

Limit Category	Description	Application
Hard Limit	Must be met - causes the DER to trip off or cease generation / consumption	Solar PV Backstop (Generation Limit)
Soft Limit	Must be met - but can be done so by ramping power output/consumption.	Dynamic Operating Envelope (Export Limit)
Conditional Limit	Must be met by actively managed DER - but can be breached if done so by only unmanaged load. (i.e. household load is not required to respond)	Dynamic Operating Envelope (Import Limit)

4.1 Reference Location

It is important to note that DOE always applies to a connection point and not to any individual DER.

In practice, this means that a DOE is generally applied at a Network Metering Identifier (NMI) level. In theory, it could be applied at other connection points such as a Transmission Node Identifier (TNI).

DOE are limits and not controls – they set a range in which a connection point may operate within. An analogy is that a speed limit sets the maximum speed allowed - it doesn't instruct you to drive at that speed. They are designed to be agnostic to which devices operate in response to these limits and empower the customer to have choice about how their behind-the-meter assets should be managed, whilst still ensuring the network operates within safe limits.

5 Demand Management Hierarchy

Effective management of electricity demand relies on a coordinated suite of tools that work together to maintain the secure and reliable operation of the grid. Dynamic Operating Envelopes (DOEs) are one of these tools. They are part of a broader hierarchy of mechanisms designed to manage network constraints, optimise customer participation, and support secure and safe grid operation.

The following mechanisms in demand management hierarchy can be viewed as a progression from the most routine, customer driven mechanisms through to emergency actions used only when required.

1. Tariffs (Pricing)

Tariffs are the foundational tool for influencing customer behaviour. Time-varying or demand-based tariffs encourage customers to shift consumption and local generation to reduce strain on the network. Pricing mechanisms are widely deployed and represent the least intrusive approach to demand management, however, are not always effective at fully relieving constraints on peak days.

2. Operating Envelopes

Dynamic Operating Envelopes (DOEs) provide near real time and forecast export and import limits based on the operating conditions of the local network. They enable smarter integration of customer energy resources such as rooftop solar and behind the meter batteries, while ensuring the grid stays within technical limits. DOEs complement tariffs by providing a technical signal that reflects actual network capacity.

3. Flexibility Services

Flexibility services involve contracting customers or aggregators to adjust their demand or generation in response to grid needs. These services are typically procured to address specific constraints or maintain reliability and may include demand response, controlled load shifting or battery dispatch. They provide a targeted, market-based option when pricing signals and DOEs alone are insufficient.

4. Emergency Generation & Load Curtailment (Backstop)

When routine mechanisms cannot maintain system stability, the network may activate emergency generation or request short notice load curtailment from contracted participants. These backstop measures ensure the grid remains secure during extreme conditions or unexpected events but are used sparingly due to their impact.

5. Feeder Shedding

Feeder shedding is the last resort in the hierarchy. It involves disconnecting sections of the network to protect system integrity during severe overloads or overgeneration emergency situations. While highly effective at preventing broader outages, it is disruptive and therefore only used when all other tools are exhausted.

6 Connections

For every customer connection (generally defined per NMI) a contractual bound within which the DOE may be defined will be specified by the connection contract.

- The Minimum / Maximum Export Limit is the range for the allocated export limit.
- The Minimum / Maximum Import Limit is the range for the allocated import limit.

In addition to contractual limits, the geographical location and electrical connectivity will determine how a DOE is applied to a specific connection.

- The Management Point associated with a connection defines the network component that headroom should be allocated from (e.g. a distribution transformer for LV customers, and a distribution feeder for MV customers).

Note these conditions are considered with allocating export and import limits for both dynamic and non-dynamic connections.

For a customer with a static export limit, the minimum and maximum export limit are both specified as the static export limit as this limit does not vary.

For a customer with a static import limit, the minimum and maximum import limit would be defined by the service fuse size. However, for the purposes of achieving realistic allocations, a lower assumed static import limit may be desired to prevent over-allocating capacity to fixed customers above what they would realistically be likely to import. For residential customers, the assumed static import limit is recommended to be set to the After Diversity Maximum Demand (ADMD) for that customer instead of the service fuse limit.

7 Management Points

A management point is a point in the network for which it must be ensured that network constraints are not exceeded. In the context of DOE calculations, each connection must be associated to one of the following management points:

- Distribution Substation
- Distribution Feeder

Management points can also contain other management points. For example, a distribution feeder might include both MV connections, and distribution substation management points which themselves contain LV connections. In future, this calculation methodology may need to be expanded to consider management points for additional components such as:

- LV Feeder (circuit fuse)
- Recloser (Protection Zone)
- SWER Isolator
- Substation Power Transformers
- Sub-Transmission Feeder
- Interconnection Points with Transmission Network

7.1 Types of Constraints

Each management point will have a constraint (apparent power flow rating) specified in both the forward and reverse direction. When referenced throughout this document, the forward direction refers to power being supplied from the grid to customers, and the reverse direction refers to power being received from the grid from customers. Whilst generally symmetrical, there are instances where the constraint may vary depending on the power flow direction.

There are many factors that drive the maximum rating of a network component, and constraints can vary throughout the year based on weather conditions (especially for thermal constraints). Due to the nature of how DOE are communicated and the inherent time delay in a response, it is not desirable to push the network right up to the point where protection would operate, as this may result in unwanted trips of equipment if this target is overshot and cause unwanted outages.

As such, in the context of this DOE calculation methodology, the constraint or rating refers to the Target Maximum Utilisation (TMU) for the management point rather than the absolute maximum amount of power flow that a given part of the network can handle at any point in time. This allows for a small buffer for additional load should the DOE overshoot its target for a short period of time.

7.1.1 Voltage

In addition to power flow ratings, it may also be necessary to define voltage constraints, as these may sometimes be triggered before a thermal limit. It is important to note however, that voltages are not considered a core component of the DOE calculation methodology. The feedback loop for DOE is too slow to adequately respond to voltage fluctuations, and so they are considered a secondary constraint that are primarily managed outside of a DOE by faster acting solutions. Voltage issues at customer connections are primarily managed by network solutions (such as tap changers, voltage regulators or STATCOMs) and by autonomous functions in the inverter (volt-var and volt-watt response). Incorporating voltage constraints as a secondary mechanism will improve the headroom calculation where these voltage management solutions aren't available or are inadequate (such as older inverters, that do not support the voltage autonomous functions).

To incorporate voltage constraints into the methodology, voltage constraints should be converted to a power flow rating by derating the management point. This is achieved by applying a derating percentage if a voltage threshold is exceeded. These thresholds should be defined by four variables, V_1, V_2, V_3 and V_4, where X is the measured voltage.

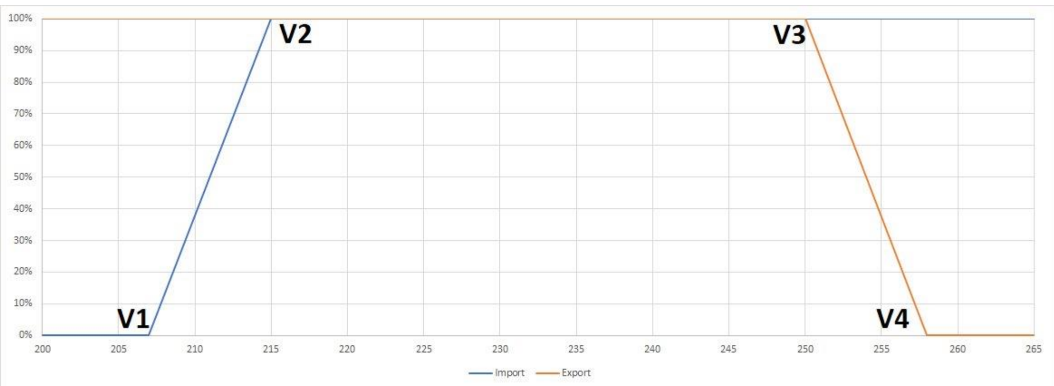


Figure 1: Voltage Threshold Example

Table 2: Voltage Threshold Calculations

Voltage of X	Rating Override (Forward)	Rating Override (Reverse)	Comments
$X < V_1$	0%	100%	Reduce rating to 0% in forward direction.
$V_1 \leq X \leq V_2$	$\frac{(X - V_1)}{(V_2 - V_1)}$	100%	Linearly reduce rating between V1 and V2 in forward direction.
$V_2 \leq X \leq V_3$	100%	100%	No voltage issue, constraint driven by power flow only
$V_3 \leq X \leq V_4$	100%	$\frac{(V_4 - X)}{(V_4 - V_3)}$	Linearly reduce rating between V3 and V4 in reverse direction.
$V_4 < X$	100%	0%	Reduce rating to 0% in reverse direction.

7.1.2 Power Constraint

A power constraint should be defined in the forward and reverse directions.

7.1.3 Upstream Constraint

If a management point is downstream of an upstream management point, a headroom constraint at the higher point of the network may cause the lower management point to be derated compared to its power rating.

7.1.4 Operator Constraint

At any time, operators may manually override the power constraint for a given management point. This constraint would be considered a higher priority and ignore any other constraints.

8 Constraints

In the below sections we outline some specific guidelines on how constraints will be set for specific management points.

It should also be noted that operators will have the ability to manually specify an override of the constraint for a particular part of the network, for a particular time range, based on the current operational needs of the network. The circumstances for which operators may wish to manually override a constraint is considered out-of-scope of this document.

8.1.1 Distribution Feeder

The feeder rating in the forward direction should be set to the Target Maximum Utilisation (TMU) of the feeder. The TMU varies with the category of feeder and is defined in Table 9-1 of the Standard for Sub-transmission and Distribution Planning [2]. For example, for an urban feeder has a TMU of 75% of the thermal rating.

Unless specified otherwise for a given feeder, the feeder rating in the reverse direction should be set to the same rating as the forward direction.

The voltage limits should be set as per below.

Table 3: Distribution Feeder Voltage Thresholds

	V1	V2	V3	V4
Head of Feeder	0.92 pu	0.95 pu	1.04 pu	1.07 pu

8.1.2 Distribution Substation

Distribution transformers generally have both a nameplate rating and a cyclic rating, with the cyclic rating generally set to above the nameplate rating. For this methodology, a distribution transformer will have the forward and reverse target power rating specified as the nameplate rating of the transformer.

The voltage limits should be set as per below. For distribution transformers, the voltage limits used will vary based on where the telemetry is sourced from.

Table 4: Distribution Transformer Voltage Thresholds

	V1	V2	V3	V4
Transformer LV Terminals	216	221	248	253
End of LV Line	207	215	250	258

It is important to note that it is expected autonomous power quality response functions of inverters would generally modify power output before these limits are triggered, and that they are only intended to act as an additional safeguard against situations where this may not have occurred. They may be set outside statutory voltage limits with the understanding that other mechanisms also exist to regulate voltage within these limits, prior to being restricted by DOE.

9 Telemetry

9.1 Control Loops

There are two separate control loops that run at different frequencies. These loops will by their nature have different sources of telemetry. When running control loops, it's important to consider the timing of when the calculations are made and how they align to a dispatch window. Dispatch windows should always be aligned to the top of the minute.

9.1.1 Forecast Loop

The forecast loop will generally run every 30 minutes. It should consider the forecast power flow at each management point in 30-minute intervals for up to 24 hours ahead.

9.1.2 Near Real Time (NRT) Loop

The NRT loop will run as frequently as every 5 minutes. It should consider the most recent available source of telemetry and apply this in 5-minute intervals for up to 30 minutes ahead.

All telemetry considered by the NRT loop should have a Time-To-Live (TTL) that discards readings as stale if they exceed this threshold. The TTL should be nominally set at 1,200 seconds (20 minutes) to allow for latency in readings and system processing times.

9.2 Telemetry Sources

We consider three sources of telemetry, listed by preference.

1. Measured
2. Synthetic
3. Fallback Profile

It should be noted that most sites do not have NRT measured or synthetic telemetry available currently. In most cases, the fallback profile will be used as the telemetry source.

9.2.1 Measured

The preferred source of telemetry is an actual measurement for that management point coming from the field.

In the context of a forecast, this would be a historical measurement at that management point being included as an input in the forecast calculation.

9.2.2 Synthetic

Where an actual measurement for a management point is not available, it may be possible to estimate a synthetic measurement based on other nearby measurements. For example, estimated distribution transformer loads and voltages calculated by Distribution System State Estimation (DSSE) or from data from downstream smart meters.

In the context of a forecast, this would represent synthetic data being used as an input in the forecast calculation.

9.2.3 Fallback Profile

Where measured or synthetic telemetry are not available (either for the NRT or Forecast calculations) the estimated load for a management point will be determined based on a seasonal load profile. Both forward and reverse power profiles are specified to allow for uncertainty and ensure that an appropriately conservative power estimate is determined. Only power flows are considered by a fallback profile, voltages are not considered in the fallback profile.

9.2.3.1 Daily Curves

For a given calendar day, a curve can be defined dictating how some metric should be scaled by its reference magnitude at each time interval of that day. Curves are normalised by the reference magnitude and so values at a given point in time will generally be between 0-1.

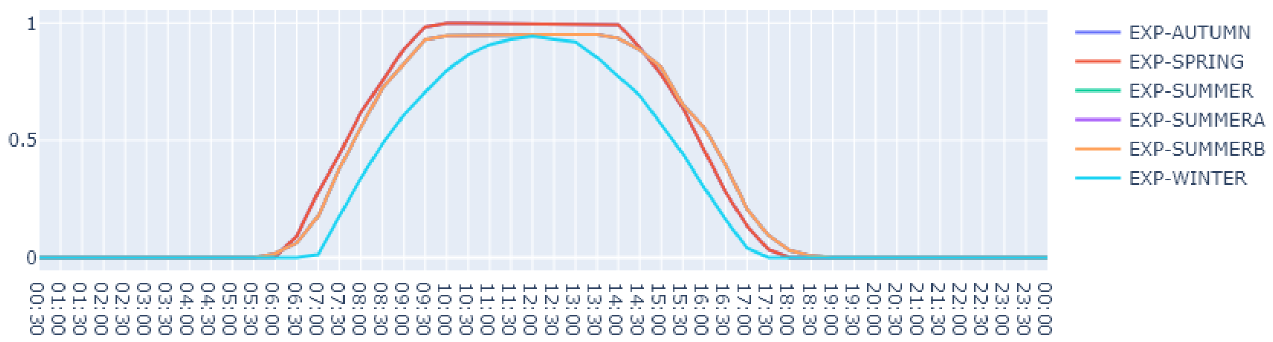


Figure 2: Example Export Curves

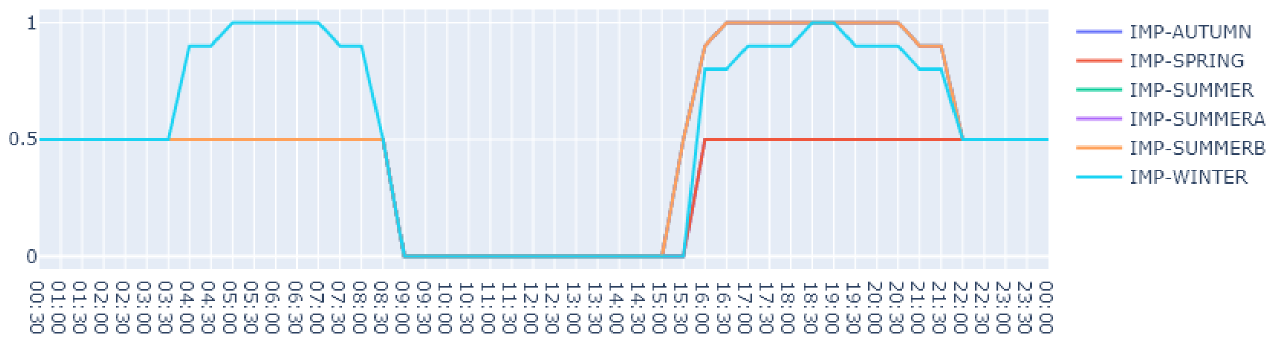


Figure 3: Example Import Curves

Curves can be as bespoke as having a separate curve for each management point, or as generic as a single curve that applies to all management points in a network. More information on how curves should be determined is covered in Annex A.

9.2.3.2 Yearly Profiles

A profile defines which curves should be applied on which days of the year. For example, a different curve might be applied by day of week (weekdays vs weekends) or varied by season.

9.2.3.3 Reference Magnitude

For each management point, and for each power flow direction (forward and reverse) a profile and reference magnitude are specified.

Table 5: Example of management point profile configuration

	Forward Direction (Imports)	Reverse Direction (Exports)
Magnitude	75.0 kW	-97.8 kW
Profile	9a485ba3-7a7f-dbe6-62ae-e9fe45beb68b	cd15dc47-3e26-d24e-e862-6887bc6de275

This allows the generation of a fallback profile for any calendar day to represent worst case power flows should synthetic or measured telemetry be unavailable.

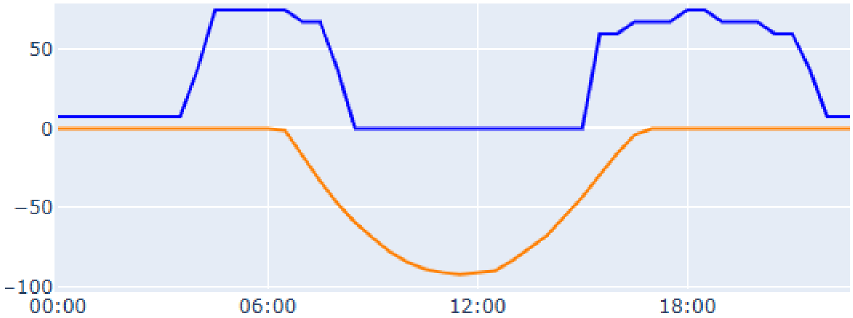


Figure 4: Example Transformer Fallback Profile

Typically, the fallback magnitude will represent the maximum and minimum historical demand for that management point.

For distribution feeders, the majority will have historical measurements of load available for calculating this magnitude.

For distribution transformers, the following options are available for determining the magnitude, depending on availability.

- Historical load measurements from network monitors
- Synthetic load measurements based on downstream smart meter data
- Assumptions based on installed DER capacity and customer counts
  - Load should be assumed based on the number and ADMD of customers
  - Generation should be estimated based on total approved export capacity

The magnitude should be reviewed at least yearly and include provisions for a margin to cater for future customer growth.

9.2.4 Phase Aggregation

Telemetry is considered on a three-phase basis, and not on a per-phase basis.

Where only single-phase measurements are available that should be converted to a three-phase equivalent.

10 Headroom (Allocatable Capacity)

The headroom (or hosting capacity) at a given management point represents the difference between the constraint and power flow at a point in time. A headroom value exists for both the forward and reverse direction. A positive value represents additional network capacity is available. A negative value represents that a constraint is being exceeded, and flexible resources are required to be adjusted.

An overallocation coefficient defines how much the headroom can exceed the constraint. It is not desirable to allocate beyond this coefficient in case of a sudden change to underlying power flows (such as a sudden change in cloud cover). The default overallocation coefficient should be 1.3 (130% of rating). This number may be increased in future once a better understanding of the risk of sudden power flows has been developed.

For example, if we have a transformer with a rating of 100 kVA in both the forward and reverse direction, and an overallocation coefficient of 1.3, the following headroom would be calculated for varying power flows.

Table 6: Example of headroom calculations for 100 kVA Transformer

Power Flow	Forward Headroom (raw magnitude)	Forward Headroom (overallocation)	Reverse Headroom (raw magnitude)	Reverse Headroom (overallocation)
200	-100	-100	300	130
100	0	0	200	130
50	50	50	150	130
0	100	100	100	100
-50	150	130	50	50
-100	200	130	0	0
-200	300	130	-100	-100

A headroom may additionally be impacted by a voltage constraint as previously outlined in Table 2.

11 Additional Headroom

A headroom may also be expressed as a change (or delta) of a previously issued headroom. Additional headroom may be impacted by ramping coefficients that apply to an increase or decrease in headroom relative to the rating or constraint of the management point.

Default values for these coefficients are specified in Table 7.

Table 7: Default ramping coefficient

	Forward	Reverse
Ramp Up Coefficient	0.2	0.2
Ramp Down Coefficient	0.4	0.4

An example of how additional headroom is calculated is provided in Table 8.

Table 8: Example of additional headroom calculations

Time	Forward Headroom	Previous Allocated Headroom (no ramping)	Additional Forward Headroom (no ramping)	Previous Allocated Headroom (ramping 20%)	Additional Forward Headroom (ramping 20%)
00:00	100	0	100	0	20
00:05	90	100	-10	20	20

00:10	95	90	5	40	20
00:15	100	95	5	60	20
00:20	98	100	-2	80	18

12 DOE Allocation

Headroom needs to be allocated to all connections associated with a given management point.

Allocations are calculated separately for the forward (import) and reverse (export) directions.

If allocating based on an "additional headroom" the previous issued allocation will need to be considered to determine the total headroom.

Some allocation methodologies of note are:

- Equal Waterline: This is the preferred allocation methodology and provides the most equitable distribution of allocations for customers.
- Proportional: This is the simplest allocation methodology to implement, but favours connections with larger system sizes.
- Optimal: These allocation methodologies use advanced optimisation techniques to maximise a defined system-level objective (such as renewable generation or network losses). Our trials of more advanced model-free and model-based DOEs have shown that objective functions that maximise exports can significantly increase aggregate allocations but can lead to higher curtailment for customers located towards the ends of the network. This reflects the innate trade-offs between efficiency and fairness highlighted in Project EDGE[2]. This is also the most data intensive, computationally complex DOE allocation methodology.

Equal Waterline is used for allocating headroom among customers that share a common distribution transformer. Proportional allocation will be used for allocating headroom between MV customers and downstream management points such as distribution transformers. This approach aligns with the AER's principles for capacity allocation[3], is simpler for customers to understand than more complex optimisation-based methods, is low cost to implement and provides equitable allocations based on local network constraints.

More advanced optimisation approaches may be introduced in future to further increase overall network hosting capacity. However, because optimisation can lead to less equal allocations - where some customers may experience higher curtailment to maximise aggregate hosting capacity - such methods should be paired with more granular price signals. These signals can help ensure customers who incur a greater share of curtailment are appropriately compensated, supporting both fairness and efficient utilisation of network capacity.

Regardless of allocation methodology (and whether the limits are for imports or exports), connections always start with their minimum limits on the first allocation iteration. This means that the total DOE

[2] Project EDGE - Fairness in DOE Objective Function FINAL

[3] Export limit guidance note | Australian Energy Regulator (AER)

allocated can exceed the available headroom target if the available headroom is less than the summated minimum limits. In these instances, the network may have been overprovisioned, and network augmentation may be required.

A visual example of these allocation methodologies is provided below. The starting conditions are shown in Figure 5, where all customers receive their minimum fixed limits regardless of the target. How the allocations are divided under the different methodologies is then shown in Figure 6, Figure 7, and Figure 8. For the optimal example, it was assumed a higher target capacity (22 kW instead of 20 kW) is available due to reducing the allocation for customers at the end of the line.

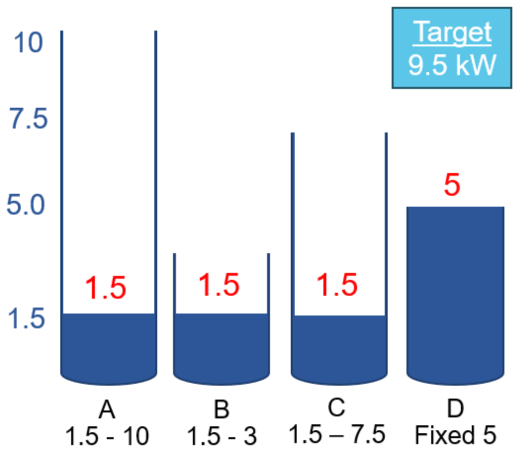


Figure 5: Example of starting conditions

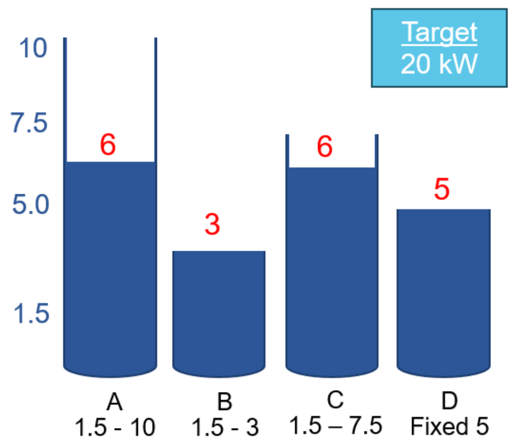


Figure 6: Example of Equal Waterline Allocation

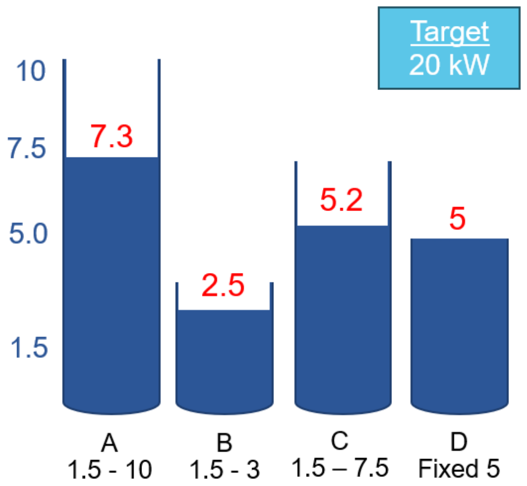


Figure 7: Example of Proportional Allocation

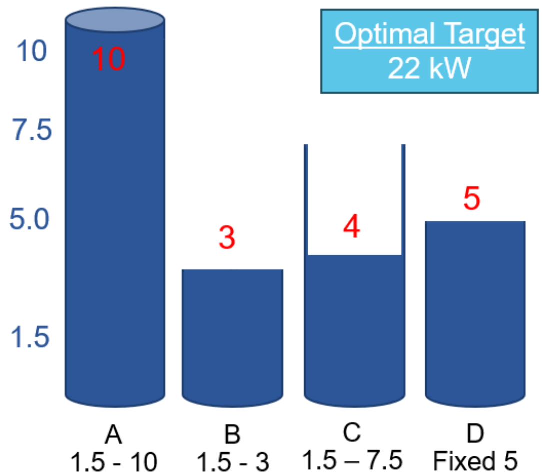


Figure 8: Example of Optimal Allocation

It should also be noted that, as with constraints, operators will have the ability to manually specify an override for a DOE of a customer to meet the current operational needs of the network. Unlike for autonomous operations, operators may be required to set limits below the minimum limit in emergency situations. The circumstances for which operators may wish to manually override a DOE is considered out-of-scope of this document (however, one example is the emergency backstop mechanism).

12.1 Equal Waterline Allocation Methodology

Equal allocation is performed by allocating all connections their minimum limit, then increasing capacity equally until all capacity is exhausted. Once a customer reaches their maximum limit, they do not continue to receive additional capacity.

12.2 Proportional Allocation Methodology

Proportional allocation is performed by allocating all connections their minimum limit. Connections are then allocated any additional capacity proportionally to how much additional capacity is available.

We can compare a proportional example where all customers get 68% of their maximum capacity (Figure 7). Compared to equal allocation (Figure 6), Customer A receives a greater allocation as they have a larger system, but B and C are smaller allocation using this methodology. As Customer D is a fixed connection, they are not impacted by allocation method.

12.3 Optimal Allocation Methodologies

Additional aggregate capacity could be allocated through methodologies that optimise using more advanced allocations methods. For example, if there is a voltage constraint, prioritising customers that are closer to the transformer and deprioritising customers further from the transformer may result in more total capacity being allocated (Figure 8). This introduces fairness and equitability concerns and so has not been considered further at this time.

13 Forecast Tapering

Forecast limits should taper (or decay) from the actual expected limit such that they trend towards the minimum limit at the end of the forecast period. This is to ensure that there is not a sudden change in response (across the fleet) because of a widespread communication outage when the forecast is exhausted (e.g. after 24 hours). Without tapering, such a communication outage could have a significant impact on system stability if a large number of customers are impacted.

Forecasts should be tapered linearly as per the below function:

$$y = y_1 + (y_2 - y_1)\,\frac{(x - x_1)}{(x_2 - x_1)}$$

Where x_1 is the hour to start tapering and x_2 is the hour to stop tapering.

Where y_1 is the value start applying tapering at and y_2 is the value to stop applying tapering at (these should be a number between 0 and 1).

Table 9: Forecasting Tapering Calculations

Hours in future (x)	Tapering Amount	Comments
$\boldsymbol{x_1 \geq x}$	$y = y_1$	Initially start at y_1 (e.g. 100%.)
$\boldsymbol{x_1 > x > x_2}$	$y = y_1 + (y_2 - y_1)\,\frac{(x - x_1)}{(x_2 - x_1)}$	Linearly taper between y_1 and y_2.

$x \geq x_2$	$y = 2$	Finish tapering at y_2 (e.g. 20%.)

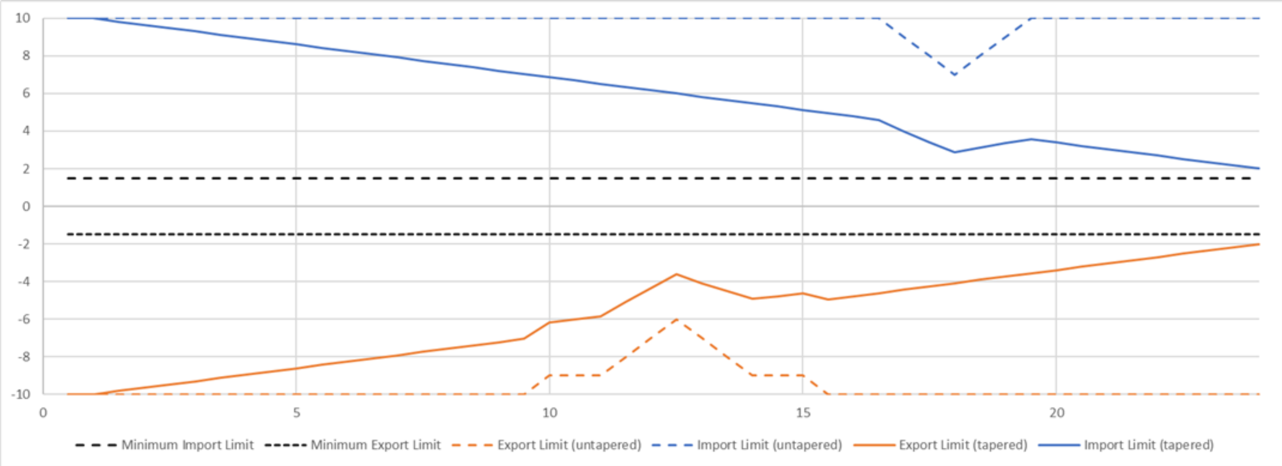


Figure 9: Example of forecast tapering

As the minimum import or export limit is generally above zero (e.g. 1.5 kW) it may not make sense to have the tapering fall all the way to zero percent at the end of the tapering period - as it would be set higher than zero due to the minimum threshold regardless - and cause the forecast to flatline at the default limit before the end of the forecast period.

Table 10: Default Tapering Configuration Values

Variable	Default	Comments
x_1	6.0	This should be adjusted based on the confidence of short-term forecasts.
x_2	24.0	This should be set to the maximum time forecasts are being dispatched into the future.
y_1	1.00	This will generally be set to 100%.
y_2	0.40	This should be set such that forecasts taper towards the fallback limit for most sites.

14 Dispatch Thresholds and Frequencies

14.1 Thresholds of Measurement

Small fluctuations in measurements could result in a small change in headroom calculations, and therefore the limits calculated for an individual site. To reduce unnecessary updates of forecast dispatches each time a headroom is calculated, it is recommended that limits are not republished as a new dispatch if they have only changed by a small amount.

To achieve this, all limits should be rounded to (at least) the nearest 100 W (0.1 kW) to remove updates to dispatches that aren't significant.

14.2 Interval Durations

Due to the way the communication protocol is implemented, all signals are inherently implemented as future scheduled events with a defined start and end time. As the start time gets closer to the current time, the forecast network state may become more accurate and previous scheduled events may be cancelled and new replacement events issued in their place.

Event intervals should always be aligned to the top of the minute, as shown in Table 11.

Table 11: Example of Event Intervals

Event Duration	Examples Intervals	Comments
30 s	00:00:00 – 00:00:30 00:00:30 – 00:01:00 00:01:00 – 00:01:30	Fast response times may be required for some use cases (such as isolated microgrids)
300 s (5 min)	00:00:00 – 00:05:00 00:05:00 – 00:10:00 00:10:00 – 00:15:00	Five minutes intervals are desired wherever possible to align with market settlement.
1800 s (30 min)	00:00:00 – 00:30:00 00:30:00 – 01:00:00 01:00:00 – 01:30:00	Forecasts beyond 1 hour in the future will generally be issued in 30 min intervals.

Best endeavours will be made to not cancel or supersede events that have already started or are scheduled to start within 30 seconds. In addition, best endeavours will be made to not create new events with a start time that is less than 30 seconds in the future. This means that there is generally a lag from when telemetry is received, to when that telemetry is factored into the envelope received by the site.

For example, if new NRT telemetry is received for a transformer at 10:13:20, the newly calculated headroom based on this telemetry would be dispatched for the next 5-minute interval at 10:15:00 – 10:20:00. If instead the NRT telemetry wasn't received until 10:14:45, because the next interval would be scheduled to start within 30 seconds, the new data would not be incorporated into the calculation until the dispatch at 10:20:00 – 10:25:00.

14.3 Calculation Loops

Due to the nature of how a DOE is calculated, the calculation of dispatches will generally be split into two separate calculation loops - a Near Real Time (NRT) Loop and Forecast Loop. Additional loops may also exist based on other factors (such as a manually triggered calculation triggered by operator intervention). End users will not have visibility of which loop was used to trigger an update to a specific event period. This implementation detail is provided for informational purposes only.

14.3.1 Forecast Loop

Sites will receive forecast scheduled limits at 30-minute durations for up to 12-24 hours in the future. Forecast limits may taper or decay from the actual expected limit such that they trend towards the default control at the end of the forecast period.

Forecast events scheduled to start within the next 60 minutes may be split into equivalent 5-minute events to simplify cancellations and conflict resolution for clients with NRT limits they may receive.

Even if the underlying telemetry forecasts have not changed, the forecast loop will generally run every 30 minutes so that the tapering function (outlined in Section 13) can be re-applied.

14.3.2 Near Real Time Loop

Where Near Real Time (NRT) visibility of the grid is available, sites will receive limits at 5-minute durations for up to 60 minutes into the future. Where these are available, and have changed compared to the forecast, these will supersede forecast limits. Events may be cancelled and re-issued by the server as network conditions change. As mentioned 14.2, there will be a lag to when these will be applied, new data is always applied to event intervals that are in the future.

Annex A

Informative

Determining Curves

To determine a curve, an ideal way to do this would be to look at measured data for indicative points on the networks. As not all management points will have historical measurements available, curves should be somewhat generic to cover a representative method to group similar management points.

Some ways that management points could be grouped:

- Climatic zones or regions
- System sizes (e.g. transformer rating, number of customers, installed DER)
- Customer types (e.g. the mix of residential or business customers)

The curves could be further split amongst a calendar year:

- Seasonal or monthly curves
- Curves by day of week (or weekday vs weekend)

Within a grouping, historical measurement data should be analysed to determine the worst-case indicative loading for the period of interest. One way to do this to calculate an import and export curve for a management point would be to determine the minimum and maximum value for each time period and then add a small buffer for future network growth. An example of this is demonstrated in Figure 10 and Figure 11.

The curves should then be normalised by their reference magnitudes, such that they can be applied to other similar management points within the grouping (with different reference magnitudes), as seen in Figure 12.

Figure 10: Ten example days for an indicative management point

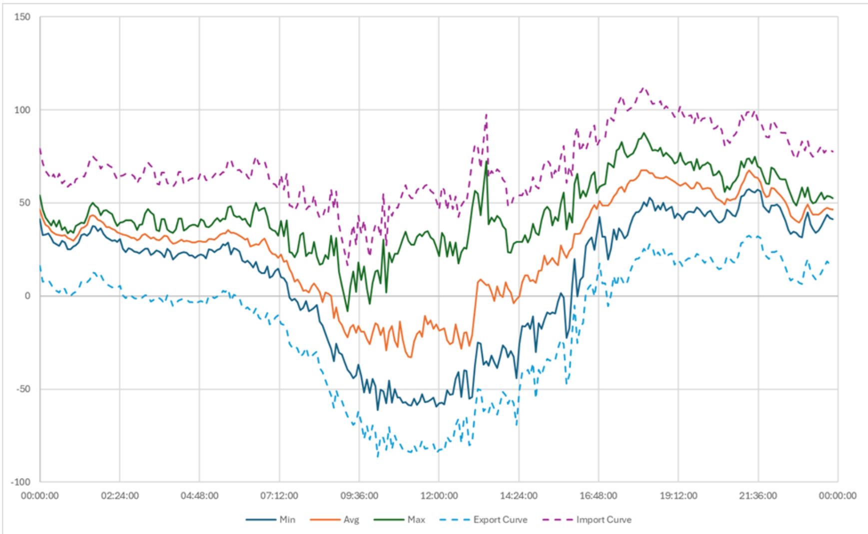


Figure 11: Statistical analysis of 10 example days

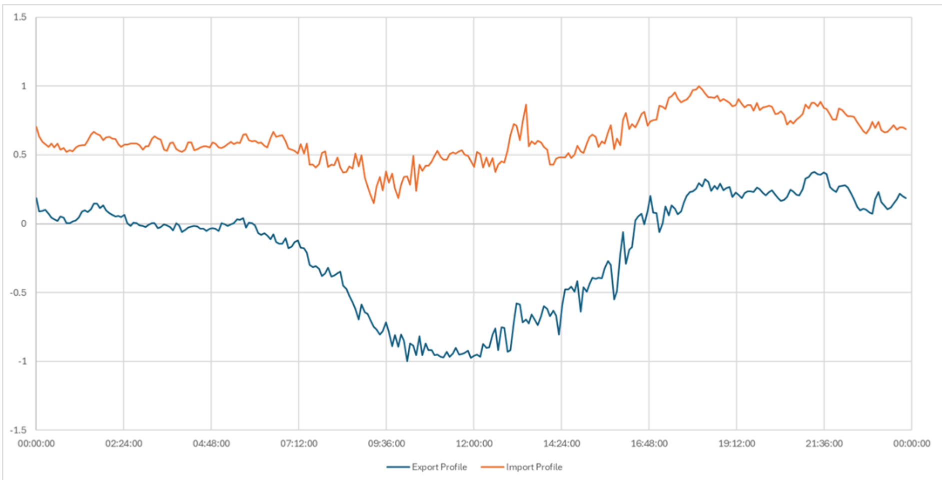


Figure 12: Normalised example curves

Annex B

Informative

Performance Monitoring

All program dispatches for a given day may include several conflicting events across overlapping time periods that need to be considered and resolved, as well as the fallback or default control if no dispatches are sent during an interval. As such, it is not economical to record the full historical history of all dispatch events for every program indefinitely and these should instead be resolved as consolidated limits.

To allow for historical performance reporting, the following metrics should be calculated and recorded for each dispatch program at the conclusion of each calendar day.

Table 12: Example of historical DOE Performance Metrics

Measure	Export Example	Import Example
Program	DOEPRG312XXXX123	DOEPRG312XXXX123
Mode	opModExpLimW	opModImpLimW
Date	2025-07-01	2025-07-01
MinLimit (W)	1500	1500
MaxLimit (W)	10000	18000
Total_Day (Wh)	119000	216000
Total_Night (Wh)	120000	214000
TimeBelowMax_Day (s)	900	0
TimeBelowMax_Night (s)	0	1800

When calculating these metrics, “Day” refers to 06:00 to 18:00 and “Night” refers to 00:00 to 06:00 and 18:00 to 00:00 in the AEST (UTC+10) time zone.

In addition to historical performance metrics, it is useful to simulate estimated future performance for all management points. This should be achieved by simulating what performance metrics would look like using the ‘fallback profile’ method for a hypothetical new customer connection on that management point. This would represent what a new customer connecting to this network would be likely to expect.