V2G Dynamic Headroom Control

Control Algorithm Definitions

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1. Introduction

This report describes the control algorithms to be considered in the simulation work for the Network Innovation Allowance V2G Dynamic Headroom project. It should be read in conjunction with deliverable 1.1 report (available upon request) that provides details about the project and specifies NGED sample areas of interest and the reasoning for their selection.

These algorithms will be explored in work package 1 of the project, where customer demand data will be synthesized, and in work package 2, where customer demands will be based on smart meter data.

This version of the document has been updated following the Control Algorithms Workshop held online on 12th December 2024.

2. Simulation modelling

The modelling would include up to 195 substations, as defined in deliverable 1.1 Site Selection Report. Some of these may need to be excluded from the modelling if the set of customers included in the smart meter data collection, as defined in the CROWN records, does not match well with the locations of customers and their assumed feeder connections.

The modelling work will use power-flow analysis software developed at Loughborough University to determine the voltages and currents within LV networks.

This software builds on validated power-flow analysis methods originally developed by Andrew Urquhart and Murray Thomson [1], [2], and significantly extended for work on the WPD Losses Investigation project and the WPD Parc Eirin Three-Phase Analysis project.

When operating in LV mode, each model represents a single LV feeder. Network data is imported from a National Grid Electric Office database, defining the geographic route of each LV feeder main underground cable or overhead wire, and the corresponding line code type. Cables and wires in the Electric Office database are each assigned a circuit identifier and the modelling software selected those corresponding to the selected LV feeder.

The modelling may also estimate the impact of voltage drops within the distribution transformer due to the combined LV feeder demand. This could either use an approximate method where the demands of individual feeders are combined to estimate the total voltage drop, or ideally in an integrated power-flow analysis where the impact of the transformer voltage drop is taken into account in calculating the voltages and currents within each LV feeder.

Some customer connections are also defined in the Electric Office database. These are also imported and included in the network model. However, the majority of customer connections are not defined in the network data and so additional service cable connections are synthesized. Customer locations for each Meter Point Administration Number (MPAN) are imported using data extracted from the National Grid CROWN database. A straight-line route is then determined from each customer location to the nearest point on the assigned LV feeder. Typically, this requires a new junction node to be inserted into the LV feeder main so that the service cable can be connected.

There is no information in the Electric Office network data to determine the phases of single-phase customer connections. Although phases are sometimes shown by graphical labelling on plotted network diagrams, the positions of the phase labels are not linked in the database to the corresponding cables. For the initial simulations, phases of single-phase customers are therefore assigned sequentially (L1, L2, L3, L1 etc). Later modelling work in Work Package 2 will determine the phases by applying phase identification methods based on smart meter voltage data.

Impedances for each network cable or wire are determined using the line code, as defined in the Electric Office database, and the length of the geographic cable route. The impedance per kilometre of each cable type uses data originally derived for the Losses Investigation project. There are many different line codes used within Electric Office, but only a limited number of cable types in the modelling library, and so missing codes have been manually assigned to known cable types that appear to be close approximations.

The models will create a time-series demand profile for each customer and then use power-flow analysis to calculate the voltages at each customer connection and the currents in each cable branch. This will require a number of assumptions to define the characteristics of the existing low carbon technologies (LCTs) as well as the behaviour of the V2G devices.

For each customer, a time-series demand profile is created, initially using Elexon profiles to represent the existing demand from conventional appliances, making an approximation that no additional LCTs have yet been installed. An appropriate profile is defined for each customer based on their profile class and estimated annual consumption (EAC) which is defined for each MPAN in the CROWN data extract. These models will use half-hourly time resolution, as in the Elexon profiles.

Additional demand data can then be added to represent the LCTs, including solar PV, electric vehicle charging, and heat pumps. Numbers of these appliances are defined by scenarios in the Distribution Future Energy Scenarios (DFES) [3]. These scenarios are defined for each local authority area, and will inevitably differ for each of the selected substations that are distributed across the four NGED regions. However, given that the scenarios already include a range of uncertainty, with results presented for four different uptake rates, it is assumed that data for one local authority area in each region can be selected and applied as an approximation throughout the region.

A detailed explanation of the methods used to model the solar PV, heat pump and EV charging demands is included in report section 7 of the report ‘Network Impacts of Three-phase Services’ produced by Loughborough University for NGED as part of the Parc Eirin Three-Phase Analysis project [4].

3. Export devices

Exports from V2G could be expected at 7 kW per phase, matching the import power of the EV charger.

Exports could also arise from domestic battery storage systems, likely to be limited to 3.68 kW per phase, as permitted under a G98 connection arrangement [5]. A V2G or domestic battery system installed under a G99 connection arrangement [6] could have a capacity up to 32 A per phase and be classed as a Small Generation Installation. This permits a total capacity of no more than 60 A per phase, taking account of other solar or storage systems that might also be connected. For aggregated registered capacities of greater than 16 A per phase, a G100 application is required, limiting the total exports to no more than 32 A per phase.

The number of active devices for V2G or battery storage system exports is hard to predict. For V2G this depends on the predicted number of installed EV chargers and the proportion of those having V2G capability, the proportion of those contracted to an aggregator taking part in the grid response service, and the proportion of customers with connected vehicles and with available capacity in their batteries.

Since all these factors are unknown, the proposed approach is to model the exports arising from either 25%, 50%, 75% or 100% of EV chargers. The number of EV chargers and battery storage systems can be modelled using estimates from the DFES.

4. Export scenarios

4.1 Grid support services

V2G operation in short-term power balancing appears to have the worst-case impact due to exports from the network perspective. In this scenario, multiple devices may export power under the coordinated control of an aggregator.

Similar behaviour could arise with exports from domestic battery storage systems.

Following the export event, it seems likely that there would be a re-charging period, not controlled by the aggregator, but where a worst-case scenario would be that all the discharging devices would be active. This may represent a worst-case impact for imports as the diversity factor could be lower than for EV charging under normal conditions.

4.2 Demand shifting and peak shaving

V2G exports could also occur in response to time-of use charging periods, for example where an EV battery was changed during the day from solar PV with power available for export in the evening when prices are higher. Assuming that the tariffs for export are likely to be lower than an import tariff, then it will be preferable for a home energy management system to offset demand from the home first, and then use any remaining power for exports. The system is also likely to retain energy for use within the home if there is a high probability that power will need to be imported before there is an opportunity to re-charge the battery using low-cost electricity.

It is possible to model this mode of operation, but any model will inevitably be subject to many assumptions. The statistics of demand and generation may be known on average, but the timing of exports from the home depends on the residual differences between the individual demand and generation profiles. These are not statistically independent as the home energy management will exploit interactions between them and aim to align demand with generation where possible.

This suggests that the availability of power for net export will be more stochastically variable than in the case of grid support services and will have a higher diversity factor.

For the purposes of this study, it is therefore proposed that the modelling will mostly consider the mode of operation for grid support services, as described in the section above.

4.3 Exports permitted by G100

It is possible that the installed capacity behind the meter will be greater than the permitted export capacity, subject to compliance with G100 [7]. This standard enables a vehicle-to-home (V2H) mode of operation, provided that an export limiting system prevents exports greater than an agreed limit. G100 defines that the permitted export capacity is the lower of three thresholds, determined by thermal, protection and voltage constraints.

For domestic connections, the thermal constraint is determined by the fuse rating and so can assumed to be higher than the installed EV charger or BESS capacity.

The protection constraint is 25% above the higher of either an agreed import capacity or the agreed export capacity. The agreed import capacity is again determined by the fuse rating and so is unlikely to be a constraint for domestic customers.

The voltage constraint is determined by the DNO and is expected to indicate a level of export power that will give no more than 255.3 V at the customer point of connection, given minimum demand and maximum exports elsewhere on the LV feeder. This limit will therefore reduce for new customers once other customer are connected.

An increased power capacity behind the meter will not affect V2G or BESS exports but the constraints may reduce the permitted export capacity below the rating of the device.

The control mechanisms investigated in this project may allow the voltage and protection constraints to be alleviated as the limits can be more accurately targeted to the actual demand and generation rather than being bound by a worst-case minimum demand and maximum generation.

5. Real-time control methods

5.1 Volt-var control

The CANVAS project, UNSW Syndey[1], defines power control profiles used in Australian networks as follows:

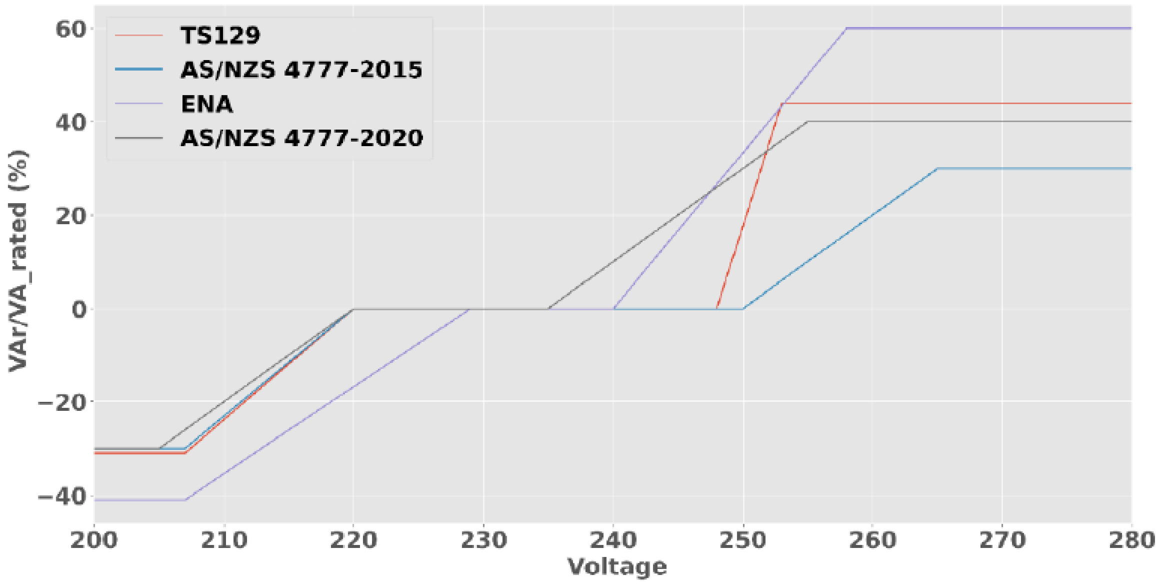

Figure 1: Volt-var control profile (CANVAS, UNSW Syndey)

In Figure 1 above, AS/NZS are Australian standards, and ENA refers to Energy Networks Australia (rather than UK). The TS129 standard [8] is the most recent and so these ramp profile parameters are proposed for use in this project.

The voltage control profile mandate is designed to address both low and high voltages and so mandates that reactive power is exported when voltages are low and imported when voltages are high.

It is assumed that the inverter is rated in kVA to allow for maximum export or import of active power. When reactive power is non-zero, the maximum possible active power flow is therefore reduced accordingly.

It is possible that reactive power from V2G inverters alone will not be sufficient to mitigate the voltage rise. However, the benefits may be greater if other appliances, for example EV chargers that do not currently have an EV connected, can participate in providing reactive power. The project will test this by determining whether the additional consumption of reactive power can reduce voltages back within acceptable limits.

The volt-var mode of operation is currently inconsistent with G98 connection requirements [5] where section 9.5.1 states “When operating at Registered Capacity the Micro-generator shall operate at a power factor within the range 0.95 lagging to 0.95 leading relative to the voltage waveform unless otherwise agreed with the DNO eg for power factor improvement.”

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[1] https://www.ceem.unsw.edu.au/sites/default/files/documents/CANVAS-Succinct-Final-Report_11.11.21.pdf

5.2 Volt-watt control

Figure 2 below shows a typical control curve for active power. An implementation of this for SA Power Networks in South Australia ramps from 100% of rated power at 253 V down to 20% of rated power at 260 V [8], [9]. However, inverters should disconnect if the voltage at the customer point of connection is over 258 V for minutes, or over 265 V for one second. The power curve range between 258 and 260 V should therefore not normally occur.

In the UK, appliances have over-voltage disconnection thresholds of 262.2 V, and an under-voltage disconnection threshold of 184 V, so any ramped control should reach zero by these limits. This functionality is defined in G98 section 10.1.3 [5] and in G99 section 10.6 [6]. These standards also require that appliances should not modulate power based on voltage within these limits. Clearly this is conflicts with the aims of volt-watt control and so it is assumed here that standards can be adapted to allow the technique to be utilised. This project will therefore investigate the potential benefits of volt-watt control, such that options to enable these through standards can be explored if the technique appears promising.

A further concern arises where EV chargers are installed at houses with TN-C-S wiring. If an open-circuit fault arises in the combined neutral and earth conductor between the house and the nearest grounding electrode, the car body will then be raised to the same potential as the live conductor. Since this car is outside of the PME grounding zone, there will be a dangerous potential between the car body and the physical earth. To mitigate this risk, and as an alternative to installing additional earth electrodes, the EV charger can implement a broken neutral detection system where the charger is disconnected if there is an under-voltage below 207 V or over-voltage above 253 V between live and neutral conductors. Since G98/G99 require appliances to remain operational up to the higher disconnection limit of 262.2 V, the use of broken neutral protection has so far prohibited vehicle-to-grid operation in NGED standard technique SD5G [10].

G99 highlights the concern around loss of generation at low voltages. In the event of a grid-scale drop in voltage, EV chargers with broken neutral detection and operating in a V2G mode would disconnect at the higher threshold of 207 V rather than remaining operational down to 184 V. The presence of V2G exports would therefore exacerbate the situation, as these would then need to be replaced by other generation at a time of network stress. The present block on V2G operation with broken neutral protection therefore seems understandable.

It is understood that revisions to standards are in progress to harmonise the disconnection thresholds such that V2G operation will be permissible in combination with broken neutral protection.

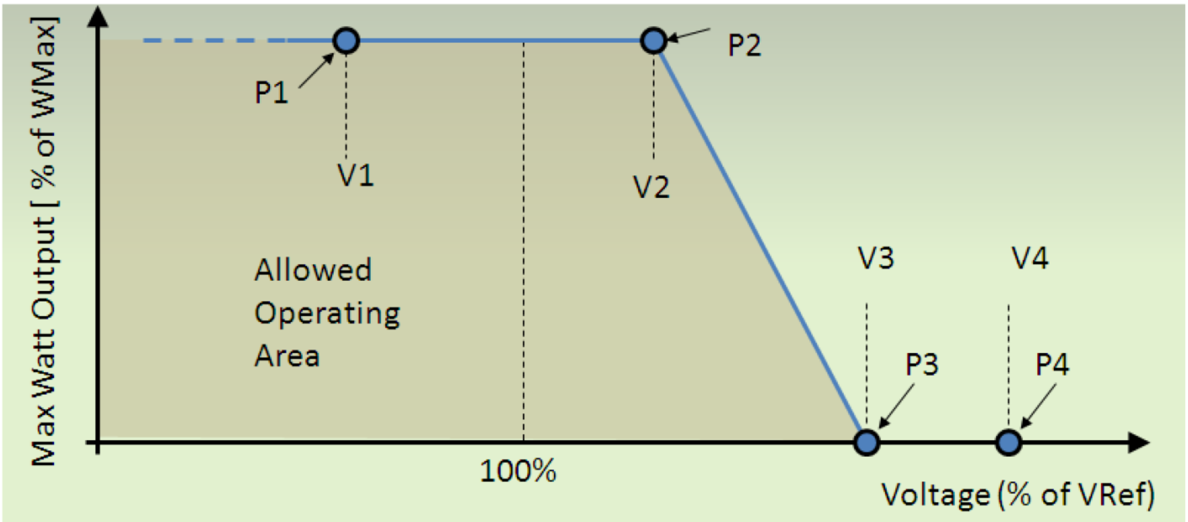

Figure 2: Volt-watt control profile (EPRI) [11]

5.3 Distribution substation on-load tap changers

There is interest in determining how distribution substation on-load tap changers (OLTC) could provide an alternative means of resolving over-voltage concerns.

Distribution OLTC could either

i) Obviate the need for inverter-based control schemes at customer appliances
ii) Work in conjunction with inverter-based control schemes at customer appliances, in which case any interactions between the two would need to be understood.

It is also possible that a fixed change to tap settings could resolve over-voltage concerns, but with the penalty of a reduced margin for voltage drops.

Simple simulation models would assume a constant voltage at the distribution substation LV busbar. This is effectively equivalent to a model with an idealised OLTC operation such that no variations from higher voltage levels are apparent on the LV feeders.

Work package 2 should make use of realistic voltage profiles to represent substation busbar voltages in the absence of OLTC operation so that full range of voltage variation can be included in the model.

Work package 1 will use a simpler assumption that either a voltage range, or an idealised constant voltage can be maintained at the substation busbar.

6. Modelling scenarios

Table 1 below outlines a list of scenarios for the analysis and simulation work.

For simplicity, exports are described here in terms of V2G, but could instead be from battery storage systems.

As a general approach, the modelling will find a level of growth of LCT connections that causes an export power constraint to be reached. V2G operation is then added, expecting that this will cause the constraint to be exceeded. A range of control methods is then tested to determine whether, these can mitigate the constraints, or to what extent, and to evaluate the corresponding loss of exports.

It is assumed that the control algorithms defined here would mostly be applied to new V2G devices. Existing generators would therefore continue operating without being affected.

An alternative approach is to assume that all generating devices are subject to the same control methods. This will allow the available capacity to be shared more equally, but is obviously a longer-term solution as it is difficult to retrospectively implement new standards on installations that already exist.

The proposed approach would be to assume that any existing devices with permitted exports would continue to operate without change, with the control methods applied to any additional battery storage or V2G devices that have a higher export capacity.

Table 1 – Proposed simulation scenarios

Scenario	**Comments**
Existing demand With no additional LCTs other than those already connected Without V2G	Assesses whether any voltage or thermal constraints have already been reached
Future LCT demand LCT growth added according to DFES predictions, taken to a future date where the first export constraint occurs Without V2G	Allow multiple possible future date scenarios to be reduced to a single year, derived individually for each feeder, where a constraint occurs. It is possible that no constraint will occur on some feeders for the foreseeable future.
As above, with V2G	Export constraints exceeded
Fixed V2G export limit per customer	As in G98, 3.68 kW
Locally customised V2G export limit per customer	Customised per substation or feeder
Seasonally customised V2G export limit per customer	Assuming that exports need less control outside of summer period
Temporally customised V2G export limit	Limits set based on time of day
Volt-var control profile All devices following defined profile Various frequencies of update are possible, e.g. seasonally, monthly, weekly	Volt-var control profile, parameters customised per LV feeder
	Volt-var control profile, parameters customised per LV feeder and phase
	Volt-var control profile, parameters customised for time of day
	Volt-var control profile, parameters customised per LV feeder and for time of day
Volt-watt control profile All devices following defined profile	Volt-var control profile, parameters customised per LV feeder
	Volt-var control profile, parameters customised per LV feeder and phase
	Volt-var control profile, parameters customised for time of day
	Volt-var control profile, parameters customised per LV feeder and for time of day

7. References

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