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South West England Network Analysis

Project: Cornwall Local Energy Market

Authors: Calum Edmunds, Simon Gill

Date: 17/08/17

Executive Summary: The report presents initial analysis of the electricity network in SW England including calculation of Locational Marginal Prices (LMPs) and the flow of power under three generation and demand cases and in two years: 2017 and 2020. The 400 kV and 132 kV networks in Cornwall and Devon are modelled along with a 33kV network from the Rame Bulk Supply Point. The report includes case studies of minimum/maximum demand and high/low distributed generation (DG) output representative of 2017 and a potential 2020 scenario. Analysis of constraints, line loading, voltage and LMPs is carried out for each case. Studies are conducted assuming an illustrative GB-wider wholesale price of electricity of £50/MWh. Key results show that where network constraints are not binding, LMPs can vary from £56.10/MWh in the cases of high import to £40.20/MWh in cases of high exports. Where constraints are binding and are caused by large availability of zero marginal cost renewable generation, the LMPs will drop to £0/MWh behind those constraints.

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1 Introduction

1.1 Project overview

The aim of this report is to present the results and analysis of the modelling of the 400 kV and 132 kV network in the south west of England (Figure 1) along with a 33 kV network (Rame) in order to understand the potential variation in Locational Marginal Prices (LMPs) and identify work that could be done to understand their use in a future Cornwall local electricity market. Any references in this report made to the South West network refer to the network show in Figure 1. AC Optimal Power Flow (OPF) was carried out using Matpower[1] with model inputs taken from the National Grid Electricity Ten Year Statement (ETYS) [2] for the 400 kV network and Western Power Distribution (WPD) Long Term Development Statement (LTDS) [3] for the 132 kV network and below.

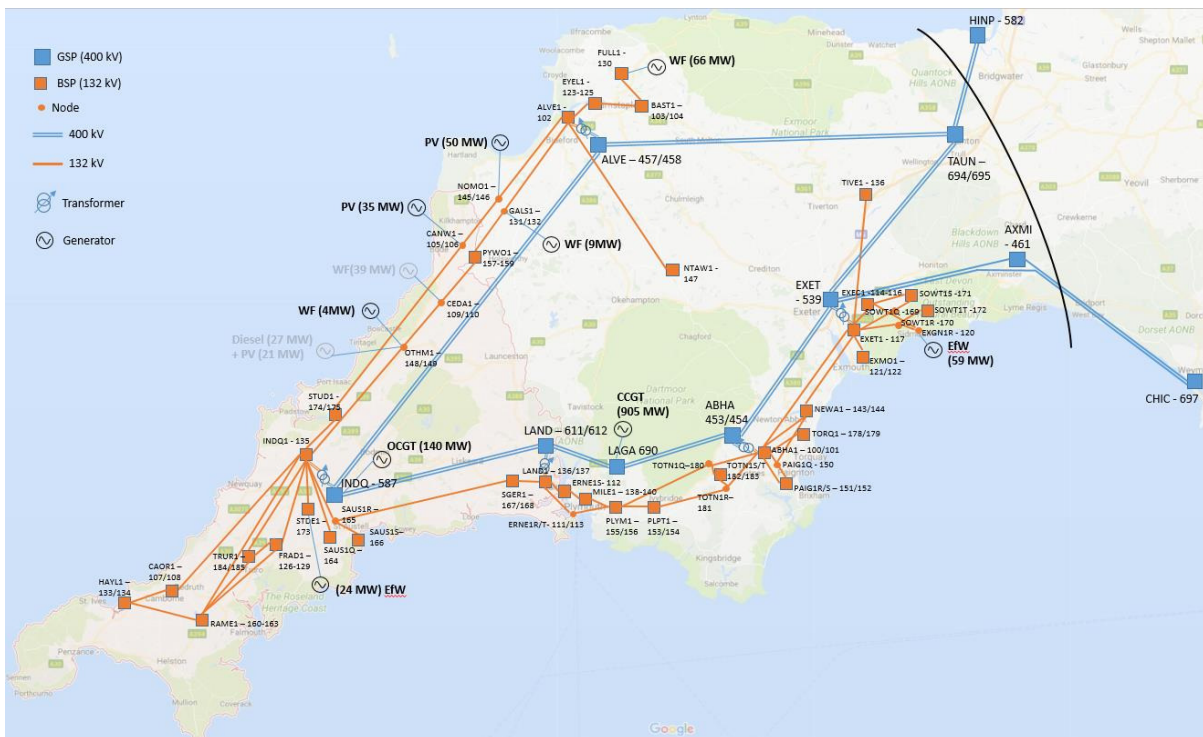


Figure 1 – SW England 400kV and 132 kV transmission network (from ETYS and LTDS). NOTE: Grid import is modelled from Hinkley Point and Chickerell. These points will provide import/export to meet system demand.

The Rame 33kV network connects to the 132kV network at the node RAME1 seen towards the bottom left hand corner in Figure 1. Figure 2 shows a schematic of this 33kV network.

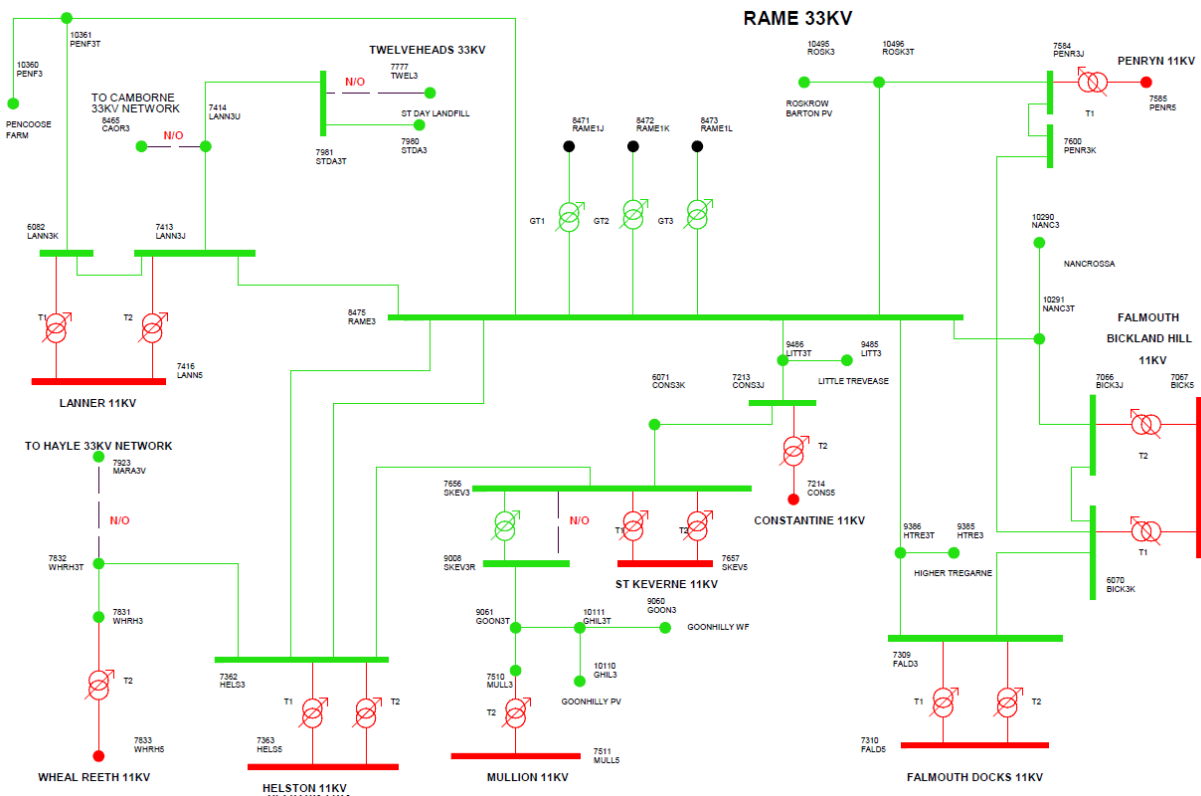


Figure 2 - Rame 33 kV network[3].

1.2 Summary of the methodology and objectives

The studies carried out for this report make use of Matpower’s AC OPF function. This carries out an optimisation of dispatchable generation against an objective function, which in these studies represents the short run marginal cost of generation. Demand is modelled as fixed power (real and reactive power demand are independent of voltage). Two transmission connected power stations are included (Indian Queens and Langage), and in the appropriate cases the OPF is able to dispatch these as part of the optimisation. As the network modelled is a small section of the GB power system, pseudo generators at Hinckley Point and Chickerell are used to represent both import and export from the wider system; export from the SW appears as negative output from these pseudo generators. The costs associated with these generators represents the wider GB wholesale price of electricity, which under competitive conditions should approach the short run marginal cost of production across GB.

As an AC optimisation, the model includes representation of magnitudes and angles of all electrical parameters and produces results which include voltage magnitudes and angles, real and reactive power flows, electrical losses, as well as LMPs (see section 1.3).

Key objectives of this study

The following is a list of the major objectives that this study has achieved:

- Develop a representative and working model of the SW peninsula 400kV transmission network and 132kV distribution network in Cornwall and Devon and one example of a 33 kV distribution network.
- Develop an understanding of the electricity network in the region and how it is operated making use of publicly available information.

- Carry out OPF studies of the system under several case studies representing likely demand and generation conditions in the area in 2017 and 2020.
- Calculate LMPs for the cases studied and illustrate how these vary across the network, in particular showing variations due to electrical losses and variations due to power system constraints.

Limitations of the studies in this report

As an initial study, this report does not cover the wider range of details, sensitivities and peculiarities of the SW peninsula network. In addition Matpower has a number of limitation that preclude the modelling of some features of the system which may be useful for more detailed future studies. We list some of these key issues here, and discuss some solutions to them in Section 3.

- **Optimisation of transformer tap settings:** Matpower does not include tap settings in its set of control variables, therefore it cannot model accurately the operation of On Load Tap Changers (OLTCs) either for traditional control schemes such as the targeting of a specified voltage at the lower voltage bus bar, or more active technical such as wide-area voltage optimisation. However, in these studies the settings have been adjusted manually where appropriate to give a voltage profile which follows expected operational practice reasonably closely.
- **Reactive power dispatch:** The SW peninsula transmission network includes groups of reactive power equipment at Abham, Alverdiscott, Exeter, Landulph and Indian Queens. These have not been included in this study as sensible voltage profiles and results were achieved without them. Future work would involve confirming the installed and operational capacities, and any advice on how and when these devices would be used on their own and in combination with the reactive power capabilities of generators.
- **Only modelling an intact network:** In these studies only an intact network has been modelled. Requirements on both the distribution and transmission operators to operate a system that is secure against certain events such as fault outages means that power flows in this intact system are unlikely to be limiting. Control systems such as Active Network Management and other aspects of a future smart grid will allow generation capacity to be installed which can exceed the limits of an intact system. The effect is shown in our 'Generation curtailment' case. For future work we would reduce network capacities can be simulated by modelling the network with particular outages, and in section 3 we discuss the possibility of using a security constrained OPF.

1.3 Locational Marginal Pricing

The GB system currently does not make use of LMPs in the design of its electricity market, however their use in pricing of electricity in a number of other systems, particularly in North America, is common. The principle is that the cost of electrical energy at any one node of a network represents the short-run marginal cost of serving demand at that location. A good approximation is to consider the additional cost across the whole system that would be incurred if demand at that node rises by 1MW. LMPs are dependent on a number of factors: firstly the cost of generation at the marginal power station; secondly the marginal change in network losses; and finally the impact of network congestion which may, for example, make it infeasible to use the marginal generator on the system to meet that demand, and more expensive 'out of merit' generation must be used instead.

OPF tools such as those provided in Matpower set up a mathematical programming problem (either linear if a DC approximation or similar is used; or non-linear if the AC power flow equations are

used). One output of these optimisations is the shadow-price of each constraint. The LMPs are the shadow-price on the energy balance constraint applied at each node. The work presented here makes use of the LMPs output by Matpower.

1.4 Generation

The model includes individual generators connected directly to the transmission network [2] and the 132kV distribution network [3]. It also includes aggregated generation by type (wind, solar, and other) for each 132 kV BSP derived from the LTDS [3] and UK government statistics on Feed-in-Tariff (FIT) installations [4]. The 2017 cases take their values directly from the ‘connected’ and ‘operational’ figures in these publications, and are listed in Table 1.

The LTDS shows 408 MW of generation (> 1MW) at 132 kV and below listed as ‘committed’ meaning that the developers have accepted connection agreements with WPD; this has been added to the 2017 case to give the estimate of connected generation in 2020. Finally a 2020 ‘Generation Constrained’ case has been developed specifically to illustrate the potential impact of generation constraints on LMPs. This adds a further 582 MW of generation capacity to the network at 132 kV and below.

At the Rame BSP, distributed generators are connected at the correct 33kV bus bar or for generators connected at lower voltage levels at the relevant primary substations. The generation connected to this network is currently 56.8 MW from the LTDS (used in the 2017 cases) with an additional 8.8 MW committed generation (added to create the 2020 cases). The reverse capacity of the three Rame 132/33 kV transformers is quoted as 3 x 36.6 MVA in the LTDS¹. In the 2020 generation constrained case, there is an additional 148 MW of generation at Rame which is above the total reverse power flow capacity of the 3 transformers (109.5 MW). This will show the effect of constraint on Locational Marginal Prices (LMPs) in the Rame 33 kV network.

Table 1 – Installed generation capacity at each voltage level

Connected (kV)	Total generation(MW) ²		Of which PV		Of which Wind	
	2016/17	2020/21	2016/17	2020/21	2016/17	2020/21
400	1,045	1,045	0	0	0	0
132 ³	247	409	85	119	79	119
<132 (>1 MW) ³	1,108	1,354	726	858	149	157
<132 (Domestic) ⁴	169	203	166	200	2.7	2.2
Total	2,569	3,011	977	1,177	231	279

¹ On the WPD website [14] the reverse flow for the Rame BSP is given as 36.6 MVA suggesting that this area of the network is planned to N-2 security. The peak demand at Rame is of a size that requires the ability to restore some demand in the case of a fault outage, on top of a maintenance outage (See Class of Supply: D; Engineering Recommendation P2/6 [11]). Further Understanding of how the DNO manages the requirements of P2/6 through redundancy, movement of normally open points etc. would be required to ensure future modelling fully captures WPD operational procedures.

² Total includes other generation at 132 kV and below which includes Energy from Waste, Biomass etc.

³ 2020/2021 Generation at 132 kV and < 132 kV (>1 MW) assumed to be sum of ‘Connected’ + ‘Committed’ generation from LTDS. Future work could be to look at dates of connection using Renewable planning database.

⁴ <132 kV (Domestic) from Feed-in-Tariff (FIT) data [4]. 2020/21 domestic generation assumed to be 20% increase from 2016/17 (Note: In National Grids Future Energy Scenarios 2017 [22], sub 1MW solar installation grows by between 14% and 35% across the whole of GB between 2016 and 2020).

1.4.1 Generation costs

The studies in this report use a generic system price of £50/MWh to represent the cost of electricity imported from the wider GB system. This is applied at the connection points between the network section modelled and the wider GB system and are at Hinkley Point and Chickerell (see Figure 1). The costs of the 400kV connected Open Cycle Gas Turbine (OCGT) and Closed Cycle Gas Turbine (CCGT) plants are set at £150/MWh and £50/MWh respectively. The short run cost of renewables generation is negligible and are modelled in as £0/MWh. Note that curtailment of renewable generation occurs for transmission contracted generation through the balancing mechanism where generators bid to reduce their output. A number of larger wind farms elsewhere in GB participate in this and bid in with a negative price - that is they require payment from the System Operator (SO) for reducing their output. The bid prices reflect the value of the Renewable Obligation Certificates (ROCs) which are renewable subsidies paid per MWh of generated electricity. It may be appropriate in further work to include this through a negative short run marginal price for renewables.

1.5 Demand

Based on data for each GSP given in the ETYS, the peak demand for the region is approximately 1.7 GW (2016/17) and is forecasted to rise to 1.75 GW in 2020/21. Information from the LTDS broadly agrees and the sum of peak demand across all primary substations is 1.81 GW in 2016/17 rising to 1.86 GW in 2020/21. The difference between the ETYS and LTDS peak demand figures may arise from the fact that peak demands at different substations may not be co-incident.

In the work conducted for this report, peak demand is assumed to be the values quoted in the LTDS for each primary substation. Minimum demand is assumed to be 50% of peak. This is an estimated value which approximately matches the historical GB-wide difference between peak and minimum prior to the growth of distributed generation. Demands are aggregated from primary substations and allocated to BSPs except in the case of Taunton and Axminster GSPs where the GSP peak demands from the ETYS are used⁵.

Whilst time series data for the flow of power from transmission to distribution at each GSP and at half hour resolution is available [5], it is difficult to interpret this to identify the true minimum of underlying demand. This is because the GSP power flows will be the net effect of underlying demand minus distributed generation. In this study, distributed generation is being explicitly modelled down to the domestic micro scale, therefore simply using the minimum of the GSP flows for the region risks double counting the output of those generators. Understanding the true demand profile and distributed generation output for the region will require further work; a short discussion of this is included in Appendix D.

⁵ 132kV networks attached to Taunton and Axminster are not modelled as these are not interconnected to the rest of the 132kV network in the SW.

1.6 Case Studies

The following cases have been modelled:

- **Case A – import to the SW:** Maximum import in to the SW peninsula assuming peak 2017 demand plus zero output from all SW generation.
- **Case B – export from the SW:** Maximum export from the SW peninsula assuming low 2017 and 2020 demand plus high output from SW generation at all voltage levels.
- **Case C – generation constrained:** A ‘stretch’ case for 2020 with greater increases in DG capacity.

Details on all the model inputs and assumptions used in building the Matpower model are given in Appendix A. A list of bus codes from the LTDS and assigned numbers in the Matpower model is given in Appendix B. The full name of each bus can be found in the LTDS [3] (Attachment 8).

Case A – Maximum Import: Peak demand and no generation

This case provides a feel for the loading and flows in the network at maximum import from the grid:

- **Demands** are set to the peak values for 2016/17 and 2020/21 from the LTDS.
- **Transmission connected generators** are modelled as unavailable
- **Distributed generators** are also switched off.

Therefore all demand is supplied from the grid connections at Hinkley point and Chickerell which are at an assumed supply cost of £50/MWh.

Case B – Maximum Export: Minimum demand and high distributed generation.

This case provides a feel for the loading and flows in the network at maximum export to the grid:

- **Demands** are set to 50% of the peak values for 2016/17 and 2020/21 from the LTDS.
- **Transmission connected generators** are modelled as available up-to their full capacity. Langage CCGT is modelled as ‘must run’ and Indian Queens OCGT is left for the OPF to dispatch (although due to its high marginal cost is unlikely to be turned on).
- **Distributed generators** at 132 kV and below are all set to have a maximum output of 80% of their installed capacity. This accounts for outages of conventional plant, and the likely maximum output of a fleet of diverse small scale renewables.

The 0 marginal cost renewable generation will be preferentially dispatched over the OCGT generation in the 400kV network.

Case C – Maximum Export and constrained generation

This case illustrates the effect of generation within the Rame 33kV network exceeding the reverse power flow capacity of the BSP transformers:

- **Demands** are set to 50% of the peak values for 2016/17 and 2020/21 from the LTDS.
- **Transmission connected generators** are as for Case B
- **Distributed generators** are set with maximum available generation of 80% of installed capacity as for Case B, but with installed capacity increased by 582MW including 148MW at Rame.

2 Results

2.1 Case A:2017 – Maximum Import: Peak demand and no distributed generation

A summary of results of OPF for the 2017 maximum import case is shown in Table 4.

Table 2 - Case A:2017 results summary

	Total	400 kV	132 kV	Rame 33kV
Available Generation (MW)	0	0	0	0
Demand (MW)	1846	290 ⁶	1482	73.6
Import from grid (MW)	1873	-	-	-
Max line loading (%)	-	24	67	56
Max transformer loading (%) ⁷	-	59	57	-
Losses (MW)	27.4	15	11.3	1.1
Min/max Voltage (kV)	-	395.5/408.0	129.6/137.3	32.1/33.3
Min/max LMP's (£/MWh)	-	50.0/51.1	50.4/53.5	52.8/56.1

2.1.1 Line loading/power flows

The network modelled represents a fully intact transmission and 132kV distribution system; the power flow results are shown in Figure 3 and Figure 4. The lines are loaded at up to 24% of the continuous MVA rating for the 400 kV lines and 67% for the 132 kV network. Transformers between the 400 kV and 132kV networks are loaded up to 59% (the highest is at Exeter). In the Rame 33kV network, with all components in service, lines are below 56% loaded and the transformers are loaded up to 57% between the 132kV and 33kV networks at the Rame BSP.

Total system losses are 27.4 MW of active power which is approximately 1.5% of total demand. 11.3 MW of losses occur on the distribution system and 15 MW on the transmission system (including the 400/132 kV transformers). There is a loss of 1.1 MW on the 33kV Rame network which is 1.5% of the local demand⁸.

Power flows in the 400 kV ring are from East to West whilst in the parallel 132 kV ring tend to flow away from the electrically closest GSP.

2.1.2 Voltage/reactive power

The voltage optimisation options available to the OPF in this case are minimal. As all generation is turned off, there are no sources of reactive power⁹. The real and reactive dispatch at the supply points is set so as to maximise the magnitude of the voltage profile within the allowed limits as this minimises losses. Matpower does not allow optimisation of transformer tap settings, therefore a trial-and-error approach was used to identify suitable tap-settings on the 400/132kV and 132/33kV transformers which give a voltage range in line with the WPD operating strategy discussed in the LTDS[3].

⁶ This 400 kV demand is for the Taunton and Axminster GSPs which have not been modelled down to lower voltages as the 132kV networks in these locations are not meshed to the other 132kV sections.

⁷ 400kV includes 400/132kV Transformers and 132kV includes 132/33kV Rame Transformers.

⁸ Note that further losses would be expected on the other 33kV networks and on the 11kV and LV networks which are not modelled in this study.

⁹ Whilst there are reactive power devices at several transmission busses these are not modelled. Sensible results were achieved without including these devices, and as limited information on how they would be used is available, they were left out at this stage.

As shown in Figure 3 (page 12) the OPF sets the transmission bus voltage to 408 kV at Chickerell. This is 2% above the nominal voltage and was chosen as the maximum level at 400kV and 33kV voltage levels for the optimisation¹⁰. These voltages drop slightly out to the extremity of the 400kV network at Indian Queens. Voltages are up to 137.3 kV on the 132kV network downstream of the GSP transformers. The upper limit at 132kV is set at 4% above nominal voltage in the import case to agree with the target voltage of between 136kV and 138kV stated in the WPD LTDS part 2 [3] (see [3] section 4.7, Operating Voltages). Voltages are between 32.1 and 33.3 kV in the Rame 33kV network which is close to the target voltage of 33.6kV for all 33kV networks in the SW stated in the LTDS.

2.1.3 LMPs

The LMPs in Figure 5 and Figure 6 show variations driven by network losses between the points of connection to the wider GB network and each individual bus. On the 400kV and 132kV networks the LMPs vary between £50/MWh at the grid connection points up to £53.5/MWh at the most distant BSPs (Camborne and Hayle) in the south west. In this case there are no constraints therefore the variation in LMPs are due to losses alone. The LMPs for the Rame 33kV network rise to £56.1/MWh at the furthest points from the BSPs (e.g. Goonhilly) due to higher losses at lower voltages. This shows that when there is no DG generating and the Rame network is importing power, losses would result in LMPs more than 10% above wholesale prices calculated to sell power at 400kV at Hinkley Point or Chickerell.

2.2 Case A:2020 – Maximum Import: Peak demand and no distributed generation

There is little difference in results between 2017 and 2020 for Case A due to the small increase of 43 MW of demand having little impact on line loadings and LMPs. The graphical outputs for 2020 are shown in Appendix E (page 36) and the summary of results is below;

Table 3 – Case A:2020 Results summary

	Total	400 kV	132 kV	Rame 33kV
Available Generation (MW)	0	0	0	0
Demand (MW)	1889	301	1514	74.6
Import from grid (MW)	1918	-	-	-
Max line loading (%)	-	25	69	57
Max transformer loading (%)	-	61	58	-
Losses (MW)	28.5	15.7	11.7	1.2
Min/max Voltage (kV)	-	395.4/408	129.3/137.3	31.9/33.2
Min/Max LMP's (£/MWh)	-	50/51.1	50.4/53.5	52.9/56.3

¹⁰ Statutory voltage limits for transmission are set in the SQSS, Chapter 6 [10]. These are between +5% and -10% of nominal for the 400kV system; 2% was chosen for this study to provide some voltage headroom for variations further up the transmission system. The voltage limits at 33kV and 132kV are chosen to be representative of operating policies of GB DNOs.

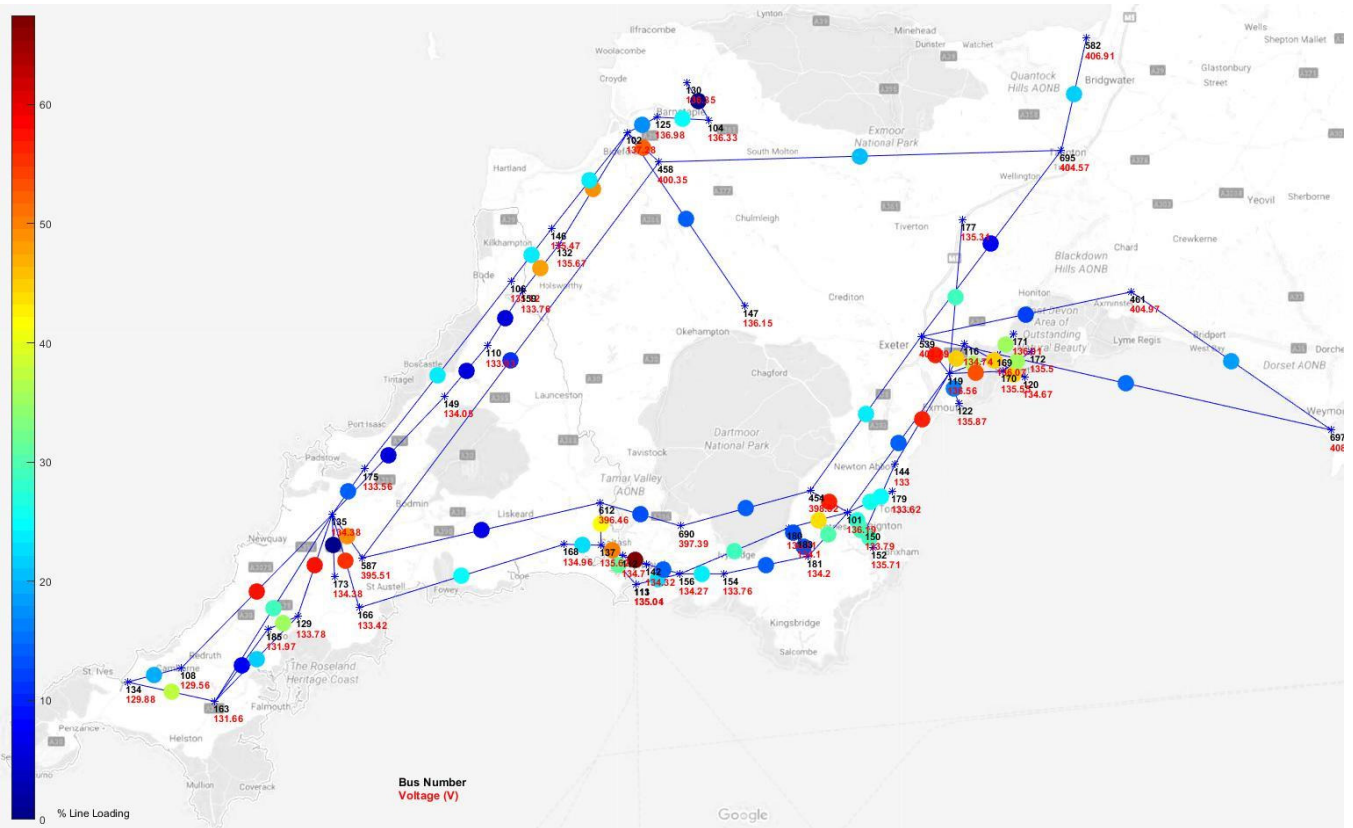


Figure 3 - Case A:2017 (No generation and peak Demand) Line loadings and voltages

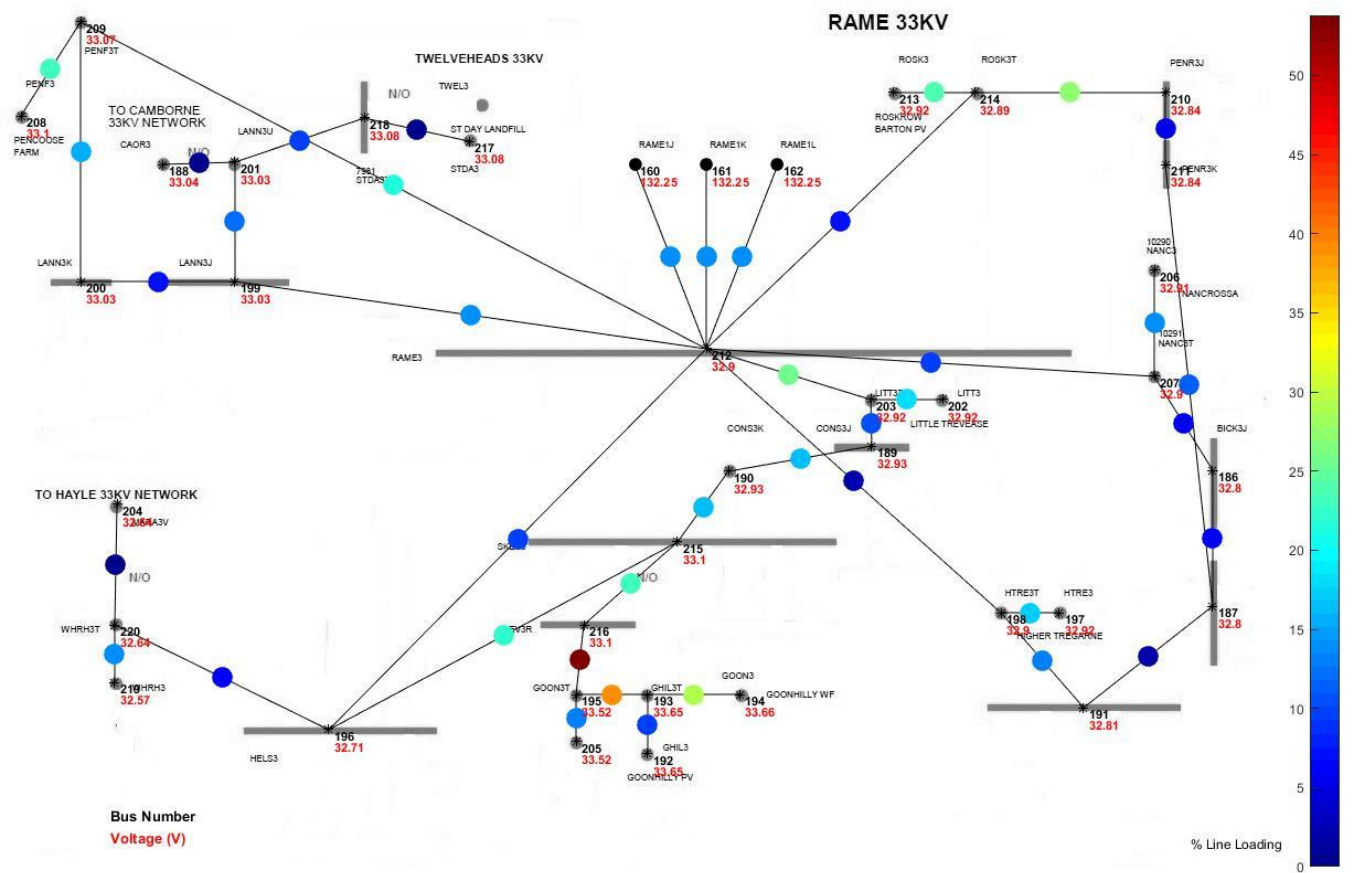


Figure 4 Case A:2017 (No generation and peak Demand) Rame 33 kV line loadings and voltages

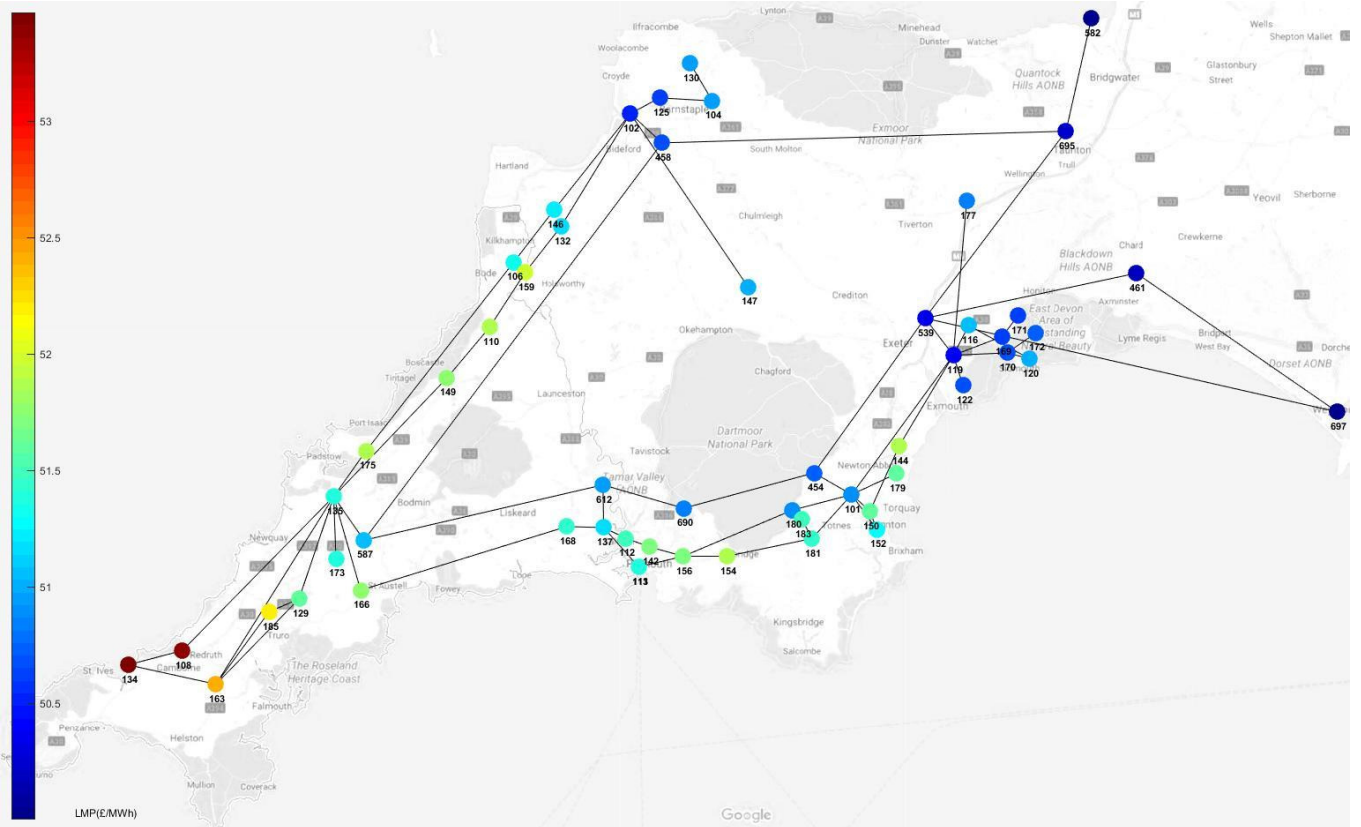


Figure 5: Case A:2017 (No generation and peak demand) Transmission and 132kV LMPs

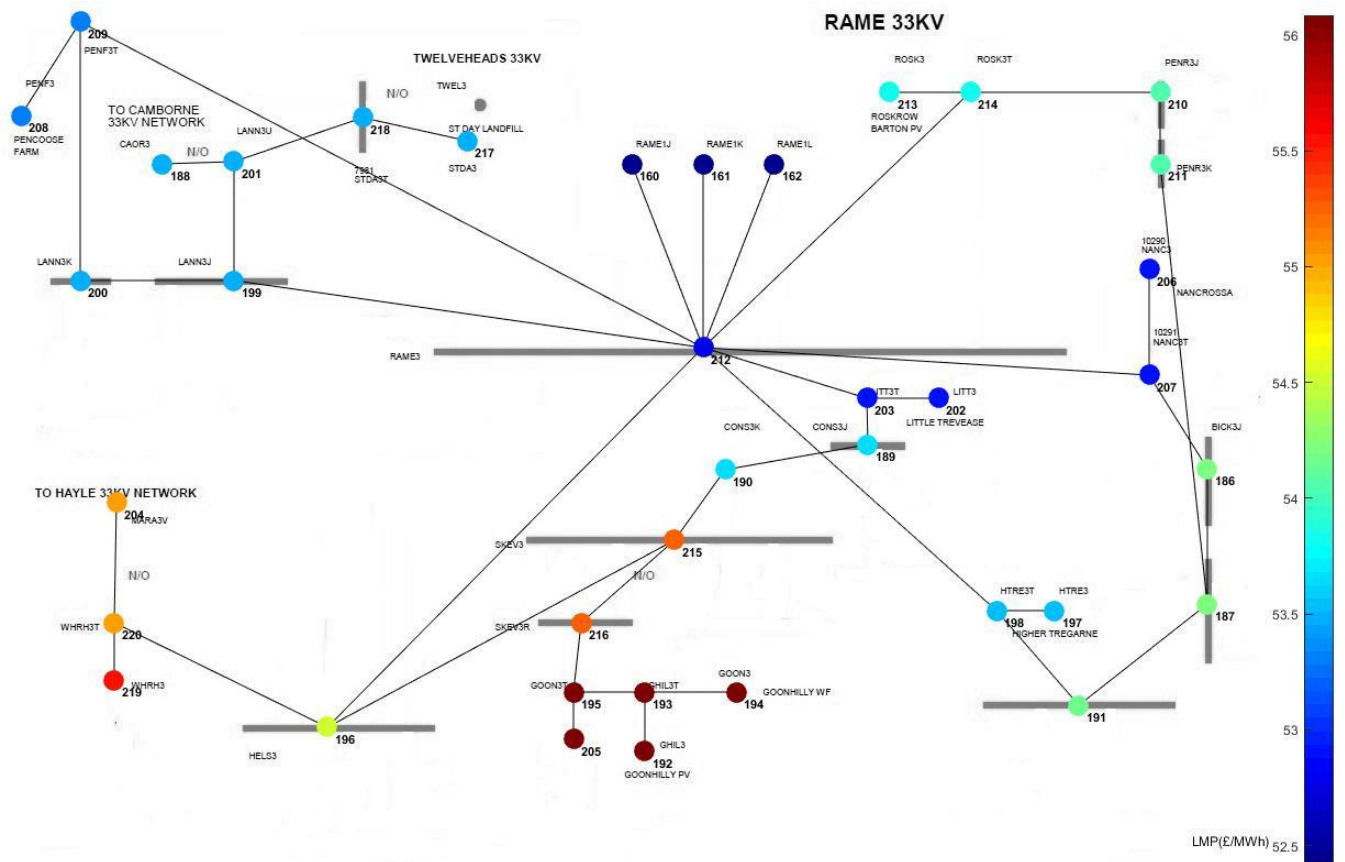


Figure 6: Case A:2017 (No generation and peak demand) Rame 33kV LMPs.

2.3 Case B:2017 – Maximum Export: Minimum demand and high distributed generation

A summary of results of OPF for the 2017 maximum export case is shown in Table 4:

Table 4 - Case B:2017 results summary

	Total	400 kV	132 kV	Rame 33kV
Available Generation (MW) ¹¹	2263	1045	1167	51
Dispatched Generation (MW)	2123	905	1167	51
Demand (MW)	923	145	741	36.8
Export to grid (MW)	1185	-	-	-
Max line loading (%)	-	30	57	54
Max transformer loading (%)	-	40	14	-
Losses (MW)	15.9	11.3	4.2	0.4
Min/Max Voltage (kV)	-	401.3/405.5	130.4/134.3	32.6/33.66
Min/Max LMP's (£/MWh)	-	49.1/50.0	47.9/50.0	42.2/48.9

2.3.1 Line loading/power flows

Available generation includes 905 MW at the transmission connected CCGT station at Langage which is modelled as must-run for this scenario¹². The OCGT at Indian Queens is not dispatched by the OPF due having a significantly higher marginal cost of £150/MWh than the grid supply cost of £50/MWh. There is 1218 MW distributed generation available, representing 80% of installed capacity, which is all dispatched by the OPF due to its zero cost. Therefore the SW peninsula exports 1185 MW to the wider GB system.

The power flow results for this case are shown in Figure 7 and Figure 8. The most highly loaded branch is between Barnstaple BSP and East Yelland BSP which is 57% loaded. This branch exports 63 MW which is the difference between 14 MW demand at Barnstaple, 24 MW generation aggregated to Barnstaple and 53 MW generation from Fullabrook wind farm. The line between the Fullabrook windfarm and Barnstaple is the next most highly loaded 132kV line at 44%.

Transmission line loadings are up to 30% with GSP transformers loaded up to 40%. Total system losses are 15.9 MW of active power which is around 0.75% of total generation. The Rame 33kV lines are mostly loaded below 50% except the 54% loaded branch 195->216 which is exporting 13 MW generation from Goonhilly wind farm and PV minus the local demand of 2.4 MW from Mullion 11kV (assigned to bus 205). The Rame BSP transformers are loaded at up to 14%. Losses in the Rame network are 0.4 MW which is 0.8% of the total Rame export. 0.14 MW of these losses occur in the branch between bus 195 and 216 due to the high resistance and relatively high power flow between Goonhilly and St Keverine. This results in a large differential in LMP between 195 and 216 as discussed below.

Power flows in the 400 kV ring are from West to East except between Langage and Indian Queens where some flow is directed west from the CCGT at Langage. At the GSPs reverse power flow occurs from 132kV to 400kV except Abham and Landulph.

¹¹ Available generation is based on full capacity for 400kV connected generation and 80% of capacity for generation connected at 132kV and below.

¹² In the absence of specific network constraints, dispatch of this plant under current GB market arrangements will depend on the situation across GB rather than specific conditions in the SW peninsula

2.3.2 Voltage/reactive power

Voltages range between 401.3 kV and 405.5 kV on the transmission system with the highest voltage at Indian Queens and lowest at the grid supply points (Chickerell and Hinkley C). Voltages at 132 kV level are between 130.4 kV and 134.3 kV, highest at the points with most DG (e.g. Canworthy) and lowest around Exeter where there is less DG. The same is seen in the Rame 33kV network where the highest voltages (33.66 kV) are seen at the Goonhilly wind and PV farms.

The optimisation has the ability to dispatch reactive power from the two transmission connected generators in this case. Distributed generation have been constrained to operate at unity power factor, but both the OCGT and CCGT can be dispatched in the range 0.95 leading to 0.85 lagging. The output of this case shows that Langage is dispatched to absorb 104 MVAR reactive power, equivalent to a power factor of 0.993 leading.

The reactive power limits are set to mirror existing practice: DNOs generally mandate a fixed power factor for the operation of distributed generation, often unity, therefore requiring close to zero reactive power interchange between the generator and the network. However, this operational practice is likely to change. For example in [6] Western Power note that any target power factor between 0.95 leading and lagging may be set for new connections, and these generators must be capable of operating across this range. For transmission connected generators, the grid code stipulates that generators should be capable of being dispatched by the SO to between 0.95 leading to 0.85 lagging [7].

2.3.3 LMPs

The LMPs for 400kV and 132kV shown in Figure 9 (page 17) vary between £50/MWh at the grid connection points down to £47.9/MWh at buses with high DG output and no load (Canworthy and Northmoor PV farms). There are no constraints therefore the variation in LMPs are due to line losses alone. Price variation of down to -4.2% show that even for maximum export to the grid, the effect of DGs on price at 132kV and 400kV is limited. However it is interesting to note that these areas that are most expensive in the import case (Case A) such as Camborne, Hayle and Pyworthy, become among the cheapest when all DGs are generating. The biggest swing is at Hayle where a 9% variation is seen in LMP between importing and exporting.

At 33kV (Figure 10, page 17) LMPs as low as £42.2/MWh are seen at Goonhilly wind farm which shows that if an additional 1 MWh load was supplied at this bus, the grid supply price of £50/MWh could be discounted by 16%. This discount accounts for the fact that these generators are exporting power which is not being used by local demands and therefore exported back up the system. Increasing local demand would reduce losses rather than transmitting the power to loads further away. The biggest swing in LMPs from import to export is seen for the Goonhilly WF and PV buses which vary by 25% between the two cases. In terms of load buses the biggest swing in LMPs is seen at St Keverine which varies by 17% from the import to export cases. Flexible loads and storage could respond to these large variations in LMP. Further time series studies could consider the effect of DG output and demand on LMPs and the ability of flexible loads at business/commercial and domestic level to respond to these changes.

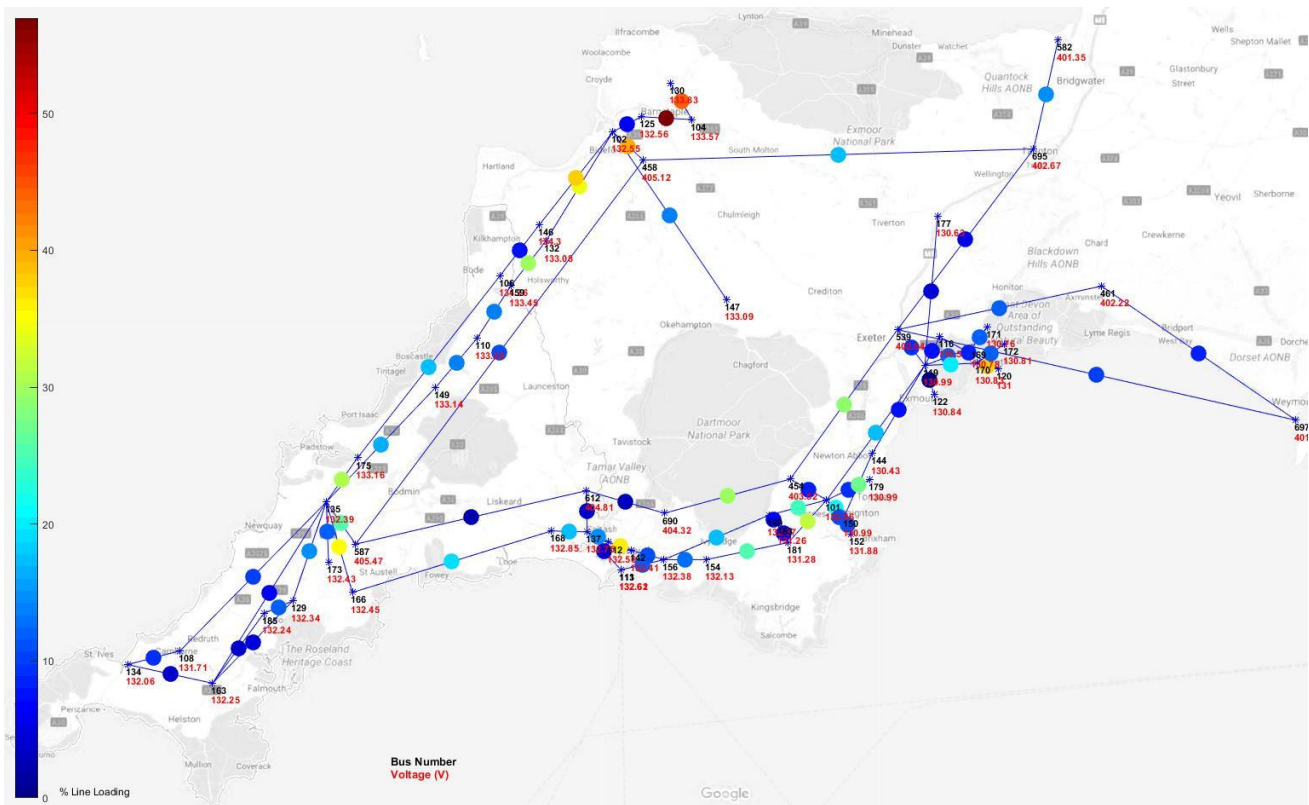


Figure 7 - Case B:2017 Line loadings and voltages for 400kV and 132kV networks.

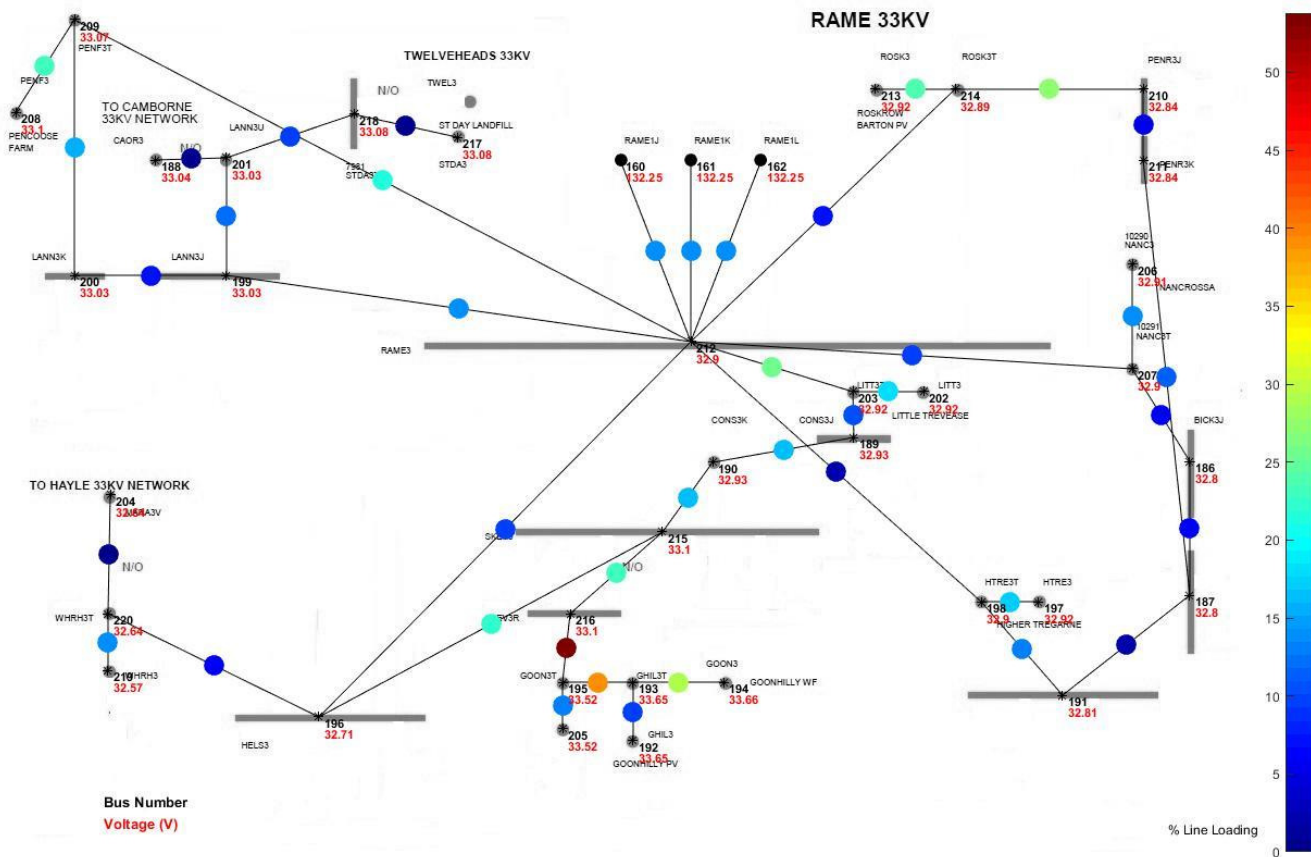


Figure 8 - Case B:2017 Line loadings and voltages for Rame 33 kV.

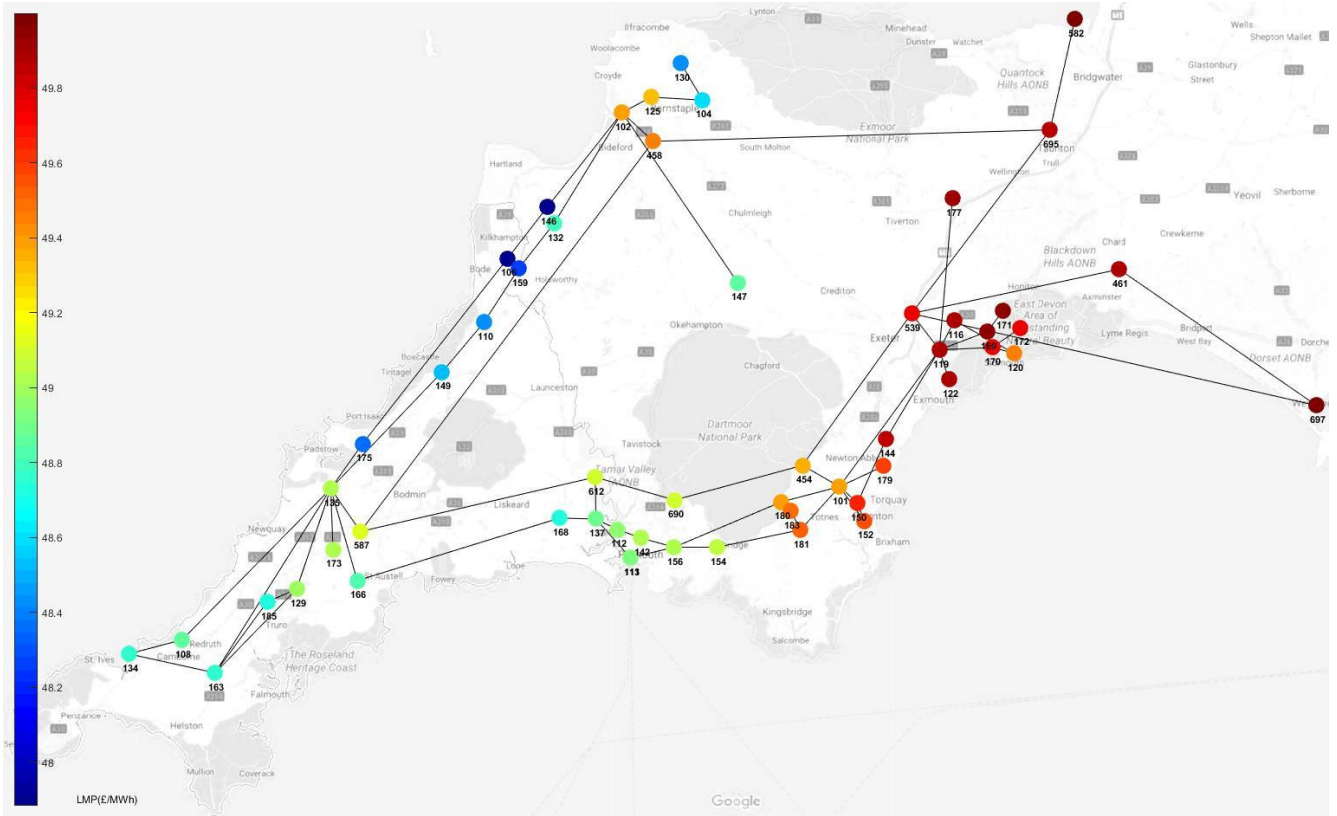


Figure 9- Case B:2017 (Minimum demand and high DG output) LMPs for 400kV and 132kV networks.

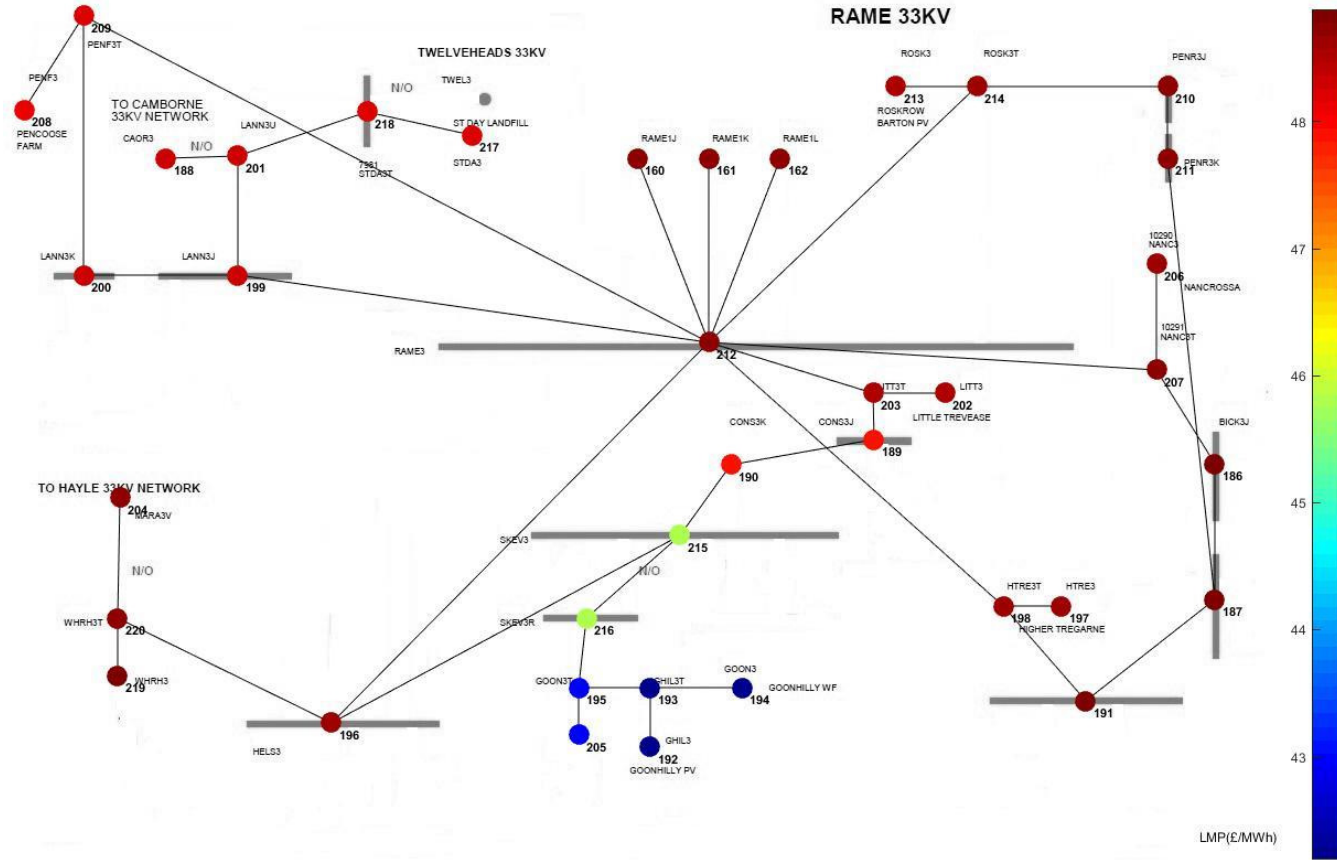


Figure 10 - Case B:2017 (Minimum demand and high DG output) LMPs for Rame 33 kV.

2.4 Case B:2020 – Maximum Export: Minimum demand and high distributed generation

With 294 MW generation and 22 MW demand added between 2017 and 2020 there is a small increase in line loadings and LMP variation from the 2017 case. The most notable change from 2017 to 2020 is that in 2020 the highest loaded line at 132 kV is between Galsworthy and Alverdiscott (at 64%) due to increased DG from Pyworthy and the addition of the 39 MW Credacott windfarm which adds a further 14 MW of flow towards Alverdiscott GSP via Pyworthy. The line between Pyworthy and Galsworthy is also one of the most highly loaded (at 59%) for these reasons.

A summary of results of OPF for the 2020 maximum export case is shown in Table 5 and the graphical output of results is shown in Appendix F.

Table 5 - Case B:2020 results summary

	Total	400kV	132 kV	Rame 33kV
Available Generation (MW)	2557	1045	1452	59
Dispatched Generation (MW)	2417	905	1452	59
Demand (MW)	945	151	757	37.3
Export to grid (MW)	1449	-	-	-
Max line loading (%)	-	33	64	53
Max transformer loading (%)	-	52	20	-
Losses (MW)	22.6	15.4	6.8	0.4
Min/Max Voltage (kV)	-	401.8/405.6	130.5/134.4	32.6/33.66
Min/Max LMP's (£/MWh)	0/50	48.9/50.0	47.1/49.9	40.1/48.5

2.5 Case C:2020 – Maximum export and constrained generation

With 466 MW available generation added to the 2020 case, 118.5 MW of which is within Rame 33kV, constraints are seen on the Rame 132/33kV transformers (based on reverse power flow capacity of 3x36.56MVA) resulting in LMPs of £0/MWh in the Rame network.

A summary of results of OPF for the 2020 constrained case is shown in Table 6.

Table 6 - Case C:2020 results summary

	Total	400kV	132 kV	Rame 33kV
Available Generation (MW)	3023	1045	1800	178
Dispatched Generation (MW)	2852	905	1800	147
Demand (MW)	945	151	757	37.3
Export to grid (MW)	1871	-	-	-
Max line loading (%)	-	40	87	23
Max transformer loading (%)	-	66	100	-
Losses (MW)	36.5	24.5	12.0	0.04
Min/Max Voltage (kV)	-	406.8/408.0	131.6/134.5	32.6/32.9
Min/Max LMP's (£/MWh)	-	48.6/50.0	46.7/49.8	0/0

2.5.1 Line loading/power flows

As shown in Figure 11 (page 21) the lines are more heavily loaded at up to 40% of the continuous MVA rating at 400 kV and up to 87% in the 132 kV network. The most heavily loaded line is between Fraddon and Indian Queens due to the addition of 136 MW of generation for the stretch case to the Fraddon and Truro BSPs. Transformers between the 400 kV and 132kV networks loaded up to 66% between Alverdiscott GSP and BSP. Total system losses are 36.5 MW of active power which is around 1.3% of total generation. 12 MW of losses happen on the distribution system and 24.5 MW on the transmission system (including the 400/132 kV transformers).

The Rame 33kV lines are more lightly loaded at below 23% but the Rame BSP transformers are fully loaded at 100% of the reverse power flow ratings. As a result, 31 MW of generation capacity within the Rame network is constrained off.

Power flows in the 400 kV ring are from West to East. At the GSPs reverse power flow occurs from 132kV to 400kV with 1.87 GW exported to the wider system.

2.5.2 Voltage/reactive power

Voltages range between 406.3 kV and 408 kV on the transmission system with the highest voltage at Indian Queens and lowest at the grid supply points (Chickerell and Hinkley C). Voltages at 132 kV level are between 131.6 kV and 134.5 kV, highest at the points with most DG (e.g. Credacott, bus 110) and lowest around Exeter where there is less DG. On the 33kV network voltages are in a tight range between 32.6 kV and 32.9 kV.

As in Case B, reactive power is dispatched at Langage CCGT absorbing 88 MVar, equivalent to a power factor of 0.995 leading. This is well within the allowed power factor range.

2.5.3 LMPs

The LMPs for 400kV and 132kV shown in Figure 13 (page 22) vary between £50/MWh at the grid connection points down to £46.7/MWh at buses with high DG output and no load (e.g. Credacott and Otterham).

At 33kV (Figure 14, page 22) LMPs are zero for all buses which shows that an additional MWh of load anywhere within the Rame network would be served by an increase of output at a 0 marginal cost DG. In this situation losses within the Rame network itself are irrelevant as long as the generator serving these losses has zero cost as both additional demand and any additional losses can be met at no additional cost. The LMPs would remain at 0 within Rame for an additional 31 MW of load in the Rame network (which is constrained). At this load level the Rame LMPs would jump to values similar to those in Case B as further demand increase would be served by a reduction in export at the connection points to the wider system.

The zero LMPs seen here represent a potentially important effect. To allow such a condition to develop, some form of control is required which monitors the flow of power at the transformers, and constrains off the generators. This is exactly what Active Network Management Schemes, such as the SSEPD Orkney [8] and UKPN Flexible plug and play [9] projects have achieved, and proposed ANM schemes in the WPD region aim to recreate.

A key analysis of a system such as that illustrated here is to run time-series analysis to identify the frequency and duration of events leading to zero LMPs in order to understand the potential for other forms of flexibility, particularly storage and demand side management. This is explored more fully in Section 3.

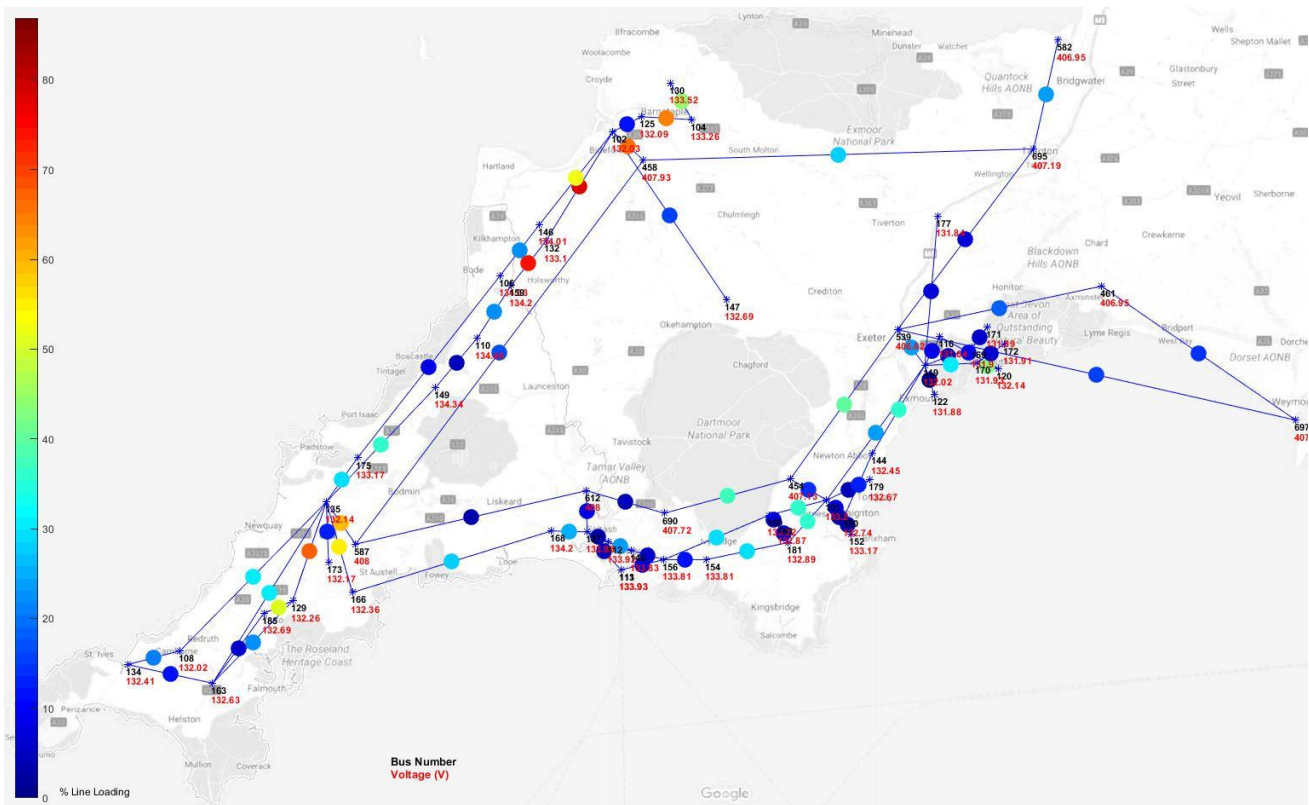


Figure 11 - Case C:2020 Line loadings and voltages for 400kV and 132kV networks.

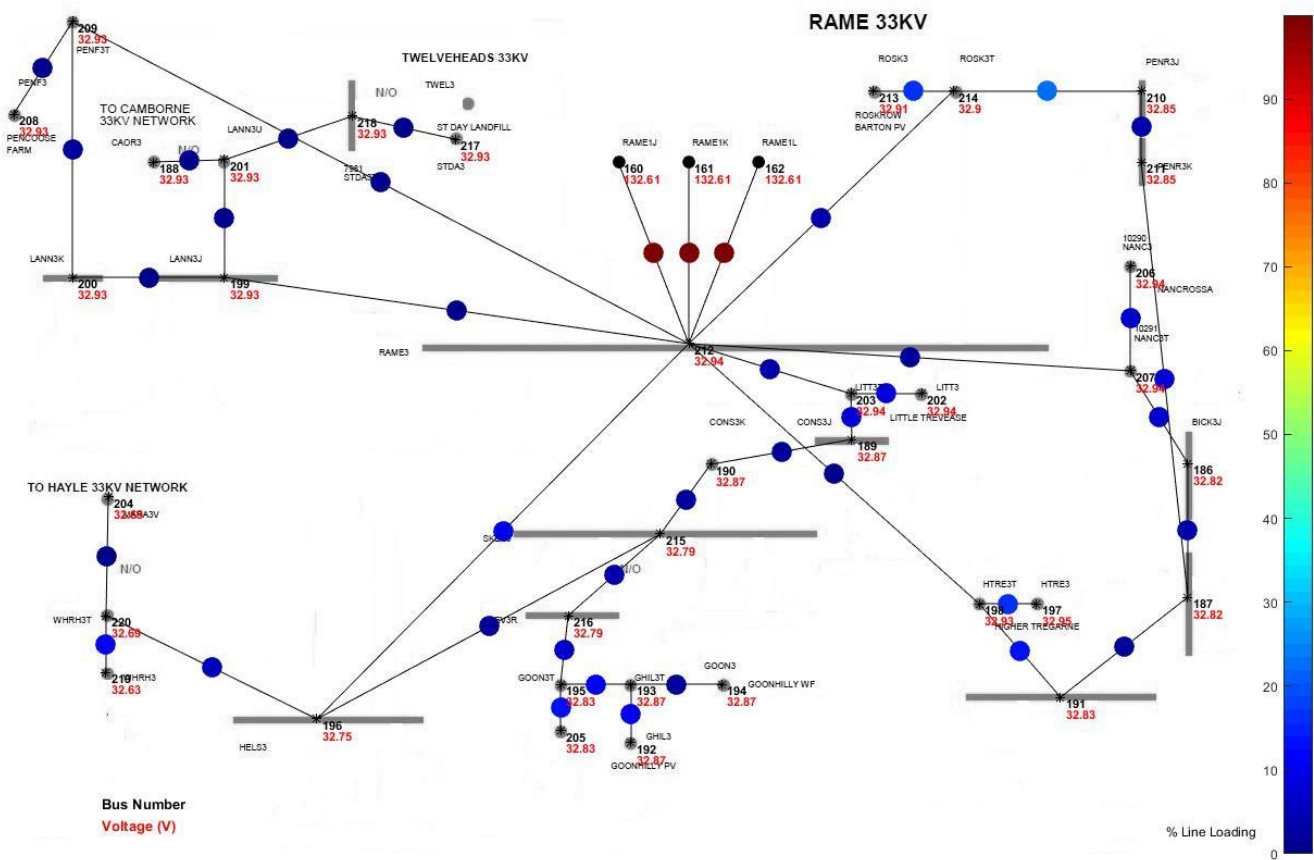


Figure 12 - Case C:2020 Line loadings and voltages for Rame 33 kV.

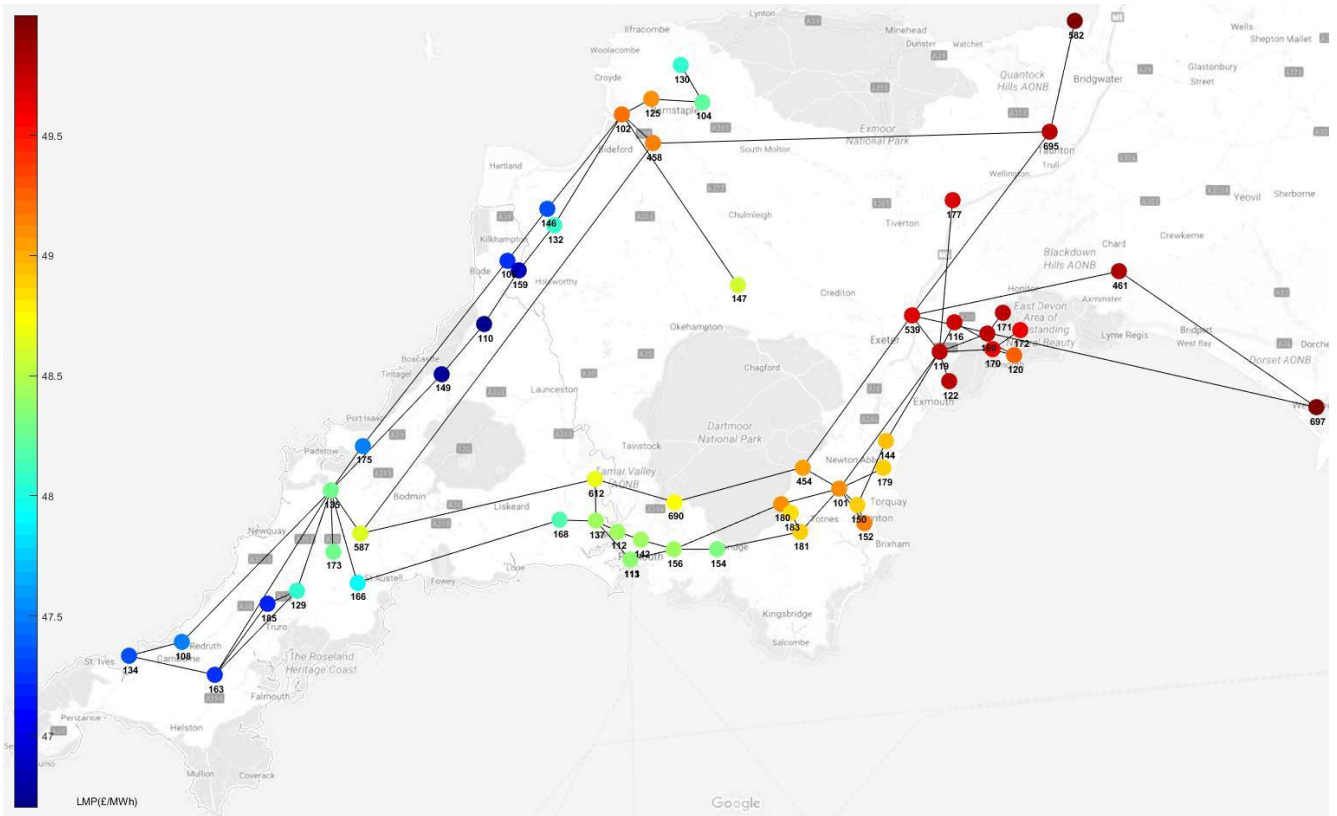


Figure 13- Case C:2020 LMPs for 400kV and 132kV networks.

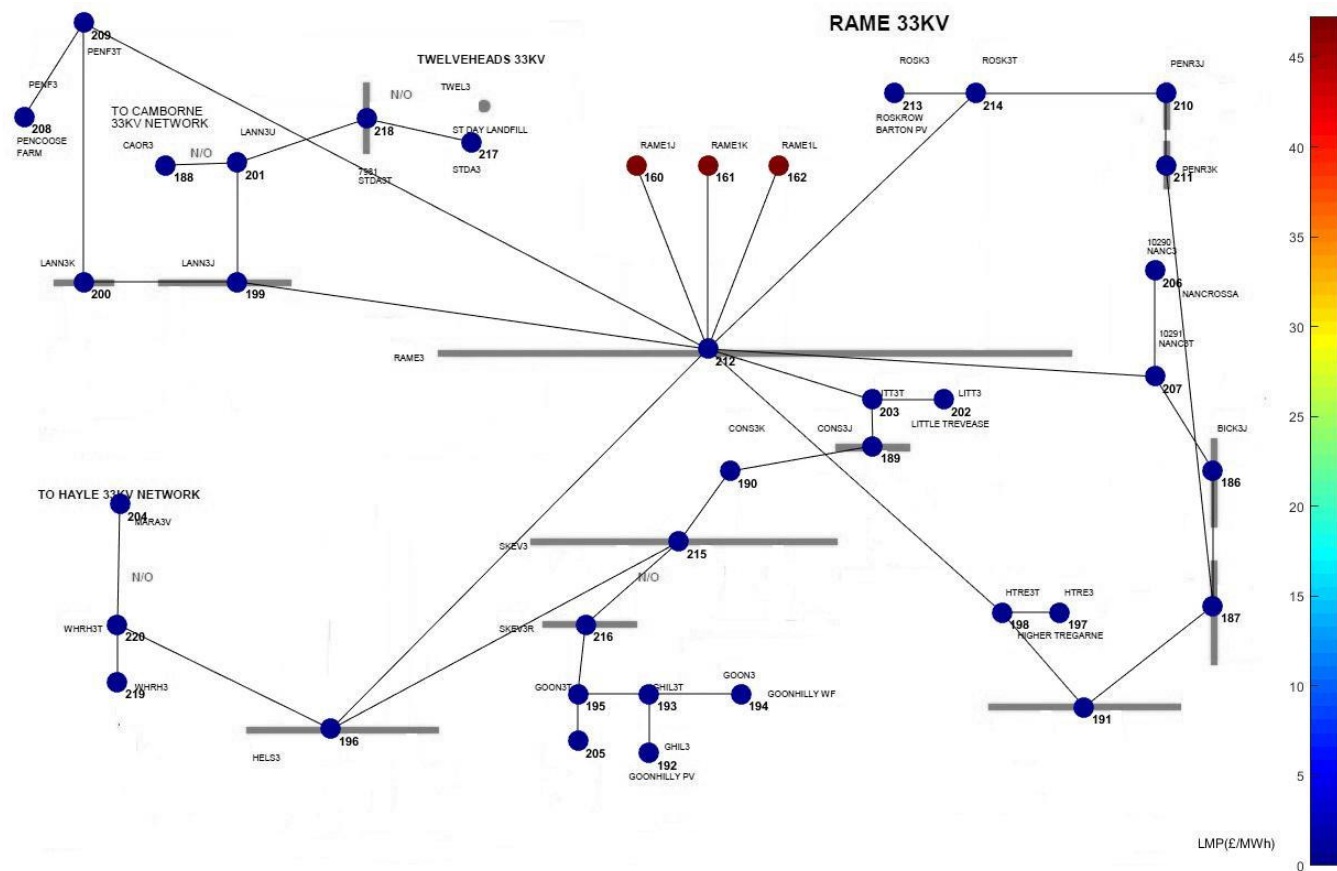


Figure 14 - Case C:2020 LMPs for Rame 33 kV.

3 Discussion

3.1 Transmission redundancy and security of supply

In all the scenarios modelled here, the loading of the transmission network is well below the circuit ratings. The maximum loading seen in any of the cases modelled is 40% for overhead lines and 66% for GSP transformers. The SQSS [10] defines the level of security to which the Main Interconnected Transmission Systems (MITS) must be planned (Chapter 4) and operated (Chapter 5), as well as additional chapters on the connection of loads and generators to the MITS. Together these requirements in effect give required levels of planned and operational redundancy.

The wording of the SQSS on operation security requires that only minimal demand can be shed after the loss of a single circuit even where this occurs at the same time as the planned outage of another component. Therefore, the network must provide the capability to continue operating the SW peninsula even after, for example, the planned outage of a double circuit followed by the fault outage of a single circuit.

Whilst the transmission network has been planned to meet these conditions under peak demand conditions for decades, it is only recently that conditions have developed where there is the possibility of invisible and uncontrollable DG exporting back onto the transmission network leading to conditions where National Grid cannot meet its obligations. Under these conditions distributed generators usually have to go through the Statement of Works process and can often be liable for major transmission upgrades if they choose to connect. However, there are now moves towards using operational rather than planning methods to manage these constraints.

As an example, National Grid has recently instigated a requirement on Western Power to maintain a capacity to de-energise all distributed generation of at least 1MW in size on instruction from National Grid, and a requirement on new distributed generation to participate in the 'South West Operational Tripping Scheme' which will constrain output during a 'N-3' outage condition¹³ [6].

3.2 Distribution redundancy and security of supply

To a large extent the issues discussed above regarding transmission security of supply are equally relevant to distribution. The network has been developed to meet prevailing security standards under peak-demand conditions, ensuring that appropriate reliability of supply is provided after planned and fault outages. The security requirements set by Engineering Recommendation P2/6 [11] become less onerous as the quantity of demand served by a network asset reduces – for example the redundancy required at a primary substations tends to be less than that required at a BSP.

However, as with transmission constraints, the growth of distributed generation is likely to create the potential for conditions where without visibility and control of generators the DNO is unable to maintain its obligations under P2/6. The default response is to stop further connection of distributed generators entirely. The introduction of active network management represents a first step to increasing generation connections to the point where the potential exists to overload the network in the case of a fault condition, but with the ANM system providing the visibility, controllability, and contract arrangements to constrain off the generation when required. This is a fundamental shift from security through planning measures and infrastructure investment, to security through operational measures and is one of the areas covered by the on-going review into P2/6 [12].

¹³ The definition of N-3 is not given, and can be ambiguous, but may align to the example given here of a double circuit planned outage and a single circuit fault outage.

3.3 Voltage optimisation and operational policy

The voltage profile of the modelled network is briefly discussed for each case, however it is worth discussing this in a more general context. The SQSS sets the statutory limits on voltage levels for transmission [10], whilst the Electricity Safety, Quality and continuity Regulations 2002 [13], a piece of UK parliament legislation, set statutory limits for distribution. In this report we have assumed a maximum voltage of 408kV (1.02 pu) for the transmission system, which is below the statutory maximum limit of 1.05 pu. This is to allow voltage headroom further up the network.

The LTDS describes, at a high level the voltage control strategy of WPD (see [3], section 4.7). The operating target voltage on the 132kV network is given as 136kV at Abham and 138kV elsewhere; for the 33kV network the target is typically 33.6kV. These target voltages will be achieved through variation of the tap ratio of OLTCs attached to GSP, BSP and primary substation transformers.

In the modelling presented here, tap settings for the maximum import case have been manually adjusted to achieve approximately these voltage levels listed. For the maximum export cases, the tap settings have been left set at neutral.

In future work discussion with WPD staff would allow greater understanding of the implementation of these voltage targets, particularly under conditions of maximum export. Under these conditions, higher than nominal target voltages at the substation may not be appropriate. High set points were often chosen based on an assumption of outward power flow where voltage levels tend to drop as power flows outwards towards the extremities.

3.4 Optimisation and Analysis Toolkit for power Systems (OATS)

There are a number of limitations to using Matpower for analysing the SW peninsula from the perspective of LMPs. Two key limitations are:

- The inability of Matpower to optimise or automatically adjust tap settings on transformers in order to capture the impact of OLTCs.
- The inability of Matpower to carry out bespoke security constrained analysis of a network.

Strathclyde has access to an in-house power system analysis suite - 'OATs' - which is capable of carrying out optimisation including both of these features.

3.4.1 Voltage optimisation in OATs

There are two modes of control for transformer tap settings that would be useful for further work looking at voltage on the SW peninsula:

- *Representation of predefined voltage targets*: a model is required where tap settings can be changed, within limits, so that the voltage at a specified bus is held at a specified target voltage. This could represent existing voltage management strategies.
- *Representation of globally optimised tap settings*: this allows limits to be set on the tap settings, and the OPF is able to optimise the setting so as to minimise the objective function. This could show the impact of moving to new operational voltage management strategies.

OATs is capable of including both functionalities in OPF calculations. In both cases the tap settings are treated as a continuous variable centred on 1 (at which point the transformer operates at its nominal turns ratio); this continuous assumption is common with many commercial power system analysis programmes.

In addition, OATs is capable of modelling loads in both a fixed power mode (where demand does not vary with changes in the local voltage) or fixed impedance (where demand does vary with changes in voltage).

3.4.2 Security Constrained Optimal Power Flow

The standard form of OPF used in the studies presented here makes full use of all available network capacity in the input model. It therefore does not obey limits which would be required to ensure operational redundancy. For example, a 1000 MW generator connected behind two 600 MW capacity circuits may be dispatched on at 1000 MW in a standard OPF, however if N-1 pre-fault operation security is required, that generator should only be dispatched to a maximum of 600MVA.

OATs has the ability to run Security-Constrained OPF (SC-OPF) under which a set of contingencies is defined. This set can be generic, for example “N-1” under which individual contingencies each with the loss of one particular network element are included; or a bespoke list of contingencies. Such an optimisation will allow the SW network to be analysed taking account of the existing operational security requirement as discussed in Sections 3.1 and 3.2. If aligned properly with the operational policy of WPD and National Grid, this analysis should be able to recreate outputs such as the constraint maps published by WPD [14].

3.5 Time series analysis.

The LMP results for Case 3 (Generation Constrained) show the marginal price of electricity in the Rame network collapses to zero due to the curtailing off of renewable generation which has zero marginal cost. This will occur whenever a constraint is reached and zero marginal cost generation is constrained. However at other times, when there are no constraints binding, the LMPs will revert to higher values set by the GB-wide system price and the impact of marginal losses.

An understanding of the opportunities that LMPs provide at this level therefore require time-series analysis where demand and generation availability time series are fed into sequential runs of the OPF software. This will create times series of LMPs at each location which can be used to identify the potential opportunities that a local market, incorporating LMPs, might provide for flexibility. The discussion in Appendix D regarding minimum demand discusses the opportunities to simulate wind and PV availability time series. Representative demand time series may be developed in conjunction with WPD if access was available to historical metering of power flows through primary substations and on primary feeders. Alternatively, a set of representative profiles is available from the DS2030 project in which all GB DNOs collaborated to produce network models and power flow profiles representative of the networks across GB [15].

4 Conclusions and Future Work

OPF modelling of the SW England 400 kV and 132 kV networks has been carried out with line loadings, voltages and LMPs identified for several cases in 2017 and 2020. The work has been useful in identifying the most constrained areas of network where participation of a range of flexibility providers (e.g. batteries and flexible demands) in local markets could potentially increase penetration of DGs and lower costs to consumers. In Rame 33 kV, with all connection offers in the LTDS accepted by 2020, the BSP transformers become constrained for reverse power flow. Large variations in LMPs occur in areas most remote from the 400 kV network and in areas with large amounts of DGs. Areas such as Camborne and Hayle go from being among the most expensive to the cheapest when going from importing to exporting power. This effect is seen to a greater extent further down the network (33 kV and below) where higher losses result in large swings in LMPs from importing to exporting.

4.1 The potential for using LMPs in local markets

Variation in LMPs represent a well understood and clear signal for the dispatch of generation, and the need for network upgrades. The implementation of LMP markets for transmission systems, making use of DC-OPFs is well established, however such markets are yet to extend down to distribution levels. This is an area of growing interest, and a number of recent studies has discussed the use of “Distribution LMPs”, the most notable of which is the MIT Utility of the Future report [16].

This work has illustrated a number of examples of LMP variation, primarily caused by variations in network losses and thermal constraints in an intact network. However the future work ideas listed below would allow this to extend to voltage constraints and to take account of operational security.

Of particularly interest is how to implement these ideas in practice. As discussed in Case 3, existing ANM schemes in Orkney and in East Anglia have created situations where zero marginal cost distributed generation is regularly constrained off. In these networks, curtailment is applied to manage thermal constraints on 33kV networks, and the theoretical concepts shown in this report have been created in practice: short run marginal cost of meeting additional demand behind those constraints truly is zero during curtailment events. The availability of this zero marginal cost energy has created an incentive to innovate. For example on Orkney the local DNO has run an innovation project which led to the installation of a 1MW battery which was dispatched to reduce curtailment [17]. More recently a community that owns a heavily constrained generator has been developing options for behind-the-meter electrolysis of Hydrogen to make use of constrained zero marginal cost generation [18].

These innovations have to date been tended to be piecemeal rather than the collaborative and strategic approached that could create true local markets. Creating a successful local market would require greater transparency and sharing of the location and reason of generation constraints, together with the ability to trade constrained (or non-constrained) energy at mutually agreed prices. Whilst systems such as ANM provide the start of technical developments in this area, it is a combination of understanding technical capabilities and techno-economic concepts such as LMPs that is needed.

4.2 Future work

The studies presented here illustrate a number of aspects of LMPs in the context of the SW peninsula. The limitations of this initial work have already been discussed, and future would aim to solve these. Use of Strathclyde's in-house OATS software would likely be a major part of future work, and therefore **validation of the tool against Matpower results** would be an early priority. In addition we would propose the following pieces of work:

- **A review of planning and operating policy for the SW peninsula networks:** detailed discussion with network engineers would allow the subtleties of the planning and operation of the network to be understood. In particular, greater understanding of redundancy and security of supply would be useful, along with indication of how maintenance outages are taken. Finally, understanding of some of the new operational measures that are being initiated to manage a constrained network would be useful. In particular, WPDs proposed ANM schemes and other 'alternative connection options' and National Grids South West Operational Intertripping schemes.
- **Security constrained OPF:** Consider resiliency of network to N-1 and N-2 outages and potential involvement of ANM as part of a revised Engineering recommendation P2/6.
- **Voltage optimisation:** There are a number of technical options for managing voltage constraints. These include making greater use of the inherent reactive power capabilities of distributed generation, new methods of using OLTCs, and changes to operational voltage strategies.
- **Extending the network model:** There are two important areas where the network model used for this study could be extended: (a) to include other 33kV networks; and (b) to include 11kV networks. The addition of more 33kV networks could be done from the existing publically available information, although discussion with WPD would be useful to ensure that it is modelled as it is operated. The addition of 11kV networks would require the use of WPD data that is not publically available, or the use of generic 11kV network models such as those created through the DS2030 project [15].
- **Time series analysis and identifying the potential for LMPs in local markets:** carrying out time-sequential OPF modelling to identify time-profiles of LMPs and network conditions would represent the first stage of understanding the potential of LMPs in a particularly local market. This would show for example, if the variation of LMPs (including their potential collapse to zero, or even negative values if the impact of lost renewable subsidies were included) is large enough and often enough to be attractive to storage developers. This work may also look at some of the technical requirements for local LMP based markets – such as the communications, control and data-sharing needs. This work would require more detailed modelling and synthesis of renewable output time-series to combine with power flow time series measured by national grid and WPD.

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6 Appendices

Appendix A - Matpower model method/assumptions

The method and assumptions are shown below in the order they are input to the Matpower model, Buses, Generators, Branches and Generator costs;

General

- Matpower files are set up as follows;
 - SW05 has 2016/17 data.
 - SW05F has 2020/21 data.
 - SW05FS has 2020/21 data + additional generation (connection offers from LTDS) for use in Case C.
- For case A: All demands are set as winter peak. All generators at 132kV and below are switched off (status set to 0).
- For case B & C: All demands are set as 50% of winter peak. Generators at 132kV and below are set so that their maximum output is 80% of installed capacity.
- In the Matpower file SW05 and SW05F all demands are set to 50% and all distributed generator's maximum outputs are set to 80% of capacity as per case B.

Buses

- 400kV buses as per ETYS (except for the 2 CHIC4 buses which are combined as bus 697), bus numbers are taken from model supplied internally. 132kV buses as per LTDS with bus numbers assigned starting at 100. 33kV Rame buses also from LTDS with bus numbers starting at 186. List of bus numbers is shown on page 33.
- For all cases bus EXEC1Q is removed/commented out due to being an islanded buses downstream from a normally open point.
- 400 kV winter peak demands are included for Taunton and Axminster as per 2016/17 from ETYS. In case of Axminster the AXMI40_SEP and AXMI40_WPD demands are combined. Power factor of 0.99 is assumed for all loads at 400kV. Q is calculated from P using $Q = \text{TAN}(\text{ACOS}(\text{PF})) * P$. Peak demands for all other GSPs are set to 0 due to being included at 132 kV.
- 132 kV winter peak demands as per LTDS loads for 2016/17 and 2020/21. The LTDS loads are provided for each 33 kV bus (such as TRUR3). To move the loads onto the 132kV buses (such as TRUR1J and TRUR1K) the loads are divided among the 132kV buses feeding the 33kV bus.
 - One difficult case is Plymouth where PLYM1 supplies all 3 transformers to PLYM3 the 33kV bus however node PLYM12 is between PLYM1 and one of the transformers and PLYM1. In this case it is assumed PLYM1 has 2/3 of the load reported for PLYM3 whereas PLYM12 has 1/3.
 - Rame BSPs (160-162) loads are set to 0 as they are accounted for within Rame 33kV.
- Power factor for 132kV buses loads taken from LTDS. Assumed to be the same for the 132kV buses as for the connected 33kV buses for which the power factors are quoted in the LTDS. Q is calculated from P using $Q = \text{TAN}(\text{ACOS}(\text{PF})) * P$.
- 33kV buses as per LTDS with bus numbers assigned starting at 186. For 33 kV all nodes from LTDS network maps are included (even short sections of 0 impedance used to represent circuit breakers).

- 33 kV winter peak Demands as per 2016/17 and 2020/21 from LTDS multiplied by 50% for minimum demand. Loads for 11 kV buses (e.g. CONS5) are moved to associated 33 kV primary (e.g. CONS3J). Power factor taken from LTDS (0.98 for all loads).
 - Mullion 11kV load is attached to MULL3
- Maximum bus voltage set to 1.02 p.u. , increased to 1.04 for 132kV buses in the maximum demand case (import case) to be in line with WPD target voltages from LTDS part 2 (p23, section 4.7 Operating Voltages) of 136/138kV.
- Minimum bus voltage set at 0.9 p.u as per statutory limit for transmission (-10%) set out in [10]
- All load buses are PQ buses (type 1 in Matpower), All buses with generation are PV buses (type 2) and HINP is chosen as slack bus for any runs of Power Flow (type 3).

Generators

- Chickerell (CHIC) and Hinkley point (HINP) are taken as grid supply points able to import/export as required by the network. Pmax of 2000 MW for CHIC and HINP was chosen for both to provide enough power for max total demand (1824 MW). Pmin of -2000 MW for both CHIC and HINP allows model to export up to 4 GW which exceeds max export for case C.
- Generator capacities (Pmax) for 400kV generators (LAGA and INDQ) taken from ETYS (ETYS16 Appendix F generation data) and 132kV and below from LTDS for DGs at 1 MW and above (Table 5 – Embedded Generation).
- Pmax for 400kV generators is set to full capacity. For 132kV and below Pmax is 80% of capacity.
- Qmax calculated from P using $Q_{max} = \tan(\arccos(PF)) * P$ using PF = 0.85 (lagging) for Qmax and 0.95 (leading) for Qmin as per grid code [7]. $Q_{min} = -(\tan(\arccos(PF)) * P)$. All other generators at 132kV and below have Qmax and Qmin as 0.
- DGs <5 MW are taken from Feed in Tariffs (FiTs)[4] for domestic generation.
- It is assumed that all non-domestic generation from the FiTs data between 1 and 5 MW is captured in the LTDS. Therefore only domestic generation from the FiTs is added to the LTDS generation to avoid doubling up of generation. Total FiTs non domestic generation for the region is 226 MW whereas the total generation between 1 and 5 MW (not including 5 MW) from the LTDS is 260 MW.
- For domestic generation FiTs data was used for installed capacity in each parliamentary constituency (PC) within the SW model (e.g St Ives, Tiverton and Honiton etc.).
- The PV capacity was far greater than wind or any others at domestic level. Hydro, AD and MicroCHP were ignored due to being close to 0 MW generation but wind was included.
- Capacities for each PC were assigned to a BSP using PC maps and BSP locations.
 - Within Rame 33 kV FiTs capacity was divided equally between Primaries.
- The LTDS generators are provided for each 33kV bus (such as TRUR3). To move the gens onto the 132kV buses (such as TRUR1J and TRUR1K) the capacities are divided among the 132kV buses feeding the 33kV bus.
 - In the case of the Rame 132kV buses generation is set to 0 as it is included within the Rame 33kV network.
- Only generators with status ‘connected’ in the LTDS are included in 2017. For 2020 generators with ‘connected’ and ‘committed’ are included.
- It is assumed that domestic capacity from the FiTs register increases 20% from 2017 to 2020.

Branches

- 400kV from ETYS Appendix B (NGET Circuits 2016/17 tab).
- 132kV from LTDS Table 4 – Branches. Zones filtered to include all transmission zones in Figure 1 minus Taunton, Axminster and Chickerell which are not connected to the rest of the system at 132 kV and are considered outside the scope.
- For 132kV all nodes from LTDS network maps (Attachment 2) are included (even short sections of 0 impedance used to represent circuit breakers).
- Excel Vlookup used to match assigned bus numbers in Matpower to branch IDs from LTDS `BUS_NO=IFERROR(VLOOKUP(BRANCH_CODE,BUS_CODES_AND_NUMBERS,BUS_NUMBER,2),0)`
- Values of R, X and B divided by 100 to convert from % into p.u.
- All zero impedance branches (used in WPD network to represent circuit breakers) have values of R,X and B increased from 0 to 0.0001 to allow Matpower to solve.
- Line ratings rateA, taken to equal the ‘Winter Rating’ from the ETYS and the ‘Cold’ from the LTDS. NOTE: ratings in LTDS converted from phase to neutral Amps to line to line MVA by multiplying by nominal voltages and by $\sqrt{3}$. i.e. $\text{RateA} = \text{RATE}_{\text{LTDS}} \times V_{\text{nom}} \times \sqrt{3}$
- Data for 400/132kV transformers taken from ETYS sheet B-3-1c and for 132/33kV Rame transformers data taken from LTDS Table 2.
 - NOTE: St Keverine Voltage regulation transfer is set to status ‘0’ as Matpower is unable to model tap changing transformers.
 - For Case A all GSP transformer tap ratios were adjusted to 0.94 to raise voltages at 132kV towards the target values in the LTDS part 2 (p23, section 4.7 Operating Voltages) of 136/138kV.
 - For Case A the Rame 132/33kV transformer tap ratios were adjusted to 0.97 to be closer to the LTDS target voltage of 33.6kV.
 - For Case B and C Tap ratios for all transformers are set at 1.
 - Tap ratios are adjusted using the ‘ratio column.
- Normally open points represented by branches with status ‘0’ i.e. disconnected. Branch connecting to bus 114 removed/commented out due to the islanded buses preventing the model from solving.
- Branch MILE1X -> MILE1Y is shown in the WPD network map but missing from branch data. This branch has been inserted to reflect the network map
 - Branch parameters taken to be same as low impedance branch MILE1Y -> MILE1K.
- For the Rame 33kV network the normally open points are left as connected as they do not connect to any other network in this model. This is to prevent islanded nodes being created.
- Reverse power capability of Rame 132/33 kV transformers from LTDS used in model files (SW05, SW05F and SW05FS). When running an import case (Case A) these are changed for the normal forward power flow ratings.

Generator costs

- Quadratic and constant terms set to 0. Linear term of polynomial: Grid = 50. OCGT = 150. CCGT = 50. Wind EfW and PV assumed to have 0 cost. NOTE: start-up and shut-down costs are not used in calculations.

Appendix B - Bus codes and numbers

453	ABHA41		129	FRAD1S		173	STDE1
454	ABHA42		130	FULL1		174	STUD1J
457	ALVE4A		131	GALS1		175	STUD1K
458	ALVE4B		132	GALS1T		176	TIVE1Q
461	AXMI41		133	HAYL1J		177	TIVE1R
539	EXET41		134	HAYL1K		178	TORQ1Q
582	HINP41		135	INDQ1		179	TORQ1R
587	INDQ41		136	LAND1		180	TOTN1Q
611	LAND41		137	LAND1Q		181	TOTN1R
612	LAND42		138	MILE1J		182	TOTN1S
690	LAGA41		139	MILE1K		183	TOTN1T
694	TAUN41		140	MILE1L		184	TRUR1J
695	TAUN42		141	MILE1X		185	TRUR1K
697	CHIC41		142	MILE1Y		186	BICK3J
100	ABHA1J		143	NEWA1J		187	BICK3K
101	ABHA1K		144	NEWA1K		188	CAOR3
102	ALVE1		145	NOMO1		189	CONS3J
103	BAST1Q		146	NOMO1T		190	CONS3K
104	BAST1R		147	NTAW1		191	FALD3
105	CANW1		148	OTHM1		192	GHIL3
106	CANW1T		149	OTHM1T		193	GHIL3T
107	CAOR1J		150	PAIG1Q		194	GOON3
108	CAOR1K		151	PAIG1R		195	GOON3T
109	CEDA1		152	PAIG1S		196	HELS3
110	CEDA1T		153	PLPT1J		197	HTRE3
111	ERNE1R		154	PLPT1K		198	HTRE3T
112	ERNE1S		155	PLYM1		199	LANN3J
113	ERNE1T		156	PLYM12		200	LANN3K
114	EXEC1Q		157	PYWO1J		201	LANN3U
115	EXEC1R		158	PYWO1K		202	LITT3
116	EXEC1S		159	PYWO1L		203	LITT3T
117	EXET1		160	RAME1J		204	MARA3V
118	EXET1Q		161	RAME1K		205	MULL3
119	EXET1R		162	RAME1L		206	NANC3
120	EXGN1R		163	RAME1Q		207	NANC3T
121	EXMO1Q		164	SAUS1Q		208	PENF3
122	EXMO1R		165	SAUS1R		209	PENF3T
123	EYEL1J		166	SAUS1S		210	PENR3J
124	EYEL1K		167	SGER1J		211	PENR3K
125	EYEL1T		168	SGER1K		212	RAME3
126	FRAD1A		169	SOWT1Q		213	ROSK3
127	FRAD1B		170	SOWT1R		214	ROSK3T
128	FRAD1R		171	SOWT1S		215	SKEV3
			172	SOWT1T		216	SKEV3R
						217	STDA3
						218	STDA3T
						219	WHRH3
						220	WHRH3T

Appendix C – SW Network Map



Figure 15 - South West 400kV and 132kV networks with codes from LTDS and numbers used in Matpower modelling

Appendix D – Minimum demand discussion

Information on power flows is available for GSPs at half-hourly resolution[5]. These power flows are effected both by variation in underlying demand and output of embedded generation. Future work could more accurately estimate embedded generation output and therefore allow estimates of minimum end-use demand for electricity at each GSP. To estimate minimum underlying demand it is necessary to estimate the time-series of distributed generation output. However, time-series of the output of the majority of these generators is not public, and in addition micro-generation output may only be metered on a quarterly basis. Therefore a method of simulating the output of this generation is required.

In many scenarios, minimum underlying demand is likely to occur during a summer night time during which solar generation can be assumed to be zero (currently accounting for approx. 64% of total capacity at 132 kV and below in the SW). To obtain minimum underlying demand, generation output from the remaining distributed generators (wind, biomass, CHP, diesel etc.) would need to be added to the import. Careful considering of assumptions would be required, however the following gives an example of what might be used:

- Diesel generation is highly expensive, and installed mainly as peaking plant. Therefore it could be ignored from scenarios related to minimum demand as it is unlikely to run at these times.
- The output of wind generation (which makes up 15% of total capacity at 132 kV and below in the SW) can be simulated from meteorological analysis. These methods work by using weather re-analysis datasets such as the MERRA database held by NASA[19]. MERRA provides indicative wind speed time-series for specific historical periods (various aspects of the database start from points in the 1970s and continue to almost present day). These wind speeds can be converted to wind power using appropriate power curves, and the resultant wind-power time series can be calibrated against monthly energy production figures for any ROC registered wind farms in the region.
- Note that for day-time periods, a similar method using the MERRA database's records of solar-irradiance can be used to estimate the output of a fleet of solar PV.

An example of the method is available at [20] and ongoing work at Strathclyde University is improving the methodology [21].

For example overnight import data for Abham GSP is shown in Figure 16 with randomly generated embedded generation included to illustrate how minimum end-use demand would be estimated. The minimum end use demand would be the minimum of the night time power flow import with embedded generation netted off as depicted by the orange line in Figure 16.

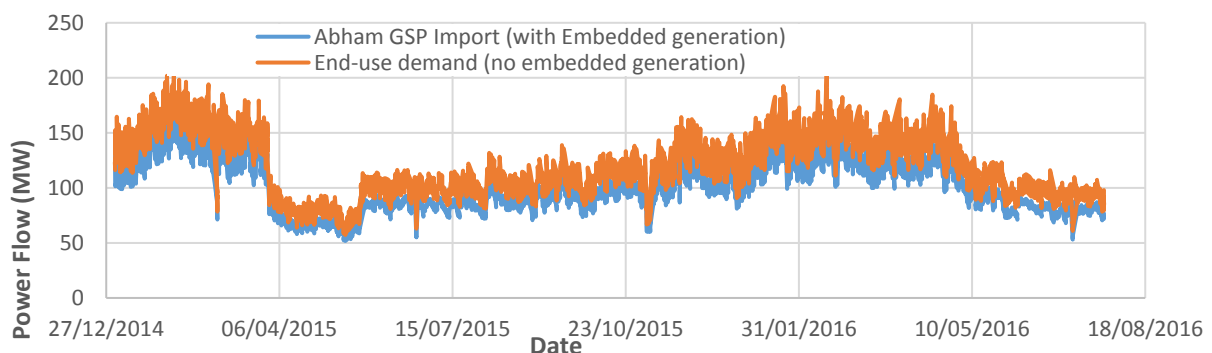


Figure 16- Abham GSP overnight (03:00 – 06:00) import. Figures for Abham GSP import from Elexon.

Appendix E – Case A:2020 Results

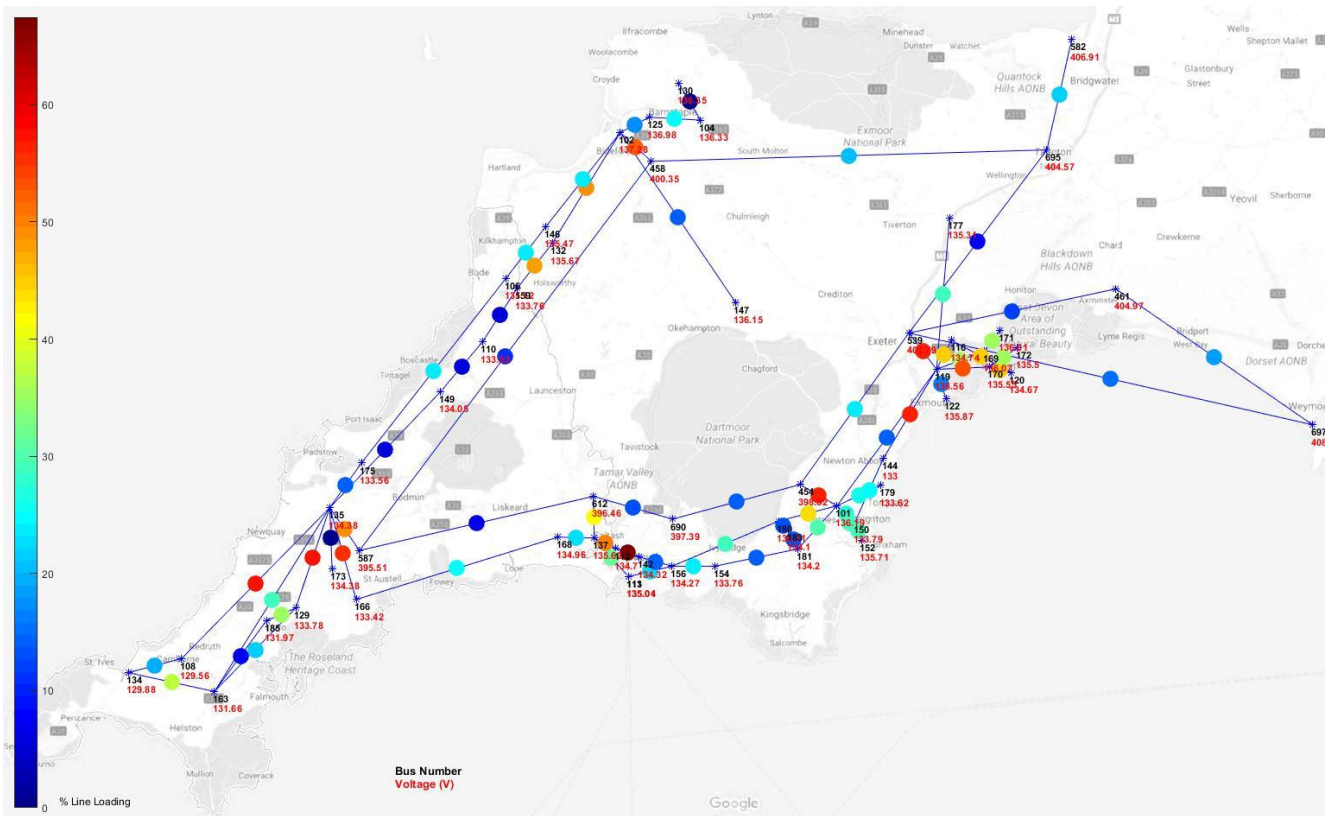


Figure 17 - Case A:2020 (No generation and peak Demand) Line loadings and voltages

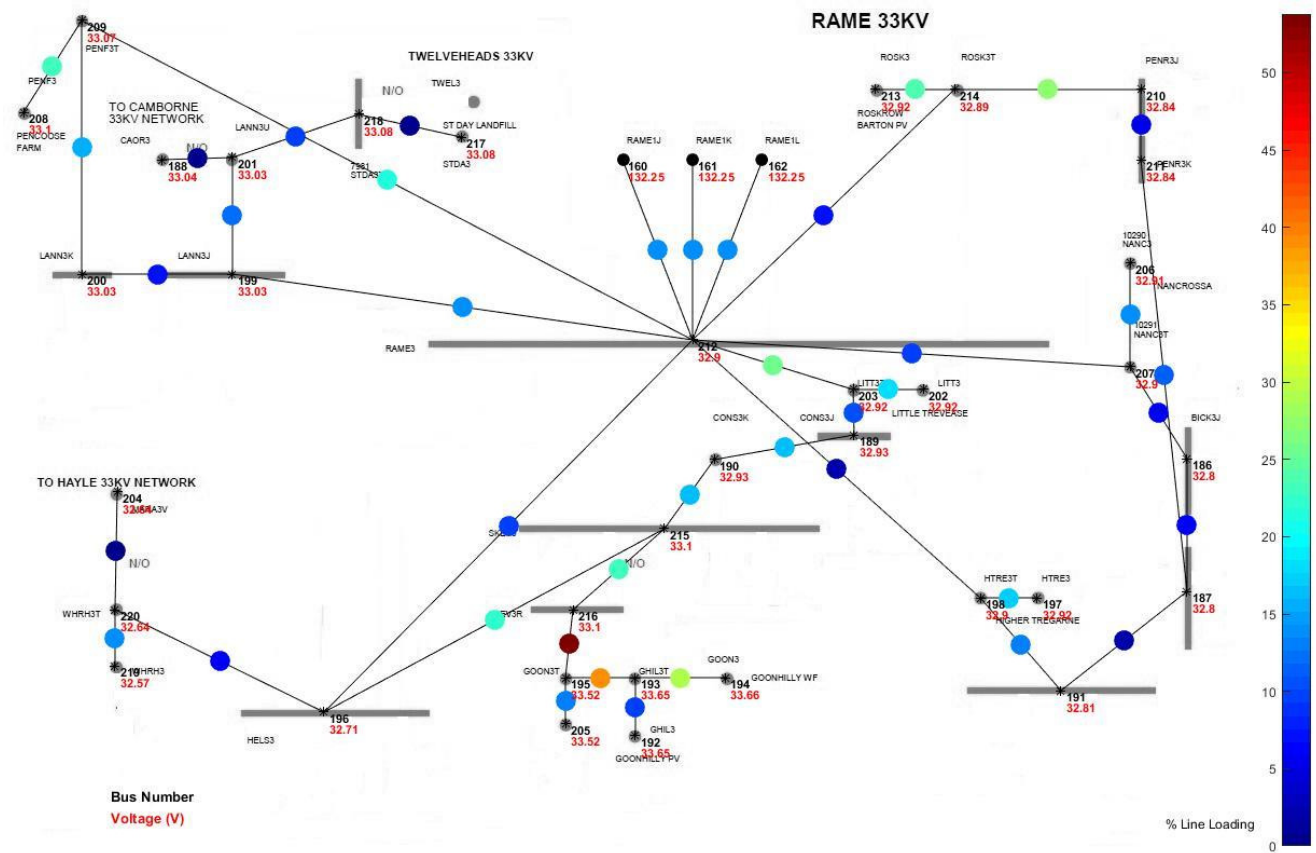


Figure 18 Case A:2020 (No generation and peak Demand) Rame 33 kV line loadings and voltages

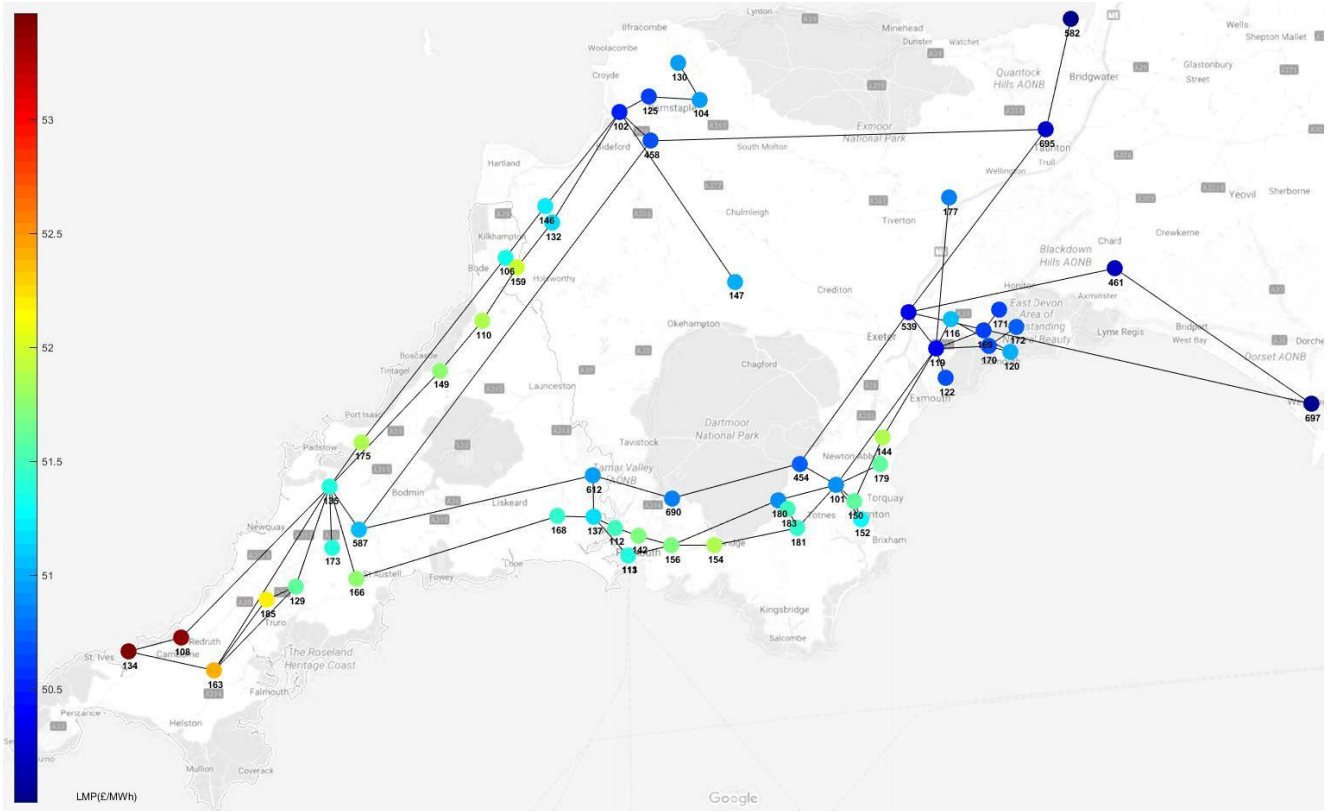


Figure 19: Case A:2020(No generation and peak demand) Transmission and 132kV LMPs

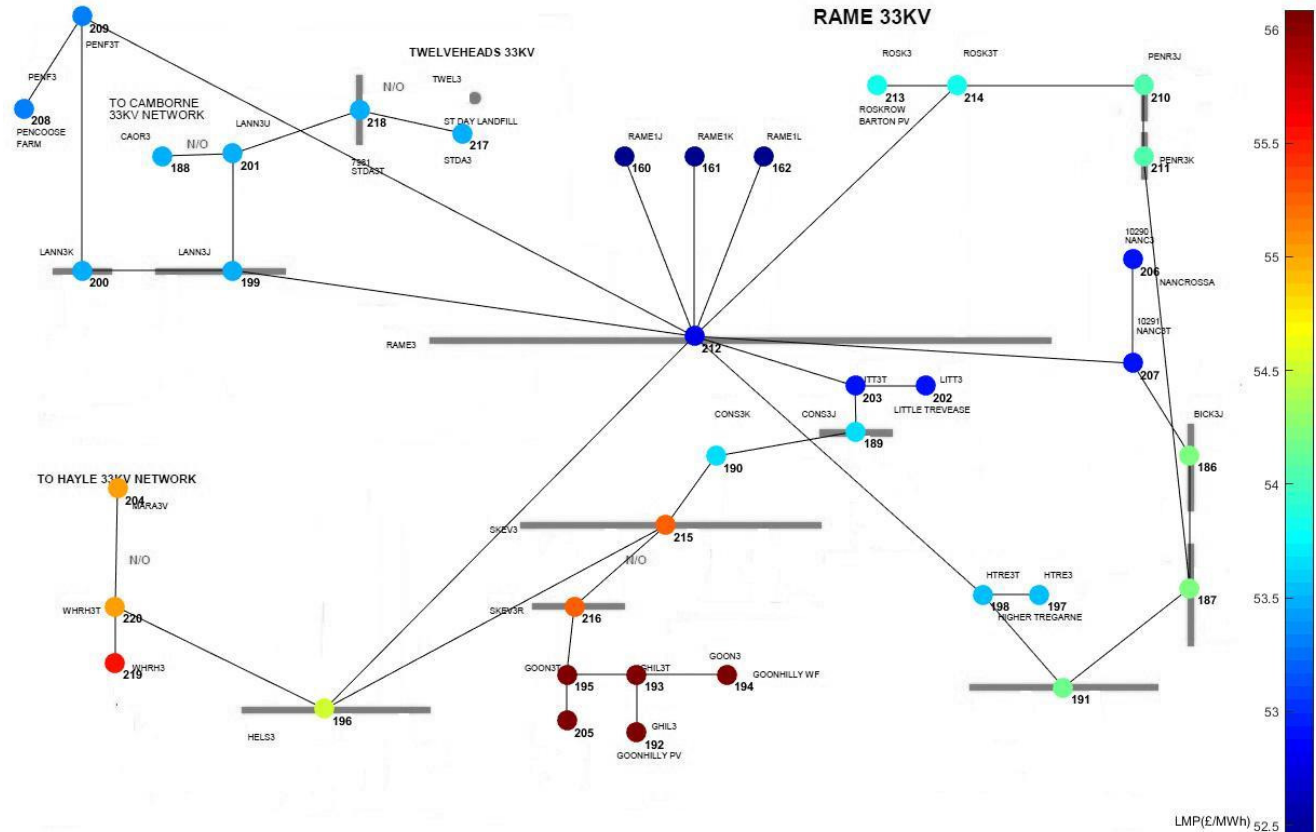


Figure 20: Case A:2020 (No generation and peak demand) Rame 33kV LMPs

Appendix F – Case B:2020 Results

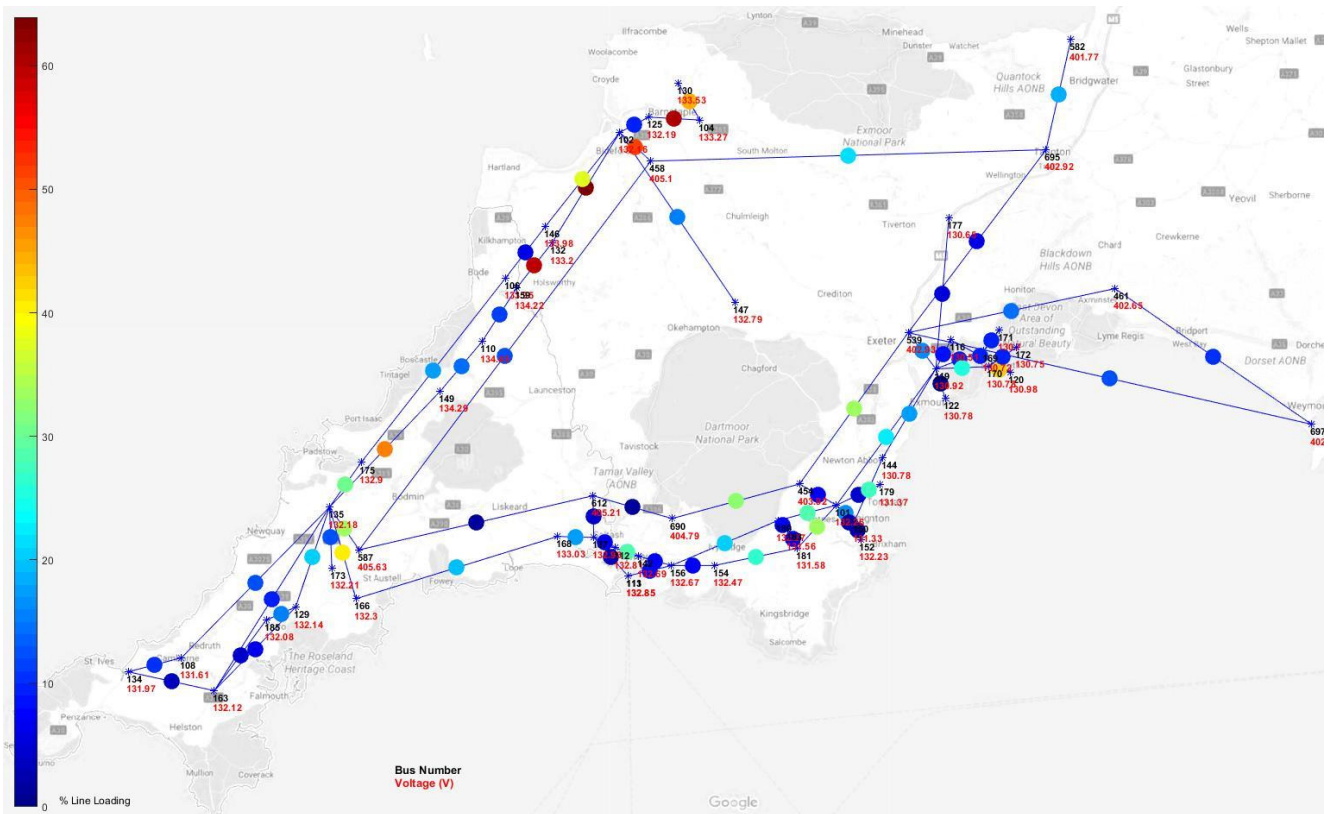


Figure 21 - Case B:2020 Line loadings and voltages for 400kV and 132kV networks.

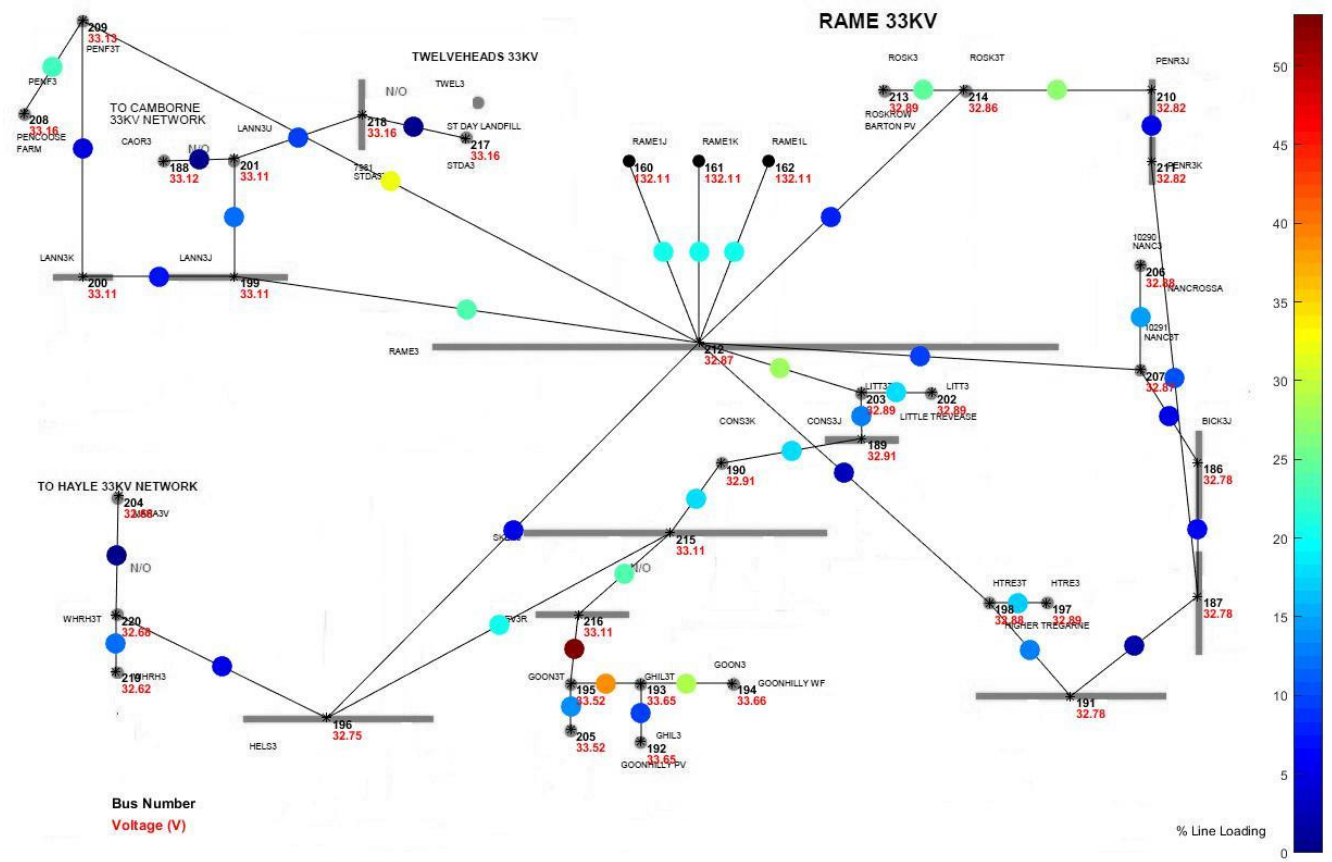


Figure 22 - Case B:2020 Line loadings and voltages for Rame 33 kV.

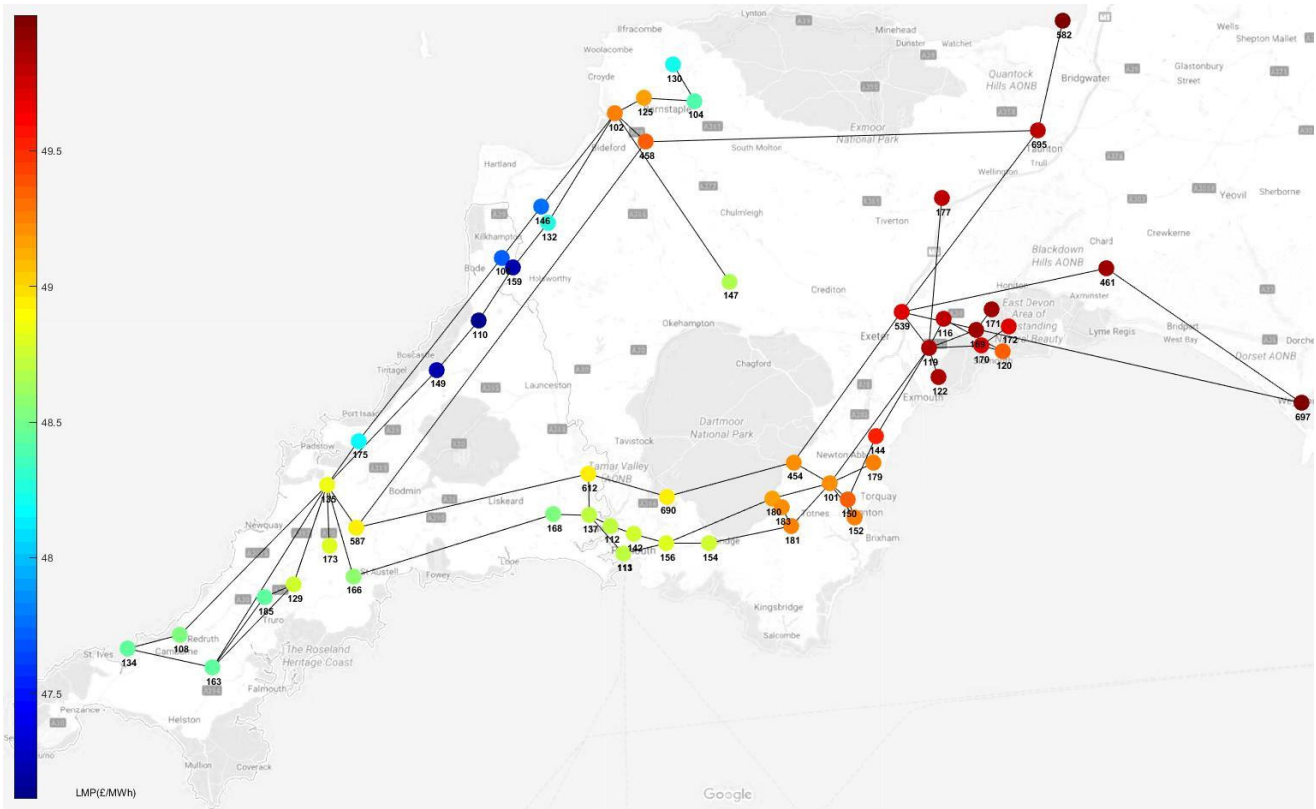


Figure 23- Case B:2020 (Minimum demand and high DG output) LMPs for 400kV and 132kV networks.

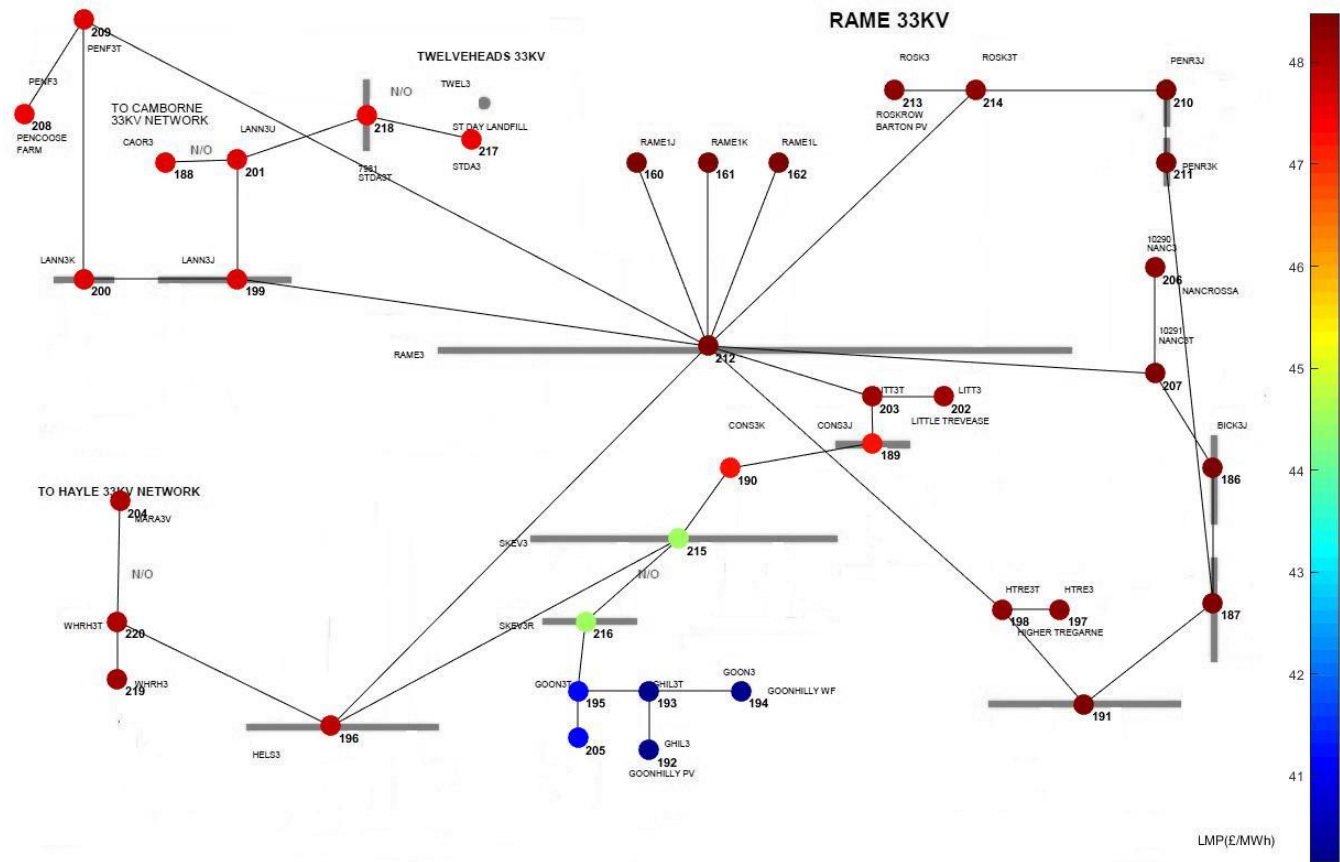


Figure 24 - Case B:2020 (Minimum demand and high DG output) LMPs for Rame 33 kV.