An assessment of the wider Hampshire distribution network capacity and potential constraint points for renewable generation (v1.0)

A report to Hampshire County Council's Climate Change Team

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IN CONFIDENCE

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1 Executive Summary

Our previous work estimated the potential renewable electricity generation capacity in the wider Hampshire area using tidal (High scenario: 636 MW), offshore wind (1,800 MW), onshore wind (313 MW), utility-scale solar photovoltaics (13,325 MW) and rooftop solar photovoltaics (482 MW) against the currently installed capacity of 706 MW (Ridett & Anderson, 2023). However, these results did not include an analysis of the available capacity of the network across Hampshire which determines how much of the potential installable capacity could actually be connected before load management would be required.

This report presents new analysis using the potential utility-scale onshore wind and solar PV generation capacity results and the network capacities of the 153 primary substations across the pan-Hampshire area to determine the level of constraint that would occur with this level of renewable capacity. In order to enable prioritisation of development, the report also estimates how much, and where capacity could be connected to the network without constraints arising.

The results suggest that up to 50% of substations in the area would experience constraints under the High development scenario. The most severe constraint level exceeds the substation's capacity by approximately 896 MW which would require significant intervention. From the results, it is clear that constraints would mainly occur in rural areas where both network capacity and local demand levels are low and where scope for installable renewable capacity is high.

The results suggest that a theoretical capacity of 2,280 MW could be connected to the wider Hampshire network before network reinforcement or load management would be required. However, because some sub-station areas have little scope for additional renewable installation, of the potential installed capacity identified in the previous work, a maximum of 1,258 MW (55% of theoretical capacity or 9% of the estimated potential) is connectable without constraints arising. This could comprise a maximum of 218 MW of onshore wind and 1,040 MW of utility-scale solar PV generating approximately 1,747 GWh of electricity per year or 23% of Hampshire's 2020 electricity demand (7,520 GWh).

Since local demand absorbs local generation, increased local demand (or storage) enables additional capacity to be connected to the local network before a constraint occurs. The National Grid's Future Energy Scenarios suggest that electricity demand is set to rise to 250% of current levels, mainly due to the electrification of heat and transport. Under a uniformly distributed demand growth model, this would increase the theoretical installable capacity from 2,280 MW to 3,509 MW and the actual connectable potential generation capacity to 1,918 MW. This could support an energy mix of 280 MW of onshore wind and 1,638 MW of utility-scale solar PV, generating approximately 2,535 GWh of electricity per year. However, this would only meet 13% of Hampshire's projected electricity demand after the increase (18,800 GWh).

Overall, it is clear that network capacity limits are likely to inhibit energy self-sufficiency via local, distributed generation as there is insufficient network capacity to allow the exploitation of the potentially available renewable supply. This work identifies areas at greatest risk of constraints arising, which will require intervention from the DNO, and also areas that could be prioritised for renewable generation developments due to their high available capacity and generation potential.

2 Background and Relation to Previous Work

As local authorities seek to achieve their net-zero carbon emission aspirations and maximise local low emissions economic development, they will look to encourage a local renewable energy power generation portfolio. As an example, Hampshire County Council wish to "*enable and support renewable energy generation capacity and distribution across the county with a focus on providing low carbon, resilient energy to residents and businesses, whilst reducing costs*" in order to "*stimulate and support green growth in Hampshire*" (Hampshire County Council, 2020).

Our previous work identified the potential for renewable electricity generation in the wider Hampshire area given a range of environmental, landscape and development constraints (Ridett & Anderson, 2023). With varying levels of development and penetration of the renewable generation sources, different scenarios were developed to understand the renewable capacity required to meet or exceed current and potential future electricity demand across the pan-Hampshire area. Under the 'High' scenario the work suggested that there was significant potential for tidal (636 MW), offshore wind (1,800 MW), onshore wind (313 MW), utility-scale solar photovoltaics (13,325 MW) and rooftop solar photovoltaics (482 MW) against the currently installed capacity of 706 MW.

However, these results did not include analysis of the available capacity of the electricity distribution network across Hampshire which would determine how much of the potential installable renewable generation capacity could actually be connected. If the available network or substation capacity were exceeded by additional local generation, then a substation's thermal limits could be exceeded leading to faults and potential blackouts. In this case the local network would be 'constrained' and network infrastructure reinforcement or other interventions such as energy storage solutions would be required to avoid faults (Anees, 2012).

This report therefore builds on the previous work by analysing network capacities at primary substation level across Hampshire to determine what level of constraint would occur given the previously developed renewable generation scenarios and what generation capacity is actually possible, without the need for other interventions. This work highlights the need for network regulators and distribution network operators (DNO) to address these capacity issues through network reinforcement, energy storage solutions or by altering the spatial distribution of electricity demand.

As noted, the previous work indicated suitable areas for utility-scale tidal, onshore wind, offshore wind, solar photovoltaics (PV) and micro-scale rooftop solar PV. However, in the case of offshore wind and tidal sites, it is unclear where exactly the point of connection between the mainland grid network and the offshore site would be, and often these sites will develop a new transmission level substation. As a result, these generation sources have not been included in this analysis.

In addition, in our previous work micro-scale rooftop solar PV systems were estimated using different penetration percentages of buildings across Hampshire. As this method did not provide insights for the suitable rooftops for solar PV across the whole of Hampshire (methodology tested for Southampton and Winchester only), it is unclear where exactly these systems will be connected to the network and so they were also not included in this analysis. The inclusion of micro-scale generators such as rooftop solar PV systems without battery storage would only increase the risk of constraints occurring in the network. This is because their generation is unlikely to be completely absorbed on-site, meaning they would have to export power back through the substation to be exported to other areas (Tevar, Gomez-Exposito, Arcos-Vargas, & Rodriguez-Montanes, 2019).

3 Methodology

3.1 Data

The data used in the constraint analysis is shown in Table 1, identifying where it was obtained, whether it is open access, the scale of the data, and what it was used for.

Table 1 - Data collection table stating source, whether it is open access and what it is used for.

Data	Source	Access	Use
Distribution Substation Location	SSEN	Closed – provided to the project for the purposes of WP1 and WP3	Create Thiessen polygons of distribution substation areas for aggregation to form synthetic primary substation boundaries.
Primary Substation Locations	SSEN	Open	Create Primary Substation Areas, Network information at primary substation level.
Network Rating Information	SSEN	Open	Network capacities, min load and existing distributed generation at Primary Substation level, used to determine level of constraint.
Potential renewable generation sites*	Own work (WP1)	Available on request	Level of potentially installable renewable generation connected to each primary substation under five scenarios.

* Output of WP1

3.2 Mapping Primary Substation Areas

Conceptually, local distribution networks are composed of a large number of distribution substations which receive power from a smaller number of primary substations and lower the voltage level to 230-240 V so it is safe to be used by end consumers. Figure 1 shows the general location of distribution substations as shaded polygons and the indicative location of primary substations in the area of interest. Higher densities of both distribution and primary substations indicates urban areas.

Unfortunately, Scottish and Southern Electricity Networks' (SSEN) network thermal capacities are only currently recorded at *primary substation level*. This means that the highest granularity that capacity and constraint analysis can be conducted is also at primary substation level. As a result, we are unable to analyse thermal limits at the granularity of distribution substations which would more closely match our previously modelled potential capacity areas and would have more value for local area energy planning.

To conduct capacity and constraint analysis we therefore needed to develop synthetic primary substation areas (PSAs) which represent the area that each primary substation distributes to. Each potential generation site from our previous work could then be allocated to a primary substation if it lay within the PSA boundary and the aggregated potential generation compared with the recorded PSA thermal capacity.

To create the PSAs, the location of each distribution substation was given an area using the *Create Thiessen Polygon* tool in ArcGIS Pro. Thiessen polygons are used to allocate space to the nearest point feature and in this case, they define an area around the distribution substation where every location is nearer to this point (the substation) than to all other points as shown in Figure 1. While the resulting boundaries are unlikely to be a complete match to 'on the ground' distribution substation supply boundaries, they provide a reasonable proxy with which to create primary substation areas.

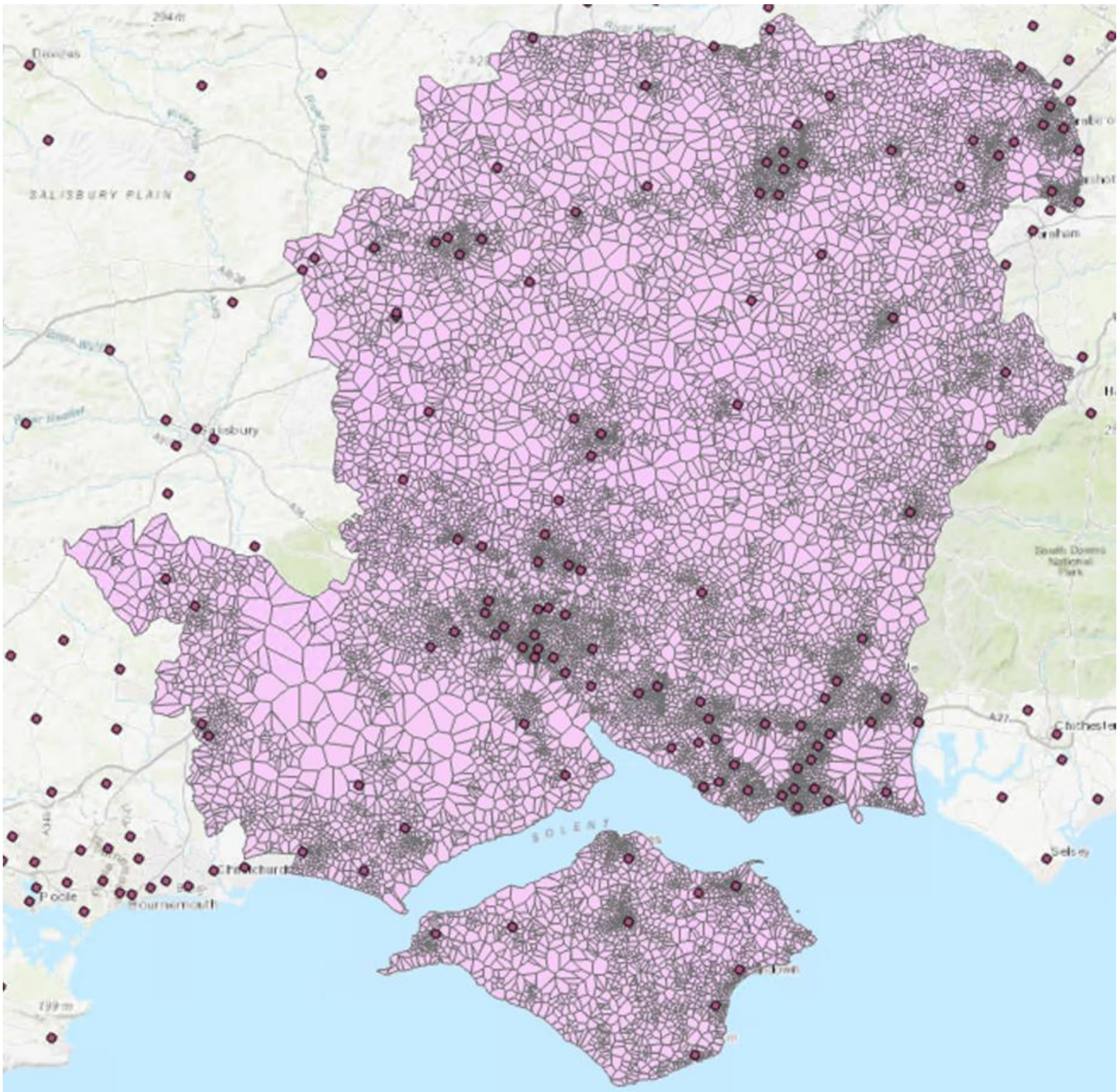

Figure 1 – Thiessen polygons for distribution substations (exact location of distribution substations not shown) with primary substation location points indicated.

Synthetic primary substation areas were then created by dissolving (aggregating) the distribution substations' Thiessen polygons according to the primary substation to which they were connected[1]. This resulted in the synthetic primary substation areas (PSAs) shown in Figure 2. While these may not exactly match the actual primary substation boundaries we believe the method offers a useful approximation. The potential renewable capacity

[1] Each distribution substation is allocated a specific network reference number code by SSEN, which includes the code of the primary substation that it is connected to.

modelled in our previous work can then be allocated to the PSA area in which it is lies. This is described in further detail in Section 3.4.1 below.

Each primary substation has a capacity, or transformer nameplate rating (MVA), which determines the maximum power that can flow through the transformer. These capacities were assigned to each PSA as shown in Figure 2. This clearly shows that rural substations are likely to have much lower ratings than more densely populated urban or industrial/commercial areas.

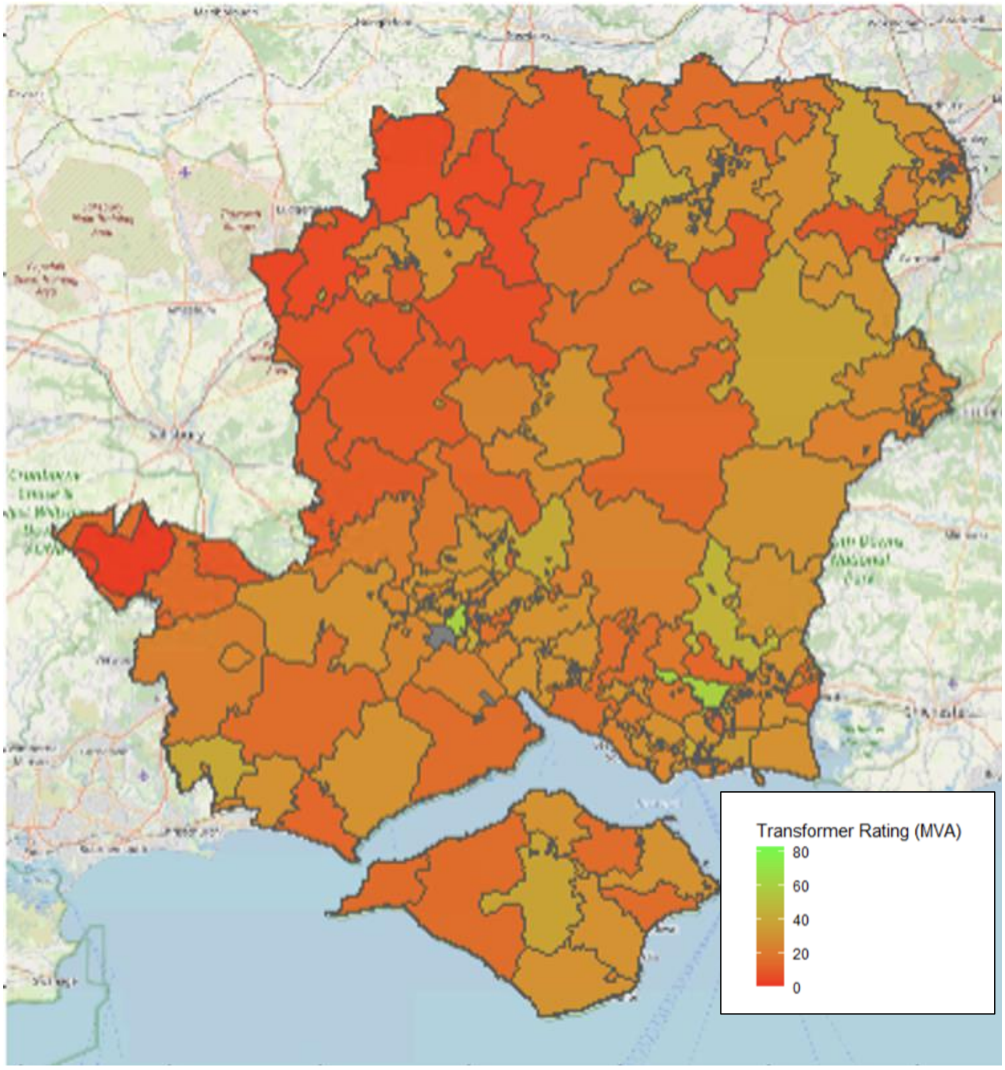

Figure 2 – Derived Primary Substation Areas indicating transformer rating (MVA).

3.3 Renewable generation scenarios

In our previous work 5 scenarios were created to show the effect of different levels of implementation of renewable generation technologies (Table 2). The work showed that the 'Low' scenario would not meet current pan-Hampshire electricity use (7,520 GWh in 2020) but all other scenarios either met or exceeded this value. The high scenario would accommodate a near trebling of Hampshire's electricity use (to 20,800 GWh/year), a level of increase in excess of those implied by the NG-ESO Future Energy Scenarios 2022.

The technical maximum scenario uses all suitable areas obtained from the previous work and represents an unrealistic upper limit of what could potentially be implemented. The other scenarios are scaled by the corresponding percentiles accordingly, as described in Table 2.

Table 2 – Details of the % implementation assumptions for the different scenarios.

Scenario	Offshore wind	Tidal	Utility-scale solar PV	Onshore wind	Rooftop solar PV
Technical maximum	100% of site	100% of site	100% of areas	100% of areas	All buildings
High	50%	50%	25% of areas	25% of areas	25% of all buildings
Medium-high	25%	25%	20% of areas	20% of areas	20% of all buildings
Medium-low	10%	10%	15% of areas	15% of areas	15% of all buildings
Low	5%	5%	10% of areas	10% of areas	10% of all buildings

As this work is only considering constraints as a result of onshore utility-scale generation, the utility-scale solar PV and onshore wind generation will be used for the analysis. Table 3 below shows the estimated capacity (MW) and annual generation (GWh / year) for utility-scale, onshore generation technologies for each of the scenarios.

As this analysis is looking at the risk of exceeding network constraints (in MVA, equivalent to MW), only the potential generation capacity will be used. This is because each substation has a limit to how much generation can be connected and how much power can flow through it (bi-directional). Further, analysis is restricted to the four 'High' – 'Low' scenarios since the Technical Maximum is considered to be unrealistic (see Ridett & Anderson, 2023).

Table 3 – Capacity (MW) and annual generation (GWh / year) for each scenario and utility-scale, onshore generation technology.

Scenario	Utility-scale solar PV		Onshore wind		Totals	
	MW	GWh / year	MW	GWh / year	MW	GWh / year
Technical Maximum	53,301	51,361	1,252	4,277	54,553	55,638
High (25% of areas)	13,325	12,840	313	1,069	13,638	13,909
Medium-High (20%)	10,660	10,272	250	855	10,910	11,127
Medium-Low (15%)	7,995	7,704	188	642	8,183	8,346
Low (5%)	5,330	5,136	125	428	5,455	5,564

3.4 Estimating constraints under current demand

The renewable generation potential results for each of the four (High – Low) scenarios were then used in conjunction with network capacities to determine whether constraints are likely to occur at primary substation level given current levels of demand. In its simplest form this would be when the installable renewable generation for the PSA exceeded the recorded capacity value once local demand was taken into account.

3.4.1 Assigning renewable potential to PSAs

For the purposes of this work we assume that all generation will be connected to the distribution and not the transmission network. Although this may not be the case in practice where installations are large (e.g. over 100 MW), the assumption required the modelled generation capacity to be assigned to primary substation areas.

To do this, the potential renewable generation polygons from our previous work was allocated to the PSA in which the polygon's centroid was located using the Spatial Join tool in ArcGIS Pro. The modelled potential renewable generation capacity was then summed within each of the PSAs to represent the maximum potential generation possible at any given time. Note that this does not account for any temporal asynchronicity in local generation and so represents both a 'best' case in terms of generation and a 'worst case' in terms of potential network constraints.

This capacity corresponded to the technical maximum scenario as specified in Table 2. The other four scenarios were then considered by scaling the technical maximum potential renewable generation capacity for each PSA by the corresponding scenario scaling factors. This determined the potential renewable generation capacity within each synthetic primary substation area according to the four scenarios.

3.4.2 Estimating constraint levels for each PSA

When generation at a distribution or primary substation exceeds local demand, power flows back towards and through the substation to be distributed elsewhere. This is called reverse power flow. For all SSEN primary substations in the Hampshire area, the reverse power flow capacity is stated as 50% of the transformer nameplate rating. For the purposes of this work *we take this reverse power flow capacity to be the threshold at which a constraint would occur if the levels of renewable generation indicated by the scenarios were to be connected within the PSA*.

Each primary substation also has a current minimum load (MW) experienced which is the minimum demand on a primary substation after deducting the existing distributed generation. A negative minimum value indicates the existing amount of reverse power flow already flowing through the primary transformers. This will also have an impact on the level of constraints as local generation can be absorbed by demand, reducing the need for power flow through the substation's transformers.

The level of constraint (MW) for each scenario was therefore calculated using the following equation[2]:

$$Constraint = (Capacity * 0.5) + Min\ Load - Potential\ Generation \qquad (1)$$

Where;

- Capacity x 0.5 is the reverse power flow capacity as defined above,
- Min Load is the minimum demand experienced by the substation after deducting the existing distributed generation (positive as absorbs generation and acts as extra capacity) and

[2] See https://www.ssen.co.uk/globalassets/our-services/standard-network-capacity-report-ws1b-p5/ssen-standard-network-capacity-ws1b-p5---methodology-and-assumptions.pdf for a related 'Generation Headroom' approach.

- Potential Generation is the result from the previous work for each scenario (negative as acting against the minimum load). Note that this assumes maximum output with no consideration of diversity or seasonality.

If the value estimated is positive, then there is spare capacity (the PSA is 'non-constrained') and if negative, then there is overload through the substation ('constrained').

There are 153 primary substations in total analysed across the Hampshire region with varying capacities. However, there are 4 primary substations that did not have a capacity value displayed and so return NA for the calculations.

3.5 Potential installable generation capacity without intervention

If there is no intervention provided by the DNO, the maximum potential generation that can be connected to the network for some PSAs is likely to be dramatically lower than the technical potential generation identified in the previous work, affecting Hampshire's ability to meet current and potential future demand. To estimate the level of generation that could be installed in each PSA without intervention, we re-use equation 1 above but ensure that a negative value (constrained) is not returned.

The generation capacity that is available with no intervention or reinforcement is given by the following equation:

$$Available\ Capacity = (Capacity * 0.5) + Min\ Load \tag{2}$$

For the areas that were deemed as constrained (a negative value in equation 1), the installable generation capacity is given by the available capacity (since up to 100% of potentially installable generation can be installed). For non-constrained substations, the installable generation capacity remains unchanged (100% can be installed)

3.6 Potential installable generation capacity following projected demand increase

The National Grid-ESO's Future Energy Scenarios (National Grid ESO, 2023) predict that electricity demand is due to rise by approximately 250% of current demand in the future mainly due to the electrification of heat and transport. An increased electricity demand would absorb more generation, reducing the amount that may flow back through a substation (reverse power flow). This would therefore reduce the risk of constraints occurring and would increase the potential generation capacity that can be connected to the network. To analyse this effect, equation 2 was still used but with the minimum demand (Min Load + existing distributed generation) increased by 250%. This assumes that there are no technical limits to increasing the level of local demand serviced by the primary and distribution substations in each PSA provided. It also assumes that demand will increase uniformly across all PSAs. This is unlikely as demand is likely to increase more substantially in urban areas due to the concentration of demand for heat, transport and industrial processes. Nevertheless, this projection provides a simple initial model.

4 Results

This section reports available capacity and then divides the results into analysis based on current minimum demand levels and analysis based on future demand increases.

4.1 Available capacity

Error! Reference source not found. shows the available generation capacity (MW), as determined using equation 2, for each PSA across Hampshire. Across the 149 primary substations that have the required data, there is approximately 2,280 MW of capacity available for connected generation, in addition to current contracted generation. This is just 16% of the potential generation capacity for the previously estimated High (25%) scenario and would provide approximately 31% (4,075 GWh) of current annual Hampshire electricity use.

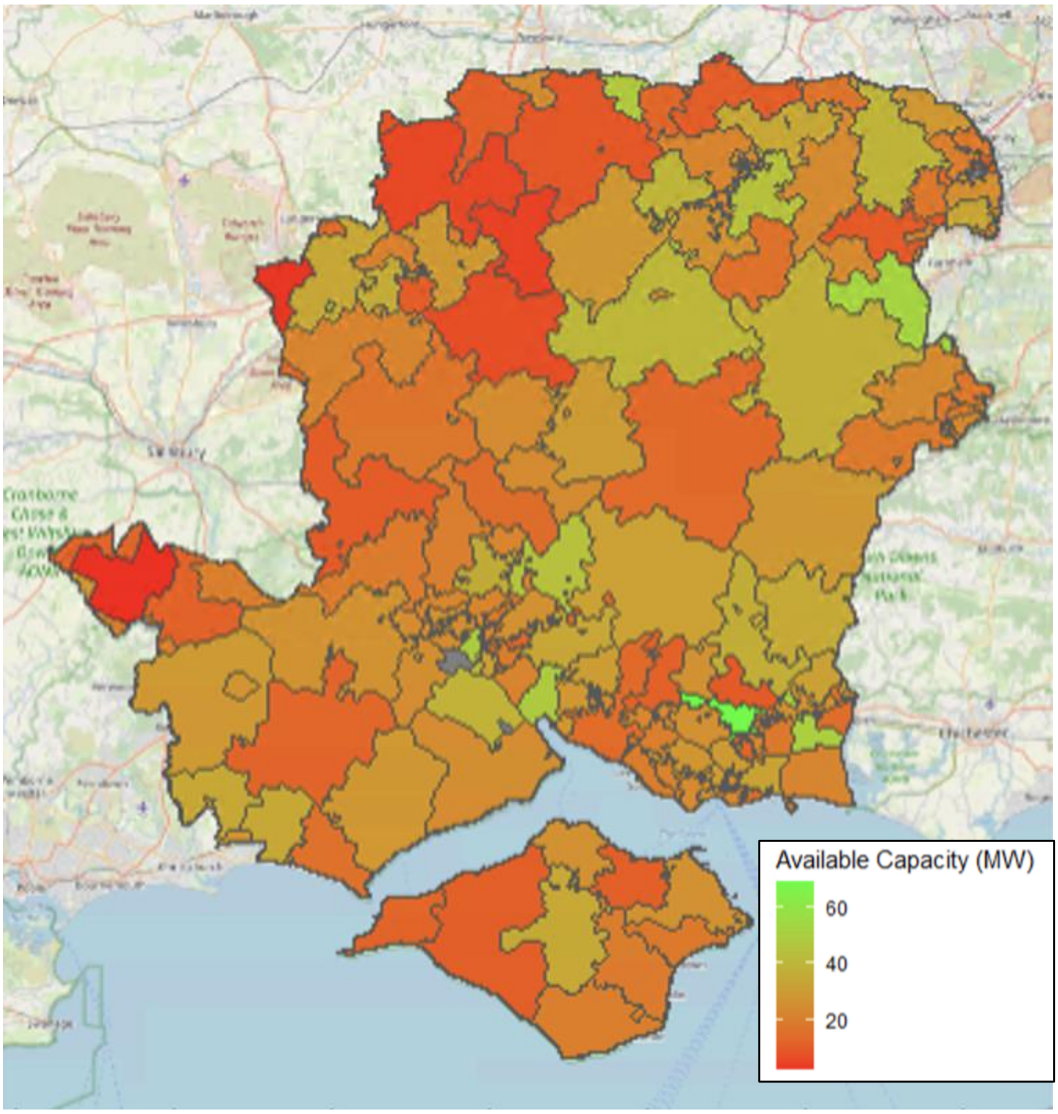

Figure 3 – Available Generation Capacity (MW) for each PSA based on substation limits and current minimum Load

However, since some of the substation areas have little scope for additional renewable generation (e.g. urban areas), not all of this theoretical capacity can be connected. The following sections estimate the level of potential generation that could be connected under current and future demand scenarios.

4.2 Potential installable renewable generation under current demand

This section discusses the primary substations that will become constrained as a result of the increasing deployment of renewable generation for each of the scenarios. It looks at each utility-scale, onshore generation type exclusively first and then combines them together. This is to show which generation technology is likely to contribute most to the constraints that may arise and where they may occur. A combination of the two is likely to occur as diverse energy mix is required to match more closely to demand (Raugei et al., 2018).

4.2.1 Solar Photovoltaics Generation

The number of primary substations across Hampshire projected to exceed their reverse power flow capacity, and therefore experience constraints, for each scenario solely from utility-scale solar PV generation is shown in Figure 4.

It can be seen that even for the High scenario, just over 50% of primary substations will experience constraints. The number of constrained primary substations decreases as the potential solar PV generation capacity decreases, as expected.

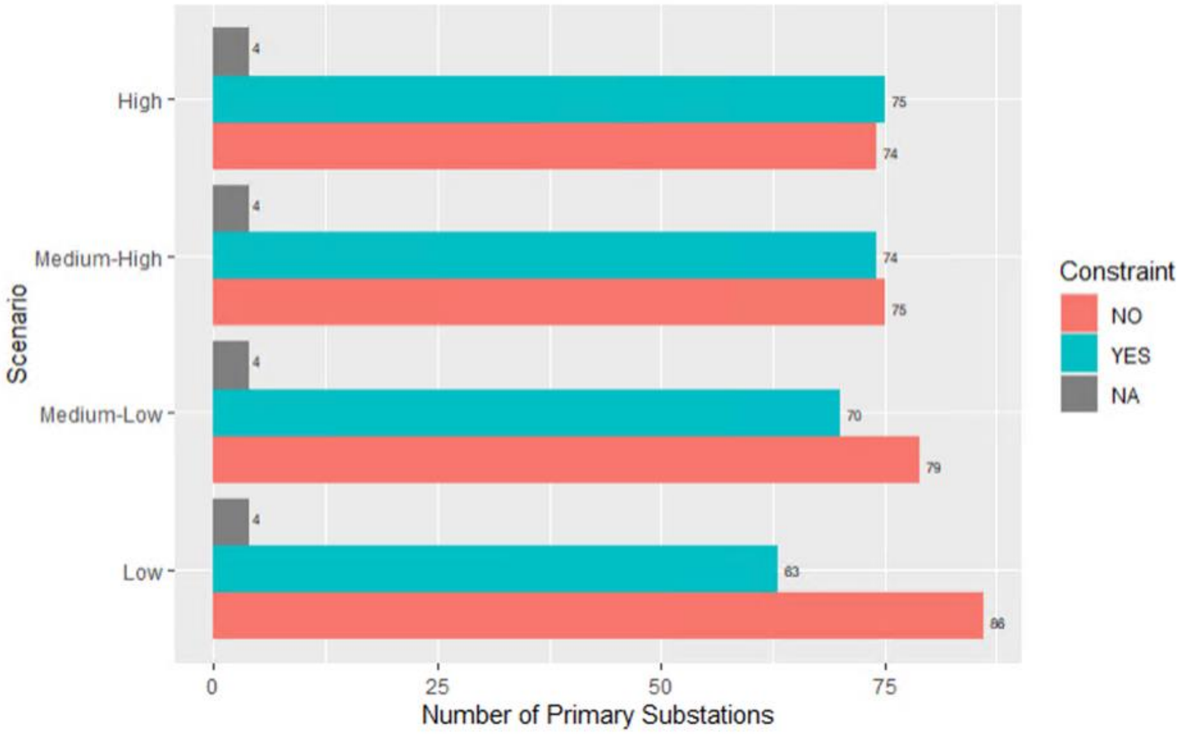

Figure 4 - Number of primary substations across Hampshire projected to exceed its capacity (constrained) for each solar generation scenario.

Figure 5 provides a spatial analysis by showing the locations of the primary substations that will or will not experience constraint (shown as PSA). It should be noted that rural areas are larger than urban PSAs and so appear to visually dominate the map, in contrast to the histogram which does not distinguish.

It is clear that in the High scenario, the non-constrained areas are largely within built-up urban areas such as Portsmouth, Southampton and Winchester. This is due to the relatively low potential solar PV capacity compared to more rural areas, which will have greater areas to develop on. Urban PSAs, however, would have a larger rooftop solar PV potential so there are risks of constraints arising in these areas if significant rooftop solar is implemented. In addition, the larger PSA within rural areas could also accommodate a larger number of suitable sites. Rural areas also tend to have lower demand and therefore a lower network capacity available.

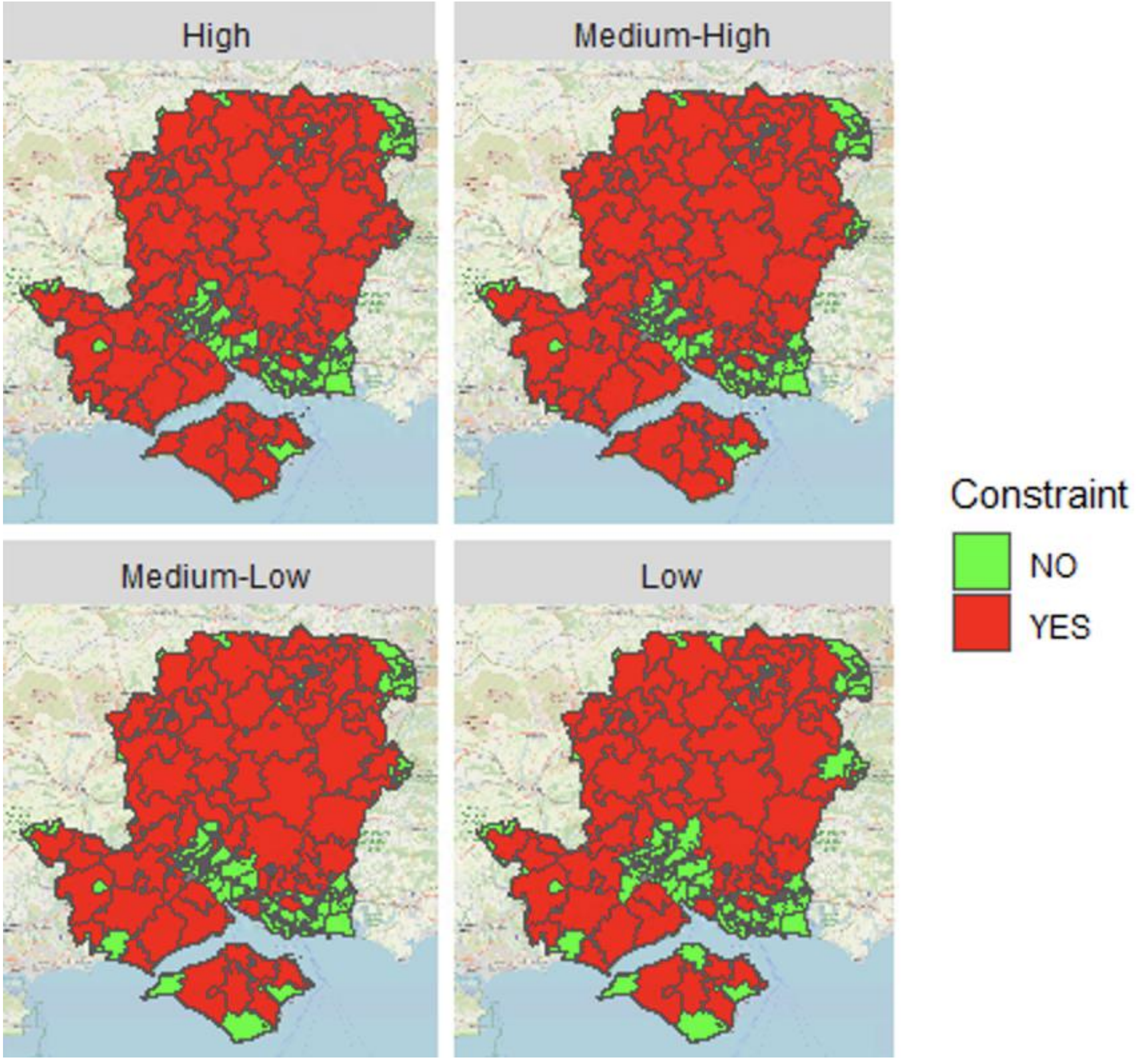

Figure 5 - Primary substation areas that are either constrained or not constrained for each solar generation scenario.

Figure 6, Figure 7, Figure 8, and Figure 9 show the severity of the potential constraints projected for the High, Medium-High, Medium-Low, and Low scenarios, respectively. Any level of constraint that is positive (green bars) represents substations that are not constrained from utility-scale solar PV systems and could connect the full potential renewable capacity modelled in our previous work. Any level of constraint that is negative (red bars) are substations that are constrained by the estimated potential level of utility-scale solar PV. The available capacity (orange bars) shows the generation capacity that *could* be connected to the network within each PSA without any constraints arising, based on the network's limits, and current levels of demand and generation. Summing the green and orange bars (where there is no green) therefore provides an estimate of the total installable capacity before interventions are required.

For the High scenario (Figure 6), a total of 13,325 MW of utility-scale solar PV capacity was projected in our previous work. Of this potential, only 1,252 MW (~9%) can be connected with no intervention or reinforcement from the DNO. As we move down the installable generation scenarios, we will find more substations will be 'green' as they no longer breach the constraint threshold.

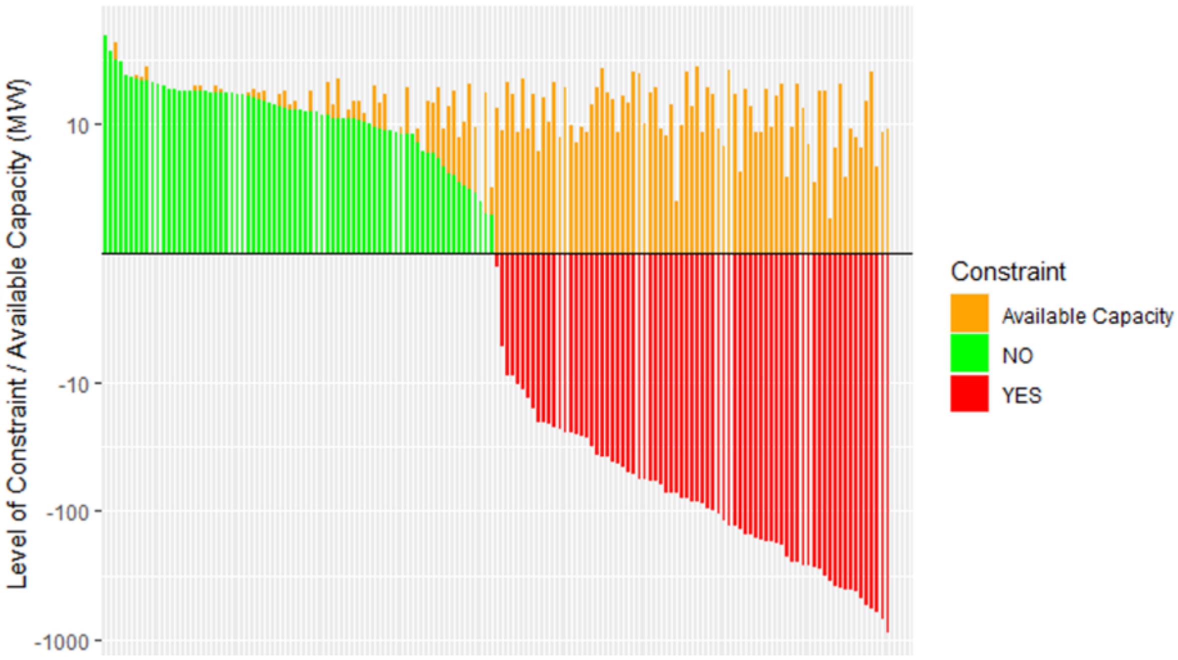

Figure 6 – Level of constraint (green and red, MW) and Available Capacity (orange, MW) for all primary substations in the Hampshire region for the High (25% penetration), utility-scale solar PV generation scenario.

The Medium-High Scenario (Figure 7) previously projected 10,660 MW of utility-scale solar PV across Hampshire. Of this potential, 1,201 MW (~11%) could be connected to the network without any intervention from the DNO.

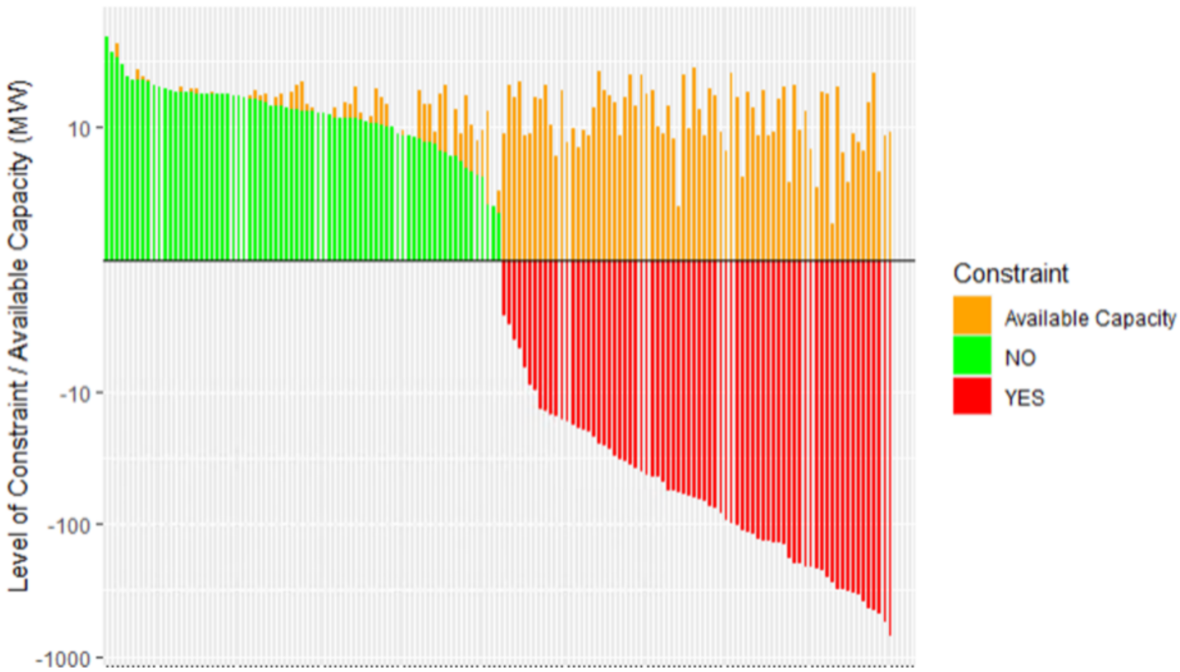

Figure 7 - Level of constraint (green and red, MW) and Available Capacity (orange, MW) for all primary substations in the Hampshire region for the Medium-High (20% penetration), utility-scale solar PV generation scenario.

The Medium-Low Scenario (Figure 8) previously projected 7,995 MW of utility-scale solar PV across Hampshire. Of this potential, 1,143 MW ~(14%) could be connected to the network without any intervention required from the DNO.

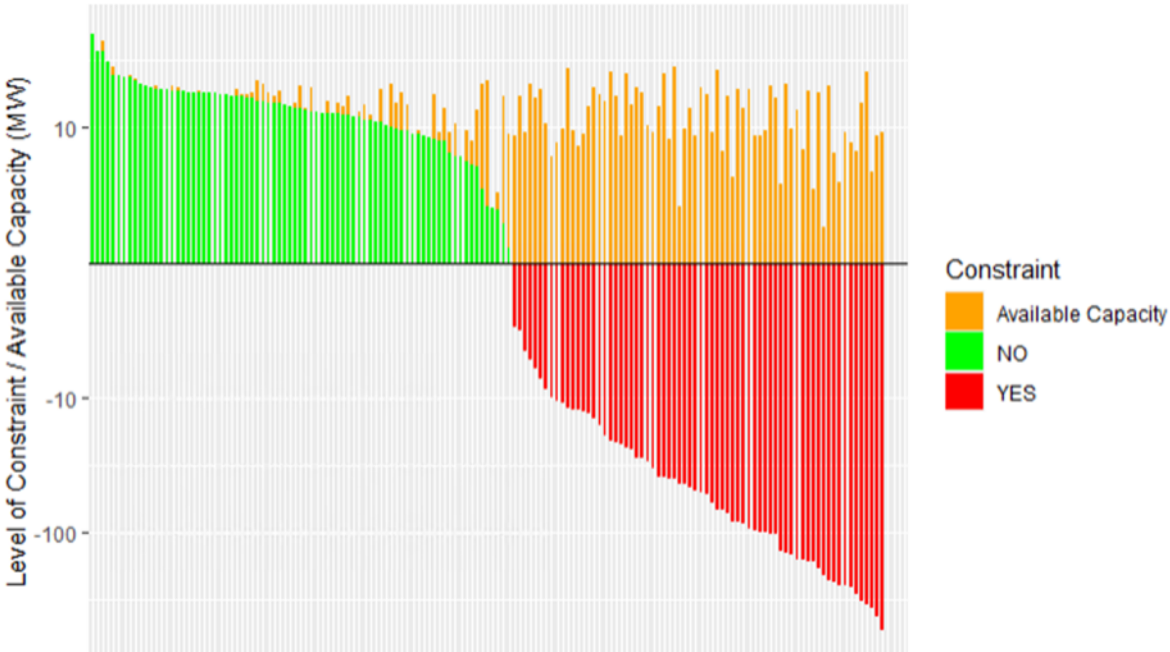

Figure 8 - Level of constraint (green and red, MW) and Available Capacity (orange, MW) for all primary substations in the Hampshire region for the Medium-Low (15% penetration), utility-scale solar PV generation scenario.

The Low Scenario (Figure 9) previously projected 5,330 MW of utility-scale solar PV across Hampshire. Of this potential, 1,058 MW (~20%) could be connected to the network without the need for any intervention from the DNO.

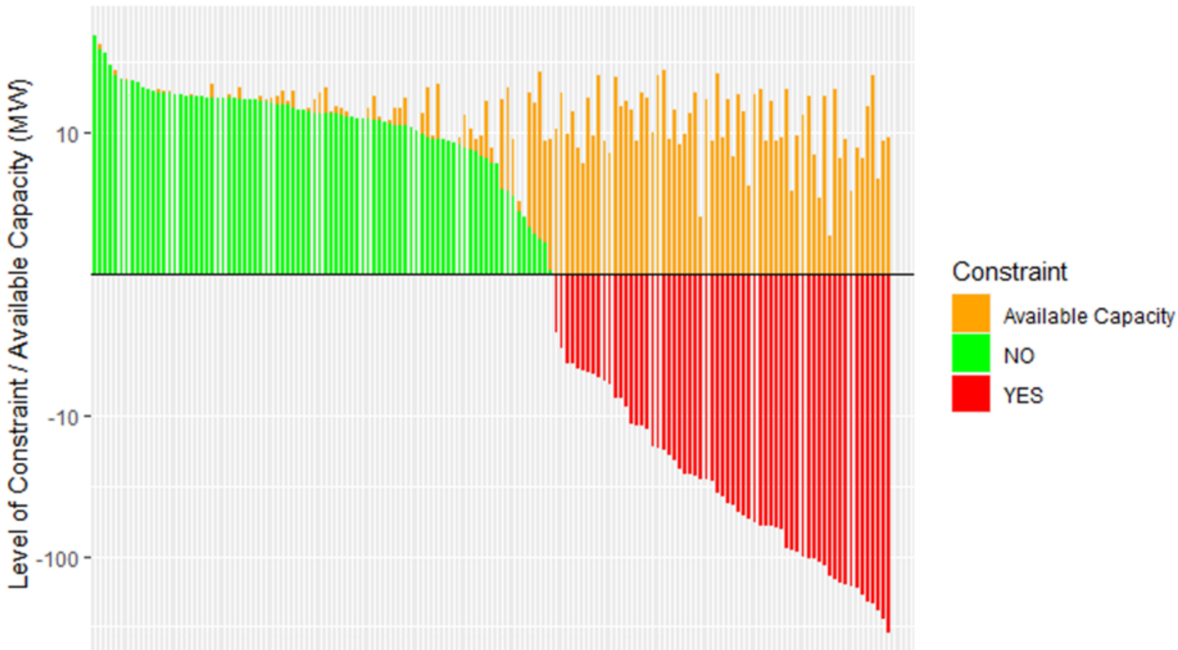

Figure 9 - Level of constraint (green and red, MW) and Available Capacity (orange, MW) for all primary substations in the Hampshire region for the Low (10% penetration), utility-scale solar PV generation scenario.

If all 2,280 MW of stated network available capacity was utilised by utility-scale solar PV, approximately 2,200 GWh of electricity would be generated per year. This corresponds to 29% of Hampshire's 2020 electricity demand (7,520 GWh).

However, as Table 4 shows if the maximum currently installable PV under the High scenario (1,252 MW) was connected, approximately 1,206 GWh of electricity would be generated per year. This corresponds to 16% of Hampshire's 2020 electricity demand. As would be expected, this value decreases under the less ambitious scenarios.

Table 4 – Potential installable solar PV before network intervention required under all scenarios

Scenario	Modelled potential (MW)	MW capacity installable	% of modelled potential	GWh/year	% current Hampshire demand
High	13,325	1,252	9%	1,206	16.0%
Medium-High	10,660	1,201	11%	1,157	15.4%
Medium-Low	7,995	1,143	14%	1,101	14.6%
Low	5,330	1,058	20%	1,019	13.6%

Given that solar PV generation is intermittent and does not generally match with current peaks in electricity demand due to its temporal and seasonal variation. As a result, substantial peak demand reduction, shifting or storage would be required.

4.2.2 Onshore Wind Generation

Looking at Figure 10, it is clear that solar PV will be the driving force behind any potential network constraints across Hampshire as the vast majority of primary substations will not experience network constraints solely from onshore wind. For the high and low scenarios, it is projected that only 14 and 4 primary substations will experience network constraints solely from onshore wind, respectively.

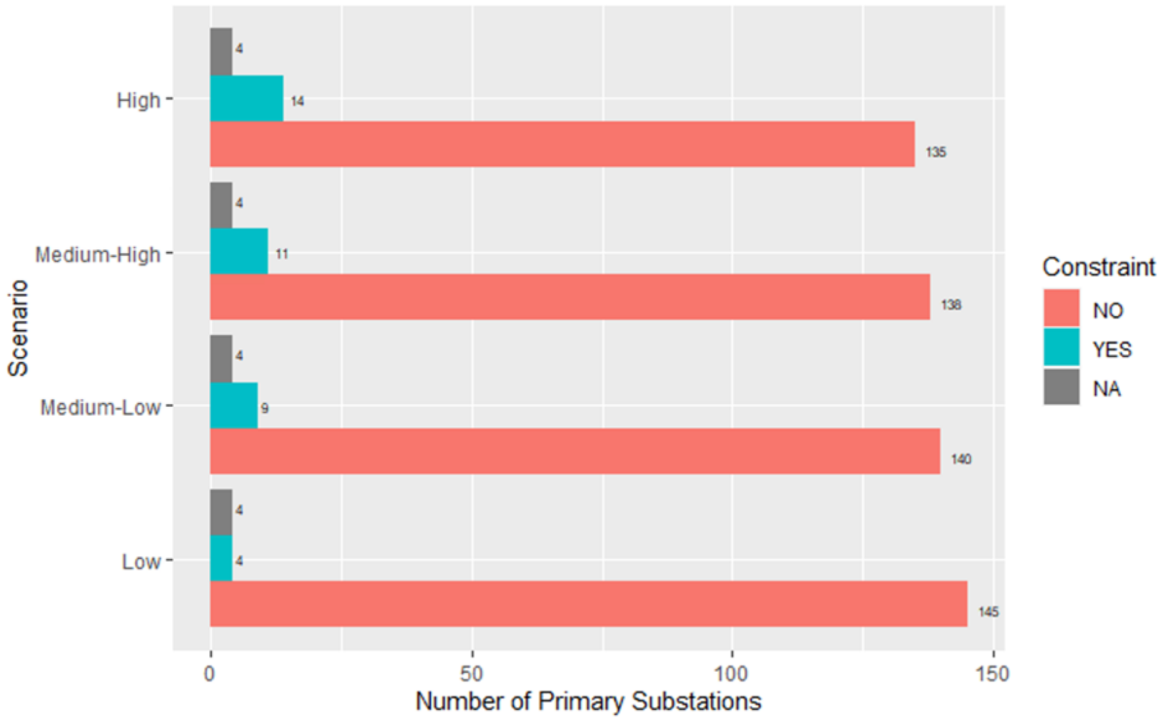

Figure 10 - Number of primary substations across Hampshire projected to exceed its capacity (constrained) for each wind generation scenario.

Figure 11 shows the spatial distribution of the constrained and non-constrained PSA solely from onshore wind generation for each scenario. These, again, are shown to be in more rural areas across Hampshire which is expected due to the strict criteria that had to be satisfied for a site to be deemed 'suitable' in the previous work.

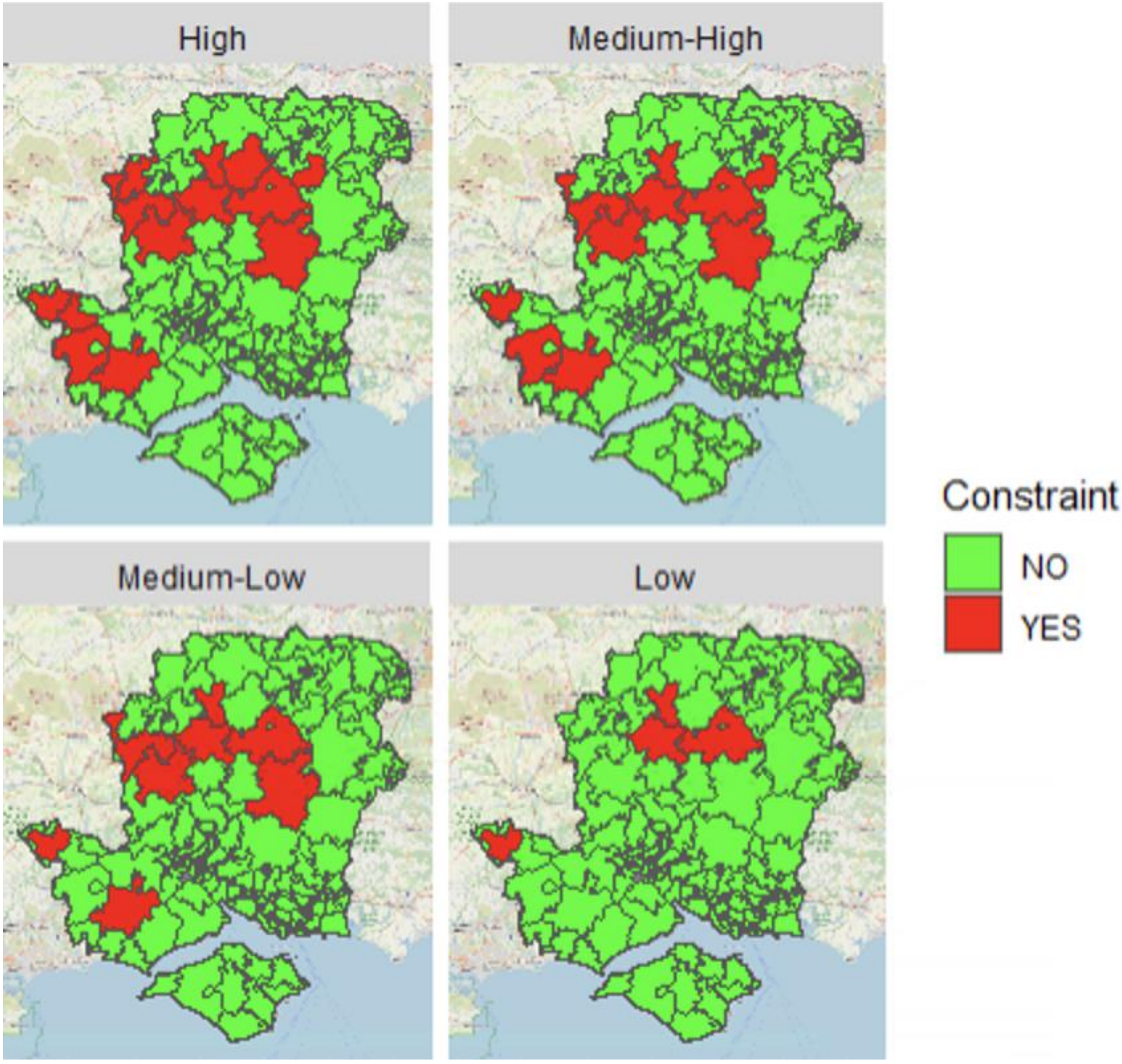

Figure 11 – Primary substation areas that are either constrained or not constrained for each wind generation scenario.

Figures 12, 13, 14, and 15 show to what level the constraints could occur across the network solely from onshore wind for the High, Medium-High, Medium-Low, and Low scenarios, respectively. Any level of constraint that is positive (green bars) are substations that are not constrained from onshore wind developments. Any level of constraint that is negative (red bars) are substations that are constrained from onshore wind developments. The available capacity (orange bars) shows the generation capacity that can actually be connected to the network within each PSA without any constraints arising, based on the network's limits, current levels of demand and generation.

It is clear that the network has sufficient capacity for onshore wind developments across the majority of primary substations, and even all substations for the low scenario (Figure 15). This is largely due to the stricter suitability requirements for onshore wind sites, resulting in a lower potential capacity across the Hampshire area.

However, even the most severely constrained substations due to onshore wind generation are only constrained by approximately 22 MW (Figure 12), which will still require intervention but is manageable. The total onshore wind capacity that is able to be connected to the network without any intervention is 218 MW (~ 70% of total potential capacity), 190 MW (~ 76%), 159 MW (~ 85%), and 118 MW (~ 94%) for the High, Medium-High, Medium-Low and Low scenarios, respectively. The total connectable onshore wind generation capacity represents 10%, 8%, 7%, and 5% of the total network stated available capacity across Hampshire for the High, Medium-High, Medium-Low, and Low scenarios, respectively.

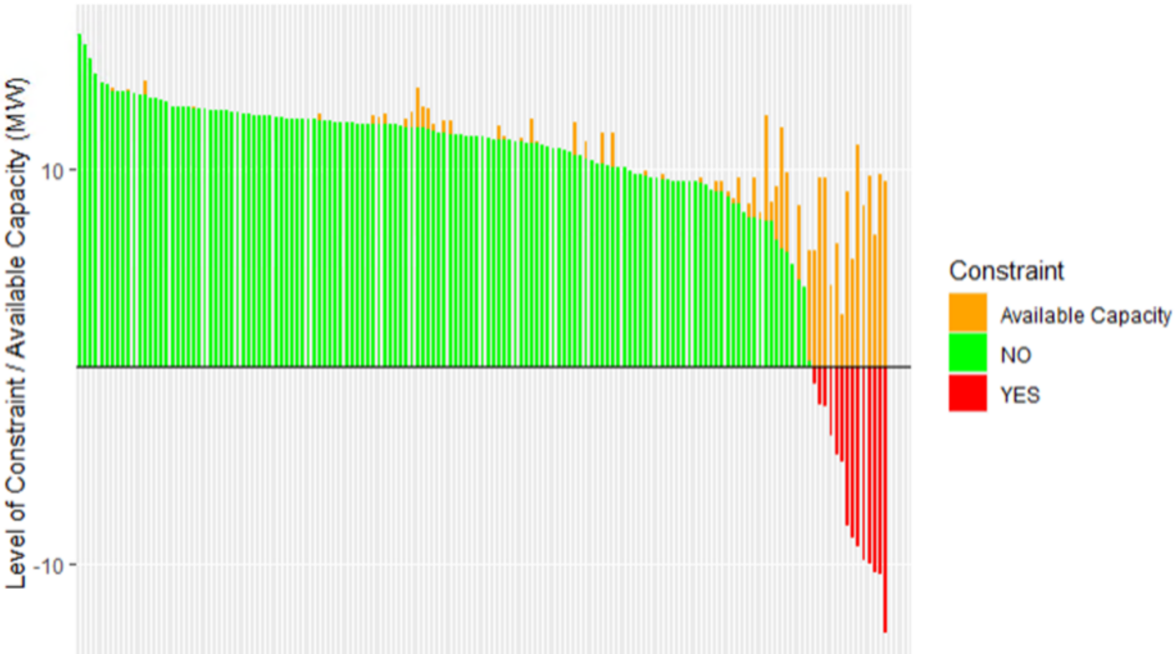

Figure 12 - Level of constraint (green and red, MW) and Available Capacity (orange, MW) for all primary substations in the Hampshire region for the High (25% penetration), onshore wind generation scenario.

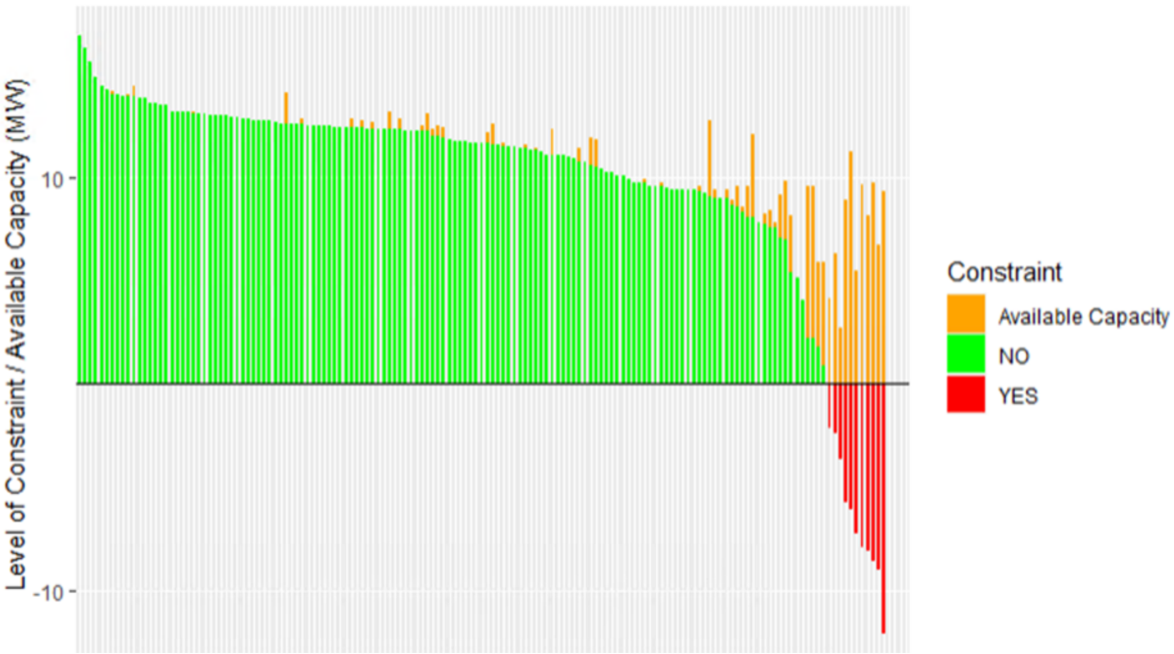

Figure 13 - Level of constraint (green and red, MW) and Available Capacity (orange, MW) for all primary substations in the Hampshire region for the Medium-High (20% penetration), onshore wind generation scenario.

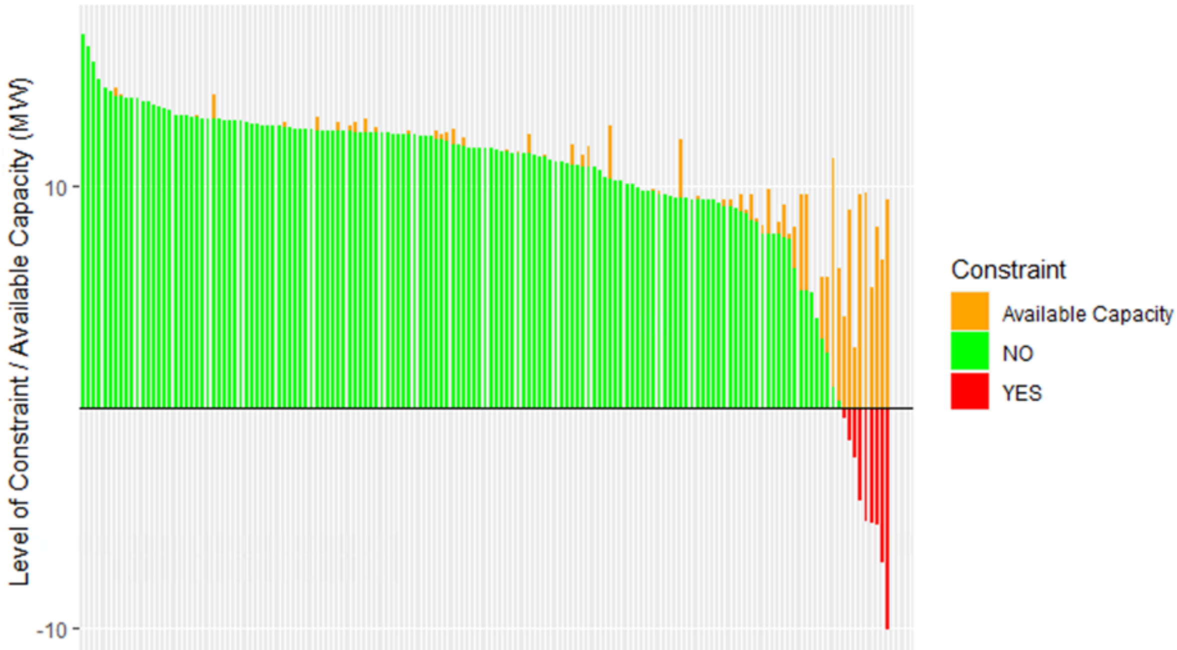

Figure 14 - Level of constraint (green and red, MW) and Available Capacity (orange, MW) for all primary substations in the Hampshire region for the Medium-Low (15% penetration), onshore wind generation scenario.

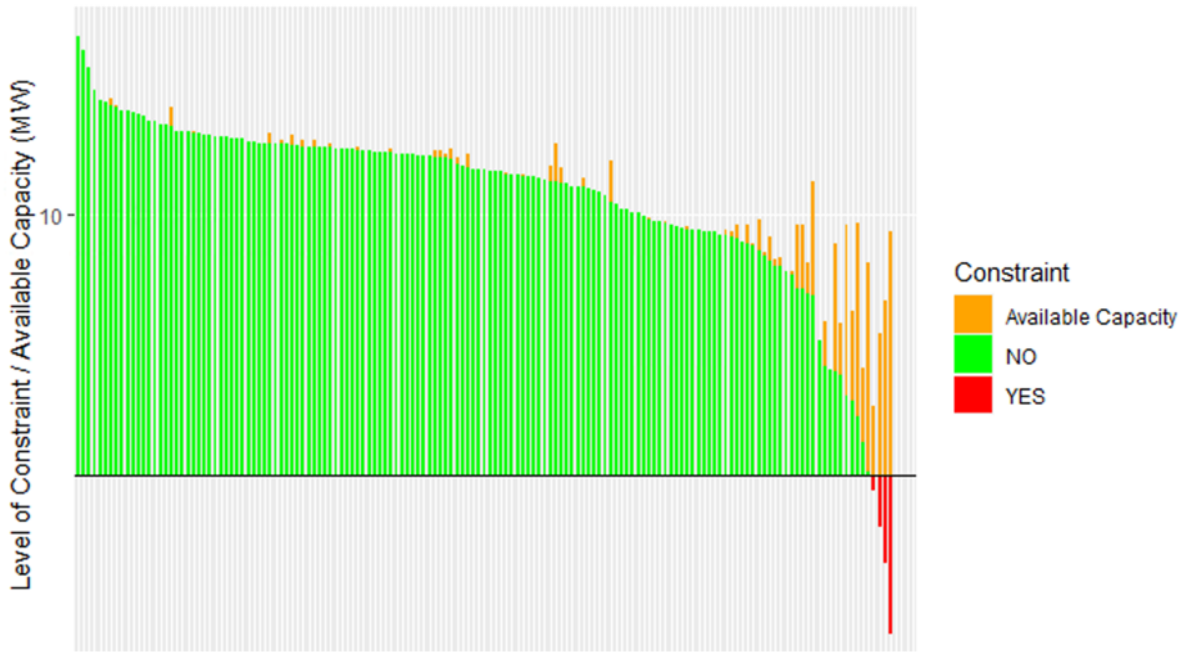

Figure 15 - Level of constraint (green and red, MW) and Available Capacity (orange, MW) for all primary substations in the Hampshire region for the Low (10% penetration), onshore wind generation scenario.

As Table 5 shows, if the maximum installable wind under the High scenario (218 MW) was connected, approximately 745 GWh of electricity would be generated per year. This corresponds to 10% of Hampshire's 2020 electricity demand. As would be expected, this value decreases under the less ambitious scenarios.

Table 5 – Potential installable wind before network intervention required under all scenarios

Scenario	Modelled potential (MW)	MW capacity installable	% of modelled potential	GWh/year	% current Hampshire demand
High	313	218	70%	745	9.9%
Medium-High	250	190	76%	650	8.6%
Medium-Low	188	159	85%	543	7.2%
Low	125	118	94%	404	5.4%

Due to the relatively low onshore wind potential (313 MW for high scenario, 218 MW installable before intervention) compared to the utility-scale solar potential (13,325 MW for high scenario, 1,252 installable before intervention), a mix of the two generation technologies will be required. Having a diverse energy mix also helps balance the intermittency issues that occur from renewable generation sources (Gross et al., 2007).

4.2.3 Combined Generation

This section combines the above results and shows the number of primary substations across Hampshire projected to experience constraints for each scenario as a combination of both utility-scale solar PV and onshore wind (Figure 16). As before over 50% of primary substations will not experience constraints under any scenario. However, for the Medium-High, Medium-Low and Low scenarios, there are a greater number of constrained primary substations than for solely utility-scale solar PV. This shows that the addition of onshore wind generation was enough to exceed the limits for some of the primary substations.

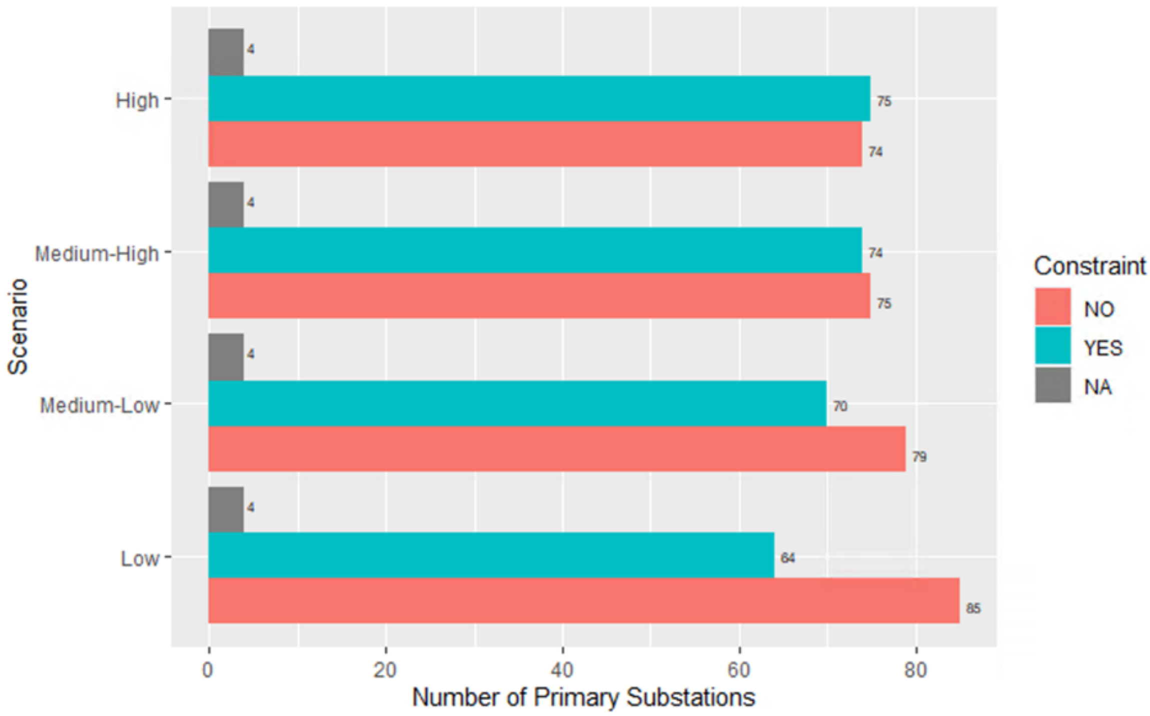

Figure 16 – Number of primary substations across Hampshire projected to exceed its capacity (constrained) for each combined generation scenario.

Figure 17 shows the spatial distribution of the constrained and non-constrained PSA across Hampshire for each scenario. It again shows that the more rural areas, which tend to have greater potential generation capacity and lower demand, are at greatest risk of constraints arising. It is clear that the same spatial distribution is occurring as before, with non-constrained areas largely being within more built-up urban areas, especially in the High and Medium-High scenario. This, again, is due to the relatively low potential solar PV capacity compared to more rural areas, which will have greater areas to develop on. These areas, however, will have a larger rooftop solar PV potential so there are risks of constraints arising in these areas. Also, the PSA within rural areas are larger than within urban areas, meaning that it is likely that a larger number of suitable sites can be connected to a single primary substation. Rural areas also tend to have lower demand and therefore a lower network capacity available.

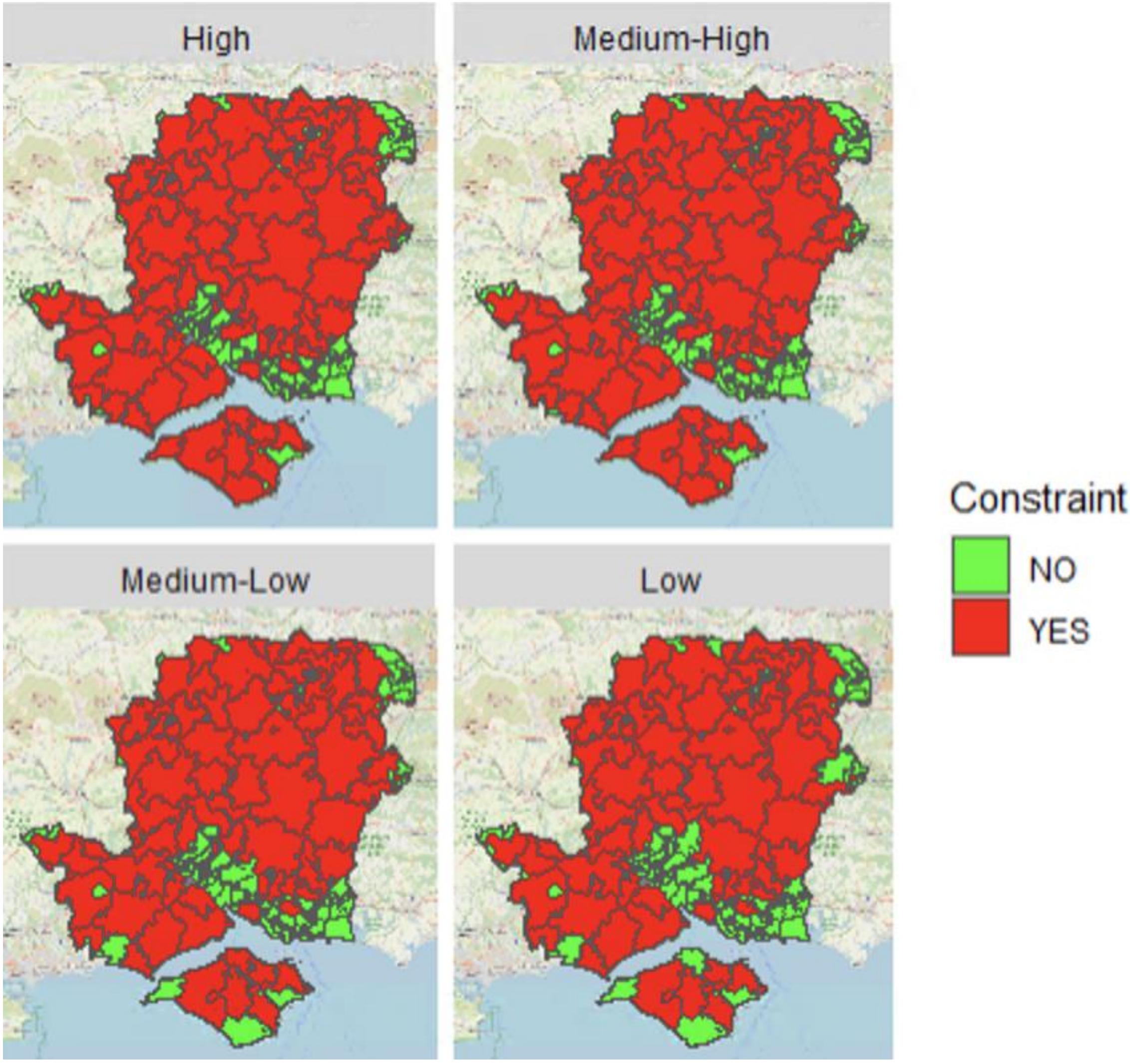

Figure 17 – Primary substation areas that are either constrained or not constrained for each combined generation scenario.

Figures 18, 19, 20, and 21 show the level of constraint and current available capacity (orange) that may arise due to the deployment of utility-scale solar PV and onshore wind developments for the high, Medium-High, Medium-Low and Low scenarios, respectively. The constrained primary substations (red) were projected to have a potential generation capacity that exceeded the network's limits without any intervention. For these PSA, the maximum generation capacity they can currently connect is shown by the available capacity.

The non-constrained primary substations (green), have sufficient capacity to cope with the projected levels of generation and do not require any intervention, unless development past the available capacity is required. For most of the non-constrained PSA there is available headroom, meaning that further the projected generation capacity is below the available capacity, and so further generation can be added without causing constraints. This could be from micro-generators such as rooftop solar PV systems.

For the High scenario (Figure 18), a total of 13,638 MW of utility-scale solar PV and onshore wind capacity was projected in our previous work. Of this potential, 1,258 MW (~9%) can be utilised with no intervention or reinforcement from the DNO. As we move down the installable generation scenarios, we will find more substations will be 'green' as they no longer breach the constraint threshold.

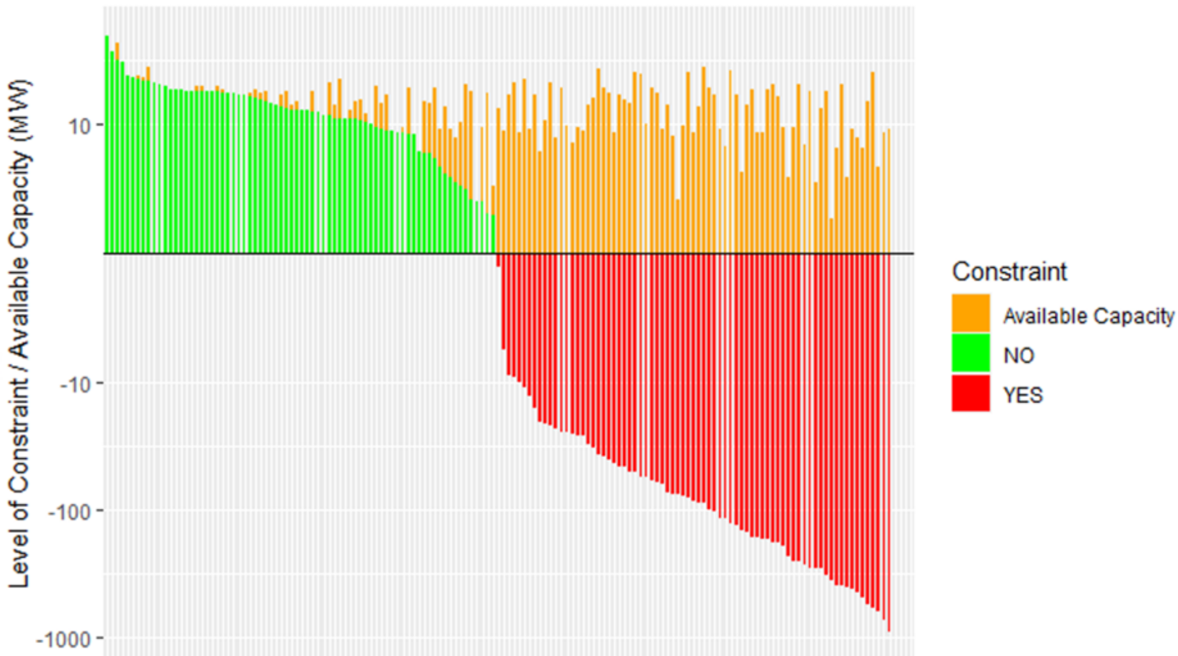

Figure 18 – Level of constraint (green and red, MW) and Available Capacity (orange, MW) for all primary substations in the Hampshire region for the High (25% penetration), combined generation scenario.

The Medium-High Scenario (Figure 19) previously projected 10,910 MW of utility-scale solar PV and onshore wind across Hampshire. Of this potential, 1,206 MW (~11%) could be connected to the network without any intervention from the DNO.

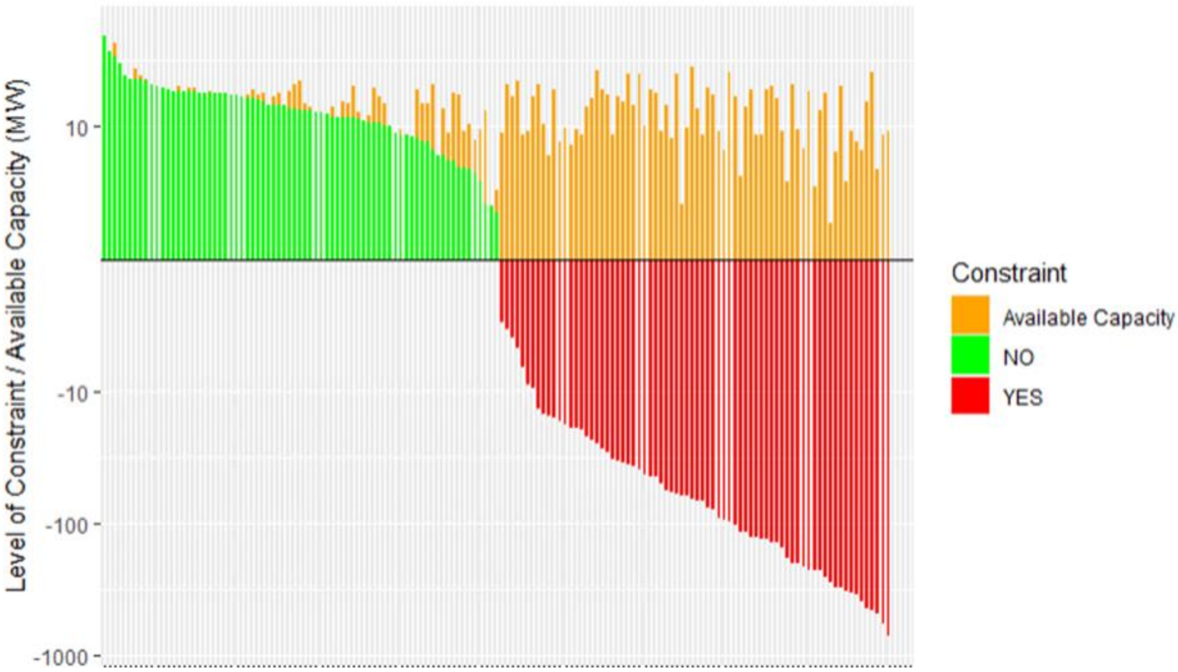

Figure 19 - Level of constraint (green and red, MW) and Available Capacity (orange, MW) for all primary substations in the Hampshire region for the High (20% penetration), combined generation scenario.

The Medium-Low Scenario (Figure 20) previously projected 8,183 MW of utility-scale solar PV and onshore wind across Hampshire. Of this potential, 1,147 MW (~14%) could be connected to the network without any intervention from the DNO.

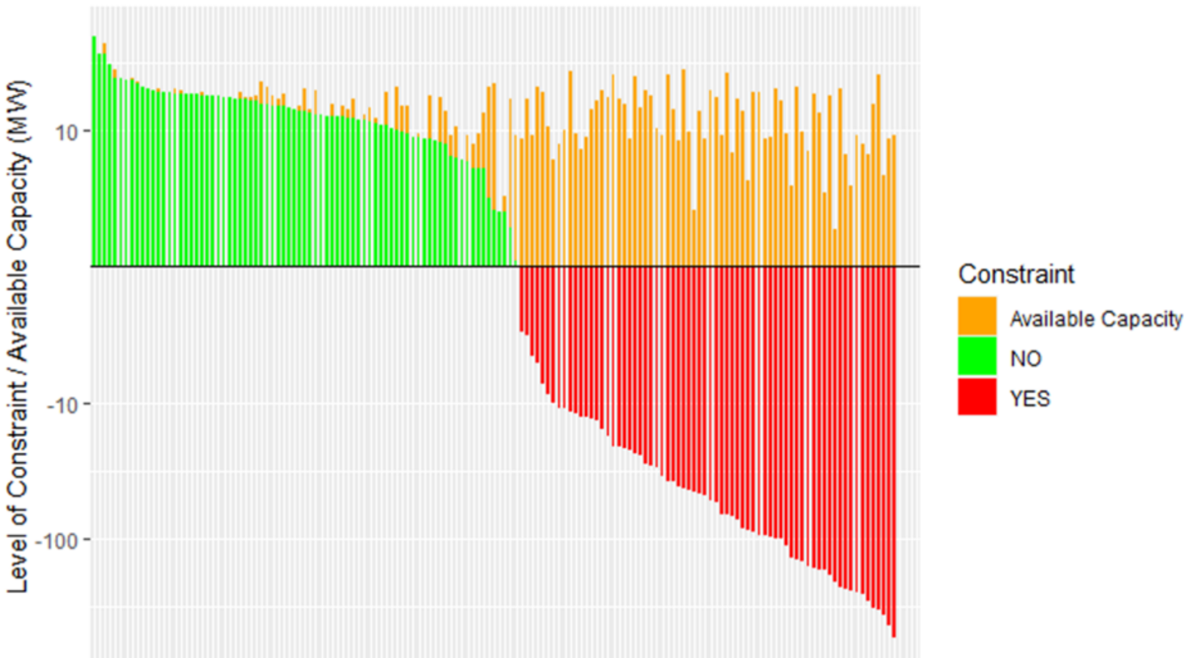

Figure 20 - Level of constraint (green and red, MW) and Available Capacity (orange, MW) for all primary substations in the Hampshire region for the High (15% penetration), combined generation scenario.

The Low Scenario (Figure 21) previously projected 5,455 MW of utility-scale solar PV and onshore wind across Hampshire. Of this potential, 1,062 MW (~19%) could be connected to the network without any intervention from the DNO.

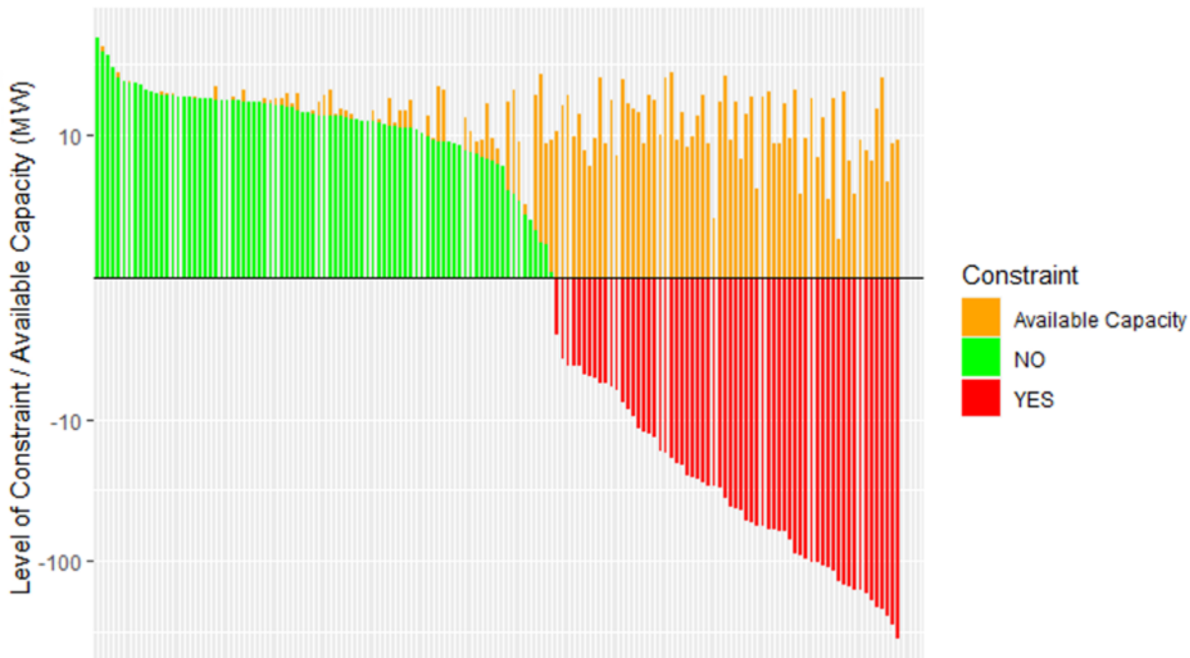

Figure 21 - Level of constraint as a percentage of primary substation capacity for all primary substations in the Hampshire region for the Low (10% penetration), combined generation scenario.

If, due to the lower projected capacity, we consider full development of onshore wind capacity for each scenario, we can assume that the remaining network stated available capacity can be utilised for utility-scale solar PV systems. For the High scenario, this would result in an energy mix of 218 MW of onshore wind and 1,040 MW of utility-scale solar PV. This would generate approximately 1,747 GWh of electricity per year. This is only enough to satisfy 23% of Hampshire 2020 electricity demand (7,520 GWh) as Table 6 shows.

Table 6 – Potential installable solar PV and wind before network intervention required under all scenarios

Scenario	Modelled potential (MW)	MW capacity installable	% of modelled potential	GWh/year	% current Hampshire demand
High	13,638	1258	9%	1747	23.2%
Medium-High	10,910	1206	11%	1628	21.6%
Medium-Low	8,183	1147	14%	1495	19.9%
Low	5,455	1062	19%	1313	17.5%

Table 7 below shows the 20 primary substations with the highest connectable generation (MW). This is the total projected generation that can be connected to the network without causing any constraints. For projected non-constrained substations (positive available headroom), this is simply the projected generation. For projected constrained substations (negative available headroom), the connectable generation is the available capacity. These are areas with the greatest technical potential generation capacity after including the network's capacities. These areas should be targeted first as they have the highest potential generation capacity without the need for intervention or reinforcement from the DNO.

Table 7 - Projected top 20 primary substations with the highest connectable generation (MW) across Hampshire for the High scenario.

Primary Substation	Available Capacity (MW)	Projected Generation (MW)	Available Headroom (MW)	Connectable Generation (MW)
WATERLOOVILLE	28.11	117.75	-89.64	28.11
EASTLEIGH NORTH	27.10	64.75	-37.65	27.10
HOUNDMILLS	26.28	156.00	-129.72	26.28
ALTON LOCAL	25.88	610.50	-584.62	25.88
CHRISTCHURCH	25.36	77.00	-51.64	25.36
NEWPORT	25.26	106.00	-80.74	25.26
HITCHES LANE	25.03	81.25	-56.22	25.03
NETLEY COMMON	22.34	33.50	-11.16	22.34
NEW MILTON	21.04	30.25	-9.21	21.04
THATCHAM	20.95	43.25	-22.30	20.95
GORDON ROAD	20.70	275.50	-254.80	20.70
ANDOVER EAST	20.40	201.75	-181.35	20.40
PETERSFIELD	20.35	417.75	-397.40	20.35
FLETCHWOOD	19.47	119.25	-99.78	19.47
DOWN GRANGE	19.40	58.50	-39.10	19.40
RYDE	19.40	79.75	-60.35	19.40
COWES	19.28	44.00	-24.72	19.28
BASINGSTOKE	18.97	191.00	-172.03	18.97
LYMINGTON	18.86	182.50	-163.64	18.86
HOOK	18.41	304.50	-286.09	18.41

Table 8 below shows the primary substations that have the greatest projected level of constraint and are therefore at greatest risk of faults occurring. These areas will have the greatest potential for renewable generation but without intervention, their full potential cannot be exploited to any great extent. This highlights the need for intervention from the DNO to effectively (increasing demand or energy storage) or physically (network reinforcement) increasing the network's capacity in these areas. However, even in this case development up to the substation's available capacity can occur without intervention and some substations (e.g. Alton Local) are found in both tables.

Table 8 – Projected 20 most severely constrained primary substations across Hampshire for the High scenario.

Primary Substation	Available Capacity (MW)	Projected Generation (MW)	Constraint (MW)
ALRESFORD	9.12	905.00	-895.88
PRESTON CANDOVER	8.56	738.25	-729.69
BARTON STACEY	4.48	623.00	-618.52
ALTON LOCAL	25.88	610.50	-584.62
BISHOPS WALTHAM	15.27	568.00	-552.73
HOUGHTON	6.45	500.50	-494.05
MIDDLE WALLOP	7.69	447.25	-439.56

OVERTON	9.05	431.00	-421.95
HURSTBOURNE TARRANT	3.64	414.25	-410.61
PETERSFIELD	20.35	417.75	-397.40
KINGSCLERE	6.39	400.00	-393.61
ROCKBOURNE	1.31	354.25	-352.94
HORNDEAN	18.11	341.50	-323.39
MILL LANE	13.34	304.00	-290.66
WHITCHURCH	3.23	289.50	-286.27
HOOK	18.41	304.50	-286.09
DUNBRIDGE	6.78	277.50	-270.72
GORDON ROAD	20.70	275.50	-254.80
LANGLEY	9.56	264.25	-254.69
THRUXTON	3.60	237.75	-234.15

Of these, it is instructive to note that SSEPD are planning to upgrade the EHV/HV components of Alresford substation during the ED2 period (2023 - 2028)[3].

4.3 Potential installable renewable generation under increased demand

This section repeats the above analysis but under the increased demand scenario and for combined solar and wind alone for simplicity.

After adjusting the Minimum Load (increasing electricity demand by 250%, as described in Section 3.6), the new theoretically available generation capacity was determined. This is shown below in Figure 22. As expected, it is clear that the available generation capacity has increased as the minimum load increases. The total available capacity across all PSA in Hampshire is now approximately 3,509 MW. This has increased by approximately 54% from the available generation capacity based on current electricity demand. This increased available generation capacity is approximately 25% of the potential generation capacity for the High (25%) scenario, as identified in the previous work. However, this increased capacity would only meet 19% of Hampshire’s increased total electricity demand of 18,800 GWh per year.

[3] See https://www.ssen.co.uk/globalassets/our-services/standard-network-capacity-report-ws1b-p5/ssen-standard-network-capacity-ws1b-p5---methodology-and-assumptions.pdf

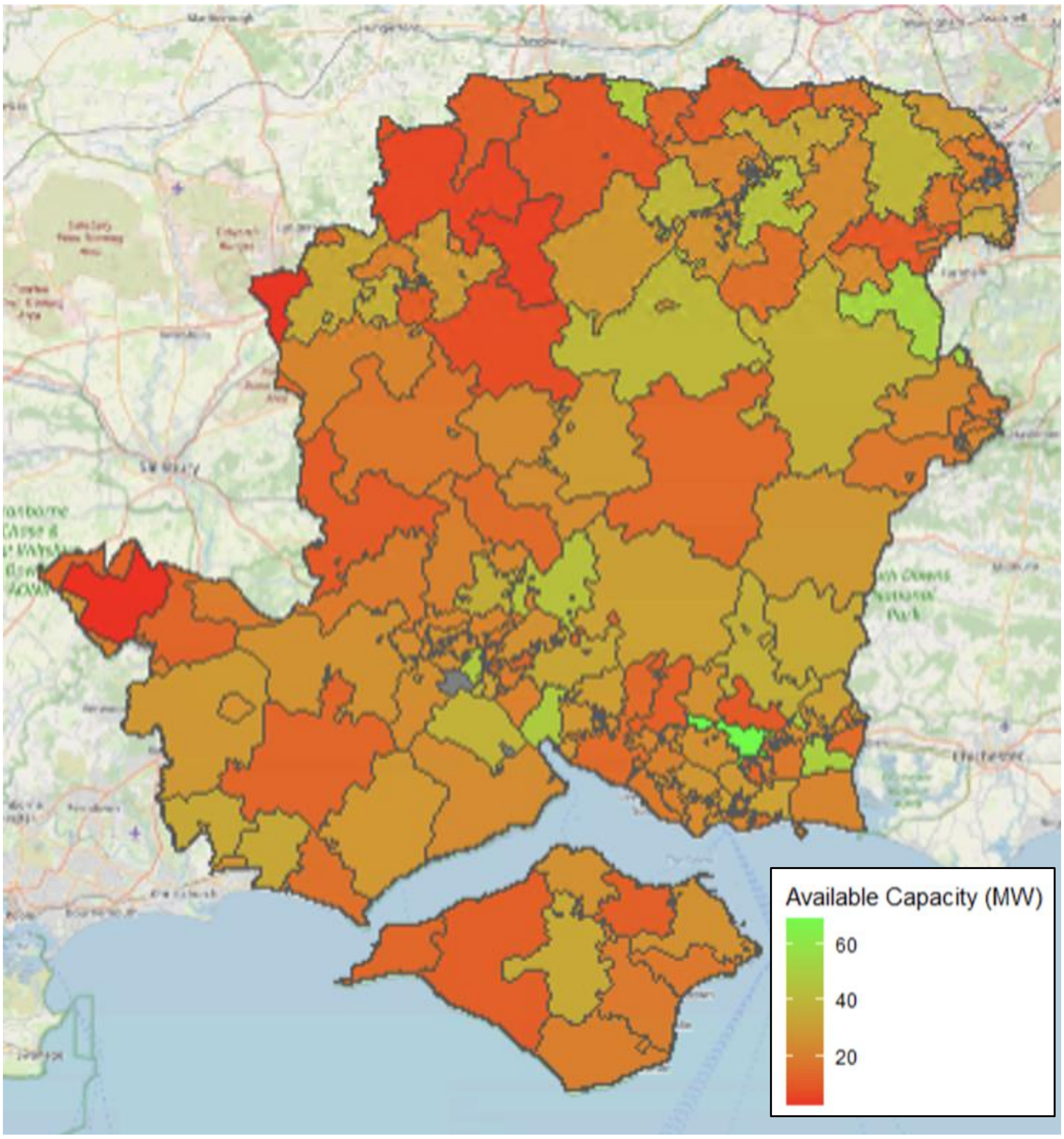

Figure 22 - Available Generation Capacity (MW) from substation limits and projected increased Min Load (250% of current Min Load), for each PSA.

This increase in electricity demand will also therefore decrease the risk of reverse power flow constraints occurring throughout the network. Figure 23 shows the number of primary substations that are projected to exceed their network capacity after electricity demand increases to 250% of the current value. It is clear that there are 4, 5, 7, and 11 fewer substations than before the demand increase that will be constrained in the High, Medium-High, Medium-Low, and Low scenarios, respectively.

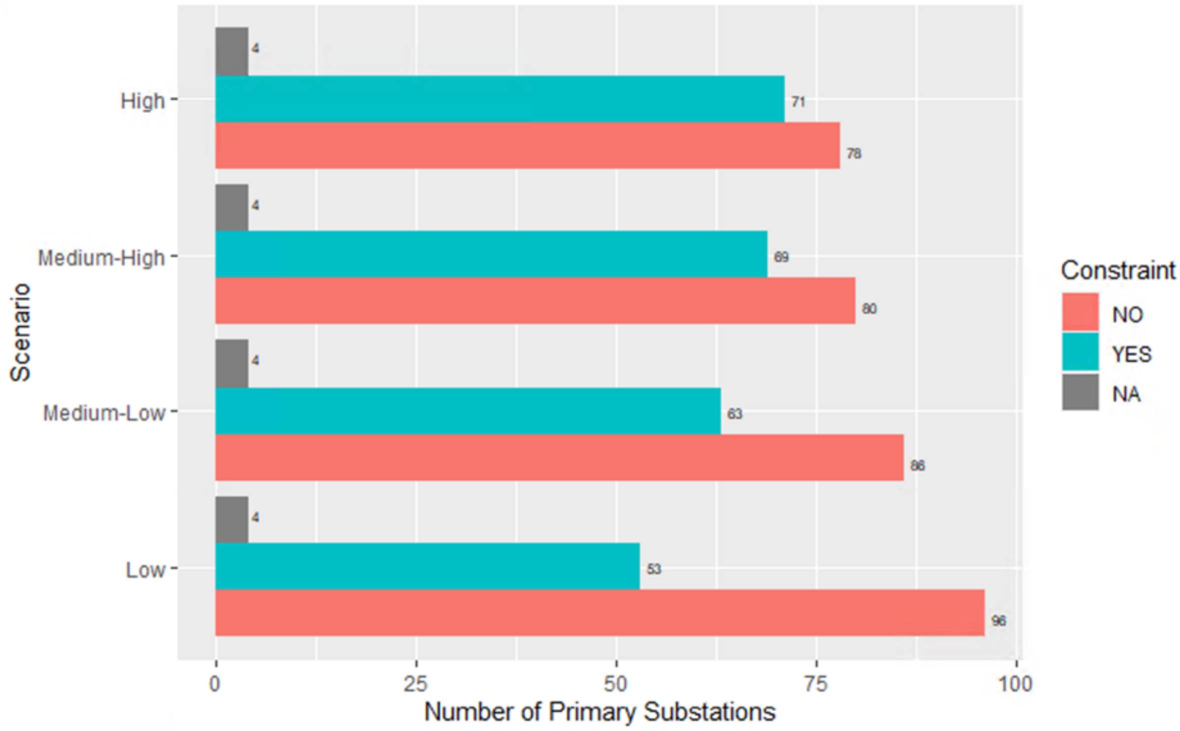

Figure 23 - Number of primary substations across Hampshire projected to exceed its capacity (constrained) for each combined generation scenario after increasing electricity demand to 250% of current demand.

Figure 24 shows the spatial distribution of the constrained and non-constrained PSA across Hampshire for each scenario. It again shows that the more rural areas, which tend to have greater potential generation capacity and lower demand, are at greatest risk of constraints occurring. However, due to the increase in electricity demand there are more rural areas which are not constrained. However, as noted above this method assumes that all electrical demand within all PSA will increase to 250% of the current demand, which is unlikely. It is more likely that overall increase of electricity demand across Hampshire will largely be driven by increasing electricity demand within cities.

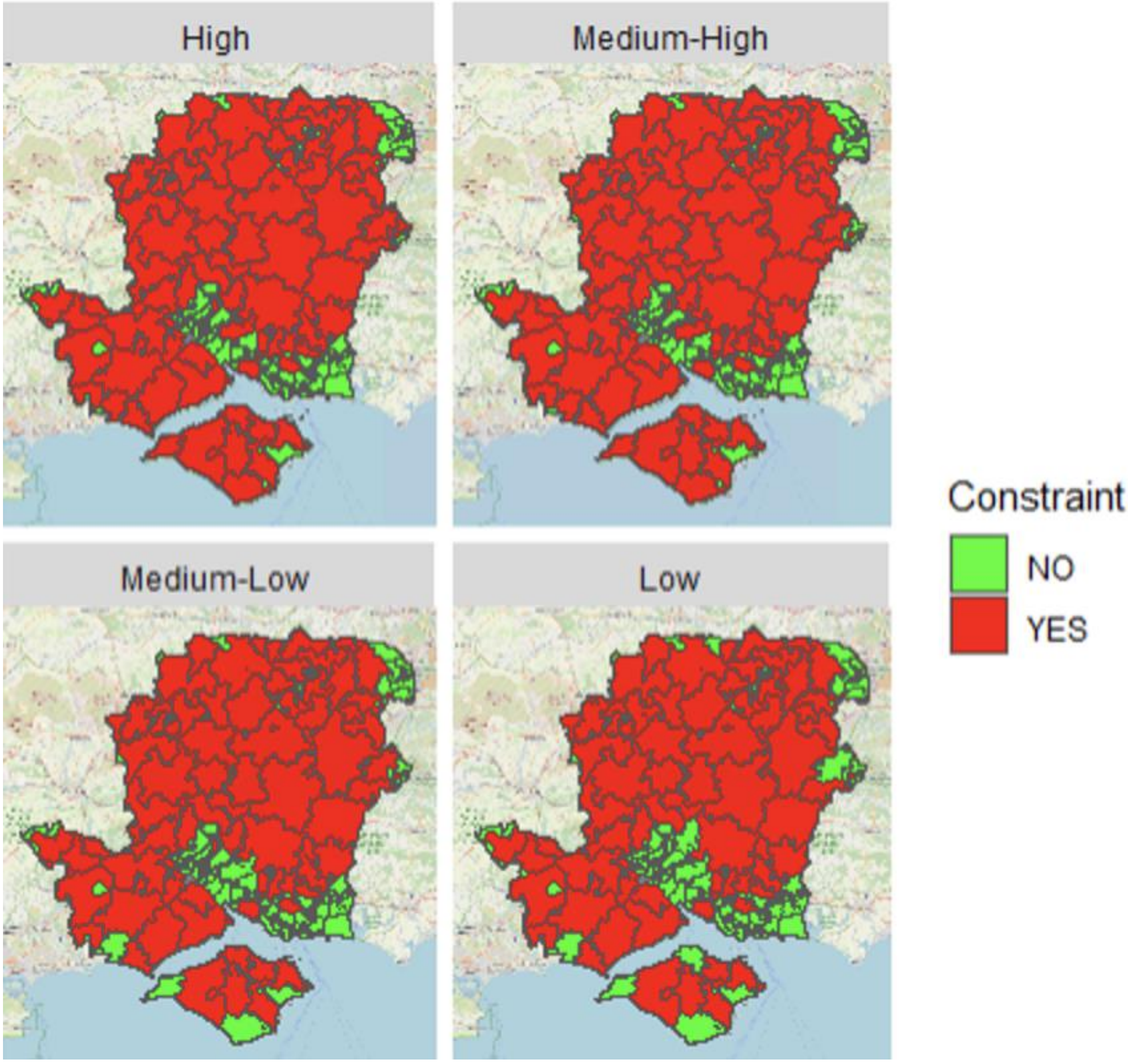

Figure 24 - Primary substation areas that are either constrained or not constrained for each combined generation scenario after increasing electricity demand to 250% of current demand.

Figures 25, 26, 27, and 28 show the level of constraint and adjusted available capacity (orange) that may arise due to the deployment of utility-scale solar PV and onshore wind developments for the high, Medium-High, Medium-Low and Low scenarios, respectively. The constrained primary substations (red) were projected to have a potential generation capacity that exceeded the network's limits without any intervention. For these PSA, the maximum generation capacity they can currently connect is shown by the available capacity. Due to the increase in demand, the available capacity has increase, as expected. Due to the increase in the available capacity, the level of constraint has decreased.

The non-constrained primary substations (green), have sufficient capacity to cope with the projected levels of generation and do not require any intervention, unless development past the available capacity is required. For most of the non-constrained PSA there is available headroom, meaning that further the projected generation capacity is below the available capacity, and so further generation can be added without causing constraints. This can be from micro-generators such as rooftop solar PV systems.

After increasing electricity demand, 1,918 MW (~ 52% increase) of potential solar PV and wind generation can be connected with no intervention or reinforcement from the DNO under the High scenario. This represents 14% of the modelled potential and would generate around 2,535 GWh/year meeting 13% of Hampshire's future increased demand. As we move down the installable generation scenarios, we will find more substations will be 'green' as they no longer breach the constraint threshold.

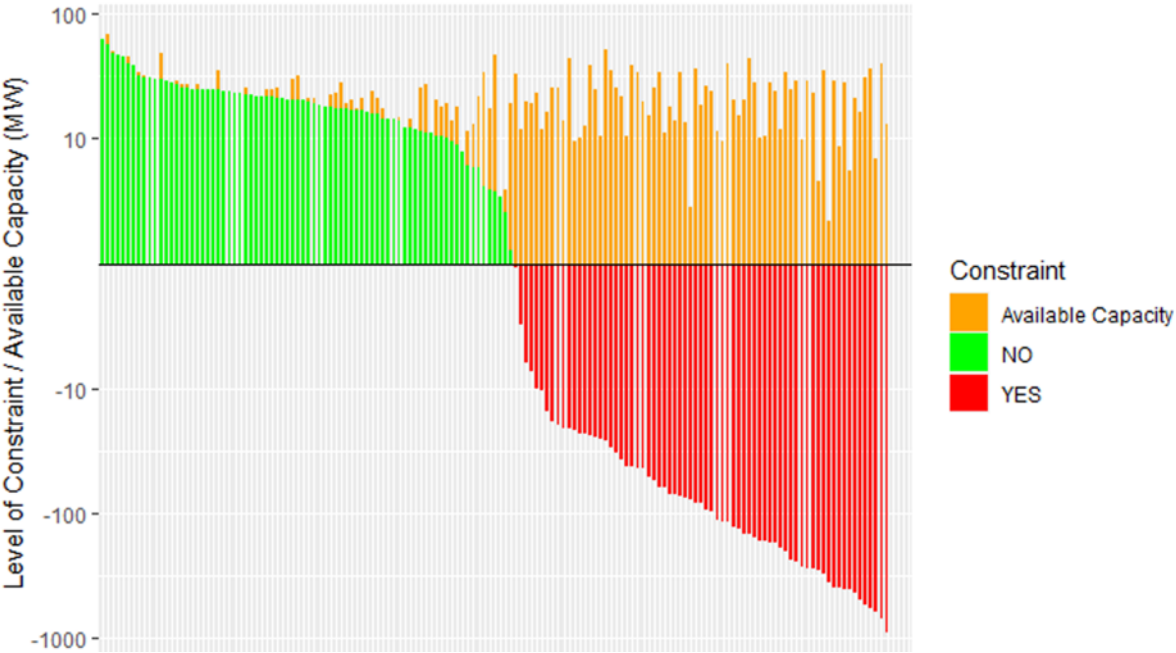

Figure 25 - Level of constraint (green and red, MW) and Available Capacity (orange, MW) for all primary substations in the Hampshire region for the High (25% penetration), combined generation scenario, after increasing electricity demand.

After increasing electricity demand, 1,841 MW (~ 53% increase) can be utilised with no intervention or reinforcement from the DNO for the Medium-High scenario.

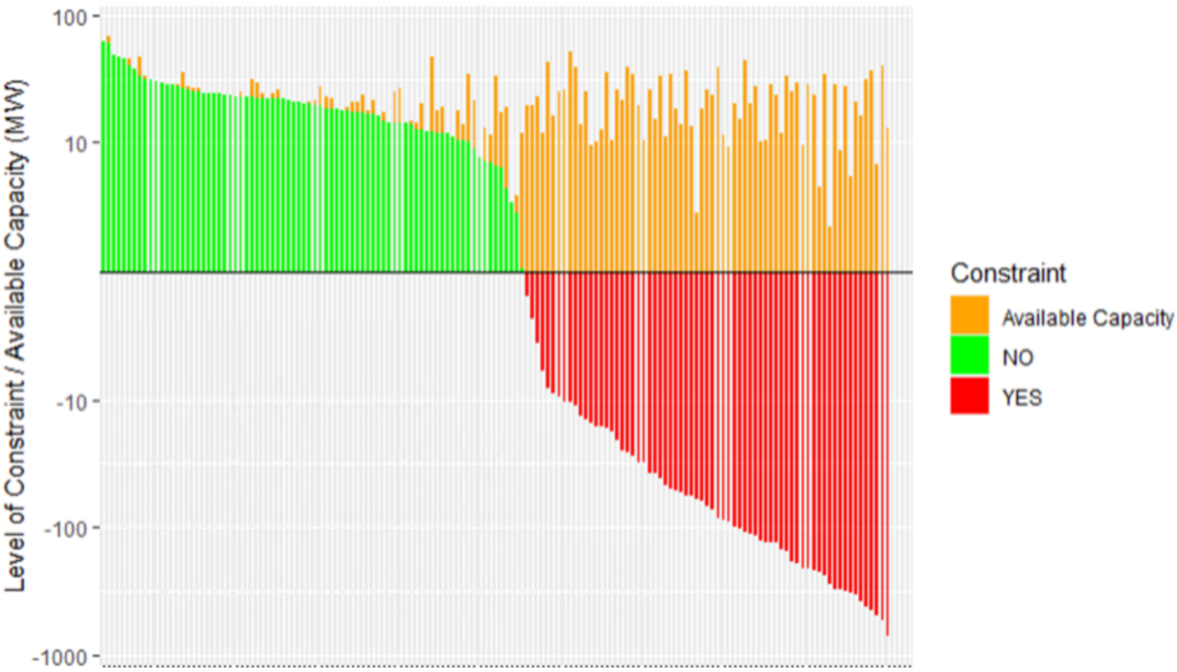

Figure 26 - Level of constraint (green and red, MW) and Available Capacity (orange, MW) for all primary substations in the Hampshire region for the Medium-High (20% penetration), combined generation scenario, after increasing electricity demand.

After increasing electricity demand, 1,739 MW (~ 52% increase) can be utilised with no intervention or reinforcement from the DNO for the Medium-Low scenario.

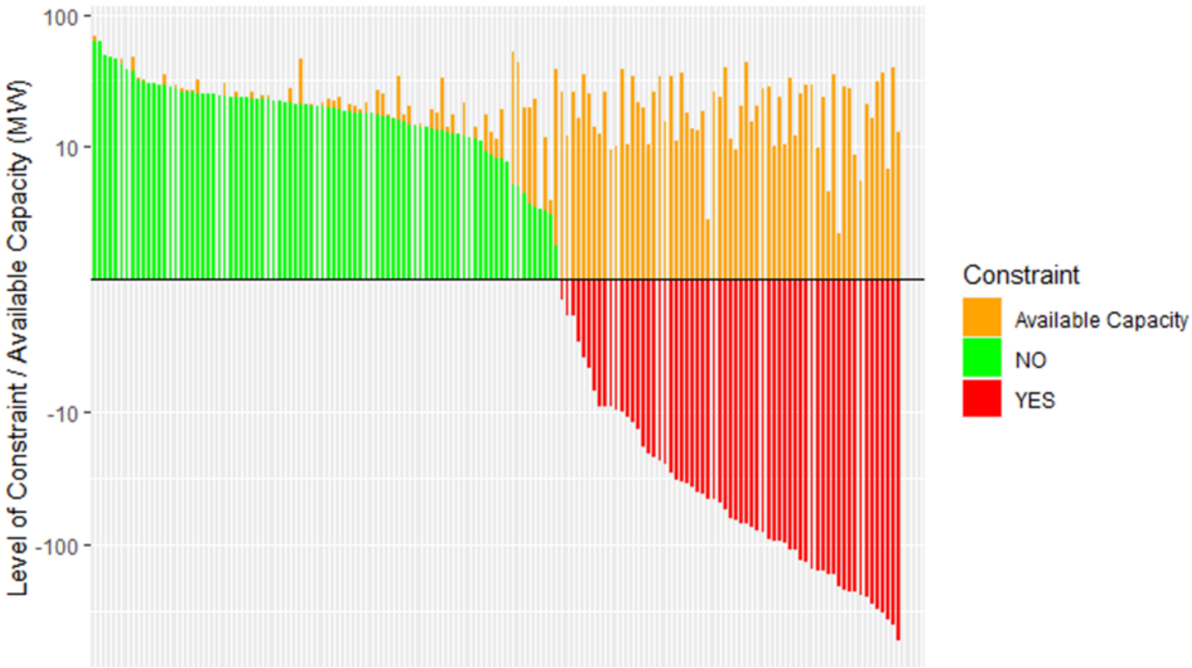

Figure 27 - Level of constraint (green and red, MW) and Available Capacity (orange, MW) for all primary substations in the Hampshire region for the Medium-Low (15% penetration), combined generation scenario, after increasing electricity demand.

After increasing electricity demand, 1,550 MW (~ 46% increase) can be utilised with no intervention or reinforcement from the DNO for the Low scenario.

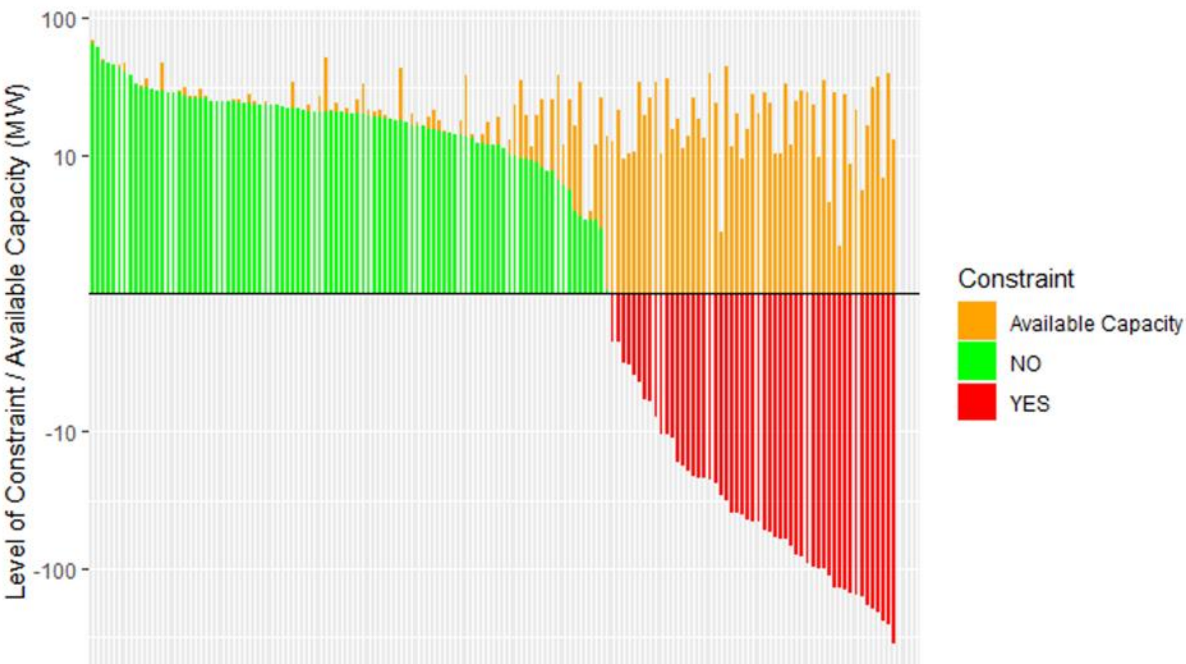

Figure 28 - Level of constraint (green and red, MW) and Available Capacity (orange, MW) for all primary substations in the Hampshire region for the Low (10% penetration), combined generation scenario, after increasing electricity demand.

If, due to the lower projected capacity, we consider full development of onshore wind capacity for each scenario, we can assume that the remaining network stated available capacity can be utilised from utility-scale solar PV systems. For the High scenario, this would result in an energy mix of 280 MW of onshore wind and 1,638 MW of utility-scale solar PV.

As Table 9 shows this would generate approximately 2,535 GWh of electricity per year. This would only meet 13% of Hampshire's projected electricity demand after the increase (18,800 GWh). As expected the lower ambition scenarios would meet progressively less of this projected future demand.

Table 9 – Potential installable solar PV and wind before network intervention required under all scenarios (under increased demand)

Scenario	Modelled potential (MW)	MW capacity installable	% of modelled potential	GWh/year	% future Hampshire demand
High	13,638	1,918	14%	2,535	13.5%
Medium-High	10,910	1,841	17%	2,343	12.5%
Medium-Low	8,183	1,739	21%	2,122	11.3%
Low	5,455	1,550	28%	1,800	9.6%

Table 10 highlights the effects of increasing electricity demand on connectable generation capacity without constraints arising. It is clear that the available capacity of each substation increases substantially allowing for much greater generation to be connected to each primary substation. As electricity demand is likely to increase in the future, mainly due to the electrification of heat and transport, these are the PSA that generation projects should look to develop in as they can connect the highest generation capacity without the need for intervention or reinforcement.

Table 10 – Projected top 20 primary substations with the highest connectable generation (MW) across Hampshire for the High scenario after increasing electricity demand to 250% of current demand.

Primary Substation	Available Capacity (MW)	Projected Generation (MW)	Available Headroom (MW)	Connectable Generation (MW)
WRECCLESHAM	51.95	78.25	-26.30	51.95
BASINGSTOKE	44.05	191.00	-146.95	44.05
EASTLEIGH NORTH	43.63	64.75	-21.12	43.63
THATCHAM	46.83	43.25	3.58	43.25
PRESTON CANDOVER	40.15	738.25	-698.10	40.15
HOUNDMILLS	39.45	156.00	-116.55	39.45
HITCHES LANE	38.97	81.25	-42.29	38.97
BUTTS ASH	38.78	62.50	-23.73	38.78
ALTON LOCAL	36.95	610.50	-573.55	36.95
WATERLOOVILLE	36.60	117.75	-81.15	36.60
PORTWAY	35.50	65.25	-29.76	35.50
HORNDEAN	34.78	341.50	-306.73	34.78
NEWPORT	34.65	106.00	-71.35	34.65
CHRISTCHURCH	34.15	77.00	-42.85	34.15
BRAMLEY GREEN	33.82	95.00	-61.19	33.82
THRUXTON	33.68	237.75	-204.08	33.68
NETLEY COMMON	33.35	33.50	-0.15	33.35
BISHOPS WALTHAM	31.43	568.00	-536.58	31.43
NEW MILTON	34.23	30.25	3.98	30.25
GORDON ROAD	29.25	275.50	-246.25	29.25

Table 11 below shows the 20 most severely constrained primary substations based on the generation projections of the previous work. With the increased electricity demand, the level of constraint has decreased for each substation. However, the level of constraint is still extremely large if the complete High scenario is to be considered. Again, these substations have the greatest renewable generation potential with insufficient network capacity to cope with the projections. Any DNO interventions to manage network constraints should be considered within these areas first as could measures to significantly further increase local demand in co-ordination with increased local generation.

Table 11 - Projected 20 most severely constrained primary substations across Hampshire for the High scenario after increasing electricity demand to 250% of current demand.

Primary Substation	Available Capacity (MW)	Projected Generation (MW)	Constraint (MW)
ALRESFORD	13.05	905.00	-891.95
PRESTON CANDOVER	40.15	738.25	-698.10
BARTON STACEY	6.70	623.00	-616.30
ALTON LOCAL	36.95	610.50	-573.55
BISHOPS WALTHAM	31.43	568.00	-536.58
HOUGHTON	16.28	500.50	-484.23
MIDDLE WALLOP	21.18	447.25	-426.08
HURSTBOURNE TARRANT	5.35	414.25	-408.90
OVERTON	28.03	431.00	-402.98
KINGSCLERE	8.63	400.00	-391.38
PETERSFIELD	28.75	417.75	-389.00
ROCKBOURNE	1.78	354.25	-352.48
HORNDEAN	34.78	341.50	-306.73
WHITCHURCH	4.33	289.50	-285.18
HOOK	23.53	304.50	-280.98
MILL LANE	29.08	304.00	-274.93
DUNBRIDGE	9.66	277.50	-267.84
GORDON ROAD	29.25	275.50	-246.25
LANGLEY	25.15	264.25	-239.11
THRUXTON	33.68	237.75	-204.08

As above, of these substations SSEPD are planning to upgrade EHV/HV components of Alresford during the ED2 period (2023 - 2028).

5 Discussion

The analysis shows that of the two technologies considered, large utility-scale solar PV potential will be the main source of network constraints to arise across Hampshire, with onshore wind marginally increasing any issues that may arise. Considering utility-scale solar PV generation connection alone, a potential 50% of all primary substations across Hampshire will experience constraints under our High (25% of technical maximum implementation) scenario. Even for a 10% level of deployment of utility-scale solar PV, a potential 42% of all primary substations across Hampshire will experience constraints. One substation even has the chance of exceeding its network capacity by approximately 875 MW, which would require significant intervention and reinforcement to prevent this from occurring.

Implementing utility-scale solar PV and onshore wind in combination marginally increases the problem. For the 25% and 10% level of deployment scenarios, 50% and 43% of all primary substations across Hampshire are projected to experience constraints, respectively. This could lead to maximum constraint levels of approximately 896 MW to 350 MW respectively.

Looking at the spatial distribution of the constrained areas, it is clear that they mainly occur within more rural areas rather than built-up, urban areas. This may be because rural areas were found to have a greater generation potential than urban areas due to the criteria for suitable site selection. In addition rural areas tend to have lower minimum demand than built up areas due to a lower concentration of domestic and non-domestic properties, and they usually have a lower capacity rating and are therefore unable to accommodate substantial reverse power flow. Finally, the rural PSAs were generally larger than urban areas, which means that more generators are likely to be connected to a single substation than in smaller PSAs within urban areas. However, while urban areas are unsuitable for utility scale solar PV and wind, the lower constraint levels may allow for a greater rooftop solar PV capacity to help meet local urban demand.

Overall, due to the network constraints the theoretically available capacity across the Hampshire network is 2,280 MW under current demand levels. This means that of the previously identified potential capacity, only 9%, 11%, 14% and 15% can be connected to the network without any intervention (before any thresholds are breached) for the High, Medium-High, Medium-Low and Low scenarios, respectively. For the High scenario, if all of the connectable capacity was utilised with 218 MW of connectable onshore wind and a maximum of 1,040 MW of utility-scale solar PV, approximately 1,747 GWh of electricity would be generated per year (see Table 12). This is only enough to satisfy 23% of Hampshire's 2020 electricity demand (7,520 GWh).

Table 12 – Potential installable utility scale solar PV and wind before network intervention required under all scenarios and under current and increased demand

	Scenario:	High	Medium-High	Medium-Low	Low
Modelled potential		13,638	10,910	8,143	5,455
Current demand	MW capacity installable	1,258	1,206	1,147	1,062
	% modelled potential	9%	11%	14%	19%
	GWH/year	1,747	1,628	1,495	1,313
	% Hampshire current demand	23.2%	21.6%	19.9%	17.5%
Increased demand	MW capacity installable	1,918	1,841	1,739	1,550
	% modelled potential	14%	17%	21%	28%
	GWH/year	2,535	2,343	2,122	1,800
	% Hampshire future demand	13.5%	12.5%	11.3%	9.6%

The National Grid-ESO's Future Energy Scenarios state that electricity demand is set to rise up to 250% of current levels, mainly due to the electrification of heat and transport. This would increase Hampshire's electricity demand to 18,800 GWh. As demand absorbs local generation, an increase in electricity demand will result in a decreased power flow back towards and through substations to be distributed elsewhere. This will reduce the risk of constraints occurring and effectively "add" network capacity, without reinforcing the network, so more generation can be connected.

An electricity demand increase of this scale would increase the theoretically available network capacity by 54% to 3,509 MW. The potential renewable capacity that is able to be connected to the network increases from 1,258 to 1,918 MW under the High scenario (see Table 12). This would enable an energy mix of 280 MW of onshore wind and a maximum of 1,638 MW of utility-scale solar PV to be connected to the network before network intervention would be required. This would generate approximately 2,535 GWh of electricity per year (see Table 12), not enough to satisfy Hampshire's 2020 electricity demand (7,520 GWh) and only 13% of the increased annual electricity demand of 18,800 GWh.

The analysis shows that although increasing minimum electricity demand would increase the theoretically available connectable capacity, and thus increase the connectable generation, the proportion of future (increased) energy demand that could be met would be lower. It is therefore extremely clear that network reinforcement, local load management and local demand stimulation will all be required if Hampshire wishes to maximise the benefits of the level of potential local renewable generation modelled in our previous work.

6 Conclusion

The above analysis shows that there are critical local distribution network limits to the exploitation of the potential renewable generation capacity modelled in our previous work. Under current levels of local demand only 9% of our modelled High development renewable capacity scenario can be connected without some form of network intervention. This would meet 23% of current Hampshire demand. In a future higher demand context this increases to 14% but would meet a lower percentage (13.5%) of the increased overall demand leaving the reminder to be met by other sources.

Further, the analysis suggests that a mix of strategies will be needed to reduce the risk of constraints in areas with high renewable potential. Clearly network reinforcement will be important to accommodate reverse power flow but the co-location of local 'clean energy hubs' with additional renewable capacity could be used to increase minimum local demand in areas of high constraints and high renewable potential and so. This would help to more easily balance increased local renewable supply with demand, prevent reverse power flow through a distribution or primary substation, potentially reduce the need for network reinforcement and also offer significant local 'clean green' economic opportunities. The results of the analysis suggest that in many cases there would need to be a significantly higher than 250% increase in current minimum demand levels in the absence of storage (see e.g. Table 11). This could, for example, include the introduction of a hydrogen production facility which used electricity in the production process. The hydrogen produced can then be used as an energy storage method, for transport, heating methods or other alternatives (Parra, Valverde, Pino, & Patel, 2019).

Local energy storage systems could also be utilised to help balance the temporal mismatch between renewable electricity generation and electricity demand thus preventing the need to accommodate reverse power flow at times of high generation and low demand. This is done by storing energy if demand is low during peak generation times and releasing it at a later time, or date (if seasonal storage is available) when demand increases. This can reduce constraints by absorbing generation before it flows back through a substation to be distributed elsewhere (Pienaar, Kusakana, & Manditereza, 2018) and would allow greater renewable generation capacity to be connected to the network. Co-location of storage with generation is already in place for some of the existing small to medium-scale (~50MW) solar installations in Hampshire and nearly all of those approved but currently awaiting construction[4].

Direct 'private wire' connections could be used to bypass the local distribution network and provide renewable supply to demand centres at some distance from the source of generation (Plecas, Gill, & Kockar, 2016). This would avoid distribution network constraints and is, in effect, the exact opposite of a 'clean energy hub' where demand is moved towards the source of supply.

Finally, it may be possible for larger installations (e.g. > 100 MW[5]) in specific areas to connect directly to the transmission network. This would also bypass distribution network constraints and could enable a significant increase in the exploitable renewable capacity in the Wider Hampshire region. Analysis of potential connection to the transmission network was outside the scope of the work reported here but could be assessed in the future. For context, as of July 2023 there were no operational solar PV sites over 75MW in the UK[6] and of the nine over this capacity currently in planning or awaiting construction (up to a

[4] Source: https://www.gov.uk/government/publications/renewable-energy-planning-database-monthly-extract.

[5] See https://www.nationalgrid.com/electricity-transmission/how-to-get-connected/how-can-i-connect. A 100 MW solar PV site would require approximately 200 Ha or roughly 280 football pitches.

[6] Source: https://www.gov.uk/government/publications/renewable-energy-planning-database-monthly-extract

proposed 600 MW site near Lincoln) nearly all are proposed in the Eastern or East Midlands regions.

Overall, unless addressed in a co-ordinated way, the network limits described are likely to inhibit Hampshire County Council's and other local and national government's net-zero ambitions, especially in terms of meeting increased local demand and capturing local economic value from local, distributed generation. This is because there is likely to be insufficient distribution network capacity to enable the full exploitation of the potential renewable generation that could be available. This work identifies primary substation areas at greatest risk of constraints arising, which will require significant intervention, and also areas that could be prioritised for renewable generation development due to their high available capacity and generation potential.

Finally, we note that the absence of capacity data at the distribution substation level means that the model is limited to analysis at the relatively large area primary substation level. Availability of distribution substation level data would increase the model's ability to use our potential renewable generation results to determine likely constraints at a much finer geographical granularity. This would substantially add to the value of the results in local renewable energy planning.

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