

## **OPF evaluation of distribution network capacity for the connection of distributed generation**

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## **Abstract**

Distributed generation (DG) capacity will increase significantly as a result of UK Government-led targets and incentives. While the technical problems arising from distribution level connections may be mitigated for individual connections, the anticipated connection volumes imply a potential risk of conflict between connections, in that inappropriately sized or located plant could constrain greater development of the network and consequently threaten the achievement of renewable energy targets.

One means of addressing this risk is to encourage development at sites that are more suitable whilst discouraging those at inappropriate ones. First network operators must be able to evaluate the available capacity on the system (i.e. the headroom). Here, a technique is presented that facilitates such analysis. Termed 'reverse load-ability', the approach models fixed-power factor DG as negative loads and uses optimal power flow to perform negative load shedding that effectively maximises capacity and identifies available headroom. The technique was applied to an extensive distribution and sub-transmission network. It was found to rapidly identify available headroom within the imposed thermal and voltage constraints. Furthermore, its use is demonstrated in examining the consequences of a sequence of connections in terms of the impact on available headroom and in sterilising the network.

## 1. Introduction

The European Union Renewables Directive and national incentives such as the UK Renewables Obligations [1]-[2] are encouraging the development of renewable energy resources. These distributed generators (DGs) will increasingly be connected to distribution networks given that the resources are generally located in remote areas.

Connection of DG fundamentally alters distribution network operation and creates a variety of well-known impacts that range from bi-directional power flows to increased fault levels although capacity is predominantly limited by voltage rise in more rural networks [3]. While a range of options exist to mitigate adverse impacts, under existing (deep-connection) UK commercial arrangements the developer will largely bear the financial responsibility for their implementation. The economic implications can make potential DG schemes less attractive and has been an impediment to the development of renewable energy. While the shallower connection charging regime to be introduced in April 2005 will lessen this effect, the burden will increasingly fall on Distribution Network Operators (DNOs) who will have to justify their investment and tariff setting approaches [4]. A further issue is that current DNO policies of assessing DG connections on a first come-first served basis can limit holistic DG development in that an early and perhaps quite minor connection can constrain development of other, potentially larger, opportunities in the same area, effectively 'sterilising' parts of the network.

The need to mitigate DG-related effects occurs because of the mismatch between the location of renewable resources and the capability of the network in those areas to accept new generation. The problem is compounded as, currently, the connection process ignores the consequent effects of decisions. One means of tackling both challenges is for DNOs to encourage development at the most

suitable locations by issuing information to developers regarding the existence, or otherwise, of spare connection capacity or from the locational signals created by connection pricing. Indeed it is a key driver in Ofgem's Registered Power Zones initiative in order to "signal to potential generators and other interested parties a DNO's development intentions or network capabilities at a particular location" [5]. The starting point for such initiatives is for DNOs to quantify the capacity of new DG that may be connected to distribution networks with and without the need for reinforcement.

## 2. Capacity Evaluation

A recent study of the transmission system in Scotland has published guidance on the location and capacity of new renewable generation that may be connected given current and future investment in the network [6]. Given that a significant fraction of new plant will connect to the sub-transmission or distribution network there is a clear need to perform similar studies at distribution level. However, the greater influence of DG on customer voltages (given the circuit and load characteristics and the relative lack of automatic voltage control), together with a significantly larger number of connection points means that a study on even a relatively small section of the distribution network is laborious. As such, evaluating distribution network headroom requires a means of effectively dealing with the problems of multi-dimensionality without unduly increasing the associated computational burden.

Among the literature devoted to optimisation problems at distribution level [7], several studies consider techniques for locating DG plant for optimal benefit. Rau and Wan [8] employ gradient and second order methods to determine the optimal location for the minimisation of losses or line loading. Kim *et al.* [9] use a combination of fuzzy non-linear goal programming and Genetic Algorithm (GA) techniques to locate DGs and minimise overall power losses. Nara *et al.* [10] apply tabu search techniques to the same problem. Griffin *et al.* [11] demonstrate an iterative method that provides an

approximation for the optimal placement of DG for loss minimisation. Within this, individual DG units were sited at selected buses and the impact on losses examined. Locations were ranked on the basis of loss reduction and DG units added incrementally until losses were minimised. Finally, Celli and Pilo [12] present a GA approach that, for a defined planning horizon, minimises the cost of network investment and losses whilst meeting feeder thermal, voltage profile and fault level constraints.

The wide fluctuation in demand (particularly at LV) and, an uncertain coincidence with DG export, makes loss minimisation, in itself, a complex, real-time issue. As such, the requirement here was to determine the maximum DG capacity at one, multiple or all connection points whilst satisfying network physical and operational constraints. While many of the approaches highlighted above might be adapted for this purpose, the intention was to make most use of tools that are already available and whose rigour is accepted by DNOs. Accordingly, optimal power flow (OPF) is employed for the capacity evaluation.

### **3. Problem Formulation**

Optimal power flow has been developed extensively through power systems research to address problems ranging from economic despatch to loss minimisation [13] and is a common feature in many power flow packages. As such, the use of OPF to maximise generation capacity appears to be a logical approach, however, it is not without difficulty. The generator models traditionally employed in OPF are of synchronous generators operating in voltage control mode. Given that DG is generally operated at a constant, pre-set, power factor, there is a need to preserve the power factor during

optimisation. Hence, alternative models are necessary and although this is feasible with bespoke OPF programs, it is generally not an option for proprietary packages.

To overcome this, the solution method presented here takes advantage of the commonly used technique of modelling steady-state DGs as negative loads. OPF has been used extensively for load shed optimisation in, for example, finding the conditions for voltage collapse. In this case, however, the conditions for voltage and thermal violation are of primary concern. By representing each DG as a negative load, the capacity evaluation problem can be expressed as a load addition problem – essentially a negative load shed where the cost of the negative load is minimised. This procedure has been termed ‘reverse load-ability’.

### 3.1 Mathematical Formulation

The capacity maximisation is adapted from an OPF formulation designed to minimise the cost of load shed [14]. The objective function ( $f$ ) and associated formulae are given as follows:

$$\min f(\psi) = \sum_{i=1}^n -C_i \cdot MW_i^0 (1 - \psi_i) \quad (1)$$

subject to:

$$\psi_{MIN,i} \leq \psi_i \leq \psi_{MAX,i} \quad (2)$$

$$MVA_i^{DG} = \psi_i \cdot MVA_i^0 \quad (3)$$

$$V_{MIN,j} \leq V_j \leq V_{MAX,j} \quad (4)$$

$$S_k - S_{MAX,k} \leq 0 \quad (5)$$

The capacity adjustment factor ( $\psi$ ) controls the capacity of each DG ( $i$ ) located at one of the  $n$  locations selected. It acts to multiply initial machine active power capacity ( $MW^0$ , p.u.) by a value between specified upper ( $\psi_{MAX}$ ) and lower ( $\psi_{MIN}$ ) limits, defined in (2). The negative capacity cost ( $-C$ ) represents the benefit derived per unit MW of DG capacity connected and ensures that the optimisation delivers the most negative value for the objective function. DGs possessing greater benefit are favoured. Equation (3) ensures that the output of each DG ( $MVA^{DG}$ , p.u.) remains at the same power factor as originally specified ( $MVA^0$ ). Clearly, different power factors, costs and capacity ranges can be specified for each potential DG. The allowable network voltage (at each bus  $j$ ) and thermal constraints (for each branch  $k$ ) are given in (4) and (5), respectively.

### 3.2 Implementation

The technique was implemented using the OPF component of the PSS/E power flow package (which uses an interior-point method) together with a bespoke user interface to manage the evaluations (termed 'simulation manager'). Further details of the implementation can be found in Appendix 9.2. However, the formulation should be applicable to any OPF package with the capability to optimise bus loading.

#### **4. Available Capacity within an Extensive Distribution Network**

The capacity evaluation technique has been applied to a section of the UK transmission and distribution network with a voltage range of 11 to 400 kV and around 6,000 and 600 km of overhead line at 11 and 33 kV, respectively. The network serves around 100 MVA of load in a mainly rural setting and the region has extensive potential for on- and offshore wind, mini-hydro and other renewable energy developments. Furthermore, over 300 MW of larger, centrally dispatched, generation is located in the network. In many respects the DG issues facing the network are reflective of the UK as a whole.

Figure 1 shows a sub-section of this network consisting of the 132 kV sub-transmission system with five Grid Supply Points (GSPs) – labelled A to E – modelled down to the 11 kV primary substations. Buses 1 to 12 are at 132 kV with the circuit between buses 1 and 2 representing the primary route for import and export from this portion of the system. The GSP groups are generally radial (with only limited inter-group connections) and supply loads that range from rural to urban-rural.

##### **4.1 Analytical Considerations**

With several voltage levels present, the operation of auto-tap transformers to provide voltage control must be considered. The algorithms in power flow simulations allow effective modelling of the auto-tap changers in meeting target secondary voltages. Unfortunately, such operation is not normally defined within the OPF; rather, tap settings are altered such that voltage profiles optimise the solution, *i.e.*, by maximising export from the DG. This mode of operation, along with the practice of fixing taps (as used in initial studies, *e.g.* [15]) was considered to be unrealistic, although this

capability could enable examination of potential operational changes to accommodate more DG. The difficulty was resolved by constraining the secondary bus voltages to their target values.

The evaluation was set up as follows: The capacity adjustment factor ( $\psi$ ) was set to 1, initially, within a range of zero to 100. With an initial active power capacity of 1 MW this allowed DG capacities of between zero and 100 MW. To ensure a balanced evaluation of capacity, the capacity benefit value was set to be the same for all locations (although clearly this could be set differentially to reflect the costs and benefits of alternative generating technologies). Testing found the optimisation to be relatively insensitive to the actual value so this was set, arbitrarily, to 100 units per MW.

The evaluation was subject to thermal and voltage constraints. Thermal constraints applied were the relevant line and transformer ratings. A simplification has been made in setting transformer reverse power flow capability equal to that for the forward direction; some transformers have lower reverse capabilities and these can be incorporated through appropriate directional flow limits. The maximum voltage limits are defined by Statute [16] although DNO planning policies (which implement relevant technical standards such as Engineering Recommendation (ER) P28 [17]) specify more rigorous constraints in order to allow for the impact of upstream voltage variations, switching events, outages and tap changer operation. To illustrate how voltage constraints impact on network headroom, two constraint policies were applied:

1. voltage range as allowed by statute, i.e.  $\pm 6\%$  at 11 and 33 kV,  $\pm 10\%$  at higher voltages
2. voltage range of  $\pm 3\%$  at 11 and 33 kV (as defined by ER P28).

These applied to all locations other than 11 and 33 kV transformer secondary buses that were constrained to nominal voltage.

The range of DG sources is diverse and this is reflected in the range of power factors that must be considered. Here, several scenarios are considered: generation operating at power factors of 0.95 leading, 0.95 lagging or at unity. Load level also has a major bearing on the capability of a network to accept generation: accordingly, conditions of 25% or 100% of maximum demand were examined.

The analysis of network headroom is illustrated using individual GSP groups and one group is analysed in detail. Following that, the analysis is extended to the network as a whole.

## **4.2 Capacity available in GSP groups**

Here, each GSP group was considered as a stand-alone unit without inter-group connections. While this will tend to reduce the maximum potential power export, the connections are limited and are designed to facilitate supply in the event of a loss of line. As such, the estimates of headroom will be reasonably realistic. Firstly, GSP Group A is considered in detail (with Table 1 providing the characteristics of the network in the vicinity of the GSP).

### **4.2.1 Group A**

Estimates of available capacity at each 11 kV substation in GSP Group A were generated by locating negative load at each 11 kV bus (Buses 21, 23 and 26) and executing the OPF. This was carried out for several combinations of power factor and load level and the results are given in Table 2 for statutory voltage constraints and Table 3 for the narrower  $\pm 3\%$  limits.

For the scenarios examined, there are significant variations in the overall capability of the network to absorb power injections ranging from 26.6 MW at a lagging power factor to 69.3 MW at leading.

The effect of load is significant and, as would be expected, the network exhibits greater absorbance at higher load-levels. Further, leading power factors tend to allow greater absorbance as the import of reactive power tends to ease voltage rise resulting from active power export and, accordingly, greater export may be achieved before voltage limits are reached.

The pattern of capacity availability tends to indicate the type of constraint restricting power injections at each primary bus. Where the capacity remains similar across the range of power factors this highlights a thermal limitation, *e.g.*, Bus 21 which, for all cases, is limited by the 8 MVA transformer rating. Alternatively, buses showing significantly different capacities across power factors and, particularly at different allowable voltage ranges, are voltage-constrained with Buses 23 and 26 as clear examples.

While this suggests the general rules, it masks significant differences between each of the scenarios in terms of the constraints that apply. Figure 2 shows the portion of the network in Figure 1 that covers GSP A. It contains a subset of the scenarios from Tables 2 and 3, and details available capacity and the applicable constraints influencing the capacity evaluation. (a) and (b) are examples at 25% load and  $\pm 6\%$  voltage range while the others are at 100% load and  $\pm 3\%$  voltage range.

The predominance of voltage constraints at leading power factor can be seen in (a) and (c) where the voltage rise along the 33 kV feeders results in bus voltages at the far end (*i.e.* at Buses 22 and 24) at the applied limits. In both cases the OPF favours capacity at Bus 23 over Bus 26. The dominance of thermal constraints at lagging power factor is apparent in (b) and (d) where the transformer supplying Bus 26 and the line from bus 20 to 22 are at their limits. Further, in (d) the significant reactive power demand from generation at Buses 23 and 26 are seen to depress the voltages along the bus 20 to 24 feeder with voltage at Bus 24 as low as 0.97 pu. Across (a) to (d), the transformer

supplying Bus 21 is thermally limited as the direct connection to the GSP allows capacity to be sited essentially independently of the rest of the network.

The analysis for Group A (and all others) has not considered fault conditions in that parallel paths are assumed to be in-service. True worst-case scenarios would consider capacity with one or more paths out-of-service. For example, in case (a) with both transformers supplying Bus 23, export is constrained by voltage on the 33 kV feeders. However, the loss of a transformer would limit net export from Bus 23 to the thermal rating of the remaining unit (24 MVA). The impact on overall capacity available would depend on which transformer remained in service; the loss of that connecting Buses 24 and 23 would potentially allow additional export from Bus 26. The non-consideration of fault conditions should be borne in mind when interpreting the capacities suggested in the remainder of the analysis.

#### 4.2.2 Groups B to E

Given the network size, there is insufficient room to allow detailed analyses of GSP Groups B to E. However, an examination of the overall capacities available at the 11 kV Primaries within each GSP provides an understanding of the constraints on DG development in the relevant portion of the network. These capacities are summarised in Tables 4 and 5 for the same voltage limits as above.

As before, it is possible to infer the constraints that dominate within each GSP group. Hence, from Tables 4 and 5 we can see that capacities within Group A are heavily influenced by voltage constraints, Group E is also partly voltage constrained albeit to a lesser degree. The relatively small differences between available capacities in Groups B to D highlight thermal limitations, with e.g., Group B limited by the rating of the 132/33 kV GSP transformer (connecting Bus 6 and 30). In

Group D, the lower capacity available at leading power factor is due to the reactive power import along the relatively long parallel feeders 'crowding out' active power export.

While it can be misleading to infer network characteristics from one line diagrams (as they do not convey distance or impedance information), the topology of the various groups can be related to the pattern of available capacity and the constraint patterns. Export along sets of meshed double circuit feeders tend not to be voltage-constrained, rather the rating on the 33/11 kV Primary transformers are the limiting factor (e.g. Group D). Conversely, paths with several long single circuit spurs tend to suffer voltage limitation (e.g. Groups A and E).

It should be noted that for one condition in each of Tables 4 and 5 the capacity available is marked 'N/C'. This refers to the non-convergence of the OPF solution as a result of the inherent voltage sensitivity of the distribution network. It occurs in Group D, where the additional reactive import from DG operating at 0.95 leading power factor on top of that drawn by load at its maximum level, results in voltage collapse and, consequently, non-convergence.

### **4.3 Analysis of entire system**

In evaluating the capacity available across the whole of the network, an identical approach to that for the GSP groups was taken. Here, potential generation was sited at each 11 kV primary throughout the system and the OPF executed for conditions of maximum load with several power factors. The overall capacity accommodated and the breakdown between groups is given in Table 6 and shown graphically in Figure 3.

It is clear that the capacities indicated at each GSP are significantly below those accommodated at each GSP when considered individually (see Table 4). The reason for this is evident given that the overall capacity is essentially the same across each of the power factor options – characteristic of a thermally constrained system. This is the case as it is the rating of the circuit joining buses 1 and 2 that is the limiting factor in connecting further capacity. To accommodate further DG would require upgrading of that circuit and/or retiral of existing conventional generation.

## **5. Network Development**

The evaluations of capacity presented here represent single analyses at one point in time. Development is resource-led and so is unlikely to occur at the locations and in the capacities necessary to fit neatly with evaluations of capacity such as these. As such, DNOs need to re-evaluate capacity after each new connection and project the impact on future potential connections with and without reinforcement. The ability to evaluate connections in this manner allows planners to consider the downstream impact of connection decisions in terms of the network capacity that is taken up at each stage in the process. This process is illustrated using GSP Group A as an example with DG at 0.95 lagging power factor, load at 25% and with statutory voltage constraints.

Section 4.2.1 considered capacity available across all Group A primaries as a whole. However, in considering a sequence of connections it is enlightening to consider the capacity available at each primary, individually. As mentioned earlier, Bus 21 is essentially independent of the other two primaries and the capacity available is limited by the transformer rating (to 8.1 MW). As the evaluation favours generation at Bus 23 (34.4 MW – Table 2) to the exclusion of Bus 26, this also represents the maximum available at Bus 23 alone. The capacity at Bus 26 alone was found by executing the OPF with negative load at this bus only and resulted in a capacity of 5.1 MW. The

interdependence of Buses 23 and 26 arises from their joint contribution to the voltage rise along the feeder from the GSP. As such, capacity at one must be traded-off against capacity at the other.

It is possible to examine this trade-off by deliberately siting capacity at Bus 26 and evaluating the capacity at the other primaries. This is an identical situation to that where a developer has received a connection agreement and, as such, possesses prior access rights; any subsequent connections must be considered with the DG in operation. Figure 4 and Table 7 show the resulting availability of capacity in the network as the prior connected capacity at Bus 26 rises from zero to 5 MW. It is clear that as the prior capacity rises, the available capacity at Bus 23 falls (Bus 21 remains static). More importantly, the reduction in capacity at Bus 23 is greater than the increase at Bus 26, hence, the overall capacity that may be connected in the network falls. Table 7 indicates that for every MW of prior capacity added there is in the region of 3.3 MW of capacity lost at Bus 23. Increasing prior capacity to the maximum 5.1 MW would completely remove capacity at Bus 23. Clearly, the optimal combination of capacity is to site nothing at Bus 26 and the maximum amount at Bus 23.

This relatively simple example illustrates the consequences of inappropriately sited connections in terms of their ability to constrain capacity and eventually sterilise the network. This effect, spread across the entire distribution network represents a significant threat to the target of maximising DG penetration to achieve renewable energy targets. Clearly, the ability of DNOs to influence future developments will depend very much on their own internal policies and that of the Regulator towards distribution network access.

## **6. Discussion**

The OPF-based techniques presented are a valuable addition to the set of planning tools potentially available to DNOs. They provide a rapid, adaptable and objective means of examining connection of DG and will provide information regarding the most suitable sites to connect DG. The technique demonstrated has been evaluated on an extensive distribution and sub-transmission system and is applicable at all voltage levels. Using an extensive network (and its component parts) the capacity evaluations illustrate many of the issues surrounding the connection of DG and the constraints on development.

OPF has been in use in power systems research, planning and operation for many years. As such, this technique represents an acceptable and logical extension of the use of OPF. One of the potential benefits of performing the OPF analysis within a proprietary software package is that the analysis can be readily extended to incorporate multiple objectives such as loss minimisation or the simultaneous optimisation of existing generation.

Although not explicitly demonstrated here, use of the simulation manager limits time-consuming data entry and allows users to concentrate on more productive tasks such as determining the combinations of locations at which generation may be sited and the relevant constraint policy for connections. Further, the sequential evaluation of capacity following successive additions of plant is made straightforward.

In addition to identifying the location and magnitude of available network capacity, the OPF allows the limiting factors to be highlighted, which may be equipment thermal ratings or the specified voltage constraints. It is anticipated that the identification of the limiting factors together with the Lagrangian coefficients within the OPF could be used to provide an efficient and effective means of determining network upgrades and reinforcement that allow further DG to be accommodated.

Currently, this technique cannot take account of fault level constraints when evaluating available capacity, although a fault level study can clearly be run following the OPF to ascertain if constraints have been breached. These may predominate in urban meshed networks but are generally not a major limitation for rural feeder systems. The genetic algorithm approach presented in [12] may offer one means of incorporating fault level constraints but the authors have extended an OPF to impose fault level restrictions on the capacity evaluation [18].

One potential criticism of the approach taken here is that it uses a single deterministic optimisation. This was developed as current UK connection practice is based on the worst-case scenario. However, as execution of the evaluation is very rapid (less than one second) it is feasible to use it for time-series analyses with typical patterns of demand or wind spectra.

## **7. Conclusions**

Government-led targets and incentives will increase the capacity of distributed generation connecting to distribution networks. Distribution-level connections create a number of technical problems that may be mitigated for individual connections, albeit at a cost to the developer or network operator. With anticipated connection volumes, there is a potential risk of conflict between connections, in that inappropriately sized or located plant could constrain greater development of the network and, consequently, threaten the achievement of renewable energy targets.

One means of addressing this risk is to encourage development at sites that are suitable whilst discouraging inappropriate ones. In doing so network operators must be able to evaluate the capacity

or headroom available on the system. In meeting this challenge a technique has been developed that models fixed-power factor DG as negative loads and uses optimal power flow to perform negative load shedding. This ‘reverse load-ability’ approach effectively maximises capacity and identifies available headroom.

The technique was evaluated using an extensive distribution and sub-transmission network and is found to rapidly identify available headroom within the imposed thermal and voltage constraints. Additionally, the technique was used to examine the consequences of a sequence of connections in terms of the impact on available headroom and in sterilising the network. Overall, the approach appears to be a valuable addition to available network planning tools.

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## 10. Appendix

### 10.1 Notation

$MVA^{DG}$	= MVA capacity of DG (pu)
$MVA^0$	= initial MVA capacity of DG (pu)
$MW^0$	= initial active power capacity of DG (pu)
$V$	= bus voltage magnitude (pu)
$V_{MIN}$	= minimum bus voltage
$V_{MAX}$	= maximum bus voltage
$S$	= branch power flow (MVA)
$S_{MAX}$	= branch thermal limit (MVA)
$\psi$	= capacity adjustment factor
$\psi_{MIN}$	= minimum capacity adjustment factor
$\psi_{MAX}$	= maximum capacity adjustment factor
$C$	= capacity value (per unit MW)
$n$	= number of buses available for capacity addition
$i$	= DG bus index
$j$	= bus index
$k$	= branch index

### 10.2 Problem implementation

The reasoning behind the choice of the PSS/E package was threefold. Firstly, it is commonly used in industry and will therefore be readily available. Secondly, it possesses an OPF component with bus loading capability. Thirdly, it has the capability to automate procedures via its internal programming language (IPLAN).

Automation significantly benefited the operation and control of the OPF and earlier analytical approaches in terms of accelerating the execution of the relevant procedures. However, the repetitive process of data preparation, execution, results extraction and analysis was still time-consuming and error prone, given the large number of parameters and data required.

An elegant solution to these issues came from the development of a bespoke graphical user interface to the PSS/E package. There is no direct interaction between the two pieces of software; rather the control software is used to execute specific predefined routines by initiating PSS/E and exchanging data through suitably formatted text files. The relationship and data flows between the two packages are shown graphically in Figure 5. In addition to relieving the problems identified earlier, the simulation manager has also facilitated the integration of non-network-related data and allowed complex analyses to be conducted with relative ease. While the simulation manager was developed

for DG network analysis, the techniques established are readily portable to other tasks addressed with PSS/E.

## Tables

Table 1. Characteristics of distribution network in vicinity of GSP A

Line (Nominal Voltage)	Impedance (Rating)
Buses 6 to 7, 6 to 8 (132 kV)	0.022 + j0.049 pu (132 MVA)
Bus 20 to 22 (33 kV)	0.340 + j0.454 pu (19 MVA)
Bus 20 to 24 (33 kV)	0.258 + j0.453 pu (27 MVA)
Bus 24 to 25 (33 kV)	0.872 + j0.625 pu (11 MVA)
Transformers	Ratings
Supply to Bus 20	2 × 60 MVA
Supply to Bus 21	1 × 8 MVA
Supply to Bus 23	2 × 24 MVA
Supply to Bus 26	1 × 5 MVA

Table 2. Capacity available (MW) for DG connection at 11 kV Primaries within GSP group A (voltage  $\pm 6\%$ )

Bus	25% Load / Power Factor			100% Load / Power Factor		
	0.95 lag	Unity	0.95 lead	0.95 lag	Unity	0.95 lead
Bus 21 (MW)	8.1	8.4	7.8	9.3	9.6	8.8
Bus 23 (MW)	34.4	35.5	37.7	47.2	53.8	48.2
Bus 26 (MW)	0.0	4.8	4.9	0.0	6.0	5.6
Total (MW)	42.5	48.7	50.4	56.5	69.3	62.5

Table 3. Capacity available (MW) for DG connection at 11 kV Primaries within GSP group A (voltage  $\pm 3\%$ )

Bus	25% Load / Power Factor			100% Load / Power Factor		
	0.95 lag	Unity	0.95 lead	0.95 lag	Unity	0.95 lead
Bus 21 (MW)	8.1	8.4	7.8	9.3	9.6	8.8
Bus 23 (MW)	18.5	29.3	37.7	31.4	53.8	48.1
Bus 26 (MW)	0.0	0.0	4.9	0.0	6.0	5.4
Total (MW)	26.6	37.7	50.4	40.7	69.3	62.3

Table 4. Maximum DG connections (MW) within GSP groups under statutory voltage constraints

GSP Group	25% Load / Power Factor			100% Load / Power Factor		
	0.95 lag	Unity	0.95 lead	0.95 lag	Unity	0.95 lead
A (MW)	30.6	48.7	50.4	56.5	69.3	62.5
B (MW)	23.0	22.6	20.4	31.0	30.2	24.9
C (MW)	39.7	39.0	39.6	57.7	57.3	39.7
D (MW)	121.4	126.0	115.8	157.1	158.5	N/C
E (MW)	76.5	80.7	79.8	107.1	115.3	102.2

Table 5. Maximum DG connections (MW) within GSP groups under 3% voltage constraints

GSP Group	25% Load / Power Factor			100% Load / Power Factor		
	0.95 lag	Unity	0.95 lead	0.95 lag	Unity	0.95 lead
A (MW)	15.7	37.7	50.4	40.6	69.3	62.3
B (MW)	22.6	22.8	20.4	30.7	30.1	24.9
C (MW)	38.9	38.8	39.9	57.0	58.1	56.3
D (MW)	121.4	126.0	115.8	157.1	158.5	N/C
E (MW)	62.0	74.5	65.6	92.5	100.7	101.7

Table 6: Maximum connections (MW) at 11 kV for entire network at 100% load and within statutory voltage limits.

GSP Group	Power Factor		
	0.95 lagging	Unity	0.95 leading
A (MW)	3.7	0.0	0.0
B (MW)	9.4	7.8	12.6
C (MW)	4.1	8.3	7.1
D (MW)	50.2	55.3	23.1
E (MW)	38.2	33.4	63.2
Total (MW)	105.6	104.9	106.0

Table 7. Available capacity (MW) at 11 kV within GSP Group A with prior connected capacity at Bus 26.

Capacity	Prior Connected Capacity at Bus 26 (MW)					
	0	1	2	3	4	5
Available at Bus 21	8.1	8.1	8.1	8.1	8.1	8.1
Available at Bus 23	34.4	31.1	27.4	23.8	20.5	17.3
Connected at Bus 26	0.0	1.0	2.0	3.0	4.0	5.0
Aggregate	42.5	40.2	37.5	34.9	32.6	30.4
Net difference		-2.3	-5.0	-7.6	-9.9	-12.1

### **Captions for Illustrations**

Figure 1. Sub-transmission and distribution network

Figure 2. Available network capacity and applicable constraints for GSP Group A for four scenarios (a to d).

Figure 3. Available capacity at 11 kV within each GSP Group for the network as a whole.

Figure 4. Impact of prior connected capacity at Bus 26 on GSP Group A available capacity.

Figure 5. Control/data flows between simulation manager and power flow software.

Figures

Figure 1.

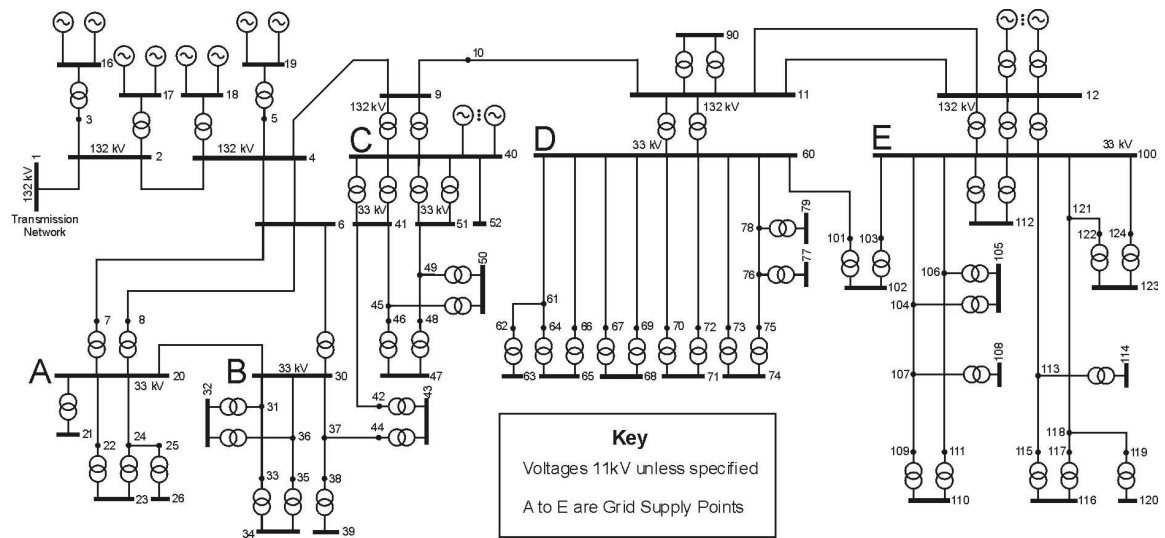


Figure 2

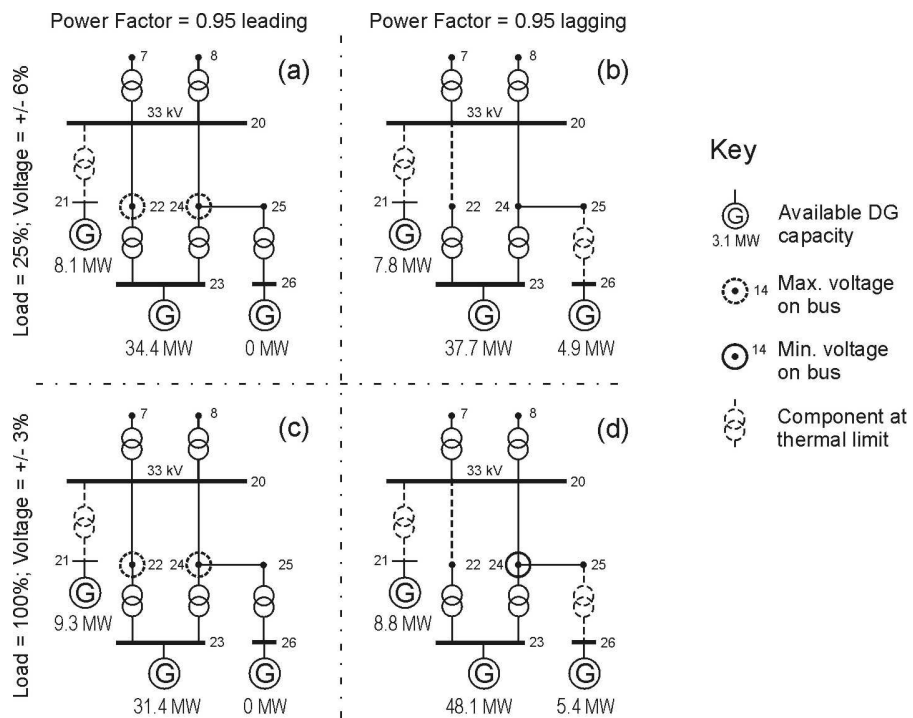


Figure 3

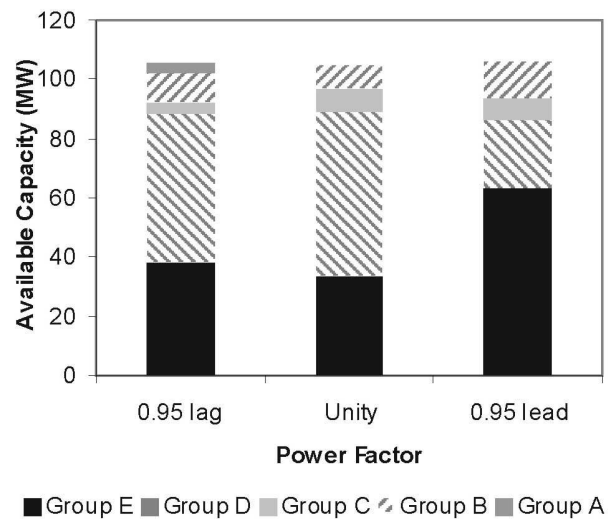


Figure 4

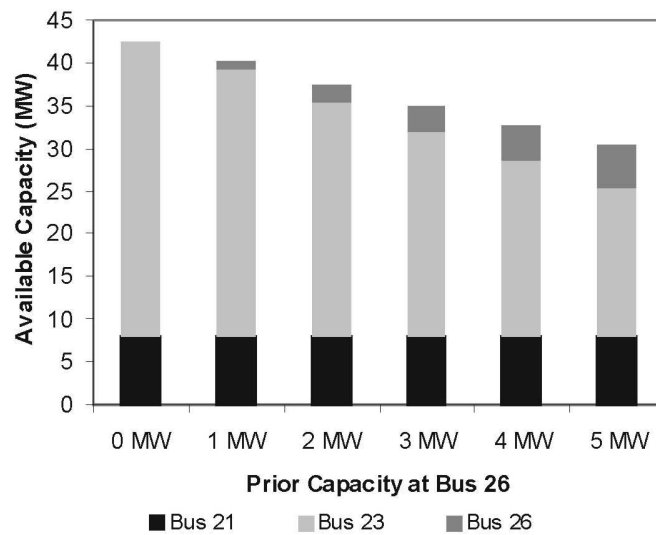


Figure 5.

