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DISTRIBUTOIN NETWORK CAPACITY ASSESSMENT: VARIABLE DG AND ACTIVE NETWORKS

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Abstract
Increasing connection of variable distributed generation, like wind power, to distribution networks requires new control strategies to provide greater flexibility and use of existing network assets. Active network management (ANM) will play a major role in this but there is a continuing need to demonstrate the benefit in facilitating connection of new generation without the need for traditional reinforcements.
Keywords: Active network management, distributed generation, distribution networks, optimal power flow, wind power.

Introduction

Integration of renewable energy sources creates significant technical and economic challenges for distribution network operators (DNOs) and developers. Despite potential benefits, such as reduction of losses or investment deferral [1] planning issues, the regulatory framework, and the availability of resources, have limited the DNOs and developers in their ability to accommodate distributed generation (DG). Many of these difficulties relate to “fit-and forget” policies where “firm” connections mandate that DG is able to output full capacity irrespective of network configuration. Assessment of connections focuses on worst-case network conditions, normally maximum generation at minimum demand. While reasonable for firm energy sources, with variable renewables maximum generation may occur infrequently and the worst-case situation tending to occur for a relatively small amount of time. Firm connection would require that the DG capacity be restricted despite the opportunity for much higher energy production. The alternative is a “non-firm” connection wherein the DNO may curtail the output of the renewable generator at low demand .

Research results

With ANM, DNOs will be capable of optimizing use of their assets by dispatching generation, controlling OLTCs and voltage regulators, managing reactive power, and reconfiguring the system [2]. Implementation of such schemes will require complex control techniques while the actual actuation of devices (e.g., tap changers) will depend on their respective response time-scales. As the proposed technique is designed for use at the planning stage, it is assumed that network components respond immediately to control actions, and have effectively one (steady) state in each period (m) . Thus, in addition to network constraints traditionally used in AC OPF formulations (e.g., voltage and thermal limits), variables and constraints derived from ANM schemes must also be incorporated in the method:

1. *Coordinated Voltage Control (CVC):* By dynamically controlling the OLTC at the substation and the corresponding distribution secondary voltage, more DG capacity might be connected [1]. Thus, in each period the secondary voltage of the OLTC will be treated as a variable, rather than a fixed parameter, while maintaining its value within the statutory range:

$$V_{b_{OLTC}}^{-} \le V_{b_{OLTC},m} \le V_{b_{OLTC}}^{+}. \quad , \tag{1}$$

Adaptive Power Factor Control (PFc): Depending on the technology utilized by the distributed generator, operation at leading, unity or lagging power factors is feasible. (For clarity, the terms leading and lagging will be replaced in the text here-after by capacitive, where reactive power is injected by the generator, and inductive power factors, respectively). However, the ability of DG units to offer “dispatchable” or adaptive power factor control will ultimately rely on the existence of an appropriate ancillary service market or through requirements in the connection agreement. Here, it is envisaged that DG provides such a scheme with the power angle of each generator, ϕ_m, considered as a variable. In practice DG will be required to operate within a certain range of power factors $(\phi(+,))$; the following constraint applies:

$$\phi_g^- \le \phi_{g,m} \le \phi_g^+. \tag{2}$$

3) Energy Curtailment: The network characteristics and wind power patterns may result in voltage and thermal limits restricting DG capacity in other cases at minimum demand or at other times. Curtailment of the DG active power output is an option to alleviate such problems [3]. Power curtailment is formulated here by adding a negative generation (or positive demand) variable (p_{curt}) at the same location of each DG unit, solely affecting the constraints related to active and reactive nodal power balance.

In general, limiting the power production of DG units requires appropriate DNO and regulatory policies to allow non firm commercial arrangements and will ultimately be assessed by developers on economic grounds. To examine the impact of different allowed levels of curtailment on overall DG capacity, the total amount of curtailed energy from each DG will be restricted to a curtailment factor , a percentage of the potential energy that could have otherwise been delivered by each DG. The following constraint follows: allowed levels of curtailment on overall DG capacity, the total amount of curtailed energy from each DG where ^{m} is the duration of period m. The curtailment variables p_{curt} need to be limited to the output of g at the corresponding period:

$$p_{g,m}^{curt} \le \omega_m p_g, \quad \forall g \in G. \tag{3}$$

In this section the multi-period AC OPF technique is applied to a generic U.K. distribution network. First, the method for aggregating times-series generation and demand data from single and multiple sources is detailed. Next, in order to demonstrate the method as a DG capacity analysis tool, a simplified version of the network is studied with only a single DG unit connected.

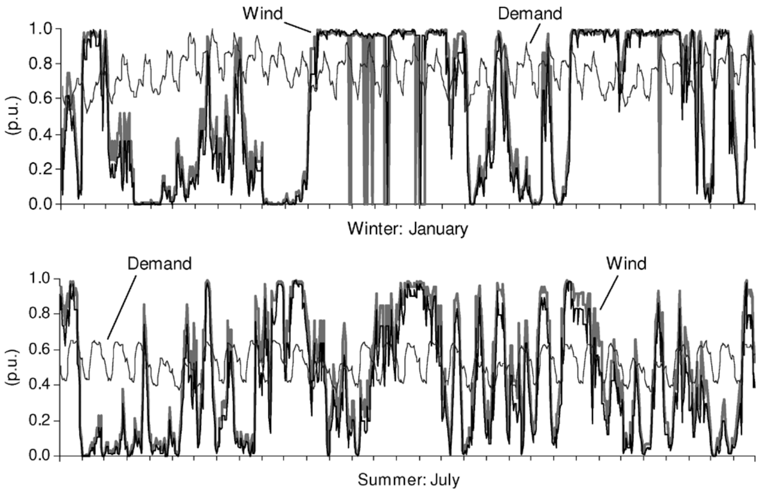


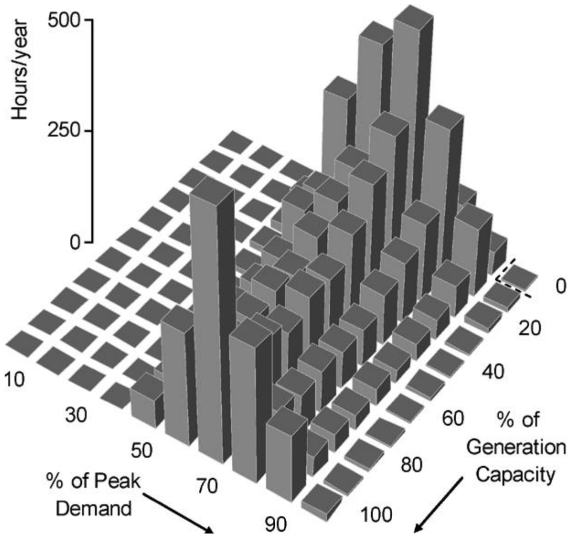
Fig. 1. (Top) Winter and (bottom) Summer hourly demand and wind power production (relative to peak) for central Scotland, 2018. Two different wind profiles are considered: WP1 (black line) and WP2 (grey line)

Subsequently, and increasing the complexity, the ability of the technique to determine capacity across several DG units is also investigated by considering the full network and two different wind power profiles. Finally, the computational performance is briefly discussed.

A sample of the hourly demand for central Scotland in 2003 is shown in Fig. 1 [4] along with coincident wind production of two different wind sites (named here, WP1 and WP2). The wind production data were derived from U.K. Meteorological Office measured wind speed data and have been processed and applied to a generic wind power curve. While for demand there is a clear seasonal and diurnal pattern, for wind the pattern is less clear, although it tends to be more significant in winter months. Moreover, due to the geographic correlation of the studied wind profiles, the potential for wind power production is to a certain extent similar. However, from Fig. 1 it is evident that particular (and sometimes critical) demand/wind scenarios could be lost if only one wind profile is adopted.

One way to reduce the computational burden of a full time-series analysis is to aggregate wind availability and demand into a manageable number of wind/demand scenarios based on their joint probability of occurrence. The “duration” of each scenario is then the number of coincident hours which it represents.

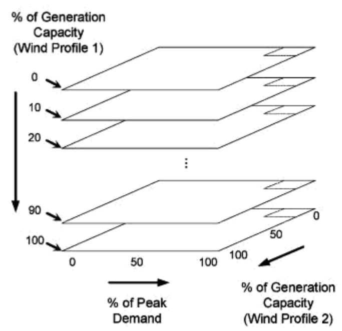
Considering the first wind profile WP1 alone, Fig. 2 presents the coincident hours for each of the scenarios used here. It breaks the demand and generation series into a series of bins: to illustrate the process, ten ranges for demand (e.g., [0,10%], (10%,20%],) and 11 ranges for generation (e.g., {0}, (0,10%], (10%,20%],) are used. With demand never below 0.35 pu (during summer), only 74 non-zero scenarios are effectively considered in the analysis (Fig. 2, right). Due to the aggregation process (using the upper values of the adopted demand scenarios), both the capacity factor of the wind data and the load factor of demand increased from 0.41 to 0.45, and from 0.63 to 0.68, respectively.



							% of Generation Capacity
10	103	158	192	127	53	2	0
43	303	451	515	339	156	11	
20	136	226	336	175	73	15	20
16	147	201	276	138	45	6	
11	79	170	212	113	41	4	40
7	63	130	161	84	33	7	
0	60	147	172	85	41	4	60
1	40	132	143	95	33	4	
0	48	123	176	90	42	8	80
2	54	144	212	110	48	6	
0	63	257	559	305	152	16	100
40		60		80		100	

% of Peak Demand

Fig. 2. Coincident hours for each of the demand/generation scenarios.



% of Generation Capacity (Wind Profile 1)								% of Generation Capacity (Wind Profile 2)
0	1	68	80	114	78	39	2	0
	9	35	78	78	49	14	0	10
10	30	211	319	356	238	100	8	10
	13	92	132	159	101	56	3	20
20	7	50	71	104	45	22	6	20
	12	78	132	200	115	47	8	30
	1	8	23	32	15	4	1	40
30	0	9	19	25	6	2	0	30
	7	88	139	181	98	29	4	40
	9	50	43	70	34	14	2	50
40	4	57	113	167	71	23	4	50
	7	22	57	45	42	18	0	60
50	5	34	84	114	54	18	5	60
	2	29	46	47	30	15	2	70
60	0	21	66	76	33	18	3	70
	0	39	81	96	52	23	1	80
70	1	24	57	79	48	10	1	80
	0	16	75	64	47	23	3	90
80	0	48	105	157	76	35	8	90
	0	0	18	19	14	7	0	100
90	2	54	144	212	110	48	6	100
100	0	0	8	4	10	11	0	0
	0	63	249	555	295	141	16	100
	40		60		80		100	

% of Peak Demand

Fig. 3. Schematic example of how the coincident hours are obtained for the two wind profiles (left) and coincident hours for each of the scenarios (right).

In this particular case, Fig. 2 shows that most of the time generation levels are relatively low. This could imply that only large wind power capacities would be able to offset significant amounts of load. Low demand (40%) and high wind availability (60% to 100%) present relatively few coincident hours. Therefore, as for firm connections if only worst-case scenarios are assumed such as minimum demand-maximum generation, generation capacity could be constrained more than is necessary.

The method is able to cater for more than one type of resource. To illustrate this, the second wind profile (WP2) is now also considered. The extra wind profile requires the aggregation of demand/generation levels to be recalculated based on their mutual joint probability. As shown in Fig. 3 (left), for each range of generation capacity of the first wind profile, a “layer” with the coincident hours of demand/generation is created for the second wind power profile. Although this approach may seem to create a large number of demand/generation scenarios, due to the geographical correlation of the wind data used here, only 146 periods contain non-zero number of hours. Fig. 3 (right) shows this. For WP2 the capacity factor increased from 0.48 to 0.52.

Conclusion

This work proposes a novel, flexible multi-period AC OPF-based technique able to determine the maximum connectable capacity for variable (renewable) generation under a range of ANM schemes including coordinated voltage control, adaptive power factor control, and energy curtailment. Results clearly show that, compared to the widely used passive operation of distribution networks, very high penetration levels of new variable generation capacity can be reached by strategically adopting ANM schemes.

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