The Impact of Distribution Locational Marginal Prices on Distributed Energy Resources: An Aggregated Approach

C. Edmunds (calum.edmunds@strath.ac.uk), W.A. Bukhsh, and S. Galloway. University of Strathclyde, Glasgow, UK

(DERs) and the trend towards electrification of heat and transport, distribution networks will be increasingly challenged and will need to be more actively managed. Distribution Locational Marginal Prices (DLMPs) offer a method of clearing markets at distribution level and providing information on transmission losses and congestion in a network due to transmission constraints. This paper examines the application of DLMPs to a region of the South West of England. The resulting DER penetration from applying DLMPs to different voltage levels was considered. It was found that by applying DLMPs down to 11 kV, distributed generation capacity and output could be increased significantly. Applying DLMPs down to 11 kV had a less pronounced effect on flexible demand dispatch due to the co-incidence of renewable curtailment and the lowest daily system prices.

***Index Terms*— Distribution networks, Locational marginal pricing, DER, Optimal Power Flow**

I. Introduction

Locational Marginal Prices (LMPs) have been applied successfully at transmission level in North American markets such as the PJM which operates Day–Ahead (DA) and Real-Time (RT) markets with LMPs calculated at 11,467 nodes as far down the network as 2 kV [1]. The LMPs are calculated in the PJM using security constrained economic dispatch on the DA and RT markets which operate as a pool with generators and demands submitting bids and offers. Although LMPs are most commonly calculated in a centralised pool dispatch, such as in the North American PJM, MISO and CAISO transmission regions, it is theoretically possible to discover LMPs in a perfectly competitive power exchange [2]. In Europe, since deregulation, centralised dispatch has been largely replaced by bilateral trades and power exchanges in zonal or uniform priced markets. A return to centralised coordination could be seen at distribution level, for example a Regional System Operator (RSO) managing competitive auctions was recommended in a recent report for the UK government [3]. Such a regional marketplace could use nodal pricing (LMPs) which allow the market operator to set the clearing prices for each node and providing the basis for network investments where constraints arise. The application of LMPs to distribution (DLMPs) offers a method of accounting for spatial variations (particularly congestion and losses) increasingly seen deep down in the network with the greater presence of distributed assets [4].

One major question in the application of DLMPs is how far down the network voltages to apply these prices, i.e. is it better to have a different clearing price for each 11 kV secondary substation, or each point in a 400 V (LV) feeder? To counter this, what are the implications of the loss of detail when prices are aggregated to higher voltages such as applying prices for each 400 kV grid supply point (GSP)?

At transmission level the comparison of nodal, zonal and uniform pricing has been discussed at length [5] [6]. From studies using a simplified transmission system model of England and Wales [6], it has been argued that nodal pricing could raise overall welfare in the UK electricity market. Despite these arguments, many countries in Europe have opted for zonal or uniform pricing of electricity. Zones can be a state or region as in the zonal pricing in Australia, Denmark, Norway and Sweden [7]. In the North American PJM, LMPs are aggregated to zones served by different electric utilities (e.g. Pennsylvania electric company) using fixed-weight aggregate factors for each node [1]. These aggregated zones are used to provide standard products such as Financial Transmission Rights but are not used in market clearing which is nodal for the PJM. The reluctance to apply LMPs in Europe could be due to being politically challenging to implement or the complexity in calculating LMPs at a large number of nodes and co-ordinating submarkets [5]. However, with increasing penetration of renewables and flexible demands, the case for nodal pricing could become stronger at distribution level.

In a comprehensive study, using a detailed model of an urban distribution network, DLMP application was considered at various levels including wholesale, zonal, down to LV nodes [8]. As would be expected an increased price spread is observed with increased granularity and it was shown that investments would be made around areas of congestion when DLMPs are applied down to LV. In contrast, no obvious patterns in DER investments were observed when flat rate energy pricing is used.

Network constraints, including thermal and voltage, occur at all voltage levels down to LV and with increasing penetration of DERs, in particular PV and future EV charging, these issues will become more prominent unless dealt with. To model higher losses, reactive power flow and voltage issues, a full AC optimal power flow (OPF) is required [4] however frequent modelling of the entire distribution networks down to LV is unrealistic due to computational requirements. One option is to aggregate LMPs to higher voltages or zones which could be a 400 kV grid supply point, 132 kV bulk supply point, 33 kV primary substation or 11 kV secondary substation. A section of the Great Britain (GB) electricity transmission network along with a section of distribution network is used in this paper to demonstrate the benefits of nodal pricing in connecting more DG at lower voltage levels.

This paper presents analytical results on the penetration of renewables and compares the dispatch of flexible loads when DLMPs are applied at different voltage levels. In this study, for high to medium voltage levels (400 kV – 11 kV) a network

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model of a region of the South West (SW) of England is used. This analysis will give the value of flexible demand unlocked by the application of a DLMP marketplace in a region with a high penetration of DGs where the UKs first local energy marketplace is being developed [9]. The remainder of this paper is as follows: Section II contains the methodology for the network modelling, Section III presents the results and discussion and finally Section IV summarises the conclusions and future work.

II. Methodology

Time series analysis (over 24 hours) was carried out on a network model of a region of the SW of England including transmission and distribution down to 11 kV. Due to the large number of nodes at 33 kV and below, a single 33 kV network region (Rame) was modelled along with an example 11 kV network connected to the Rame 33 kV network. The network model and input assumptions used in this study are the same as those outlined in a previous study on DLMP variability [10]. Any further mention of SW England network in this paper refers to this model. Generation capacities are based on the 'Future capacity' case in [10] where the DG connected at 11 kV and below is assumed to grow significantly due to lowering PV costs. The model of flexible demand is adapted from [11].

A. DLMP voltage level aggregation

The SW England network model (simplified in Figure 1) was aggregated to 4 different voltage levels (shown in Table I) to compare the effect of applying DLMPs at each voltage level on DER dispatch.

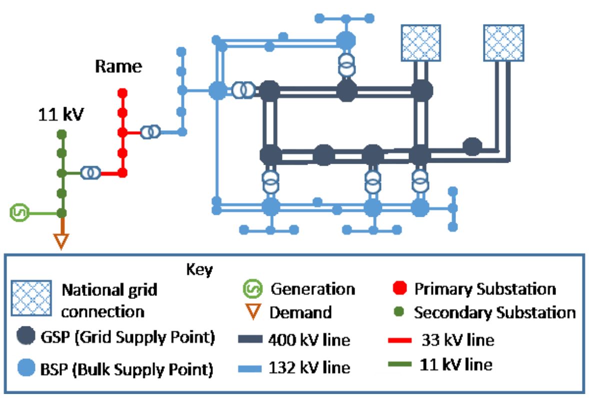

Figure 1 – Simplified SW England network diagram

TABLE I
VOLTAGE LEVELS USED IN AGGREGATION STUDIES

Voltage level	No of buses	Name
400 kV	14	SW
132 kV	27	SW
33 kV	33	Rame
11 kV	62	Example

The following two days in 2015 were selected for simulation;

- Summer's day: low demand and high DG output (5th June).
- Winters day: high demand and low DG output (18th January).

B. Generation capacity limits

For each case the demand and generation data is aggregated. However, for network visibility at different voltage levels, different amounts of DG can connect. For a fully modelled (and controllable) network there is potential to allow DG capacity beyond the network capacity and curtail DG when required (i.e. active network management [12]). If the model is aggregated (and therefore assumed not to be visible below an aggregated point) more conservative limits are required. In this work the DG capacity at voltage levels below an aggregated point are based on the maximum network capacity (limited by thermal or voltage limits) within the aggregated network with minimum demand (30% of peak demand). The resulting DG capacities within Rame 33 kV and the 11 kV network for different aggregation levels are shown in Table II.

TABLE II
DISTRIBUTED GENERATION CAPACITIES BASED ON AGGREGATION LEVEL

Aggregation	DG Capacity @ 11 kV (MW)	DG Capacity @ 33 kV (MW)	Total DG Capacity (MW)[b]
400 kV	8.8[a]	122.2	2219.7
132 kV	8.8[a]	122.2	2219.7
33 kV	8.8[a]	216.1	2313.6
11 kV	34.3	216.1	2339.1

a. The 11 kV DG capacity is limited by voltage constraints due to high voltages within the 33 kV network caused by high levels of Embedded DG
b. Includes 2089 MW of DG capacity from all SW England Bulk Supply Points (BSPs) and 132 kV connected generation

As shown in Table II, 8.8 MW of DG capacity is connected at 11 kV level when aggregating to 400, 132 and 33 kV. When aggregating to 11 kV, 34.4 MW DG is connected. In this case the DG is assumed to be curtailable in the event of thermal or voltage constraints.

C. Flexible demand

Flexible demands are added for each aggregation case. The total flexible demand in each case is 20% of the aggregated demand at the Rame 132 kV Bulk Supply Point (BSP). For SW England, the peak demand (1862 MW) equates to 15 MW of flexible demand. For the 33kV and 11 kV aggregation cases this flexible demand is spread across the lower voltage demand buses.

The OATS ACOPF [13] allows flexible demand to vary by a % for each timestep with the objective of minimising the cost of serving the total demand over a time window. This achieved at no additional cost.

D. Optimisation

In this work flexible demand is added to the SW England network model and studies are carried out with different levels of aggregation. The optimisation is carried out over a 24 hour period over which generation and flexible demand dispatch is optimised using ACOPF software [13]. The objective function of the OATS optimal power flow is simplified as follows;

$$min\left\{\sum_{t\in T}\sum_{g\in G}\begin{pmatrix}cost\ of\\ generation\end{pmatrix}+\sum_{h\in H}\begin{pmatrix}cost\ of\\ load\ shedding\end{pmatrix}\right\} \quad (1)$$

$$H=\{\,(d,t): d\in D, t\in T\ except\ d\in D^F and\ t\in T^F\}$$

Where: T = time periods, G = generation, D = demands, D^F= flexible demand ($D^F \leq D$), T^F = Time window for flexible demand.

The following constraints were implemented in the optimisation;

- *Power balance and power flow constraints*
- *Generation capacity limits*
- *Transmission capacity limits*
- *Voltage limits*
- *Conservation of demand within flexibility windows (as discussed in* [11]*)*

The network model and optimisation was used to assess the impact of LMPs applied at different voltage levels on the penetration of DERs, the results are presented in the following section.

III. Results and Discussion

To assess the effect of DLMPs at distribution, the DG output and objective function cost are compared when DLMPs are applied at different voltage levels. This is done for a summer and winter day to compare the effect of DLMPs with high and low DG output.

A. *DG output with aggregation*

Applying DLMPs to 11 kV significantly increases DG capacity and subsequent total DG output. An extra 93.9 MW DG capacity (see Table II) could be connected in the Rame network with the application of DLMPs (aggregated to 11 kV or 33 kV) and 25.5 MW is added in the 11 kV example feeder (when modelling to 11 kV).

Table III
Total DG Output and Objective Function at Aggregation Levels (with/without Flexible Demand) – 5th June

Aggregation	DG Output (MWh)		Objective Function (£)[a]		
	No Flex	Flex	No Flex	Flex	Change (%)
400 kV	47,132	47,132	-287,388	-288,192	0.28
132 kV	47,132	47,132	-277,200[b]	-278,073	0.31
33 kV	48,325	48,380	-326,379	-329,368	0.92
11 kV	48,490	48,564	-332,806	-336,253	1.04

a. Objective function values are negative as the SW is exporting on the 5th of June.
b. The objective function is higher for 132 kV than 400 kV because it includes losses at 132 kV which reduces the amount of electricity exported.

In the 33 kV aggregated case, without flexible demand, total DG output is increased by 2.5% (1193 MWh) compared to the 132 kV aggregated case on a summer's day with high PV output (Table III). In this case, the objective function is 18% lower for the 33 kV aggregated case than 132 kV aggregated case (Table III). The 93.9 MW additional DG capacity connected at 33 kV (see Table II) is based on connection applications from the Distribution Network Operator's (DNOs) development plan [14] for a single BSP. There are 28 BSPs in the SW England network, and the DNO had connection applications for an additional 871 MW in the SW in 2016 (not all applications are successful). Therefore, significant increases in DG output in the SW are anticipated, with limited network re-enforcement to date.

Applying DLMPs down to 11 kV could be beneficial assuming a high future uptake in DG at 11 kV and below. In a single 11 kV network, without flexible demand, total SW England DG output was increased by 0.3% (165 MWh) on a day in June by applying DLMPs to 11 kV compared to aggregating to 33 kV (Table III). In this case, the objective function is 2% lower for the 11 kV aggregated case than 33 kV aggregated case (Table III). With 194 secondary substations in the SW region modelled in this study, applying DLMPs down to 11 kV provides a means to connect increasing levels of DG beyond firm network capacity. This could also be achieved by active network management (without DLMPs), but without price signals there would be less incentive for optimal location of DERs.

For the network considered in this paper there are no constraints at 132 kV or between 400/132 kV transformers. Aggregating from 132 to 400 kV doesn't reduce DG capacity (as shown in Table II) which suggests there is no benefit from applying DLMPs at 132 kV. However, modelling to 132 kV is useful for accounting for the cost of losses as can be observed in the higher objective function cost at 132 kV than 400 kV (see Table III and Table IV).

For the winters day with minimum demand there is a significant level of DG output (see Table IV) despite being 32% less than the 5th of June. DG output is increased by 3% (945 MWh) by modelling down to 11 kV. This shows that even on a winter's day with low output from PV (which provides 65% of DG capacity in SW England), there are large gains to be made by applying DLMPs to 11 kV.

Table IV
Total DG Output and Objective Function at Aggregation Levels (with/without Flexible Demand) – 18th Jan

Agg	DG Output (MWh)		Objective Function (£)		
	No Flex	Flex	No Flex	Flex	Change (%)
400 kV	31,941	31,941	1,299,302	1,297,115	-0.17
132 kV	31,674	31,674	1,316,315	1,314,072	-0.17
33 kV	32,700	32,700	1,277,546	1,275,280	-0.18
11 kV	32,886	32,886	1,270,600	1,268,323	-0.18

B. *Use of flexible demand*

The dispatch of flexible demand on the 5th of June for each aggregation level is shown in Figure 2. LMPs for all nodes are shown at different levels of aggregation in Figure 3.

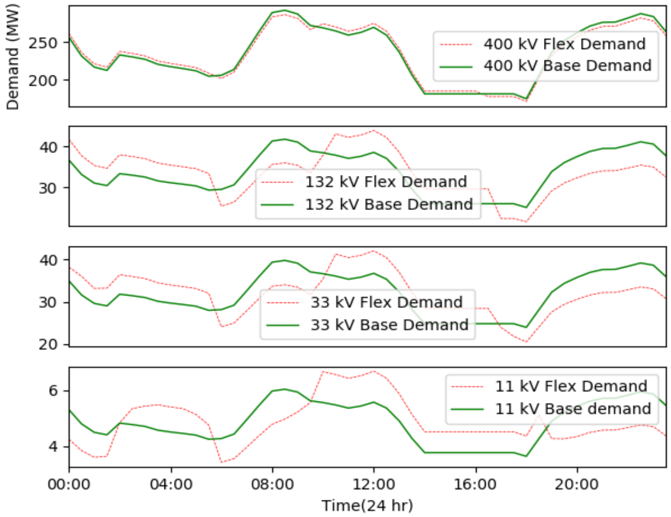

Figure 2. Flexible demand dispatch at each aggregation level for 5th of June

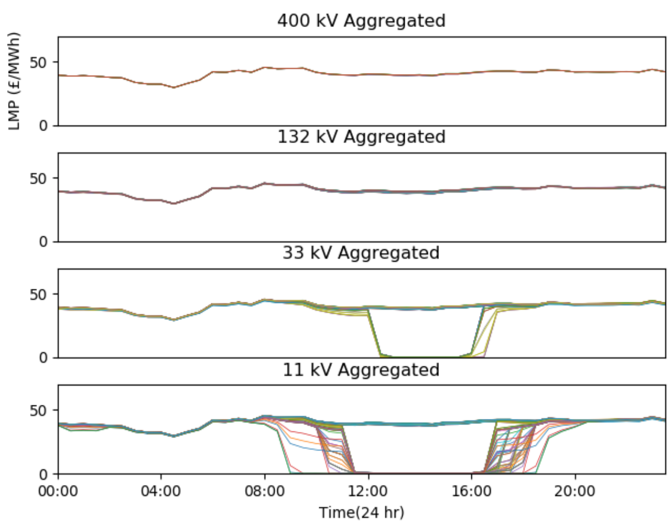

Figure 3. LMPs at all nodes at aggregation levels for 5th June

There are 2 effects on the optimal dispatch of flexible demand, one being the market price and the other being constraint resulting in LMPs of zero (in the case of zero marginal cost renewables being curtailed) behind the constraint. The flexible demand will be maximised at nodes behind a constraint and minimised at times when the market price is highest.

In general, flexible demand provides a reduction in the objective function due to shifting load from expensive to cheaper times (temporal price arbitrage). This is shown in Table III, with 20% of Rame 33 kV network demand as flexible demand, the objective function is reduced by around 0.3% for 400 kV and 132 kV aggregation without any change in DG output. DG output is already maximised at these aggregation levels therefore adding flexible demand does not increase DG output. At 33 kV and 11 kV aggregation there is constrained zero marginal cost DG and resulting zero LMPs as can be seen in Figure 3. In this case flexible demand increases DG output by providing additional demand at times of curtailment. On the SW network on the 5th of June, an additional 55 MWh (1.3%) of DG output is enabled by flexible demand at 33 kV and 27 MWh (8.6%) is added at 11 kV (as shown in Table V). This is a small percentage increase in total DG output at around 0.1%. However, this small increase in DG output along with the temporal price arbitrage results in a reduction of objective function by 0.9% at 33 kV and 1% at 11 kV (Table III).

TABLE V
DG OUTPUT AND CURTAILMENT AT 11 KV AND 33 KV AGGREGATION LEVELS (WITH/WITHOUT FLEXIBLE DEMAND) – 5TH JUNE

Aggregation	DG Output (MWh)		Curtailment (MWh)	
	No Flex	Flex	No Flex	Flex
33 kV	3,364	3,419	232	177
11 kV	314	341	203	177

Applying DLMPs down to 11 kV has a limited effect on the dispatch of flexible demand. This is because curtailment is happening at the cheapest time of day (~12-4pm). However, applying DLMPs to lower voltages provides price signals to incentivise flexible demand local to DG curtailment. For example, by adding 18 MW flexible demand to a node in a constrained DG location in the 33 kV network it is possible to reduce curtailment at 33 kV by 85% on the 5th of June 2015. This could provide financial benefit to the owners of the generation being curtailed as well as low cost energy for the owners of flexible demand.

C. *Model limitations*

This work has considered the benefits of applying DLMPs to a section of UK distribution network. The results suggest that applying DLMPs to 11 kV can facilitate increased DG output and locational signals for flexible demand. To provide a more accurate cost-benefit would require more detail on how the network is operated. A fully intact network has been assumed however DG connection limits could be further limited when applying N-1 security constraints. It is assumed that the 33 kV and 11 kV networks are operated radially however there are normally open points which can be used to link 33 kV networks. To improve the model accuracy input from the DNO would be required.

The size of the network model brings with it a computational cost. The full 222 bus SW England network model used in this study takes over 2 hours to solve over a 24 hour time series. Modelling the entire SW England down to 11 kV (including all 33 kV and 11 kV networks) would be a significant task numerically and operationally for the DNO.

Another limitation of the modelling is that flexible demand was taken as a percentage of the demand at a bus at a point in time, therefore at times of minimum demand (during the afternoon) there was less (e.g. 65% of peak) flexible demand available. Work on estimating a reasonable level of flexible demand should be undertaken as well as modelling the behaviour and availability of the flexible demand.

IV. CONCLUSIONS

This paper has shown the impact on aggregation of LMPs on the penetration of distributed generation and flexible demand. Studies were carried out for a region in SW England over a summer's day in 2015 when DG output (mainly from PV) was at its highest. It was shown that by applying DLMPs down to 11 kV, it was possible to increase DG output by 2.8% compared to aggregating to 400 kV. Flexible demand was shown to increase DG output by 8.6% at 11 kV level and reduce the objective function by 1% due to the combined effect of arbitrage and increased DG output. Modelling flexible demand down to 11 kV had a limited impact on total DG output (0.1% increase), however doing so would reward additional flexible demands in areas of constraint. When modelling the network down to 11 kV, the timing of flexible demand dispatch was the same as when aggregating to 400 kV, this is because curtailment coincided with times of lowest system price. Future work could be in carrying out timeseries analysis over a year using a DCOPF. Studies could also be carried out in other regions where DG curtailment is less likely to coincide with the lowest system prices. A DNO could use the results of this paper to assess the benefit of using DLMPs in operating their network, compared to active network management schemes with no price signals. Future work will focus on incorporating a markets-based solution aligned with DLMPs that would facilitate distributed trading.

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