WESTERN POWER DISTRIBUTION

INNOVATION

NEXT GENERATION NETWORKS

Comparison of price incentive models for locally matched electricity networks.

Appendix A: Study on local matching

Report Title	:	Comparison of price incentive models for locally matched electricity networks. Appendix A: Study on local matching
Report Status	:	Final
Project Ref	:	VPW
Date	:	19/01/2018
Prepared for WPD by	:	Open Utility with Reckon

Contents

Introduction and summary

1. This report examines the concept of local matching of electricity, and considers the potential benefits that increased local matching of electricity can bring to distribution networks and their customers.

2. Local matching of electricity is the process by which consumption by demand and export by generation that are served by the same part of the distribution network are netted off from each other when they occur within the same settlement period.

3. Locally matched electricity does not necessarily use the distribution network in the same way as unmatched electricity can do. Locally matched electricity remains within the local area, and does not need to be transported to/from other parts of the distribution network or the transmission network.

4. Increased local matching can bring benefits to the distribution network, and eventually to all electricity customers, by reducing power flows at higher levels of the network. Lower flows through these levels of the network can help avoid or defer the need for expensive network reinforcement. Lower flows can also help reduce distribution losses, and can facilitate cheaper and faster connections to the network.

5. We estimate that the potential savings from reduced power flows can be significant, and can eventually lead to lower charges for customers. Looking at WPD's network investment plans for the current price control period, we estimate that customers can benefit by up to £19 million a year between 2018 and 2023 across all four distribution areas, which is approximately 1.2 per cent of WPD's average allowed annual revenue over the same period.

6. Precise estimates of the benefits of local matching are difficult to produce. Benefits to consumers depend on the take up of local matching. The greater the extent of local matching, the lower the use of distribution and transmission networks, and higher the benefits to customers in the long term.

7. We think that demand customers and generators can be encouraged to consider local matching by introducing fairer and more cost reflective distribution charges for locally matched consumption. This can be done in several different ways, and any discounts against unmatched tariffs need to be carefully calibrated so that all customers can benefit. As an illustration, we have considered two approaches for

changes to the current distribution use of system charging methodology to facilitate local matching.

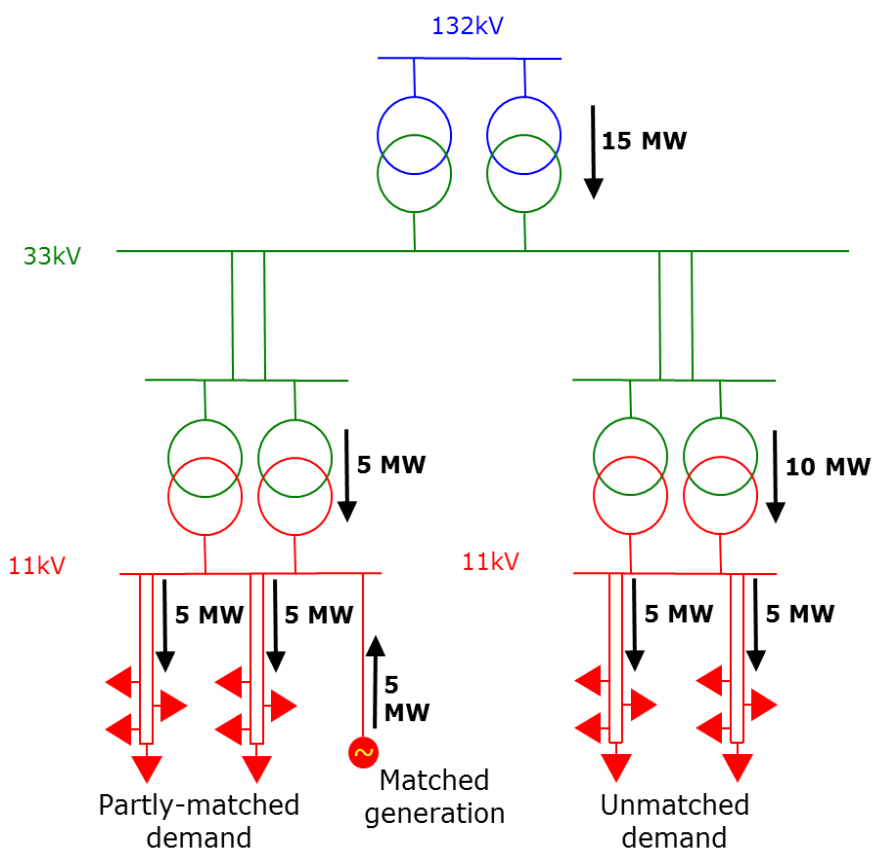
8. The final section of this document presents the impact of these changes on distribution charges for half hourly metered commercial users that participate in local matching.

What is local matching?

9. Electricity distribution networks serve both demand and generation customers, and potentially other types of customers in the future (e.g. storage). For the purposes of this study, we define locally matched electricity as electricity that is produced and consumed within a designated part of the electricity distribution network during the same settlement period (half hour).

10. The stylised network diagram below illustrates our concept of locally matched electricity.

Figure 1 Stylised network diagram illustrating the concept of local matching



11. The diagram focuses on one area of the distribution network, supplied from a 132/33kV substation. This substation supplies two primary (33/11kV) substations (A and B). Substation A supplies several demand customers and one generation customer (generation 1). Substation B supplies demand customers.

12. For the purposes of this illustration, we assume that flow through substation A is 5 MW downstream (i.e. 10 MW – 5 MW). The flow through substation B is 10 MW downstream. The flow through the 132/33kV substation is 15 MW (i.e. 5 MW + 10 MW).

13. In this example, the amount of locally matched energy in that half hour is 5 MW, and this is matched within the part of the network supplied by substation A.

14. Any part of the network that supplies a combination of demand and generation users is likely to benefit from some local matching.

The benefits of increased local matching

15. This section discusses the concept of increased local matching, and the potential benefits that increases in local matching can bring to the distribution network operator, and eventually to all customers.

Increased local matching leads to reduced power flow

16. The amount of electricity flowing through a distribution network asset at any instant is driven by the difference between the aggregate consumption by demand and aggregate export by generation served by that network asset.

17. More specifically, power flow through network infrastructure (substations, circuits etc) at any instant reflects the combination of:

    (a) Flows arising out of demand or generation connected directly to those assets; and

    (b) net unmatched flows of electricity arising out of demand and generation connected at lower network levels.

18. Any individual network asset or area may be "demand dominated", i.e. aggregate flows from demand may exceed aggregate flows from generation, or "generation dominated", i.e. aggregate flows from generation may exceed aggregate flows from demand.

19. Changes in the pattern of demand or generation that lead to a reduction in net unmatched flows can reduce the flow of electricity through network assets. Increasing demand at times when network assets are generation dominated can reduce power flows through those assets, as can increasing generation at times when network assets are demand dominated. This can be achieved by an increase in local matching.

20. Interventions targeted at increased local matching can work in two ways:

(a) By encouraging demand or generation to shift their time of operation to different times of the day so that they more closely aligned with each other.

(b) By encouraging demand or generation to connect to parts of the network that are dominated by the other – therefore offering the scope for additional local matching. For instance, encouraging new generation to connect to parts of the network that are demand dominated may provide additional opportunities for local matching.

21. If this increase in local matching takes place at the time of peak flow through the network asset, it could reduce the peak-time utilisation of the asset and therefore the total capacity required on that asset.

22. Crucially, increased local matching can lead to lower power flows without reductions in overall demand or generation.

23. Reductions in flows through the distribution network can benefit all customers.

(a) Lower flows, particularly at the time of peak load can reduce the amount of capacity required on the network, and therefore reduces the need for network reinforcement.

(b) Lower flows can lead to lower technical losses on the network. Every unit of electricity lost on the distribution network is eventually paid for by all customers. Technical losses are higher at the time of peak flows through network assets than at other times.

(c) Sustained reductions in power flows can mean that certain demand and generation connections may be accommodated without the need for costly network reinforcement.

24. We now look at each of these in turn.

Reduced need for network reinforcement

25. The capacity required on the distribution network is typically driven by the maximum power flowing through different assets on the network. DNOs make forecasts of peak power flow through different network assets, and use this information to plan network capacity and to schedule any network reinforcement expenditure that may be necessary.

26. For regulatory and price control purposes, DNOs in Great Britain categorise their larger substations (i.e. primary voltage at 33kV or higher) into five load index bands depending on the level of loading observed, i.e. the proportion of the substation's "firm" capacity that is utilised during periods of maximum flow.[1] The bands are:

    (a) LI1 – Significant spare capacity (loading of 0 – 80 per cent).

    (b) LI2 – Adequate spare capacity (loading of 80 – 95 per cent).

    (c) LI3 – Highly utilised (loading of 95 – 99 per cent).

    (d) LI4 – Fully utilised, mitigation requires consideration (loading of 99 per cent or more for fewer than 9 hours per year).

    (e) LI5 – Fully utilised, mitigation required (loading of 99 per cent or more for more than 9 hours per year).

27. WPD has provided data on the number of its larger substations that fall within each load index band in its RIIO ED1 Business Plan submission.[2]

Table 1 Substation load indices in the four WPD distribution services areas

[1] For further details please see Ofgem (2015) RIIO ED1 Regulatory Instructions and Guidance: Annex E – Reinforcement.
[2] Please see WPD's Business Plan SA-05 Supplementary Annex – Expenditure.

DNO area	Load band	Number of substations in each band In 2015/16	Projected in 2022/23 (No action)	Projected in 2022/23 (with planned reinforcement)
West Midlands	LI1	166	153	180
	LI2	42	43	42
	LI3	7	4	2
	LI4	7	13	4
	LI5	6	15	0
East Midlands	LI1	309	258	281
	LI2	108	112	119
	LI3	11	31	33
	LI4	13	19	14
	LI5	8	29	2
South Wales	LI1	150	129	129
	LI2	32	45	45
	LI3	0	7	7
	LI4	1	2	2
	LI5	0	0	0
South West	LI1	267	233	243
	LI2	54	67	69
	LI3	9	12	13
	LI4	2	9	7

	LI5	0	11	0

28. According to WPD's forecasts, in the absence of intervention, 98 substations across the four distribution service areas are expected to become fully utilised (i.e. they would have loading factors of 99 per cent or more) by the end of the current price control period in 2022/23. This compares to 37 substations that are fully utilised in 2015/16. The projected increase in the number of fully loaded substations is greatest in the West Midlands, East Midlands and the South West areas.

29. WPD's Business Plan attributes this growth in the number of fully loaded substations to forecast load growth in these areas.

30. The table below shows WPD's forecast load growth rates for each distribution services area.[3]

Table 2 WPD's "Best View" of annual growth in peak demand

Year	West Midlands	East Midlands	South Wales	South West
2015/16	0.13%	0.34%	0.07%	0.46%
2016/17	0.13%	0.39%	0.05%	0.46%
2017/18	0.14%	0.36%	0.05%	0.46%
2018/19	0.31%	0.57%	0.50%	0.77%
2019/20	0.47%	0.76%	0.75%	1.05%
2020/21	0.98%	1.38%	1.09%	1.65%
2021/22	1.14%	1.58%	1.20%	1.94%
2022/23	1.28%	1.73%	1.20%	2.14%

31. WPD's projections show that peak demand is expected to grow consistently over the duration of the current price control period, and the rate of growth is projected to

[3] Please see WPD's Business Plan SA-05 Supplementary Annex – Expenditure, available from here.

increase over time. By 2023, annual growth in peak demand is expected to be between 1.20 per cent (in South Wales) and 2.14 per cent (in the South West).

32. Increased local matching can play a crucial role in ameliorating the effects of this projected demand growth. These figures show that relatively small reductions in growth rates of peak demand – between 1 and 2 per cent a year – can significantly reduce the number of highly loaded substations and therefore avoid or postpone the need to reinforce them.

33. WPD forecast that it would spend a total of £598.5 million (in 2012/13 prices) between April 2015 and March 2023 on reinforcing its network across all four of its distribution service areas.

34. The table below shows the breakdown of these costs by reinforcement type and distribution services area

Table 3 WPD's forecast of network reinforcement expenditure between 2015/16 and 2022/23 (£m, 2012/13 prices)

Reinforcement type	West Midlands	East Midlands	South Wales	South West
Customer related reinforcement	18.1	16.8	8.7	8.4
General network reinforcement	124.8	162.7	28.6	31.4
Reinforcement for low carbon technologies	55.1	87.7	11.3	44.9
Total – Reinforcement of the network	198.0	267.2	48.6	84.7

35. For this report, we focus on "General network reinforcement" expenditure (highlighted above), which is primarily driven by forecast growth in peak demand. WPD's business plan also provides a breakdown of its forecasts of general reinforcement expenditure by network level. These forecasts are based on operational data on current levels of flow through EHV network substations, along with forecasts for load growth through each substation. Specific reinforcement schemes are developed where the available capacity is forecast to be exceeded.

36. The table below shows the forecast expenditure at higher network levels (EHV and 132kV) for each distribution services area.

Table 4 WPD's forecast of general network reinforcement expenditure at 132kV and EHV network levels (£m, 2012/13 prices)

Network level	West Midlands	East Midlands	South Wales	South West	Total
EHV	44.2	60.5	2.4	8.7	115.7
132kV	39.7	48.7	14.7	5.6	108.7
Total	83.9	109.2	17.1	14.3	224.5

37. WPD has forecast total network general reinforcement expenditure of £224.5 million at the 132kV and EHV network levels over the duration of the current price control period (2015/16 to 2022/23). This is equivalent to annual expenditure of £28 million a year.

38. Under the current (RIIO) price control framework, Ofgem sets expenditure allowances for DNOs. These expenditure allowances cover both capital and operating expenditure, and represent the expected efficient cost to the DNOs of meeting the outputs that customers want (as set by Ofgem).

39. DNOs are then allowed to collect a certain amount of revenue (the "allowed revenue") each year from customers through distribution use of system charges. Ofgem determines each DNO's annual revenue for the year through the Annual Iteration Process (AIP), as part of which it updates and publishes the Price Control Financial Model (PCFM) which contains the calculations that feed into the determination of the annual revenue. Annual revenue in any year is determined by a combination of the expenditure allowance set by Ofgem at the start of the price control period, the DNO's actual expenditure in the period leading up to that year, and external factors (e.g. updated estimates of borrowing costs, and corporation tax rates).

40. Any savings in predicted or actual DNO expenditure arising out of increased local matching would lead to lower annual revenues, and in turn, and lower distribution charges for customers.

41. As an illustration of the quantitative impact of lower-than-expected network investment, we have carried out analysis using Ofgem's PCFM to model changes to WPD's annual revenues.

42. The table and charts below show the impact on WPD's annual revenues of not reinforcing the network as currently planned over the current price control period. WPD had originally forecast total network reinforcement expenditure of £224.5 million at the 132kV and EHV network levels over the current price control period (2015/16 to 2022/23). For the purposes of our analysis, we assume that the expenditure reductions are spread over three years, starting from 2018/19, and these reductions are translated into reductions in expenditure allowances.[4]

43. This is not to say that local matching will necessarily avoid the need for all general network reinforcement. However, the fact that a relatively small amount of load growth (between 1.2 – 2.1 per cent a year) has driven these investment projections suggests that small reductions in the growth rate of power flows can be sufficient to remove the need for this investment. The actual impact would depend on the extent of take-up of local matching, and the pattern of demand and generation behavioural changes in response to incentives offered by DUoS tariffs specifically developed and applied to locally matched units.

Table 5 Impact on WPD's annual revenue of avoiding network reinforcement expenditure at 132kV and EHV network levels (£m)

Area	Baseline allowed revenue (2018/19 to 2022/23)	Revised baseline allowed revenue (2018/19 to 2022/23)	Total reduction in allowed revenue over 5 years	Average annual reduction in allowed revenue	Percentage of annual average allowed revenue
West Midlands	2,471	2,435	36	7.2	1.46%
East Midlands	2,496	2,451	45	8.9	1.79%
South Wales	1,256	1,248	8	1.6	0.63%
South West	1,785	1,779	7	1.4	0.38%

[4] The assumption that these expenditure allowances are reduced means that the full benefit is passed on to customers through reductions in allowed revenue. If allowances are not reduced, only a proportion of these reductions in expenditure would be passed on to customers through the Totex Incentive Mechanism.

Total	8,008	7,912	96	19.2	1.20%

Figure 2 WPD West Midlands - Impact on annual revenue of avoided network reinforcement expenditure at 132kV and EHV network levels

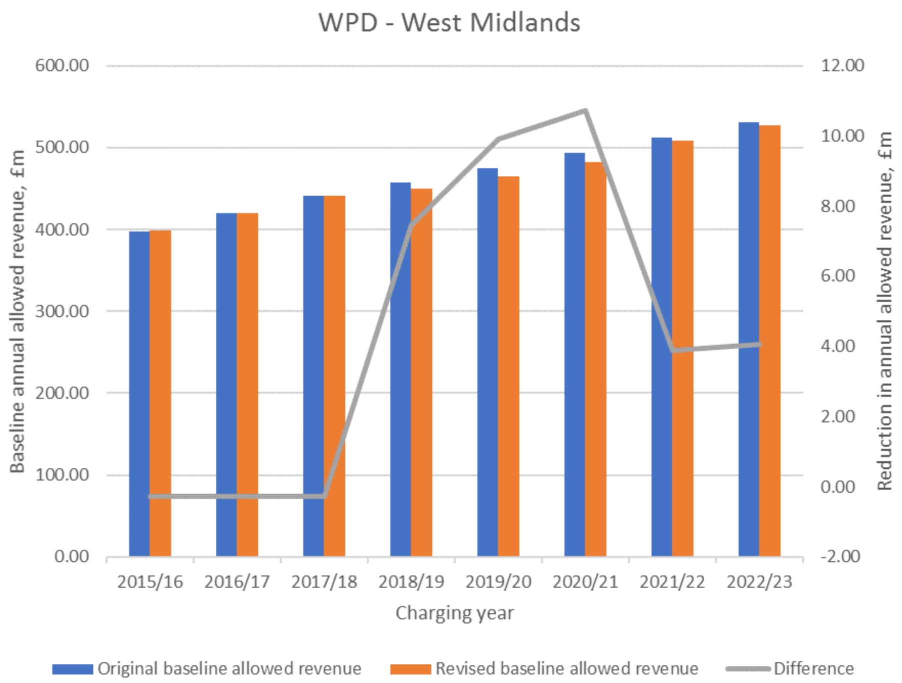


Figure 3 WPD East Midlands - Impact on annual revenue of avoided network reinforcement expenditure at 132kV and EHV network levels

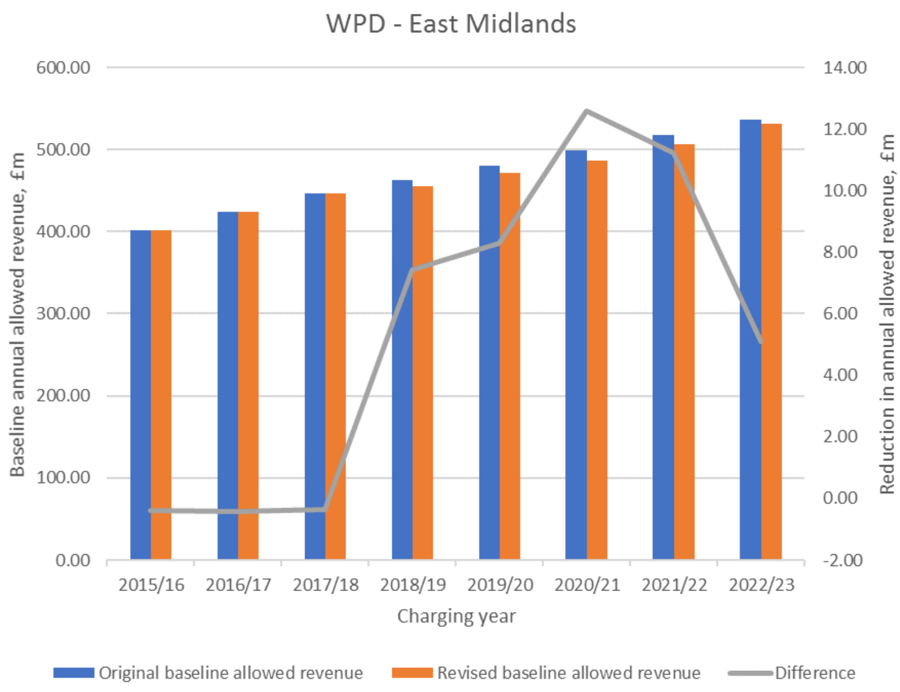


Figure 4 WPD South Wales - Impact on annual revenue of avoided network reinforcement expenditure at 132kV and EHV network levels

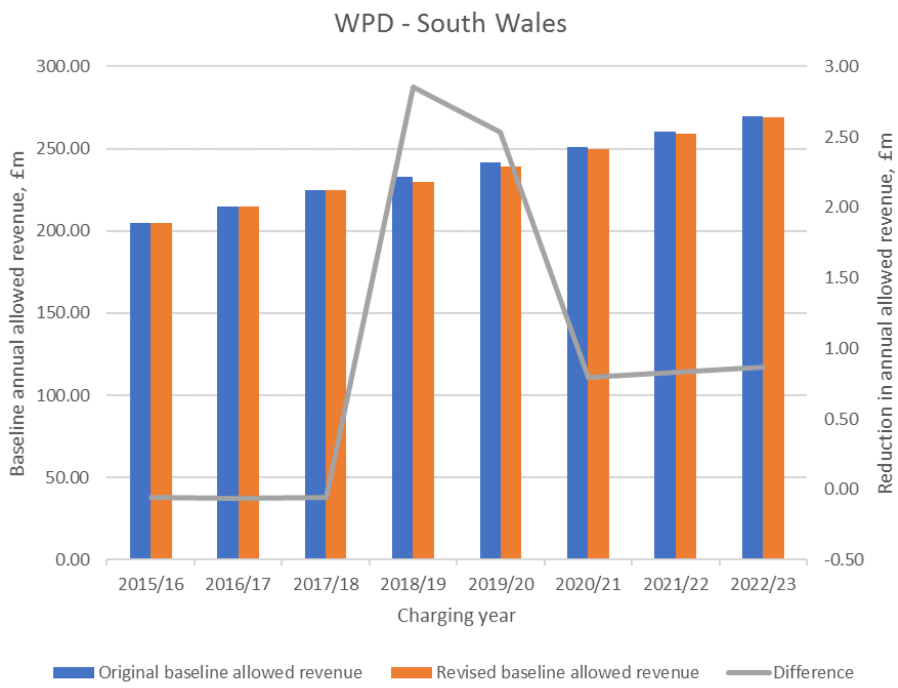
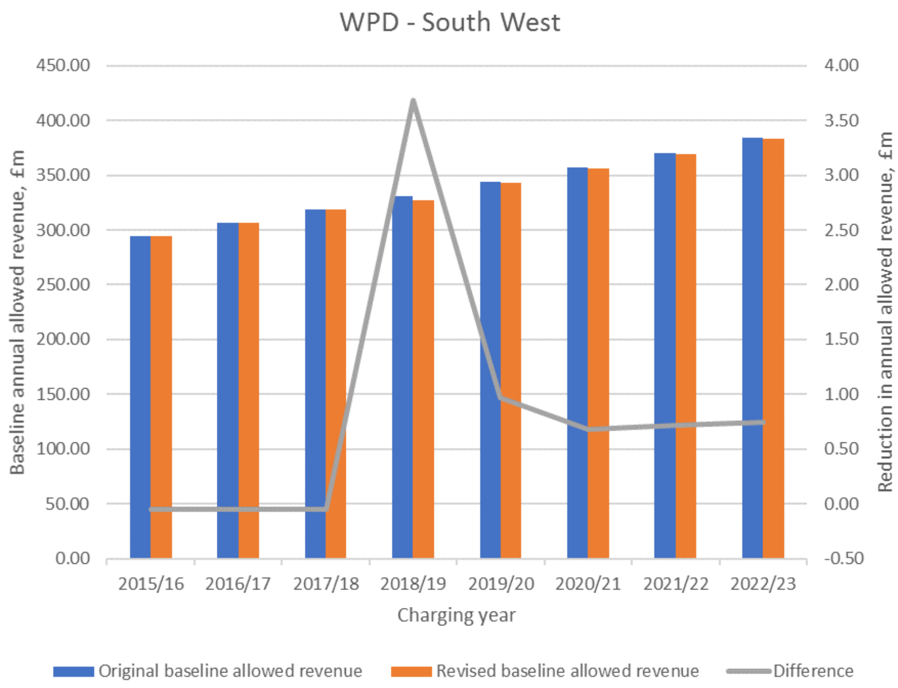


Figure 5 WPD South West - Impact on annual revenue of avoided network reinforcement expenditure at 132kV and EHV network levels



Lower distribution losses

44. As electricity is distributed through the distribution network to users, some of it is lost and never delivered to users. The difference between electricity entering the distribution network and leaving the distribution network through customer meters is called losses.

45. Losses on the distribution network are usually categorised into two types.

(a) Technical losses are attributable to technical and design factors of the network such as circuit lengths, diameter and voltage.

(b) Non-technical losses are largely attributed to illegal abstraction of electricity (i.e. electricity theft) and metering issues (i.e. consumption at unregistered sites, meter read errors etc).

46. According to the most recently available estimates, 18.907 TWh of electricity was lost through the distribution networks in the United Kingdom in 2016.[5] The cost of generating and transporting this electricity is eventually recovered from all

[5] Digest of UK energy statistics, 2017, Table 5.2

customers under the settlement mechanism, costing customers in the UK over £900 million a year.

47. The extent of losses from different parts of the distribution network, and from networks operated by different DNOs can vary considerably. Losses are affected by a number of factors, including network design and topology, customer density, network loading and power quality.

48. According to statistics published by WPD, between 5.8 – 6.6 per cent of electricity supplied to WPD's distribution networks is taken up by distribution losses.[6] This means that losses on WPD's networks are between 4.44 and 5.05 TWh, which translates into a cost to its customers of between £220-£250 million.[7] Approximately 28 per cent of these losses occur at EHV and 132kV network levels at a cost of between £62 million and £70 million, with the rest being lost at lower network levels.[8]

49. Every unit of electricity lost means one more unit has to be generated to meet overall demand. In addition to not paying for the energy itself, customers face the cost of carbon emissions caused by the additional generation. The total carbon cost of losses on WPD's network is estimated to be between £41 million and £46 million, of which £11 million to £13 million can be attributed to losses from the EHV and 132 kV network levels.[9]

50. Taken together, the energy cost and carbon cost of losses from the EHV and 132 kV network levels of WPD's distribution network is between £73 million and £83 million.

51. As part of its distribution use of system charging statements, WPD provides estimates of "loss adjustment factors" or LAFs at different network levels.[10] The LAF at any network level is the proportion of electricity lost between that network level and the highest level on the distribution network (transmission exit). For instance, a LAF of 1.02 at the HV substation network level implies that for every 1 kWh of

[6] WPD Losses Strategy, 2017

[7] This is based on total UK electricity consumption of 303 TWh in 2016, and an assumption that 25.2 per cent of total UK electricity consumption is served by WPD's four distribution networks. This assumption is drawn from figures published in a WPD Innovation Project Registration Document.

[8] Section 3.6 of WPD's Losses Strategy, 2017

[9] Reckon calculations based on a carbon conversion factor of 0.35156 Kg CO2e/kWh and a short-term traded sector carbon value of £26.22 £/tCO2e.

[10] WPD use of system charging statements are available from https://www.westernpower.co.uk/About-us/Our-system/Use-of-System-Charges.aspx

electricity transported from the transmission exit level to the HV substation level, 0.02 kWh is lost.

52. Losses can vary depending on the extent to which the network is loaded – higher the loading, the greater the losses. So different LAFs apply at different times of the day.

53. The table below sets out the LAFs at the HV Substation network level for different WPD areas, split by distribution charging time bands (red, amber and green).[11]

Table 6 Estimated loss adjustment factors split by distribution charging time bands

Area	Red time band	Amber time band	Green time band
West Midlands	1.021	1.021	1.019
East Midlands	1.019	1.019	1.020
South Wales	1.032	1.031	1.031
South West	1.020	1.019	1.018

54. LAFs at the HV Substation network level vary from 1.018 to 1.032, meaning that between 1.8 per cent and 3.2 per cent of electricity that is transported from the transmission exit level to the HV substation level is lost.

55. Increased local matching at the HV substation network level or below can help reduce losses on the distribution network by reducing the amount of electricity that needs to be transported from the transmission exit network level. The reduction in losses from local matching is likely to be lower the levels implied by the LAFs. This is because losses are caused by a number of factors specific to the network and are made up of both fixed and variable elements. It is the variable element of losses that is likely to be avoided through reductions in power flow.

56. As an illustration of the potential scale of benefits to customers through reduced distribution losses, we have modelled the potential impact on losses of assuming that 10 per cent of demand from half hourly metered LV and HV commercial users in the WPD areas is locally matched, of which half is translated in to reductions in peak flows through EHV and 132 kV network levels compared to the status quo. We have assumed that reduction in demand is spread across all distribution time bands (in

[11] Reckon calculations using data published by WPD in its charging statements.

proportion to current demand), and that 70 per cent of distribution losses at the EHV and 132kV network levels are variable.[12]

Table 7 Estimated benefits from lower losses at the EHV and 132kV levels (£ 000s/year)

Distribution area	Benefits from reduced losses (£m/year)
West Midlands	0.72
East Midlands	0.77
South Wales	0.38
South West	0.30
Total	2.16

Faster and cheaper connections to the distribution network

57. Customers requiring new connections to the distribution network apply to the relevant DNO through its connection application process. As part of the connections process, the new applicant provides details of its connection requirements, including the expected level of demand or generation load that is required to be accommodated on the network. The new connection could be a demand-only connection, a generation or export-only connection, or a connection for both demand and generation.

58. Upon receipt of a new connection application, the DNO typically considers the impact of the new connection on its existing network under its network planning rules, taking account of all known network developments and other connections in the pipeline. As part of this assessment, the DNO considers whether the network has sufficient capacity to accommodate the new customer, taking account of credible running arrangements and contingencies.

59. The DNO then provides a connection quotation that sets out the cost of any network infrastructure required to be put in place as a consequence of the connection. This connection quotation is prepared in accordance with the DNO's connection charges

[12] UKPN's Losses strategy document, 2015

methodology, which specifies the rules for the recovery and apportionment of the cost of network upgrades.

60. All else being equal, the more heavily utilised the network assets in the area, the greater the chance that expensive upgrades will be necessary to accommodate the new connection.

61. Increased local matching at lower network levels can alleviate this problem by reducing the amount of actual capacity used on the network. Provided the reduction in capacity usage is tangible and can be relied upon, increased local matching can free up capacity that can be offered to new customers.

62. This additional capacity means that connections can be offered at a lower cost, and potentially quicker than otherwise possible.

Current barriers to increased local matching

63. Local matching already takes place on the distribution network. Local demand and generation patterns are driven by a number of internal (type of demand, generation technology etc) and external factors (e.g. wholesale electricity prices and time-variant DUoS charges). There will be times when local demand is offset by local generation or local generation is offset by local demand.

64. The crucial point is that such local matching is currently uncoordinated and is driven by factors other than capacity utilisation on the local network.

65. There is currently no reason for either demand or generation users to take account of actions of other users connected to the same part of the distribution network. There are higher peak time charges for half hourly settled demand, and potentially higher peak time generation income for half hourly settled generation, but these differences are geographically averaged across the distribution network area. They do not currently take account of local network asset utilisation.

66. Take a large commercial user, say a public water and sewerage company, that both imports from, and exports electricity onto, the distribution network at a number of geographically dispersed sites. These sites may include demand (e.g. pumping stations, water treatment centres) and generation (e.g. anaerobic digestion plants, photovoltaic farms).

67. In some cases, the water company's demand and generation assets may be located at the same site or in close proximity, and therefore can operate through a "private

wire" arrangement, bypassing the DNO's network for some of its local demand requirements. The site would have a single meter that covers both demand and generation, and the power flow through the meter would reflect the net position taking into account the demand and onsite generation. The water company only pays for its metered net consumption, and the generator receives a negotiated share of the avoided demand charge as income for its locally matched output (as compared to income that is roughly half of the demand charge if its production is exported directly to the network and metered separately).

68. Being able to operate "behind the meter" provides a natural incentive for the water company to try and coordinate its demand and generation so that as much of the electricity produced and consumed is locally matched. Setting aside any concerns that private wire arrangements can potentially raise about asset duplication or the avoidance of upstream charges or levies (also known as "policy costs"), such arrangements can benefit the distribution network by reducing power flow through assets at higher network levels.

69. For the majority of its sites, the water company does not have a "behind the meter" private wire option. Its demand sites are geographically dispersed and may be several miles away from its generation sites, making installing a private wire network costly, and impractical. In respect of these sites, the water company derives no benefit from coordinating its consumption or production with other local users of the distribution network – even though doing so could benefit the distribution network, and could lead to lower charges for all customers.

70. The current arrangements for setting DUoS charges (the CDCM and EDCM) do not allow the DNO to support greater local matching of demand and generation through use of system charges.

71. The CDCM is a geographically averaged charging methodology that does not take account of local differences in the balance of generation and supply.[13] A demand customer in a generation dominated part of the network pays just as much as a demand customer in a demand dominated part of the network, even though the demand customer in the generation dominated part of the network can offset power flows through parts of the distribution network.

[13] The Common Distribution Charging Methodology (CDCM) is the methodology used by all regional distribution network operators in Great Britain to set charges for most customers connected at less than 11 kV.

72. The EDCM is a site-specific charging methodology with time of use (TOU) charging.[14] However, the time bands used for applying EDCM TOU charges are the same across the whole distribution service area. This means that charges are set based on the contribution made by users to the system-wide peak load, rather than the contributions made to peak flows through individual assets. Individual network assets can peak at different times to the whole system. For instance, in the WPD East Midlands area, 132kV assets as a whole have a 71 per cent chance of peaking at the time of system-wide peak. Similar probabilities are observed for EHV assets, across all four WPD areas.

A possible solution - Peer-to-peer matching with fairer DUoS charges

73. Peer-to-peer matching is a service that facilitates and promotes increased local matching between otherwise unrelated demand and generation users. Open Utility's Piclo platform is an example of a peer-to-peer matching service.

74. Using a peer-to-peer matching platform such as Piclo, demand and generation users in the same area (in terms of the distribution network) can schedule their consumption and production to take advantage of local matching.

75. Going back to the example of the water company, a peer-to-peer matching platform could allow the water company to identify one or more generators connected to the same part of the distribution network as its water pumping station, and try to schedule its pump operation times to match the times at which the generators are likely to generate. The generators could be owned or controlled by the water company itself, but they need not be. The benefits to the DNO of greater local matching does not rely on the matching sites being under common ownership or even supplied by the same supplier. Any local generation connected to the same part of the network will do.

76. If the DNO is able to offer a fairer and more cost-reflective DUoS demand charge for locally matched consumption irrespective of ownership or supply arrangements, this might encourage demand customers to explore opportunities for greater local matching, and potentially shift their consumption towards times when the generator is exporting.

[14] The EHV Distribution Charging Methodology (EDCM) is the methodology used by all regional distribution network operators in Great Britain to set charges for customers connected at 22kV or higher, and a small number of customers connected at 11kV.

77. Additionally, the possibility of lower DUoS charges for demand for locally matched units could encourage distributed generation to locate in parts of the network that are demand dominated by providing the generator with potential for an additional income stream.

78. This section describes some options for changes to the current methodologies used to set DUoS charges for demand and generation customers (i.e. the CDCM). Any of these options could deliver a package of fairer and more cost-reflective charges for users that opt in to tariffs that recognise local matching.

79. The changes described in this section are targeted at half hourly metered commercial demand users and all generation users. These include users that are currently charged on the LV HH Metered, LV Sub HH Metered and HV HH Metered tariffs.

Current charging arrangements

80. Most users of the distribution network are charged a set of geographically averaged DUoS charges calculated in accordance with the CDCM. The CDCM allocates the DNO's costs to each network level, and then allocates the costs at each network level to users based on their assumed used of each network level and their estimated contribution to the maximum load on the network as a whole. The CDCM allocates the following costs to different network levels:

    (a) Network asset costs. This is the amortisation and return on capital for the cost of assets at each network level, less the amount deemed to be covered by customer contributions.

    (b) Transmission exit costs. These are assigned to the transmission exit network level only.

    (c) Other DNO expenditure. This covers DNO operating expenditure (direct costs and indirect costs). These are assigned to all network levels.

81. As part of this allocation, the CDCM assumes that users connected at each level are supplied from the transmission exit point using every network level between the transmission exit point and the network level to which the user is connected.

82. For instance, CDCM assumes that HV HH Metered users make use of all the following network levels:

    (a) Transmission exit

(b) 132kV

(c) 132kV/EHV

(d) EHV

(e) EHV/HV

83. The CDCM includes DUoS credits for generators (intermittent and non-intermittent) paid for each unit of electricity exported to the distribution network. DUoS credits are calculated using the same cost allocation methodology as for demand (except for revenue matching or residual charges, which only apply to demand charges). In principle, this is equivalent to treating distributed generation as negative demand for charging and cost allocation (ignoring residual charges). Generation credits are geographically averaged, and are paid at the same rate across the distribution network.

Approaches to setting fairer DUoS charges

84. We have considered two approaches to setting fairer and more cost reflective DUoS charges for locally matched electricity.

85. The first approach involves modifying the CDCM to recognise the fact that locally matched electricity does not use network levels higher than the level at which matching takes place.

86. Our proposed modifications would distinguish between consumption that is locally matched with generation and consumption that is not locally matched. Specifically,

(a) Demand that is locally matched with generation would not attract costs attributable to network levels above the level of matching; and

(b) All other (i.e. unmatched) demand would attract costs attributable to all network levels above the level of connection.

87. Every demand customer on the LV HH Metered, LV Sub HH Metered and HV HH Metered would be allowed to opt into local matching tariffs. Demand users on local matching tariffs would be subject to two CDCM tariffs:

(a) A standard tariff that would apply to all unmatched units of consumption. This includes three unit rates (red, amber and green), a fixed charge, a capacity charge, exceeded capacity charge and excess reactive power charge.

(b) A local matching tariff with three unit rates (red, amber and green) that would apply to all locally matched units of consumption.

88. The unit rates for local matching tariffs would be lower than unit rates for the standard tariff to reflect the fact that locally matched units do not use higher network levels, and therefore do not contribute towards costs associated with those levels.

89. Within this approach, we have considered two options for changes to the CDCM that cater to local matching based on different assumptions about the level at which matching takes place.

(a) Option 1 assumes that local matching takes place at the HV network level.

(b) Option 2 assumes that local matching takes place at the EHV network level.

90. The table below sets out the attribution of costs to different network levels under each option above.

Table 8 Attribution of costs to matched and unmatched consumption

Costs at network level	Option 1 Matching at HV	Option 2 Matching at EHV
Transmission exit	Unmatched units only	All units
132kV circuits	Unmatched units only	Unmatched units only
132kV/EHV	Unmatched units only	Unmatched units only
EHV circuits	Unmatched units only	All units
EHV/HV	Unmatched units only	All units
HV circuits	All units	All units
HV/LV	All units (except for HV connected customers)	All units (except for HV connected customers)
LV circuits	All units (except for HV and LV Sub connected customers)	All units (except for HV and LV Sub connected customers)

91. Under both options, the modification would remove all DUoS credits for generation. The current system of generation credits in the CDCM assumes that distributed generation always offsets demand at higher network levels. Credits for generation are calculated on that basis and paid to all units generated, whether they are intermittent or non-intermittent.

92. Some generation does indeed offset demand on the local distribution network. Generators connected to demand-heavy areas of the network are likely to offset demand, to the extent that they generate at the same time as demand. Generators connected to generation-heavy areas of the network, and generation that occurs at times when demand is low (i.e. outside peak demand hours) are less likely to offset demand. Under the current CDCM, however, both sets of generators receive the same credits. This means that demand customers could be funding payments to generators even when they provide no benefit to the network.

93. Our proposed change to the CDCM would address this problem by ensuring that only locally matched units would be eligible for lower DUoS charges.

(a) In demand-heavy areas, generators would be able to negotiate with demand users to take a relatively large share of the DUoS reduction available from matching.

(b) In generation-heavy areas, demand users would be able to take a relatively large share of the DUoS reduction available from matching.

94. Removing DUoS credits for generators that do not benefit the network means that less revenue needs to be raised from demand users, and therefore lower charges for all demand users (including domestic customers).

95. The second approach for setting fairer DUoS charges involves the introduction of a DUoS *credit* for locally matched demand, based on the principle of remunerating local matching customers for the value of benefits that they bring to the network and other customers.

96. Under this approach, demand users on local matching tariffs would be subject to two CDCM tariffs:

(a) A standard tariff that would apply to all unmatched units of consumption. This includes three unit rates (red, amber and green), a fixed charge, a capacity charge, exceeded capacity charge and excess reactive power charge.

(b) A local matching tariff with three unit rates (red, amber and green) that would apply to all locally matched units of consumption. Only the red unit rate would be applied as a credit, and the amber and green unit rates would be set to zero.

97. The credit would apply to all locally matched units in the red time band only. This is based on an assumption that network reinforcement is driven primarily by power flows in the red time band. The value of the credit would be calculated by dividing an estimate of the reduction in DNO allowed revenue from increased local matching by the total volume of demand in the red time band.

98. There may be other ways to structure this demand DUoS credit. For example, the credit could be paid for all matched units, rather than units consumed in the red time band. The value of the credit could be calibrated such that only a part of the estimated cost savings is passed on to locally matched units – the rest being shared amongst the wider customer base.

99. Apart from lower network reinforcement, there are other potential benefits from increased local matching (as discussed in the previous section). These include savings from lower distribution losses and the consequent reduction in carbon emissions. Estimates of these savings (per unit of demand during the red time band) could also be passed on to locally matched demand as a credit.

100. To illustrate the impact of these options on DUoS tariffs in the four WPD distribution areas, we have modelled a scenario where 10 per cent of the consumption of the three HH metered commercial tariffs are assumed to be locally matched, and the entire value of the estimated cost savings from increased local matching is paid through credits to locally matched demand in the red time band only.

Table 9 WPD West Midlands - Illustrative impact on CDCM tariffs of the local matching change

Assuming 10% local matching	Current tariffs (average p/kWh)	Approach 1 Matching at HV (average p/kWh)	Approach 1 Matching at EHV (average p/kWh)	Approach 2 Demand credit on matched red units (p/kWh)
LV HH Metered	2.414	1.228	1.324	7.291
LV Sub HH Metered	2.645	0.967	1.069	7.291
HV HH Metered	1.892	0.967	0.987	7.291

Table 10 WPD East Midlands - Illustrative impact on CDCM tariffs of the local matching change (average p/kWh)

Assuming 10% local matching	Current tariffs (average p/kWh)	Approach 1 Matching at HV (average p/kWh)	Approach 1 Matching at EHV (average p/kWh)	Approach 2 Demand credit on matched red units (p/kWh)
LV HH Metered	2.118	0.979	1.243	8.111
LV Sub HH Metered	2.110	0.756	1.004	8.111
HV HH Metered	1.608	0.756	0.813	8.111

Table 11 WPD South Wales - Illustrative impact on CDCM tariffs of the local matching change (average p/kWh)

Assuming 10% local matching	Current tariffs (average p/kWh)	Approach 1 Matching at HV (average p/kWh)	Approach 1 Matching at EHV (average p/kWh)	Approach 2 Demand credit on matched red units (p/kWh)
LV HH Metered	2.741	1.443	1.598	6.587
LV Sub HH Metered	2.505	1.245	1.397	6.587
HV HH Metered	2.226	1.245	1.299	6.587

Table 12 WPD South West - Illustrative impact on CDCM tariffs of the local matching change (average p/kWh)

Assuming 10% local matching	Current tariffs (average p/kWh)	Approach 1 Matching at HV (average p/kWh)	Approach 1 Matching at EHV (average p/kWh)	Approach 2 Demand credit on matched red units (p/kWh)
LV HH Metered	2.760	1.462	1.648	5.284
LV Sub HH Metered	2.474	1.281	1.451	5.284
HV HH Metered	2.065	1.281	1.326	5.284