UK Half-Hourly Regional Electricity Cost Modelling for Commercial End Users

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Abstract:

The rising prices of electricity in the UK risks rendering businesses uncompetitive if these costs are not controlled. This issue has created the need to properly comprehend the tariffs and costing framework that influence the total cost of electricity for non-domestic customers. This paper details an open source method to model UK electricity regional costs (MUKERC) for commercial end-users; allowing users to visualise and calculate the cost of the electricity they consume. The methodology consists in a bottom-up model that defines individually all the tariff components and then aggregates them to quantify the cost of a kWh across each half-hour of the day. The disaggregated structure of the model allows users to conduct specific analysis of tariff components and to understand their rich temporal and spatial features. This granularity facilitates understanding which tariffs influence costs more during different time periods. Emphasis is given to showcasing commodity prices and network charges; known as Transmission Use of System and Distribution Use of System tariffs. 'Representative day' electricity price curves are presented for different day types, voltage level connections, and across different UK regions for 2016-17. Outputs from MUKERC can better inform companies on their energy costs and therefore allows them to perform comprehensive and bespoke energy management and energy efficiency strategies relevant to their local area. Results show that commercial buildings connected at Low Voltage in North Wales and Merseyside and the South West face the highest average electricity prices, whereas consumers connected to High Voltage in London and the North West have the cheapest electricity in the UK. Other significant findings indicate sites connected at low-voltage pay 7.5% more than high-voltage sites, winter weekday costs are 18% higher than summer weekday costs, and overall weekdays are 35% more expensive than weekends.

Keywords:

Electricity cost modelling, Energy markets, Network charges, Real-time pricing, Spatial-temporal modelling.

1. Introduction

The UK ranks second highest within the EU28 for non/domestic electricity bills, paying 53% more than the median (international energy price comparisons). Businesses across Great Britain paid in 2014 almost three times what they did in 2004, suffering the highest rise among the IEA nations in this period [1]. This cost increase, the transformation of the electricity market and the corporate social responsibility policies to fight against climate change have challenged the traditional view on energy costs as fixed overhead by organizations, promoting active energy management strategies. These proactive practices facilitate businesses to control costs, comply with legislation, and enhance their reputation by efficiently operating their assets [2]. In addition, apart from the individual goal of each company to reduce its electricity costs and decarbonise its operations, the proliferation of energy management schemes is also a consequence of the more global risk that uncontrollable electricity charges could bring to the productivity and competitiveness of businesses in the UK and therefore, to the economy of the country. However, there are many barriers to the implementation of energy cost control strategies usually related with a lack of knowledge in understanding energy price trends that complicate developing sounds business cases for energy savings [3]. For instance,

it is not uncommon in the industry for energy managers in organisations to assume a flat rate on their electricity costs and consequently miss out on the benefits that could come about from demand side management initiatives. Based on this context, there is a clear need for a robust methodology to characterise and aggregate all the components of UK electricity tariffs for non-domestic customers, with the goal to better comprehend charges and thus make better informed decisions in managing their energy use in facilities across the country. Accordingly, this paper focuses on detailing a bottom-up model that generates half-hourly electricity price curves to allow consumers to understand their electricity expenditures over time for different regions in the UK. Such outputs are useful to prove that location and voltage level connection are important aspects to consider when assessing the profitability of energy efficiency projects. The model in this paper is referred to as MUKERC and was initially introduced by Acha and Bustos [4]. Data produced from the MUKERC model have been used in [5, 6, 7] designing and scheduling distributed technologies; showing the value and relevance that can come about from applying more realistic electricity cost datasets into optimisation models.

This paper is structured into five sections. The current section has provided the motivation and a short literature review addressing electricity price modelling. In section 2 the electricity bill is explained, introducing the different tariff components and providing a classification of their spatial and temporal behaviour. Section 3 details the MUKERC methodology, where the equations used for tariff characterization are explained. Section 4 presents the results highlighting key learnings obtained from the simulations by emphasising how prices vary according to different attributes such as time, space, and voltage connection. Lastly, Section 5 covers concluding remarks.

2. UK Electricity Bill Structure

2.1. Overview

According to reports from Department for Business, Energy & Industrial Strategy (BEIS), conservative estimates suggest retail electricity prices in the commercial sector will increase by 21% between 2016 and 2021 whereas wholesale electricity prices will increase by 12% in the same period [8]. This trend is influenced by the growth in non-incumbent tariff components of the electricity bill such as network charges and tariffs supporting renewable generation [9]. Although the price of the commodity is the biggest component of the bill, it covered only 45% of the costs in 2016-17 and this value is expected to fall in the coming years [10].

Electricity is a very particular commodity: it is essential for most modern-day activities, it cannot be stored economically, and it must be transported through a network from the production sites to the consumption points. These characteristics result in complex economic structures and therefore in complex bills accounting for the costs of operating such system [11]. In addition, the organisation and regulatory framework of this complex system has changed drastically in the last few decades. Whereas the system was operated by a single vertically integrated and publicly owned company, its parts have now been unbundled and privatised creating wholesale and retail electricity markets while also implementing incentive base regulation for network asset operators (which are still operated as natural monopolies).

Retailers design the tariffs charged to consumers with the goal to recover the cost of purchasing electricity, to pay network operators and regulatory tariffs, while also recovering their costs and making a sensible profit. Non-domestic consumers, for which electricity is a meaningful operation cost, are usually proactive and negotiate their power contracts via bilateral agreements or in the wholesale market. These large energy users are encouraged to frequently revise their procurement strategies to enhance the profitability of their business [12].

2.2. Tariff Component Description

The *commodity* consists of the cost of purchasing energy in the wholesale market, usually via bilateral contracts for baseload (24 hours a day and 7 days a week) and peak load clips (from 7 a.m. to 7 p.m. during weekdays) with adjustments based on final consumption to be purchased or sold in

the spot market. Baseload requirements are usually well known, so they are traded far in advance whereas peak load clips are shorter term products; normally purchased closer to the time of consumption. It is worth highlighting these contracts also account for the energy lost when transporting electricity through the transmission and distribution networks.

The *Distribution Network Use of System* charges (DUoS) recover the costs incurred by the distribution network operators (DNO) for operating and maintaining the distribution network. The British distribution network is divided into 14 areas and owned by 6 companies. Fig. 1 shows the DNO regional map highlighting their domains. Electricity North West (1 area), Northern Powergrid (2 areas), Scottish Power Networks (2 areas), Scottish and Southern Energy Power Distribution (2 areas), UK Power Networks (3 areas) and Western Power Distribution (4 areas) [13]. DNOs recover costs via three different tariff mechanisms: *DUoS commodity*, *DUoS capacity*, and *DUoS administrative*. DUoS commodity is charged based on the energy consumed at the time of consumption, DUoS capacity is a daily charge that depends on the maximum imported capacity contracted by the customer. DUoS administrative is a fixed daily charge to cover the administration costs of keeping the customer connected. In addition, the Assistance for Areas with High Electricity Distribution Costs Scheme (AAHEDC) was introduced in 2004 to reduce the distribution charges in Northern Scotland. Without this assistance such region would face higher tariffs than the rest of the UK. National Grid recovers the assistance through a charge on all suppliers and transfers it to Scottish Hydro Electric Power Distribution Ltd [14].

The *Transmission Network Use of System* charges (TNUoS) recover the cost incurred by the transmission grid owners for managing and maintaining the transmission system. Transmission costs are recovered by charging the consumers based on their consumption during the three half hours of highest demand in the country during the winter period; commonly referred to as TRIAD periods. In the last 15 years, triad periods have happened on weekdays between 5 and 6.30 p.m. between November to February [15]. In the UK, the transmission network is owned and maintained by regional transmission companies. There are three Transmission Owners (TO): National Grid Electricity Transmission plc (NG) for England and Wales, Scottish Power Transmission Limited for Southern Scotland and Scottish Hydro Electric Transmission plc for Northern Scotland and the Scottish isles; these TO regions are depicted in Fig. 1. The operation of the system is managed by a single company, National Grid, which has the license to function as the System Operator (SO) [16].

To ensure the system is efficiently operated, Ofgem has a key role regulating the activities of the DNOs, the TOs and the SO. For this reason, Ofgem needs to approve the tariffs designed by DNOs and establishes cost targets to NG through the System Operator incentives [17]. The SO is also responsible for balancing the grid by matching supply and demand and therefore sometimes incurring in additional costs to contract reserves or frequency response services. These costs are recovered through the *Balancing Services Use of System* charges (BSUoS), computed on a half-hourly basis. This charge has two components: external and internal. The external component covers the cost of balancing services that NG purchases, while the internal component pays for the business costs of NG such as staff or office renting [18].

Lastly, UK consumers also pay regulatory obligations, these are a variety of tariffs that support the governmental strategy of decarbonising the generation fuel mix as well as making sure security of supply concerns are addressed. Charges focusing on the deployment of renewable energy sources are: The *Renewable Obligations* (RO) scheme supporting large scale investments such as wind power projects (soon to be replaced by the *Contract for Difference* scheme – CfD) and the *Feed in Tariffs* (FiT) for small scale projects. Furthermore, the UK has the *Climate Change Levy* (CCL), an environmental tax to incentivize large consumers not covered by the EUETS [19] to reduce their energy use and associated emissions. Meanwhile, the *Capacity Mechanism* (CM) is an initiative to recover the cost of running an annual capacity auction to secure energy supply during peak periods and therefore promote the investment in making capacity available at critical demand periods. For further information on tariff details the authors recommend consulting the following source [20].

2.3. Tariff Decomposition

With regards to the cost temporal variation features of tariffs, research has allowed us to classify them into five types of categories:

- *Half-hourly (HH)*: When components change every half-hour across the year;
- *Intraday (ID)*: When components change within the day in step or incremental form (but not every half-hour as in a tier system), therefore they have different values within a day;
- *Day type (DT)*: When components have different values for weekday and weekend day types;
- *Seasons (S)*: When components change by month or group of months;
- *Annual (A)*: When components are constant during a full (fiscal) year although they are subject to change from year to year.

Regarding cost spatial variation features, there are three different type of criteria to consider:

- *Voltage level (VL)*: These components are influenced by the voltage connection level of the building or facility;
- *DNO area (DNO)*: These components are location dependant according to the DNO area;
- *UK*: These components are the same for the whole of Great Britain.



Fig. 1. UK companies owning power networks: (a) DNOs (left) and (b) TSOs (right) [21].

In relation to settlement of tariffs, components are either established every HH (set by market conditions according to real time properties of the system) or every fiscal year (set by the regulated business framework). In other words, the price of the tariff components is settled at consumption (and obtained via databases) or before the fiscal year starts via stakeholder reports. Table 1 summarizes all tariff components and describes their temporal and spatial features, defining their main stakeholder and listing the data sources used to develop the MUKERC modelling framework.

Table 1. Summary of UK tariff components included in a commercial electricity bill as of 2016-17.

Tariff Component	Parameter	Bill Cost Percentage	Seasonal Category	Settlement Frequency	Spatial Variation	Main Stakeholder	Data Source
Energy	Market Index Price (MIP)	56%	HH	HH	UK	Wholesale market	Elexon APX
Tloss	Transmission Loss Multiplier (TLM)	4%	HH	HH	UK	Elexon	Elexon

Dloss	Line Loss Factor (LLF)		ID, S and DT	A	DNO and VL	DNOs	DNOs
DUoS Commodity	Red / Amber / Green tariffs	10%	ID and DT	A	DNO and VL	DNOs	DNOs
DUoS Capacity	Daily tariff per capacity unit	0.9%	A	A	DNO and VL	DNOs	DNOs
DUoS Administrative	Daily tariff		A	A	DNO and VL	DNOs	DNOs
AAHEDC	AAHEDC Tariff		A	A	UK	NG and SSE	NG
TNUoS	Triad tariff	5%	Triad	A	DNO	NG	NG
BSUoS	BSUoS price	2.%	HH	HH	UK	NG	NG
RO	RO buy-out price and obligation level	12%	A	A	UK	BEIS and Ofgem	Gov.uk and Ofgem
FiT	Tariff	3%	A	A	UK	BEIS and Ofgem	Gov.uk and Ofgem
CCL	Tariff	5%	A	A	UK	BEIS and Ofgem	Gov.uk and BEIS
CM	Tariff	N/A	ID and S	A	UK	BEIS and Ofgem	EMR
CfD	Tariff	N/A	A	A	UK	BEIS and Ofgem	LCCC

3. MUKERC Modelling Framework

3.1. General Structure

The tariff components described in the previous section are classified into one of four groups to develop the MUKERC framework; these are: *HH settled*, *deterministic*, *non-kWh*, and *constant*. The methodology followed to model each tariff component is very similar for those in the same group. Depending on their spatial limitations, the values of each tariff are applied either across mainland Britain or for each DNO region (see Table 1). Table 2 describes the characteristics of each group.

Table 2. Summary of the MUKERC groups and tariff components.

Group	Tariff Component	Description
HH Settled	Commodity, BSUoS, TLM	These components are recorded every HH and obtained via databases capturing the real-time state of the system.
Deterministic	DUoS commodity, LLF, CM	These components change during the day according to a profile defined and published by DNOs and government agencies.
Non-kWh	DUoS capacity, DUoS administrative, TNUoS	These components are established by DNOs and the TSO and do not depend on the amount of energy consumed. However, the data can be transformed into charges per unit of energy consumed.
Constant	RO, FiT, CCL, AAHEDC, CfD	These tariff component values are constant for each fiscal year.

A set of equations are established for each tariff group (explained in the following subsections) which are composed of the following sets and/or tiers:

Temporal sets:

- Half-hourly intervals ranging from 1 to 48;
- Calendar months from January to December;
- Day types being classified as either Weekday (WD) or Weekend (WE);
- Budget year covering the fiscal period of 1st April to 31st March.

Spatial sets:

- DNO areas in the UK classified from 10 to 23;
- Connection set as low voltage (LV), low voltage substation (LV Sub) or high voltage (HV).

Considering all these attributes, when accounting for 14 DNOs, each year assessed by the MUKERC model provides over 245,000 data points depicting the price of electricity. The model has been developed in Excel and Visual Basic but to visualise the spatial results custom maps have been developed using the web application Fusion Tables [22]. In addition, the polygons used as boundaries for the counties in the UK were taken from Geocaching [23] and grouped by DNO areas.

3.1. Half-hourly Settled Components

For these components (i.e. commodity, BSUoS, TLM), data for the fiscal year 2016-17 was processed to obtain a 'typical day profile' for each month and day type (*i.e.* 24 profiles).

The HH settled components are a good proxy for the costs expected to occur in 2017-18. This is because although values and trends change slightly from year to year, these differences are not that significant after reviewing the data for years 2014-15 and 2015-16. After classifying the historical datasets into different months and day types (WD and WE), daily average price profiles were obtained by calculating the average of each settlement periods (*i.e.* 1 to 48). However, it was noted that resulting average profiles tend to be smoother than actual daily profiles. To address this issue and obtain a more "realistic" profile, the daily Root Mean Square Error (RMSE) function was employed. The daily profile with the lowest RMSE was chosen to be the representative curve for the three tariff components of this group[1]. In other words, the 24 profiles closer to the average of each calendar month and day type were selected.

Commodity data was obtained from the APX spot market collected by Elexon and published in the Market Index Price and Volume databases [24]. The MUKERC methodology considers the spot price as a representative commodity cost paid by commercial consumers for electricity. However, only about 5% of energy is purchased in this market, whereas most of the demand is covered by bilateral confidential contracts in the forward market. Nonetheless, the spot price is a valid indicator as similar trends can be expected for agreed prices in the forward market as they capture the effect of procurement strategies [25].

To determine the representative day commodity profiles, it is required to calculate the average wholesale price for each settlement period for every month while distinguishing between weekdays and weekend days using Eq. (1):

$$aWP_{m,w,sp} = \frac{\sum_{i=1}^{nd} WPS_{m,d,sp_i}}{nd} \quad (1)$$

After obtaining the average profiles the daily root mean square error is minimised to select the representative day. It is important to notice that the result is a 48-element array obtained directly from the dataset that best represents the average of all the data days occurring in a calendar month. Meanwhile, the average electricity price is calculated for each settlement period. Eq. (2) is used to select the representative day:

$$rWP_{m,d} = min_i \left(\sqrt{\frac{1}{48} \cdot \sum_{s=1}^{48} \left(WPS_{m,d,sp_i} - aWP_{m,d,sp} \right)^2} \right) \quad (2)$$

Since the commodity is the largest component of the bill it is worth understanding the range of values the UK market is experiencing. The most volatile profile can be determined from the historical data. Volatility here is defined as the largest variation between any HH settlement period and the previous one as expressed in Eq. (3):

[1] Days when time changes due to Daylight Saving Time are discarded since in those days there are either 46 or 50 settlement periods instead of 48.

$$vWP_{m,d} = max_i \left(\left(\frac{1}{48-1} \right) \cdot \sum_{s=2}^{48} \sqrt{\left| WPS_{m,d,sp-1_i} - WPS_{m,d,sp_i} \right|} \right)^2 \quad (3)$$

Fig. 2 depicts the range of values obtained in wholesale prices for February 2017 in the UK; highlighting the average, representative, and volatile curves. This graph shows the range of prices for every HH during the same period (shaded area). Some insights from these profiles are:

- Annual average of the commodity for 2016-17 was £42.2/MWh up from £38.3/MWh registered for 2015-16;
- Prices on average are higher on weekdays than on weekends, particularly during winter evenings between 16:30 to 20:30 hours;
- There were 38 negative settlement periods in the financial year, a trend that is increasing due to the introduction of wind and solar power into the UK system. In the previous 2 years there were a total of 28 negative settlement periods.

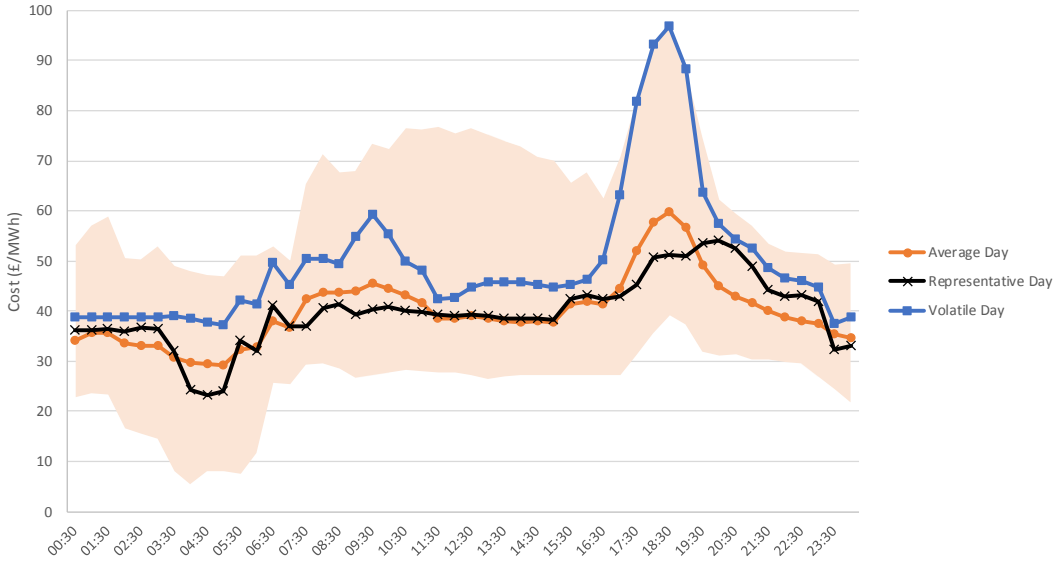


Fig. 2. Daily wholesale electricity price profiles for February 2017.

BSUoS and *TLM* components are determined like the commodity curves by going through National Grid reports [26, 27, 28]. Please see Appendix A to obtain the equation description for these terms. Some insights from analysing these datasets are:

- BSUoS charges are lower on weekdays than during the weekend. This is due to a lower demand at the weekends with an almost constant cost for balancing the grid;
- BSUoS charges are lower during the day than during the night (23:30-6:00), especially in January, November and December;
- TLMs are lower on weekdays than during the weekend and they are lower during the day than during the night;
- Average transmission losses vary between 1% and 1.5%.

3.2. Deterministic Components

Deterministic components have a fixed profile that can be different for different months or day types but are fully known in advance. These daily profiles are set by stakeholders that are regulated, such as DNOs or National Grid. Each tariff component rate is public and is influenced by several factors, but the general methodology is to allocate a value to all settlement periods in all DNO areas, leading to the following general formula and variables as stated in Eq. (4):

$$DC_{DNOx,VL,m,d,sp} = \begin{cases} v\alpha_{DNOx,VL,m,d} \; if \; sp \in \; p\alpha_{DNOx,m,d} \\ \dots \\ v\omega_{DNOx,VL,m,d} \; if \; sp \in \; p\omega_{DNOx,m,d} \end{cases} \quad (4)$$

DUoS commodity is the unit charge applied to all half-hourly energy consumed with three different tariffs for different time periods (*i.e.* green, amber, red) and these vary depending on their voltage level connection. See Appendix B for an example of DNO unit rates.

These are some typical characteristics of DUoS commodity tariffs; these are:

- Prices are higher during weekdays, when red tariff applies, than during weekends. In fact, in some DNO areas, there is not even an amber period during weekends only green;
- Tariffs increase by a factor of around ten from green to amber and from amber to red;
- Costs increase as the connection is further away from HV so LV is the most costly.

Line loss factor (LLF) is the number that scales up the metered consumption to account for the losses in the distribution network. The LLF data is obtained from DNO reports. The main differences with the DUoS commodity are that time periods change for different months of the year. Appendix B has an example of the LLF values for each period. Some general attributes of LLF are:

- Distribution losses are higher in winter than during the rest of the year. The lowest distribution losses are during the night all along the year;
- Same way as for DUoS commodity charges, losses increase as the connection is further from HV, being the highest for LV and the lowest for HV.

Capacity Mechanism (CM) is the mechanism selected by the UK government to secure electricity supply during peak periods. CM is billed during winter weekdays from 4 to 7pm and the only official data published for this component is related to the clearance price of a government auction.

3.3. Non-Kilowatt Hour Components

These components are billed based on tariffs not proportional to the energy consumed. To include them in this analysis, these tariffs are transformed into kWh-based components using average demand information. This transformation makes the results of the model business specific, as the demand profiles of buildings are highly dependent on the activity that they hold.

3.3.1. DUoS Capacity Charges

DUoS Capacity covers the cost of keeping a consumer connected to the grid. This tariff varies for each DNO area and for different voltage connection levels given in £/KVA/day. To interpret this charge over every kWh consumed, the Annual Utilisation Factor (UF) is introduced. This factor is defined as the ratio between the total annual consumption of the end-user and the contracted maximum import capacity as shown in Eq. (5). Once UF has been determined the DUoS capacity can be determined using expression Eq. (6).

$$UF = \frac{ad}{cc} \quad (5)$$

$$DUoS\ cap_{kWh_{DNOx,VL}} = \frac{DUoS\ cap_{DNOx,VL} \times 365}{UF} \quad (6)$$

For DUoS Capacity, Northern Scotland has the highest values. London, which has the lowest DUoS commodity tariffs, is the second for the capacity charge. Meanwhile, Yorkshire and Northern England have the lowest capacity tariffs, with charges around 50% lower than the average of all DNOs for every voltage level. It is also worth mentioning that LV is usually the least costly.

The *DUoS administrative* charge is a standard daily charge that has very small weight (0.1%) and therefore is neglected and not considered in this model.

3.3.2. TNUoS Triad Charges

TNUoS are charged based on tariffs published by NG and calculated taking the average demand during triad periods. Tariffs vary per DNO area and are taken from NG (2016). Following a similar methodology as for the DUoS capacity, the objective is to spread the TNUoS charge over energy

consumed; in this case, the energy used when a triad period is likely to happen. The triad consumption of a site depends on its activities during that specific interval in contrast against its maximum demand. The contracted import capacity is used here as the parameter to capture the effect of maximum allowable demand. The parameter Triad Intensity (TI) is defined as the ratio between the registered triad consumption and the contracted capacity Eq. (7).

$$TI = \frac{aTRIAD}{cc} \quad (7)$$

In addition, a factor like the UF must be used to calculate the energy demand during the triad period per KVA capacity contracted. This new factor is defined as Triad Utilisation Factor (TUF) and it is calculated in Eq. (8) considering that the consumption when a triad can happen is the same as the triad consumption. Using expression in Eq. (9) the tariffs in £/kW are transformed into p/kWh.

$$TUF = TI \times HrsYear \quad (8)$$

A Triad charge can happen in any settlement period between 5:00 and 6:30 from November to February, but their probability is not the same. To capture this temporal variation on the TNUoS charge, the triad periods of the last five years were analysed (NG 2015). From this analysis, weighting factors for each month and settlement period were allocated based on the possibility of the triad to occur (mostly from 5 to 5.30 p.m. in December and January). The TNUoS half-hourly cost is calculated with Eq. 9.

$$TNUoS_{DNOx,m,d,sp} = cTNUoS_{DNOx} \cdot tTNUoS_{m,d,sp} \quad (9)$$

3.4. Constant Components

They are constant throughout the entire year and applied to any energy unit consumed so they are modelled as a constant tariff charged to any kWh consumed and they do not change neither with the location nor with the time; the tariffs are defined annually. See Table 1 for the weight cost of each component; renewable obligations are the costliest component followed by CCL and FiT.

3.5. Electricity Component Aggregation

Before aggregating the components, the measurement point for the billing of each component is defined. Each component can be billed based on three different measurement points. Some components are billed from the transmission level and include transmission and distribution losses. Others are billed from the interface between transmission and distribution systems, called Grid Supply Point (GSP), and only include the distribution losses. Finally, there are components billed based on the final demand, called Meter Supply Point (MSP), which do not include losses. Energy and BSUoS are billed based on the measurement in the transmission level, TNUoS at the GSP and the rest at the MSP. Eq. (10) defines the methodology to aggregate all the components.

$$HHP_{DNOx,VL,m,d,sp} = \left(rWP_{m,d,sp} \cdot LLF_{DNOx,VL,m,d,sp} \cdot TLM_{m,d,sp}\right) + \left(BSUoS_{m,d,sp} \cdot LLF_{DNOx,VL,m,d,sp} \cdot TLM_{m,d,sp}\right) + DUoScom_{DNOx,VL,m,d,sp} + DUoS\,cap_{kWh\,DNOx,VL} + \left(TNUoS_{DNOx,m,d,sp} \cdot LLF_{DNOx,VL,m,d,sp}\right) + AAHEDC + RO + CCL + FiT + CfD + CM_{m,d,sp} \quad (10)$$

4. Results

Once the commodity price is calibrated and all the components modelled, 48 element arrays for electricity price can be created to represent the daily price curve. In this work a few examples are presented to discuss the main spatial-temporal characteristics of the cost profiles. In addition, a regional analysis of electricity prices is covered.

4.1. Half-hourly Results

The shape and scale of HH curves is affected considerably by TNUoS and DUoS charges. TNUoS produce a big price spike on winter weekdays for every region, while DUoS create cost differences due to its pricing time bands and voltage connection levels. Figs. 3(a) and 3(b) illustrate the range of values obtained for 3 DNOs on weekdays in winter and summer; respectively. In wintertime, due to TNUoS charges, a big spike is produced between 5 and 5.30pm and the electricity price can rise

above £1/kWh; although most of the time the cost is about 8 p/kWh. On the other hand, for the rest of the year, DUoS are the main factor shaping the profile in each region. Values range from 7 to 17 p/kWh. It is important to notice that the impact of DUoS is also present during winter weekdays, but the scale of the TNUoS charges makes it impossible to appreciate it in the graph.

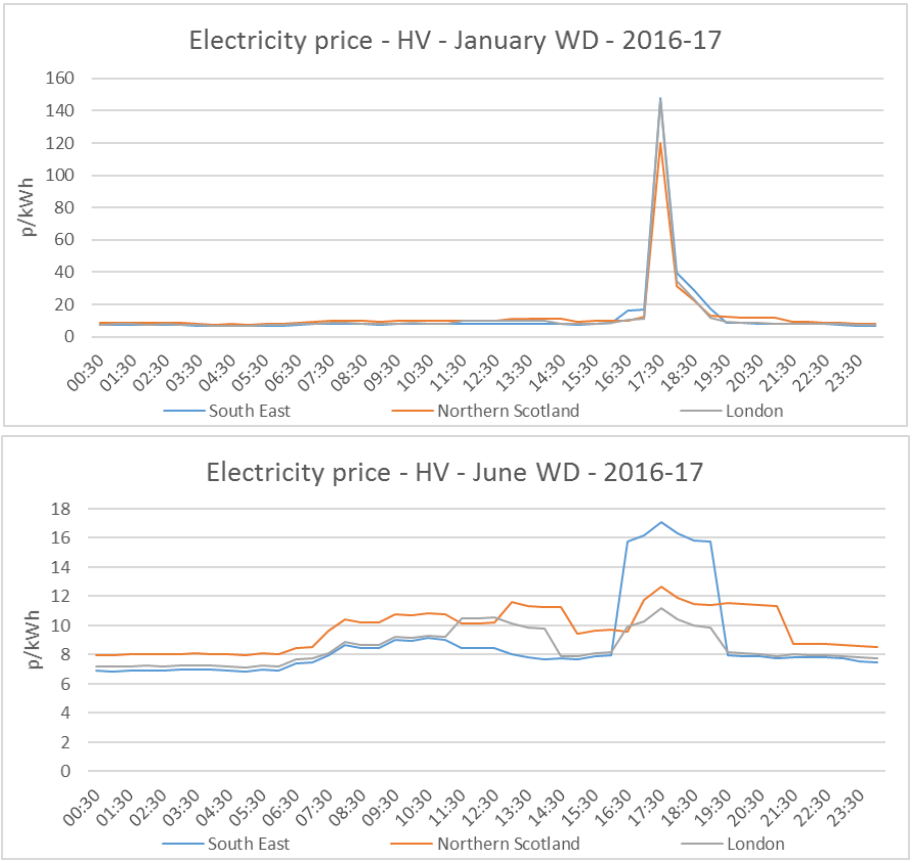


Fig. 3. HV prices for weekdays in (a) January (top) and (b) June (bottom) for year 2016-17.

4.2. Regional, Seasonal, Day Type and Connection Level Results

Regarding peak prices of electricity Fig. 4. compares all DNO areas. As expected, the areas with high TNUoS tariffs such as London, the South West and Southern England are the regions with the highest peak prices. On the other hand, peak prices in regions close to generation plants and, therefore, low transmission charges such as Northern Scotland, Southern Scotland and Northern England, have the lowest values in the UK. These figures although symbolic in nature serve to incentivise energy end-users to become proactive and curtail demand during TRIAD periods.

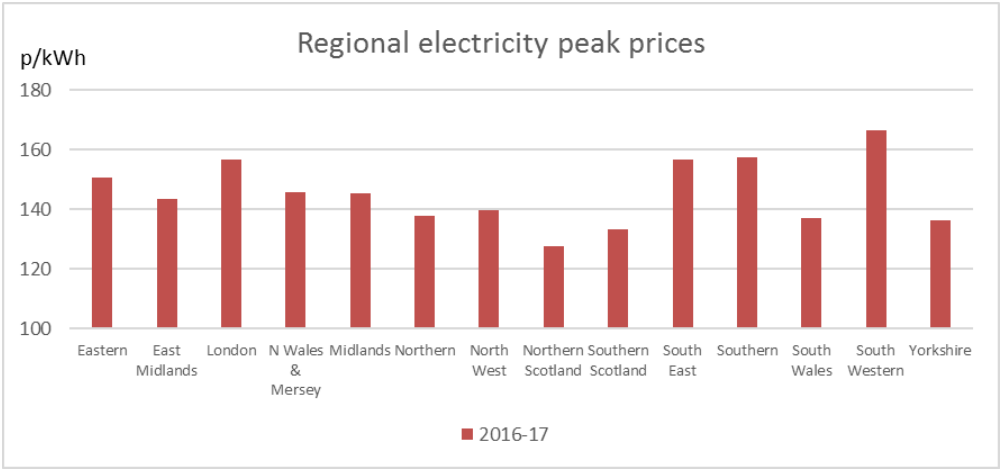


Fig. 4. Peak electricity price representation for each DNO area after distributing TNUoS charges uniformly between the November to February period for year 2016-17.

Our analysis indicates the commercial UK consumer paid 9.5 p/kWh in 2016-17. However, the months when the wholesale electricity were most expensive were November to January and the cheapest months were March, June, and July. In general, winter prices were 18% higher than in the rest of the year. Also, it was identified that consumers with an LV connection paid 7.5% more on electricity than HV consumers, while LV sub consumers paid 3.8% more than HV end-users. Regarding day type, electricity during weekdays on average was 35% more expensive than during the weekends. With these information, such as illustrated in Fig. 5, energy teams managing commercial real estate can optimise the operation of on-site generation or enact initiatives to make sure that electricity imports from the grid are minimum when electricity prices are high. In addition, these energy cost datasets are vital to effectively assess Demand Side Management and storage projects and thus quantify their business case.

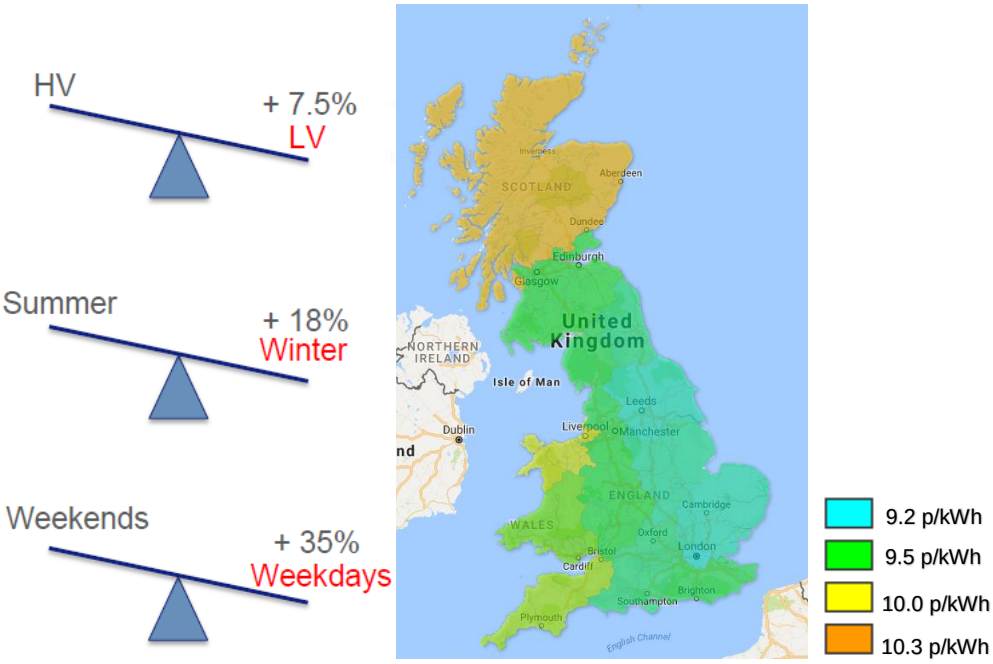


Fig. 5. Electricity cost trends for year 2016-17 based on voltage level connection, seasonal period, day type and region.

5. Conclusion

This work has showcased the MUKERC methodology, a novel approach to quantify the final electricity costs of commercial customers across the UK at half-hourly intervals. This rich temporal-spatial framework allows the user to quantify how electricity prices change not only across the year, but also accounts for the type of voltage connection and the impact regional network charges have on the total cost. Therefore, results indicate that electricity prices for customers vary across the country due to intraday and seasonal variability and voltage connection level.

The findings of this work suggest electricity prices can be closely monitored and hence should stimulate investment in energy efficiency projects and on-site generation to reduce the electricity bills of businesses. An important feature of the MUKERC modelling methodology is that it provides a holistic view of how each tariff influences what end users pay for electricity. Consequently, businesses can improve their understanding on their energy costs and adapt their consumption strategies to minimise electricity bills. In addition, the granularity of the results can inform energy management teams when is best to conduct energy investments; such as building retrofits, energy reduction measures, or installing low carbon technologies.

Results of this model prove that not only the activity and the demand of a building are important to assess profitability of energy efficiency projects, but also location and connection voltage level can play a relevant role. It is advised that a company managing a large property portfolio across the UK should use this type of information to rank and prioritise its investments in sites where electricity

costs are more expensive to secure attractive returns on their projects. Further work is required to expand the framework to consider future cost scenarios to better inform energy policy making, understand market trends, and advise large end-users on strategic decision-making.

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Appendix A

Average BSUoS profile is obtained using Eq. (A1):

$$aBSUoS_{m,d,\mathrm{sp}} = \frac{\sum_{i=1}^{nd} BSUoS_{m,d,sp_i}}{nd} \quad \text{(A.1)}$$

The representative BSUoS day is determined by reducing the daily root mean square error in (A.2):

$$rBSUoS_{m,d} = min_i \left(\sqrt{\frac{1}{48} \cdot \sum_{sp=1}^{48} \left(BSUoS_{m,d,sp_i} - aBSUoS_{m,d,sp} \right)^2} \right) \quad \text{(A.2)}$$

The average TLM is calculated for each settlement period of every month distinguishing between day types using equation (A.3):

$$aTLM_{m,d,sp} = \frac{\sum_{i=1}^{nd} TLM_{m,d,sp_i}}{nd} \quad \text{(A.3)}$$

The 24 representative TLM day curves are obtained by finding the day profile with minimum daily root mean square error when compared to the HH average on Eq. A.4:

$$rTLM_{m,d} = min_i \left(\sqrt{\frac{1}{48} \cdot \sum_{s=1}^{48} \left(TLM_{m,d,sp_i} - aTLM_{m,d,sp} \right)^2} \right) \quad \text{(A.4)}$$

Appendix B

Table B1 shows an example of DNO commodity rates for North Western England for 2016-17, while Table B2 depicts the time bands and periods for LLF values in Eastern England for 2016-17.

Table B1. DNO commodity charges for North Western England in 2016-17.

Tariff Name	**Red Band (p/kWh)** *16.00 to 19.00 hrs* *Weekdays Only*	**Amber Band (p/kWh)** *9.00 to 16.00 hrs &* *19.00 to 20.30 hrs* *on Weekdays* *16.00 to 19.00 hrs* *on Weekends*	**Green Band (p/kWh)** *0.00 to 9.00 hrs &* *23.00 to 24.00 hrs* *on Weekdays* *0.00 to 16.00 &* *19.00 to 24:00 hrs* *on Weekends*
Low Voltage Half-hourly metered	11.32	0.932	0.117
Low Voltage Sub Half-hourly metered	9.733	0.723	0.089
High Voltage Half-hourly metered	7.723	0.489	0.058

Table B2. LLF costs for Eastern England in 2016-17.

Time Period	**Low Voltage**	**Low Voltage Sub**	**High Voltage**
Period 1 *Winter Peak* *16.00 to 20.00 hrs* *Weekdays Only from November to February*	1.1150	1.0810	1.0520
Period 2 *Summer Peak* *07.00 to 20.00 hrs* *Weekdays Only from June to August*	1.0850	1.0630	1.0400
Period 3 *Winter Shoulder* *7.00 to 16.00 hrs*	1.0990	1.0720	1.0460

Weekdays Only from November to February & 7.00 to 20.00 hrs Weekdays Only in March			
Period 4 *Night 0.00 to 07.00 All year*	1.0750	1.0570	1.0350
Period 5 *All other times*	1.0890	1.0650	1.0410

Nomenclature

ad	Annual demand
aTRIAD	Average TRIAD demand
aTLM	Average offtaking TLM data point
aBSUoS	Average BSUoS tariff
aWP	Average wholesale price
BSUoS	BSUoS data point
cc	Contracted capacity
$cTNUoS_{DNOx}$	Regional transmission network charge
DC	Deterministic component
DUoScap	Distribution contracted capacity tariff
$DUoScap_{kWh}$	Distribution contracted capacity tariff in kWh
EMR	Electricity market reform
LCCC	Low carbon contracts company
HrsYear	Hours in a Year
$p\alpha$, $p\omega$	periods set by stakeholder
rBSUoS	Representative day BSUoS tariff
rTLM	Representative day TLM tariff
rWP	Representative day wholesale price
TI	Trade intensity
TLM	TLM offtaking point
tTNUoS	Triad weight factor
TUF	Triad utilisation factor
TNUoS	Regional transmission network charge
UF	Utilisation factor
$v\alpha$, $v\omega$	Values set by stakeholder
vWP	Volatile day wholesale price
WPS	Wholesale price settlement period

Subscripts and superscripts

d	Day type
DNOx	DNO area
i	Data day index
m	Month number
nd	Number of data days per month
sp	Settlement period
VL	connection type (*i.e.* voltage level)

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