Energy Day in Review Notes

Electricity Generation

1. Transmission Connected Generation by Fuel

Source: https://www.bmreports.com/bmrs/?q=generation/fueltype

National Grid measure system generation connected to the high voltage transmission system in real-time from operational metering. This is used to assist with balancing the system and confirming that generators are operating at their expected levels. This metering is aggregated into fuel type categories (Coal, CCGT, Nuclear, Oil, Wind, Interconnector-France, Interconnector-Ireland (Moyle), Pumped Storage, Hydro (non-PS), OCGT, Other, Dutch I/C, East-West I/C, Belgium I/C). The total of all categories equals the Total Transmission System Demand (TSD) which includes all demand met from the Transmission system including power station auxiliary demand, pumping demand and interconnector exports demand. The data is provided as 5 minute average MW values. As this is concerned with the breakdown by fuel type of total positive generation to meet all Transmission System Demand, any fuel type categories with negative values are capped to zero.

As this data excludes most embedded generation, the total volume of renewables is understated. Elexon estimate that (as of 2011) approximately 50% of UK wind and hydro does not have operational metering, and is therefore omitted from the generation by fuel type data.

2. Generation by Fuel Type

Source: https://www.bmreports.com/bmrs/?q=actgenration/actualaggregated

European Transparency Regulation 543/2013 (ETR) requires each Transmission System Operator (TSO) to submit information relating to generation, load, transmission and electricity balancing – 'Transparency data'.

Generation in these charts is defined by Transparency data B1620 (Actual Aggregated Generation Per Type). It is recorded on a Settlement Period (SP) (30 minute) average MW basis. As B1620 generation data includes metered and unmetered generation, it differs from the transmission connected generation figures presented in Transmission Connected Generation by Fuel charts. For example it includes Solar generation and distinguishes between Offshore and Onshore Wind.

To determine each Fuel type's capacity utilisation rate we combine Transparency Generation data with Transparency Capacity data (B1410 Installed Generation Capacity Aggregated). The highest generation achieved across the day (on average across a SP) is used to define each fuel type's peak generation (the SP in which peak generation is achieved may differ across fuel types). This is divided by each Fuel type's installed capacity (as defined by B1410 data) to calculate the proportion of utilised capacity. Note that as peak generation is defined as the highest generation achieved over a 30 minute SP, it may underestimate the peak generation achieved within a SP.

3. Interconnectors

Source: https://www.bmreports.com/bmrs/?q=generation/avghalfhourIC

Interconnector flows are measured at the following locations - Sellindge (South East England) for the Interconnector with France, Auchencrosh (South Scotland) for the Moyle Interconnector with Northern Ireland, the Isle of Grain (Kent) for the Interconnector with the Netherlands (also referred to as the Dutch Interconnector or Dutch I/C), Shotton (North Wales) for the Interconnector with the Republic of Ireland (also referred to as the East-West Interconnector or East-West I/C) and Richborough (Kent) for the Nemo Link Interconnector with Belgium. Every half hour, the average flow across each interconnector is calculated by National Grid from its operational metering values.

The convention adopted is that a positive value represents import into the GB Transmission System, whilst a negative value represents an export from GB.

4. Wind Forecast and Outturn

Source: https://www.bmreports.com/bmrs/?q=generation/windforcast/out-turn

Based on historical outturn data and detailed local wind forecasts, National Grid forecasts likely levels of wind generation for windfarms visible to National Grid i.e. those that have operational metering (Onshore and Offshore). The forecasts are produced for the period from 21:00 on the current day (D) to 21:00 D+2. Wind generation forecasts are produced by National Grid's own second generation windpower forecasting tool. The predictability of the wind varies with atmospheric conditions and so there may be periods where National Grid's forecast and outturn values differ significantly.

The peak forecast is estimated as a single MW figure across all Power Park Modules metered by the Transmission Company and is based on the Transmission Company's operational metering rather than BSC Settlement metering. Total Metered Capacity is a sum of the registered capacities of all the windfarms listed in Elexon's Power Park Modules spreadsheet (https://www.bmreports.com/bmrs/sites/default/files//PowerParkModules.xls).

5. Day Ahead Wind & Solar Generation Forecast

Sources: https://www.bmreports.com/bmrs/?q=foregeneration/dayaheadwindnsolar & https://www.bmreports.com/bmrs/?q=actgenration/actualorestimated

Forecasts of net wind and solar generation are provided by National Grid for each Settlement Period of the following day. Elexon publishes these forecasts under European Transparency data (B1440), which categorises wind generation forecasts and outturns into four groups:

- Metered Onshore;
- Metered Offshore;
- Unmetered Onshore;
- Unmetered Offshore.

Elexon's 'Legacy' wind forecast data (described in Note.4 - 'Wind Forecast Out-turn' and 'Peak Wind Generation Forecast') only include metered wind categories (Onshore and Offshore). For ETR both metered and unmetered windfarms are included, and they are subdivided into Onshore and Offshore categories. For outturn values, latest forecasts are used in place of actual metered output for unmetered windfarms. For this reason, the wind forecasts and outturns for the ETR data B1440/1620/1630 will differ from the 'Legacy' wind forecast data.

Since November 2018 three forecast values are available (but only the Day ahead forecast is used in the daily monitor):

- Day ahead Forecast - received no later than 17:00 GMT one day before actual delivery takes place.
- Intraday Forecast - received no later than 07:00 GMT on the day of actual delivery.
- Current Forecast - this is the latest update of the current forecast, and is regularly updated and published during intra-day trading.

Electricity Demand & Margin

6. Demand Forecast

Sources: https://www.bmreports.com/bmrs/?q=demand/dayanddayaheaddemand & https://www.bmreports.com/bmrs/?q=demand/initialdemandoutturn

This chart sets out four values:

- National Demand Forecast (NDF): Produced by the System Operator, based on historically metered generation output for Great Britain. It includes transmission losses but excludes station transformers load, pumped storage demand and interconnector demand.
- Transmission System Demand Forecast (TSDF): Adjusts the NDF to take into account station transformer load, pump storage demand and interconnector demand.
- Indicated Generation (INDGEN): The half-hour average MW expected generation in each Settlement Period calculated as the sum of all Physical Notifications for that Settlement Period prevailing at the time of the forecast and for BM Units for which the Physical Notifications are positive, i.e. will be exporting energy. Data supplied by the System Operator for the day ahead and current day (a number of times each day) for publication on the BMRS, comprising the Indicated Generation for each System Zone and Settlement Period and the national Indicated Generation for each Settlement Period.
- Initial Transmission System Demand Out-Turn (ITSDO): The average MW value of demand for a Settlement Period including transmission losses, station transformer load, pumped storage demand and interconnector demand i.e. comparable with the TSDF forecast definition. The ITSDO is made available by the System Operator within 15 minutes after a Settlement Period, based on their operational metering.

The peak demand forecast is based on the Transmission System Demand (TSD) definition of demand.

7. Imbalance Forecast

Source: https://www.bmreports.com/bmrs/?q=demand/dayanddayaheadmargin

Indicated Imbalance (IMBALNGC) is calculated as the difference between the sum of all Physical Notifications for exporting BM Units (i.e. the Indicated Generation - INDGEN) and the Demand Forecast (TSDF). Positive imbalance implies generation exceeds demand, negative imbalance implies demand exceeds generation. Data is supplied by the System Operator for the day ahead and throughout the current day (the last forecast being 15 minutes before the start of the Settlement Period).

The Indicated Margin (MELNGC) forecast for each Settlement Period is the difference between the sum of the MELs (Maximum Export Limit – maximum power export level of a particular BM Unit) for that period and the Demand Forecast. The greater the value, he higher the margin between available generation capacity and forecast demand i.e. the more spare capacity there is forecast to be in the system. Data is supplied by the System Operator for the day ahead and throughout the current day (the last forecast being 15 minutes before the start of the Settlement Period).

8. De-rated Margin & LoLP Forecast

Sources: https://www.bmreports.com/bmrs/?q=transmission/lossloadProbDerateMargin & https://www.elexon.co.uk/wp-content/uploads/2015/10/Loss_of_Load_Probability_Calculation_Statement_v1.0.pdf

A Capacity Margin (or Reserve Margin) is defined as the excess of installed generation over demand. A de-rated capacity margin is the *expected* excess of *available generation* capacity over demand.

Available generation is the part of the installed capacity that is expected to be accessible in reasonable operational timelines i.e. not decommissioned or offline due to maintenance or forced outage. It will also take into account any expected intermittency of the generation fleet i.e. the unpredictability of wind generation.

De-rated margins are published alongside Elexon's Loss of Load Probability (LoLP) estimates. LoLP is a measure of system reliability, or scarcity in available surplus generation capacity, and takes a value between 0 and 1. Specifically, for a given level of Capacity Requirement (CR) on the Transmission System the LoLP indicates the probability that there will be insufficient Total Generation to meet the CR. [1]

There are two types of LoLP values - Indicative and Final. Indicative LoLP values are produced at defined lead times (at midday the day before and 8, 4 and 2 hours) ahead of Gate Closure (one hour before the start of a Settlement Period) for every Settlement Period (SP). 'Indicative' LoLP values give BSC Parties an indication of the level of scarcity anticipated ahead of Gate Closure. 'Final' LoLP values are produced using data available at Gate Closure – they are the best indication of the level of expected scarcity during the SP.

The calculation of Indicative and Final LoLP values has changed over time:

- From 5th Nov the Transmission Company (TC) calculated Final LoLP values using the Static Method;
- From 1st May 2018 the TC calculated indicative LoLP values using the Dynamic Method, while continuing to calculate Final LoLP values using the Static Method;
- From 1st Nov 2018 the TC has calculated Indicative and Final values using the Dynamic Method.

Historically, the TC produced values of de-rated margin to calculate LoLP values in accordance with the Static LoLP Function Method.[2] For a given SP, the de-rated margin was determined by subtracting the Capacity Requirement (System demand (Demand[3] + Interconnector Export) plus the largest loss reserve (LLR)[4] minus the volume of NBM STOR[5]) from the Combined Generation Forecast (the sum of conventional generation and the sum of BMU wind generation forecasts for that SP as reported on BMRS).

Since the 1st Nov 2018 the Static Method has been replaced by the Dynamic Method. Under the Dynamic Method, LoLP is calculated using the direct relationship between available generation and the Capacity Requirement. For all SPs the TC is required to calculate (relevant de-rated margins are published alongside):

- Indicative Loss of Load Probability values in accordance with the Dynamic LoLP Function Methodology:

[1] LoLP values are used in the calculation of Reserve Scarcity Prices (RSP). RSP reflects the value of reserve, when it is used, based on the prevailing scarcity on the system. It is calculated as the product of LoLP and VoLL (Value of Lost Load - the price at which a consumer is indifferent between paying for their energy and being disconnected – which was increased from £3,000/MWh to £6,000/MWh in Nov 2018). Short Term Operating Reserve (STOR) actions are re-priced where the action's original utilisation price is less than the RSP (see note.11 for further details).

[2] The Static method used a pre-determined mathematical function (and lookup table) to convert a value of de-rated margin into a LoLP value. The function was derived from the historical relationship between the two variables.

[3] NDF (NG National Demand Forecast incl. system losses) + Station Load (the internal load of power stations required to supply the needs of their equipment)

[4] Determines the reserve the TC is required to hold to withstand the potential largest loss on the system.

[5] Short Term Operating Reserve – NBM STOR is measured differently to BM STOR and because NBM STOR will reduce overall demand, the TC subtracts it from CR.

- at 12:00 hours on each calendar day; and
- at 8 hours, 4 hours and 2 hours prior to the beginning of the Settlement Period for each Settlement Period during each Settlement Day;

- Final Loss of Load Probability value for each Settlement Period in accordance with the Dynamic LoLP Function Methodology at the same time as Gate Closure.

9. System Frequency

Source: https://www.bmreports.com/bmrs/?q=demand/rollingsystemfreq

System frequency is a continuously changing variable that is determined and controlled by the second-by-second (real time) balance between system demand and total generation. If demand is greater than generation, the frequency falls, while if generation is greater than demand, the frequency rises. National Grid has a licence obligation to control frequency within the limits specified in the 'Electricity Supply Regulations', i.e. +/-1% of nominal system frequency (50.00Hz) - save in abnormal or exceptional circumstances. National Grid must therefore ensure that sufficient generation and/or demand is held in automatic readiness to manage all credible circumstances that might result in frequency variations. System frequency is measured in cycles per second or Hertz (Hz) and recorded every 15 seconds.

Electricity Balancing

10. **Net Imbalance Volume (NIV)**

Source: https://www.bmreports.com/bmrs/?q=balancing/systemsellbuyprices & https://www.bmreports.com/bmrs/?q=balancing/detailprices

For further information also see Elexon's excellent imbalance pricing guide

The role of the System Operator (SO) is to ensure the Transmission System is always balanced (generation equals demand plus transmission losses). If it does not, the frequency of the Transmission System moves away from the 50Hz target and the system becomes unstable. The SO has a number of ways of balancing the Transmission System.[6]

- Balancing Mechanism (BM): operates from gate closure to real time. Parties submit notices telling the SO how much it would cost for them to deviate from their Final Physical Notification (called Bids and Offers).
- Short Term Operating Reserve (STOR): In addition to balancing available in the BM, the SO can enter into contracts with providers of balancing capacity to deliver when called upon. See Non-BM STOR notes for further details.
- Contingency Balancing Reserve and Demand Control: Some balancing actions the SO only uses as a last resort. These include contingency balancing reserve (Supplemental Balancing Reserve (SBR) & Demand Side Balancing Reserve (DSBR)) and Demand Control.

The SO's actions are recorded and submitted to the BSC systems under the headings:

- The Balancing Mechanism - for Bid Offer Acceptances (BOAs); and
- Balancing Services Adjustment Data (BSAD) - for actions taken outside of the balancing mechanism. BSAD in turn is broken down into two further components:
  - Balancing Services Adjustment Actions (BSAA): BSAA covers a number of balancing services including Forward Contracts, Demand Side Balancing Reserve and Non-BM STOR.
  - Buy Price Adjustment (BPA)/Sell Price Adjustment (SPA): Discussed further in the notes in the System Prices section.

The Balancing Mechanism operates after Gate Closure, whereas balancing actions submitted through BSAD can be taken at any point.

The accepted measure of market imbalance is the Net Imbalance Volume (NIV). NIV represents the total net amount of energy that the System Operator purchased in order to balance the system in a particular Settlement Period. The NIV is the net sum of all positive and negative system management and energy balancing system actions for the Settlement Period.

The calculation of NIV for the purposes of reporting on the BMRS only includes Accepted Bids and Offers, and actions reported in BSAD before the Indicative System Price is calculated at the end of the Settlement Period. A positive NIV indicates that the overall system was short, i.e. there was not enough energy in the system so the SO instructed generators to produce more or demand to reduce. A negative NIV indicates that the overall system position was long, i.e. there was too much energy in the system so the SO instructed generators to reduce their output or demand to increase.

[6] In principle the SO should attempt to balance the system as efficiently as possible i.e. in a least cost way. However, it is not always possible for the cheapest balancing actions to be undertaken as the SO also has to consider: Technical limitations of power stations/demand (can they respond quickly enough) and Technical limitations of the TS (can energy be transmitted to where it is needed).

The gross positive (Accepted Offers) and negative (Accepted Bids) actions for each SP are illustrated in the NIV by Fuel Type diagram. The final Net NIV for each SP is illustrated in the historic NIV diagram. Note the gross positive and negative actions for each SP are defined by Elexon's 'Arbitrage Adjusted Volume' NIV definition. This adjusts accepted volume (Bids and Offers) for the De Minimis Acceptance Threshold and Arbitrage actions.

The 'unknown' category is to flag a BMU code missing from the database – highlighting that an update is required.

11. System Prices

Source: https://www.bmreports.com/bmrs/?q=balancing/systemsellbuyprices & https://www.bmreports.com/bmrs/?q=balancing/detailprices

The monitor presents two system price charts. The first presents system prices for each settlement period (SP), along with the associated market index price. To provide historic context this chart also presents the monthly distribution of historic system prices. Given a typical day will contain 48 SP prices there can be significant variation across a month. For this reason the distribution of prices is split into three separate charts to highlight the lowest and highest 10 per cent of prices, and the middle 80 per cent. The second chart presents system prices by SP and the associated technology type (or types) for the bids and offers which set the price. This chart also overlays the NIV by SP to illustrate whether accepted bids or offers set the system price.

The system price derivation follows a number of rules and processes. Understanding some of these processes can help interpret market outcomes. A detailed explanation is provided in Elexon's excellent imbalance pricing guide. However a briefer summary is also provided below.

Historically, there were two energy imbalance prices for each SP:

- System Buy Price (SBP);
- System Sell Price (SSP).

Elexon applies the imbalance price to parties' imbalances to determine their imbalance charges. A party is out of balance when its contracted energy volume does not match its physical production or consumption. If a party under generates or over consumes compared to their contracted volume, it will have to buy that shortfall of energy at the SBP. If a party over generates or under consumes it will have to sell that extra energy at the SSP.

However, on 5th November 2015 the imbalance price calculation was changed so that a single imbalance price (SIP) is calculated for each SP. Therefore since this date the SBP and SSP are always equal.

The imbalance, or system, price is calculated to reflect the costs incurred by the SO when balancing the Transmission System (TS) in each SP. This will depend on the system's overall imbalance. Where the TS is long (too much electricity, NIV<0) the price calculation is based on actions taken by the SO to reduce generation or increase demand. Where the TS is short (not enough electricity, NIV>0) the price calculation is based on actions to increase generation or reduce demand.

The BSC systems calculate the energy imbalance price using actions accepted by the SO for each SP. There are three types of balancing actions:

- Bid Offer Acceptances (BOAs) – the Balancing Mechanim;
- Balancing Services Adjustment Actions[7]; and

[7] Including Forward Contracts (Energy Related Products; Pre-Gate Closure Balancing Transactions (PGBTs) and System-to-System services), Maximum Generation, System to Generator Operational Intertripping; Emergency de-energisation instructions, Demand Side Balancing Reserve and Non-BM STOR.

- Demand Control Instructions.

There are a number of re-pricing adjustments that can be made to these actions before they are used in the price calculation.

For example, all actions from STOR providers are included in the calculation of Imbalance Prices but some may be re-priced. Because STOR utilisation prices are pre-agreed, and because STOR providers may also receive availability payments, utilisation prices may be noticeably different to the price the SO may have paid had it called upon a BM action. Utilisation prices may therefore not reflect the prevailing market prices at time of use. To correct for this, BOAs or BSAAs from STOR plant taken during STOR availability windows (the window of time when STOR plant are required to make their capacity available to the SO) are re-priced in the event that their utilisation price is less than the Reserve Scarcity Price (RSVP).[8] Re-priced STOR actions are then treated like other BOAs for the next steps of price calculation (ranking, tagging, etc). Actions from STOR plant outside the STOR Availability Windows are not re-priced.

In addition, if Contingency Balancing Reserve or Demand Control actions are taken they are included in the imbalance price calculation at a price of Value of Lost Load (VoLL).[9]

In addition, the SO does not take all balancing actions for the same reason, and therefore not all actions are suitable for an imbalance price calculation. Elexon distinguish between:

- System Balancing Actions (taken for non-energy, system management reasons including De-Minimis, Arbitrage, SO & CADL flagging)[10]; and
- Energy Balancing Actions (actions taken purely to balance the half hour energy imbalance of the TS).

Elexon use a number of processes to try and minimise the impact of System Balancing Actions on the Energy imbalance price calculation. Broadly this involves identifying (flagging and classification) and removing (tagging) such actions from the price calculation.

After completing these processes two sets of ranked Buy and Sell actions are netted off each other (NIV tagging). The most expensive balancing actions are netted off first, leaving a net volume of Buy or Sell balancing actions. This is the NIV for a SP.

There are situations where not all of the volume of the NIV is priced. Where unpriced volume exists it must be assigned a replacement price. The replacement price is calculated from a volume weighted average of the most expensive priced 1MWh of priced actions (Replacement Price Average Reference Volume (RPAR)). Where volume has been assigned a replacement price this is identified in the monitor by a grey *re-priced* overlay.

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[8] The RSVP is designed to respond to capacity margins so that it rises as the system gets tighter (the gap between available and required generation narrows). It is calculated using a measure of system reliability called Loss of Load Probability (LoLP). LoLP is a value between 0 and 1, and represents a measure of scarcity in available generation capacity, as calculated by the System Operator at Gate Closure. The RSVP is determined by multiplying the LoLP by the price of disconnections, Value of Lost Load (VoLL) – which was increased from £3,000/MWh to £6,000/MWh in Nov 2018.

[9] If the SO is unable to use the BM or other Balancing Services to meet the current demand, then it can instruct Demand Control as a last resort emergency action. When it issues a Demand Control Instruction, it will instruct the Distribution Network Operators to reduce demand on their Distribution Systems, either through reducing voltage across the network and/or disconnecting consumers.

[10] De Minimis (actions that are so small in volume they could be the result of rounding errors); Arbitrage (actions which have no effect on the energy balancing of the system but lead to an overall financial benefit for the SO); SO flagging (actions taken for locational balancing reasons); CADL flagging (Actions taken to correct short-term increases or decreases in generation/demand).

Finally, the energy imbalance price is calculated based on the volume-weighted average of a defined volume of the most expensive actions remaining in the NIV set (adjusted for transmission losses). This defined volume is the Price Average Reference volume (PAR) and is currently 1MWh.[11] The purpose of PAR is to more closely align the energy imbalance price with the price of the marginal energy balancing action.

Sometimes a final adjustment is necessary. The Buy or Sell Price Adjustment (BPA/SPA) from Balancing Services Adjustment Data (BSAD). BPA is added when the net imbalance of the TS is short (NIV>0). SPA is added when it is long (NIV<0). The BPA is a reflection of the costs to the SO of regulating reserve and BM start-up. If Supplemental Balancing Reserve (SBR) is used Elexon re-price it at VoLL ex-post through BPA. The SPA is made up of option fees for negative reserve and forward contracts. The BPA/SPA is added to the imbalance price and is represented by the yellow bar in the chart.

Finally, if an imbalance price cannot be calculated (for example, where there are no actions left after flagging and tagging i.e. NIV=0) the Market Index price is used instead.[12]

12. Accepted Offers

Source: https://www.bmreports.com/bmrs/?q=balancing/detailprices

The Balancing Mechanism operates from Gate Closure to real time and is managed by the SO. Parties submit notices telling the SO how much it would cost for them to deviate from their Final Physical Notification (FPN). These notices are called Bids and Offers.

- An Offer is a proposal to increase generation or reduce demand
- A Bid is a proposal to reduce generation or increase demand.

The SO assesses all the Bids and Offers for each Settlement Period and chooses the ones that, alongside the balancing actions submitted through BSAD, best satisfy the balancing requirements of the Transmission System. Participation in the Balancing Mechanism is optional, and Parties that choose to do so must submit Bids and Offers before Gate Closure for each Settlement Period. For each BM Unit, a Party can submit up to ten Bid-Offer Pairs.

Each Bid-Offer Pair includes:

- An Offer Price -the price a Party wants to be paid per MWh for an increase in generation or decrease in demand;
- A Bid Price -the price a Party wants to pay per MWh for a decrease in generation or an increase in demand (although it is possible to submit negatively priced Bids, i.e. a Party is paid to reduce generation);
- The Settlement Period for which the Bid/Offer applies
- The upper and lower power levels between which the Bid/Offer applies (for example, Bid-Offer +1 applies from FPN to 50MW above the FPN, Bid-Offer +2 applies from 50MW above FPN to 100MW above FPN).

Bids and Offers are submitted in pairs because this provides an undo mechanism for Acceptances. For an Accepted Offer, the paired Bid price is the 'undo' option (and for a Bid the associated Offer

[11] Note historically the PAR volume had been 50MWh. The change to PAR1 occurred in November 2018.

[12] This price reflects the wholesale electricity price or trading in the 'short-term' market. It is derived by each Market Index Data Provider (MIDP) for each Settlement Period based on the short-term trades on its power exchanges. Any power exchange trading energy in the GB market can potentially be appointed as a MIDP. However, in order to accurately reflect a market price in the 'short-term' market, power exchanges with a significant market share of spot market trades are more likely to be appointed.

price is the ‘undo’ option). If the SO has already accepted the Offer, this is the price SO will be paid per MWh to undo the acceptance.

Accepted Bids and Offers are called Bid Offer Acceptances (BOAs). For each BOA, the SO contacts the BM Unit directly and instructs it to deviate from its FPN via a set of ‘spot points’. Each spot point represents the change in output away from FPN at a particular time.

The Boxplots present the distribution of accepted offers by technology type. The mean is presented as a hashed line and the median a solid line. The boxes extend to the lower and upper quartile values, with the whiskers extending to the 5th and 95th percentiles. Offers beyond the 5th and 95th percentiles are presented as circles.

The scatter plots identify all accepted offers by SP and technology type. The bottom half of the chart plots accepted offer prices, the top half the corresponding accepted volume (and total accepted offer volume). In both cases initial offer volume before any tagging or flagging is used.

13. **Accepted Bids**

Source: https://www.bmreports.com/bmrs/?q=balancing/detailprices

As with accepted offers (see note.12 for details) the Boxplots present the distribution of accepted bids by technology type. The mean is presented as a hashed line and the median a solid line. The boxes extend to the lower and upper quartile values, with the whiskers extending to the 5th and 95th percentiles. Bids beyond the 5th and 95th percentiles are presented as circles.

The scatter plots identify all accepted bids by SP and technology type. The bottom half of the chart plots accepted bid prices, the top half the corresponding accepted volume (and total accepted bid volume). In both cases initial bid volume before any tagging or flagging is used.

14. **Non-BM STOR**

Source: https://www.bmreports.com/bmrs/?q=balancing/nonbminstructedvalues

In addition to balancing available in the BM, the SO can enter into contracts with providers of balancing capacity to deliver when called upon. Most of the reserve the SO procures is called STOR (Short Term Operating Reserve). The SO procures STOR ahead of using it via a competitive tender process.

Under STOR contracts, availability payments are made to the balancing service provider in return for the capacity being made available to the SO during specific hours (STOR availability windows). When STOR is called upon, the SO pays for it at a pre-arranged price (its utilisation price). Some STOR is dispatched in the BM (BM STOR) while some is dispatched separately (Non-BM STOR).

This chart presents daily STOR generation dispatched outside the BM by settlement period, alongside historic monthly distributions of Non-BM STOR generation for context.

Wholesale Energy Prices

15. ICIS Power Index

Source: https://www.icis.com/explore/icis-power-index/

The ICIS Power Index (IPI) shows movements on the most liquid contracts for forward delivery on the UK electricity market, removing the impact of seasonality and weighted to reflect real consumption. The IPI is formed by calculating a volume-weighted average of front-season trades for baseload delivery concluded during the day's trading, and a volume-weighted average of the second-season baseload trades made during the trading session. These two components are then weighted according to demand varying across winter and summer. For further information see ICIS's methodology.

Note there is a two day-lag in the IPI data presented in the monitor.

16. UK Day-Ahead Electricity Prices

Source: https://www.nordpoolgroup.com/Market-data1/GB/

The data presented in the monitor reflects today's electricity prices (£/MWh) based on the previous day's N2EX Day-Ahead Auction. Block & hourly prices reflect delivery over relevant time-period. A calendar year of historic N2EX Day-Ahead Baseload and Peak Auction prices is presented to provide historic context.

- Base: 23:00 - 23:00
- Overnight: 23:00 - 07:00
- Peak: 07:00 - 19:00
- Extended Peak: 07:00 - 23:00
- Block 3+4: 07:00 - 15:00
- Block 5: 15:00 - 19:00
- Block 6: 19:00 - 23:00

Nordpool report these times as GMT/BST. Nordpool also publish associated trading volumes.

17. UK Power Futures

Source: https://www.quandl.com/ primary data from
https://www.theice.com/products/20788778/UK-Base-Electricity-Future-Gregorian/specs &
https://www.theice.com/products/20799523/UK-Peak-Electricity-Future-Gregorian/specs

The Intercontinental Exchange (ICE) provides a market for baseload (23:00 - 22:59 local time Monday - Sunday) and peakload (07:00 - 19:00 local time Monday - Friday) UK power futures. Contracts are for physical delivery of Electricity on a continuous baseload basis, through National Grid, the transmissions system operator in the UK. Delivery is made equally each hour throughout the delivery period. Traded delivery periods can include multiple month, quarter and seasons ahead. The last trading day is two business days before the start of the delivery period. Contracts are traded in £/MWh units. The baseload contract size is 1 MW times days in the contract period (i.e. month, quarter, or year) times 23, 24 or 25 hours (summer / winter time). The peakload contract size is 1 MW times days in the contract period (i.e. month, quarter, or year) times 12 hours (summer / winter time).

The monitor presents baseload and peakload settle prices for contracts up to 18 months ahead of the current month, although there is a two trading day lag on data availability. For each monthly contract the monitor presents the min, max and average (mean) contract price during the previous

12 months, as well as the latest available closing settle price.[13] For example, during August 2018 the first bar in the chart will present prices for UK power in September 2018. The min, max and mean values will reflect the price of the Sep 2018 power contract during the previous 12 months.

18. Spark & Dark Spreads

Spark and dark spreads are indicative prices giving the average difference, or spread, between the price of electricity and the cost of its production (*spark* refers to the cost of production using gas, and *dark* refers to the cost of production using coal). Spreads give some insight into the profitability (or gross margin) of coal and gas-fired electricity generation, and therefore what kinds of plants are likely to operate, or whether investment in new plants is likely.

Spreads are calculated from data presented elsewhere in the monitor, although there is a two trading day lag in data availability and therefore spread estimates i.e. Wednesday's monitor will reflect spreads based on Monday's market outcomes.

Spreads are calculated according to Platts' methodology for *clean* (inclusive of carbon costs) spreads. Under this methodology non-clean spark spreads (£/MWh) are calculated as:

$$Spark = e_p - \frac{g_p}{FE} \tag{18.0}$$

Where e_p is the electricity, or power price (£/MWh), g_p is the gas price (£/MWh) and FE is the gas plant's fuel efficiency. The FE adjustment allows for the fact a plant with 50% efficiency will need double the gas input to produce one MWh of power. Note this equation requires gas prices to be recorded in units of pounds per MWh (£/MWh). Gas in the UK is typically traded in units of pence per therm (p/therm). As a result p/therm gas prices must be transformed into equivalent £/MWh gas prices using the following equation:

$$g_p = \frac{g_p^* * 34.121}{100} \tag{18.1}$$

Where g_p^* is gas prices in p/therms and 34.121 is the energy conversion rate of one MWh into therms (where one therm is equivalent to 100,000 British thermal units Btu). Therefore non-clean spreads are calculated as:

$$Spark = e_p - \frac{g_p^* * 34.121}{100 * FE} \tag{18.2}$$

However, non-clean spark spreads fail to consider all the private input costs associated with electricity generation, and may give a misleading view of profitability. Specifically, the equation above does not consider the input costs associated with carbon permits and taxes, such as the EU Emissions Trading Scheme (EU ETS). A *clean* spark spread, which does take account of private carbon costs, is calculated as follows:

$$Clean\ Spark = e_p - \frac{g_p^* * 34.121}{100 * FE} - \frac{(p_E + p_C)0.053942 * 3.412141}{FE} \tag{18.3}$$

Where p_E is the price of a EUA (EU Allowance) (£/t) traded in the EU ETS, and p_C is the UK Carbon Price Support (CPS) levy (£/t), currently fixed at £18/tCO_2 until 2020/21.[14] Note the EUA price is traded in €/tCO_2 and as a result must be converted to £/tCO_2 with a relevant exchange rate ($r_€$ in the equation below).

$$Clean\ Spark = e_p - \frac{g_p^* * 34.121}{100 * FE} - \frac{(r_€ * p_E + p_C)0.053942 * 3.412141}{FE} \tag{18.4}$$

The 0.053942 value reflects the CO_2 emissions intensity of natural gas. Platts' define this as

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[13] 12 months is defined as the nearest trading day 365 days prior to the current date.

[14] See latest on CPS rates as of January 2018 http://researchbriefings.files.parliament.uk/documents/SN05927/SN05927.pdf

tCO_2e/MMBtu HHV - thermal basis, before combustion. Given this relates to the emissions associated with 1m Btu, the energy conversion factor (converting Btu into MWh) is a tenth of the energy conversion factor used to convert gas prices from therms to MWh. To be explicit, gas prices are scaled up to reflect the fact 34.121 therms are needed to produce one MWh of energy, or, given one therm is equivalent to 100k Btu, 3.412m Btu are needed to produce one MWh. Given the emissions intensity value of 0.053942 is the tCO_2 emissions associated with 1m Btu, the emissions associated with one MWh will be 3.412 times this amount.[15]

Dark spreads are calculated according to the following equation:

$$Clean\ dark = \ e_p - \frac{c_p * r_\$}{6.978 * FE} - (r_\$ * p_E + p_C)0.973 \tag{18.5}$$

$$Clean\ dark = \ e_p - \frac{c_p * r_\$}{6.978 * 35\%} - (r_\$ * p_E + p_C)0.973 \tag{18.6}$$

Dark spreads are calculated assuming a fuel efficiency of 35%. New variables include, c_p which is the coal price in $/t, and $r_\$$ is the £/$ exchange rate. 6.978 is the conversion factor assumed by Platts (converting one tonne of coal into MWh i.e. there are 6.978 MWh per tonne of coal).[16] 0.973 is the emissions intensity factor of coal generation (tCO_2/MWh).[17]

A single dark spread, assuming 35% fuel efficiency is calculated, but three alternative spark spreads are estimated using different fuel efficiency assumptions:

- Low efficiency: fuel efficiency = 45%;
- Medium efficiency: fuel efficiency = 50%;
- High efficiency: fuel efficiency = 60%

Further, reflecting the fact energy can be traded over a number of different time periods, two versions of each spread are produced. Day-ahead spreads assume that power is sold the day before generation, gas is purchased the day before generation, and coal is purchased a month-ahead. For month-ahead spreads all power, gas and coal prices are assumed to be sold/purchased a month-ahead of generation. Sources for each input into the calculation are as follows:

- e_p: For day-ahead calculation baseload N2EX day-ahead auction prices are used, sourced from Nordpool. For month-ahead calculation ICE GB Power front-month Futures are used, sourced from Quandl.

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[15] Carbon, or emissions, intensity values of electricity production will often be quoted in gCO_2/kWh. The definition used in the monitor implies a gCO_2/kWh value of c.370gCO_2/kWh under a 50% efficiency assumption, after scaling up by 1m to convert from tonnes to g, and scaling down by 1000 to convert from MWh to kWh. Note the Platt's definition of emissions intensity of 0.184tCO_2e/MWh (the product of 0.05 and 3.412) is equivalent to the value defined in the UK Government's Greenhouse Gas Reporting conversion factors (2018) for Natural Gas (Gross CV) 0.18396 $kgCO_2e$/kWh.

[16] Note alternative tonne to MWh energy conversion factors for coal are often used. For example, the UK Digest of Energy Statistics (DUKES) assumes a net calorific value for coal used in power stations of 25.3 GJ per tonne. The net calorific value being the total heat obtained from burning one unit of fuel, minus the heat needed to evaporate the water present in the fuel or produced during its combustion. Given each GJ is equal to 0.277778 MWh this would imply an energy conversion factor of 7.0. The alternative values reflect the fact the amount of energy produced by a tonne of coal is largely dependent on the type of coal being burned. The monitor follows the methodology as set out by Platts.

[17] Note unlike the spark spread the emissions intensity factor of 0.973 is already on a per MWh basis. Based on a plant efficiency of 35% the equivalent $kgCO_2$/kWh emission intensity factor would be c.0.34$kgCO_2$/kWh (0.35*0.973), broadly consistent with the UK Government's Greenhouse Gas Reporting conversion factors for Coal (electricity generation) of 0.311-0.323 kgCO2e/kWh (Gross CV).

- g_p^*: For day-ahead calculation natural gas prices are based on day-ahead ICE National Balancing Point (NBP) contracts, sourced from Quandl. For month-ahead calculation ICE UK Natural Gas front-month Futures are used, sourced from Quandl.
- c_p: Coal prices are based on ICE front month Amsterdam Rotterdam Antwerp (ARA) coal contracts, sourced from Quandl.
- p_E: EUA prices based on benchmark (December) ICE EUA futures on relevant trading day, sourced from Quandl.
- $r_\$$ & $r_€$: Exchange rates on the relevant trading day, sourced from Bank of England.

Note, because front-month trading does not take place on the last calendar day of each month, spreads are not currently calculated on the last calendar day of each month.

19. European Electricity & Gas

Sources: http://www.marexspectron.com/intelligence/indices# & https://www.epexspot.com/en/

The monitor presents two sources of European gas and power prices as comparisons to UK equivalents.

Marex Spectron: Energy broker who publish a range of proprietary indices on key European energy markets. The monitor reports the following:

- UK all day D.A (Day-ahead) natural gas price index (NBP (p/therm)): The all-day UK gas price index is calculated from a volume-weighted average of *all* day-ahead trades executed through Marex Spectron's phone brokering and internet brokering systems. All trades undertaken during the course of the deal day, for delivery to the NBP (National Balancing Point) the following working day (i.e. excluding weekends and bank holidays) are included.[18] Equivalent indices reflecting alternative delivery dates, such as Month-ahead (M.A) and Weekend-ahead (W/End) are also published and may be reported in the monitor.[19] Marex Spectron also publish a 'window' gas price index reflecting a volume weighted average of trades executed during a specific time period. For example, the D.A 'window' index includes trades executed between 16:25 and 16:35 (BST) through Marex Spectron's internet brokering platform. The window index is not reported in the monitor.
- European all day D.A. natural gas price index (TTF (€/MWh)): The all-day European gas price index is calculated from a volume-weighted average of *all* day-ahead trades executed through Marex Spectron's phone brokering and internet brokering systems. All trades undertaken during the course of the deal day, for delivery to the Dutch Title Transfer Facility (TTF) the following working day (i.e. excluding weekends and bank holidays) are included. Marex Spectron also publish a W/End ahead TTF index price. Note Marex Spectron publish the TTF price index on a €/MWh unit basis. To allow easier comparison to UK NBP prices the monitor also converts TTF prices into a p/therm basis by multiplying TTF prices by an energy conversion factor of 0.029307 (see Note.18 for further details[20]) and dividing by a €/£ exchange rate from the Bank of England

[18] Where the number of trades executed in a day is: 5+, the index is calculated using a weighted average of those trades; 1-4, the index is calculated using a weighted average of those trades. However it is noted that the outcome is based on less than 5 trades; zero, the index is calculated using the closing market price published in Marex Spectron's daily market summary Spectrometer.

[19] W/End ahead indices value gas trades executed on a Friday for delivery throughout the weekend following the deal date. This is usually defined as the following Saturday and Sunday, although adjacent bank holidays are included. Should a bank holiday fall mid-week it is treated as a weekend, and a weekend-ahead index is calculated for it.

[20] Specifically, multiplying by 0.029307 (MWh to therm) is the inverse transformation of multiplying by 3.4121 (therm to MWh).

(although note that due to data availability the exchange rate used is the BofE reported daily rate for the working day before the deal date, so two working days before the delivery date).

- UK power baseload all day D.A price index (£/MWh): The all day UK power index is calculated from a volume weighted average of all day-ahead baseload trades executed during the course of the day.[21] The index values power for delivery on the next working day following the deal date. Equivalent indices reflecting alternative delivery dates, such as Month-ahead (M.A) and Weekend-ahead (W/End) are also published by Marex Spectron.[22] As with UK gas prices Marex Spectron also publish a 'window' baseload price index reflecting a volume weighted average of trades executed during a specific time period. The D.A baseload power 'window' index includes trades executed between 08:00 and 12:00 (BST). The window index is not reported in the monitor.
- Geman Baseload & Peak D.A price indices (€/MWh): German power indices are calculated from the volume weighted average of all Day-ahead Baseload or Peak transactions executed between 08:00 and 11:00 (CET) for delivery into the German high voltage grid.[23] Day-ahead indices are for power delivery the next working day. A Weekend Baseload index is also calculated on a Friday based on all weekend trades concluded during the trading window that day. Bank holidays are treated as individual days separate from the weekend. Indices are published at the end of the trading window at 11:00 (CET). The same €/£ exchange rate from the Bank of England is used to convert prices into £/MWh for easier comparison to UK power prices.
- French Baseload D.A price index (€/MWh): The French power index follows the same methodology as the German index except it is calculated as a volume weighted average of all Day-ahead Baseload transactions executed between 08:00 and 11:00 (CET) for delivery into the French high voltage grid.

EPEX SPOT: Power exchange covering intra-day (same) and day-ahead (next day) markets for Germany, France, UK, Netherlands, Belgium, Austria and Switzerland and Luxembourg.[24] The monitor reports the previous days day-ahead auction results for hourly power delivery across six markets (UK, Netherlands, Belgium, France, Germany and Switzerland), as well as 12 months of historic baseload and peak power prices.[25] The same €/£ exchange rate from the Bank of England is used to convert prices into £/MWh for easier comparison to UK power prices. Note that for the *German* market (as descried in the monitor) prices up until 30th September 2018 reflect the combined Germany/Austria electricity market (as they were reported by EPEX Spot). From 1st October EPEX SPOT report two separate German and Austrian markets and the monitor reports the

[21] UK power prices follow the same rules as the gas price methodologies for prices based on limited trades, except when there are zero trades, day-ahead power prices are derived from market discussion/assessments and month-ahead power prices are calculated based on Spectormeter.

[22] The M.A daily index values power for delivery every day in the month following the month in which a deal is executed. In addition to the daily M.A index, Marex Spectron also publish a M.A cumulative index reflecting an average of all M.A trades executed during the entire month. W/End ahead indices follow a similar convention to gas prices i.e. for a standard week the Weekend and Monday indices are both calculated using deals executed on the Friday, however, the trade execution day is not strictly the previous day to the delivery day when bank holidays are a factor (for example at Easter four indices will be calculated from trades concluded in the Thursday – Friday, Weekend, Monday and Tuesday). UK bank holidays are treated as separate from the weekend.

[23] Under no trade conditions if delivery day is a weekday the average of the last four indices will be used (provided they are not a bank holiday). If it is a weekend then a weighted average of the weekend trades done two days before the weekend will be used (and so on if no trades exist for these days either).

[24] In 2015 EPEX SPOT integrated with APX Group.

[25] For France and Germany peak is defined explicitly as delivery between 09:00-20:00.

German market only.[26] As such, prices for the German market pre and post 1st October 2018 are not directly equivalent.

20. **Brent Crude Oil**

Source: https://www.quandl.com/data/CHRIS/ICE_B1 primary data from https://www.theice.com/products/219/Brent-Crude-Futures/specs

The monitor presents two sets of Brent crude oil prices based on ICE Brent crude futures ($/barrel). The ICE Brent crude futures contract is a deliverable contract based on EFP delivery with an option to cash settle.[27] Tradable contracts available up to 96 consecutive months ahead.

The last trading day for each contract is the last Business Day of the second month preceding the relevant contract (delivery) month (e.g. the March contract month will expire on the last Business Day of January). If the day on which trading is due to cease would be either: (i) the Business Day preceding Christmas Day, or (ii) the Business Day preceding New Year's Day, then trading shall cease on the next preceding Business Day.

Historic 'spot' prices are a rolling (or continuous) series of daily settle prices for the two-month ahead contract. That is, during June prices are based on the price of the August futures contract, and at the start of July prices rollover to be based on the price of the September futures contract. For this reason there is often a lag in updates at the start of each new calendar month.

The second set of prices presents settle prices for contracts up to 18 months ahead of the current month. For each monthly contract the monitor presents the min, max and average (mean) contract price during the previous 12 months, as well as the latest available closing settle price.[28] For example, during August 2018 the first bar in the chart will present Brent crude prices for delivery in October 2018. The min, max and mean values will reflect the price of the Oct 2018 Brent crude oil contract during the previous 12 months.

21. **Natural Gas**

Source: https://www.quandl.com/data/CHRIS/ICE_M1 primary data from https://www.theice.com/products/910/UK-Natural-Gas-Futures/specs

The monitor presents two main sets of natural gas prices based on ICE UK natural gas futures (sterling pence/therm). Contracts are for physical delivery through the transfer of rights in respect of Natural Gas at the National Balancing Point (NBP) Virtual Trading Point, operated by National Grid, the transmissions system operator in the UK. Delivery is made equally each day throughout the delivery period. Tradable contracts include:

- 78-83 consecutive month contracts;
- 11-13 consecutive quarters (Quarters are strips of three individual and consecutive contract months. Quarters always comprise a strip of Jan-Mar, Apr-Jun, Jul- Sep or Oct-Dec).
- 13-14 consecutive seasons (Seasons are strips of six individual and consecutive contract months. Seasons always comprise a strip of Apr-Sep or Oct-Mar).
- 6 consecutive years.

The last trading day is the close of business two Business Days prior to the first calendar day of the delivery month, quarter, season, or calendar.

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[26] The German and Austrian Electricity Transmission companies split their previously joined power markets on October 1st 2018.

[27] Against the ICE Brent Index price for the last trading day of the futures contract.

[28] 12 months is defined as the nearest trading day 365 days prior to the current date.

Historic 'spot' prices are a rolling (or continuous) series of daily settle prices for the month-ahead and two-month ahead contracts. That is, during June month-ahead prices are based on the price of the July futures contract, and at the start of July prices rollover to be based on the price of the August futures contract (plus one month for the two-month ahead series). For this reason there is often a lag in updates at the start of each new calendar month. There's also no trading on the month-ahead contract on last calendar day of each month.

The second set of prices presents settle prices for contracts up to 18 months ahead of the current month. For each monthly contract the monitor presents the min, max and average (mean) contract price during the previous 12 months, as well as the latest available closing settle price.[29] For example, during August 2018 the first bar in the chart will present UK natural gas prices for delivery in September 2018. The min, max and mean values will reflect the price of the September 2018 UK natural gas contract during the previous 12 months.

As a comparator Marex Spectron day-ahead and month-ahead natural gas prices are also reported in this section (see note.19 for further details).

22. **EUA Futures**

Source: https://www.quandl.com/ primary data from https://www.theice.com/products/197/EUA-Futures

The Intercontinental Exchange (ICE) provides a market for EU Allowances (each EU Allowance being an entitlement to emit one tonne of carbon dioxide equivalent gas). Traded in units of € and € cent per metric tonne. December contract months are listed up to 2025 and quarterly contracts are listed up to 2020. The last trading day is the last Monday of the delivery month. However, if the last Monday is a Non-Business Day or there is a Non-Business Day in the 4 days following the last Monday, the last day of trading will be the penultimate Monday of the delivery month.

The monitor follows standard industry practice in quoting the price for the next December contract. Therefore during Jan-Dec 2019 the monitor will report prices for the EUA Futures Dec 2019 contract. During Jan-Dec 2020 the monitor will report prices for the EUA Futures Dec 2020 contract.

[29] 12 months is defined as the nearest trading day 365 days prior to the current date.

Retail Prices

23. Weekly Road Fuel Prices

Source:https://www.gov.uk/government/statistical-data-sets/oil-and-petroleum-products-weekly-statistics

BEIS' road fuel price statistics provide average UK retail unleaded petrol (ULSP) and unleaded diesel (ULSD) 'pump' prices on a weekly basis. There are six companies (four oil companies and two supermarkets) that take part in the weekly fuel price survey, providing ULSP (unleaded petrol), ULSD (Diesel) and super unleaded fuel prices. These cover around 65% of the market.

The fuel companies are contacted by email every Monday morning asking for their fuel prices for that day. Prices are entered onto a spreadsheet that calculates the average weighted price for each fuel, with the weights determined by annual sales.

BEIS publish the results at 09:30am every Tuesday (except weeks including a Bank Holiday), therefore the monitor will update every Wednesday to reflect the latest road fuel prices.

For petrol, the monitor disaggregates 'pump' prices into prices pre duty & VAT, unleaded duty and finally VAT. For diesel, only the total 'pump' price is presented.

Energy Company Share Prices

24. Share Prices

Source: https://www.alphavantage.co/

The monitor reports the most recent closing share price for a selection of publicly listed energy companies including:

- National Grid
- Royal Dutch Shell
- BP
- Drax Group
- SSE
- Centrica

For each company, the monitor reports in a table the most recent closing price, daily percentage change in closing prices (the most recent close relative to the previous trading day) and the percentage change in the most recent closing price relative to the closing price 30, 90 and 180 days previous.[30]

The monitor also presents two charts. The first chart presents a historic comparison of closing prices over the previous 12 months indexed to each company's closing price one year previous. That is, for firm i on any given day, t,[31] the index is calculated as (where p is closing share price):[32]

$$Index_i = 100\left(\frac{P_t}{P_{t-365}}\right) \quad (24.0)$$

The second chart presents intraday share prices i.e. how each company's share price changed during the last trading day.

[30] Where the date falls on a weekend or bank holiday the last trading day before the weekend or bank holiday is used.

[31] Note as the monitor is typically sent the day after the most recent close t relates to the date of the most recent close, not the date the monitor is sent.

[32] Where the date falls on a weekend or bank holiday the last trading day before the weekend or bank holiday is used.