



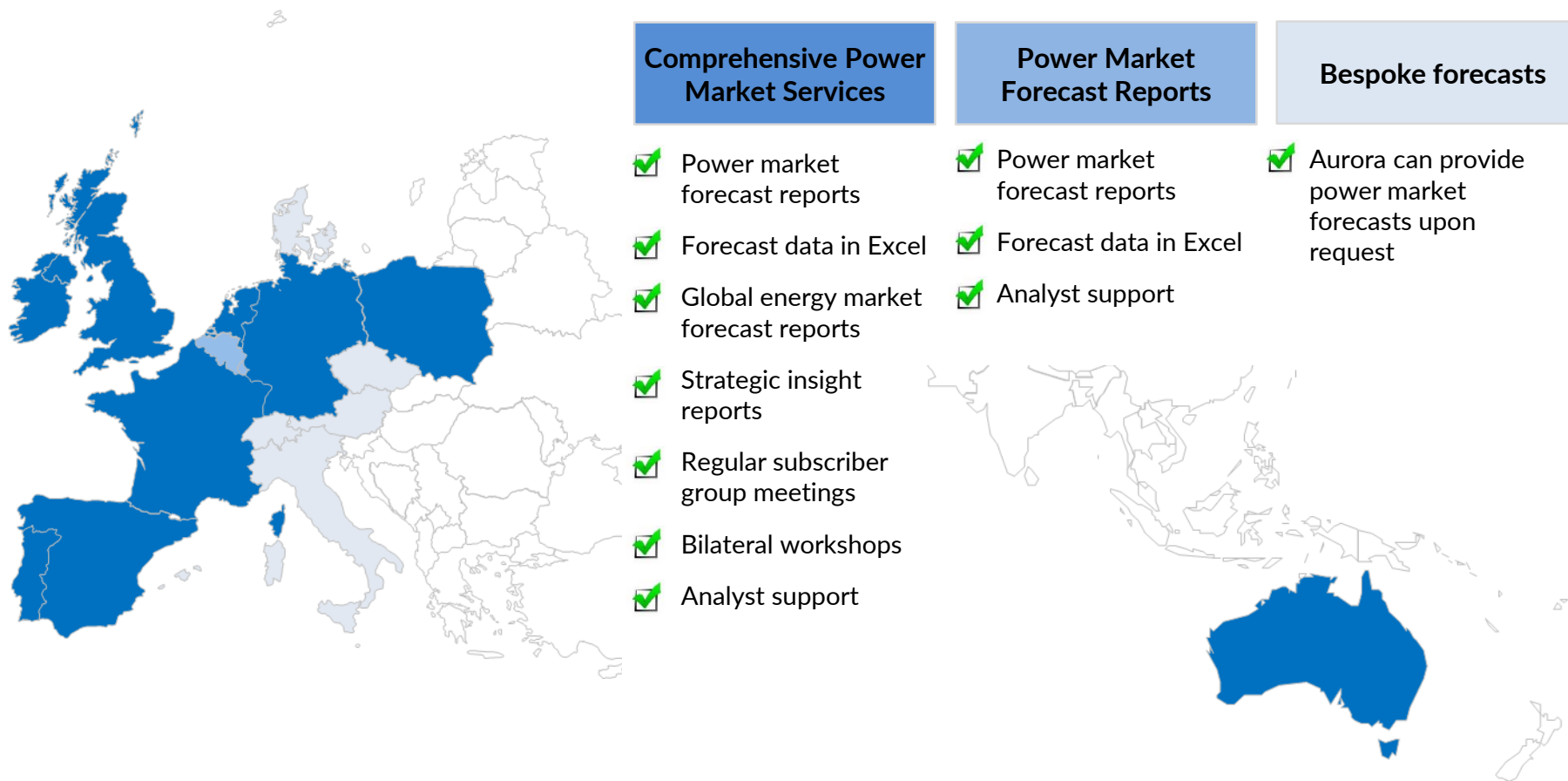
GB Wholesale Market Summary January 2020

Published February 2020

Executive summary

1. With gas prices continuing to decline, the average monthly power price in January fell to £34.8/MWh, a £2.2/MWh decrease from December. Year-on-year power prices have now declined by 42%. See [slides 5](#), [6](#), and [7](#).
2. Despite a lower gas price, sustained cold temperatures in January resulted in an increase in monthly coal generation of 0.5 TWh relative to December. See [slides 10](#) and [11](#).
3. With coal generation increasing between months, total emissions increased by 2%, from 4.6 MtCO₂e to 4.8 MtCO₂e since December. See [slides 11](#) and [14](#).
4. With stormy weather in January bringing strong winds, average load factors for wind assets rose by 6 percentage points, while capture prices fell by £2.2/MWh, or 6%. See [slides 20](#) and [22](#).

Aurora covers key European markets & Australia



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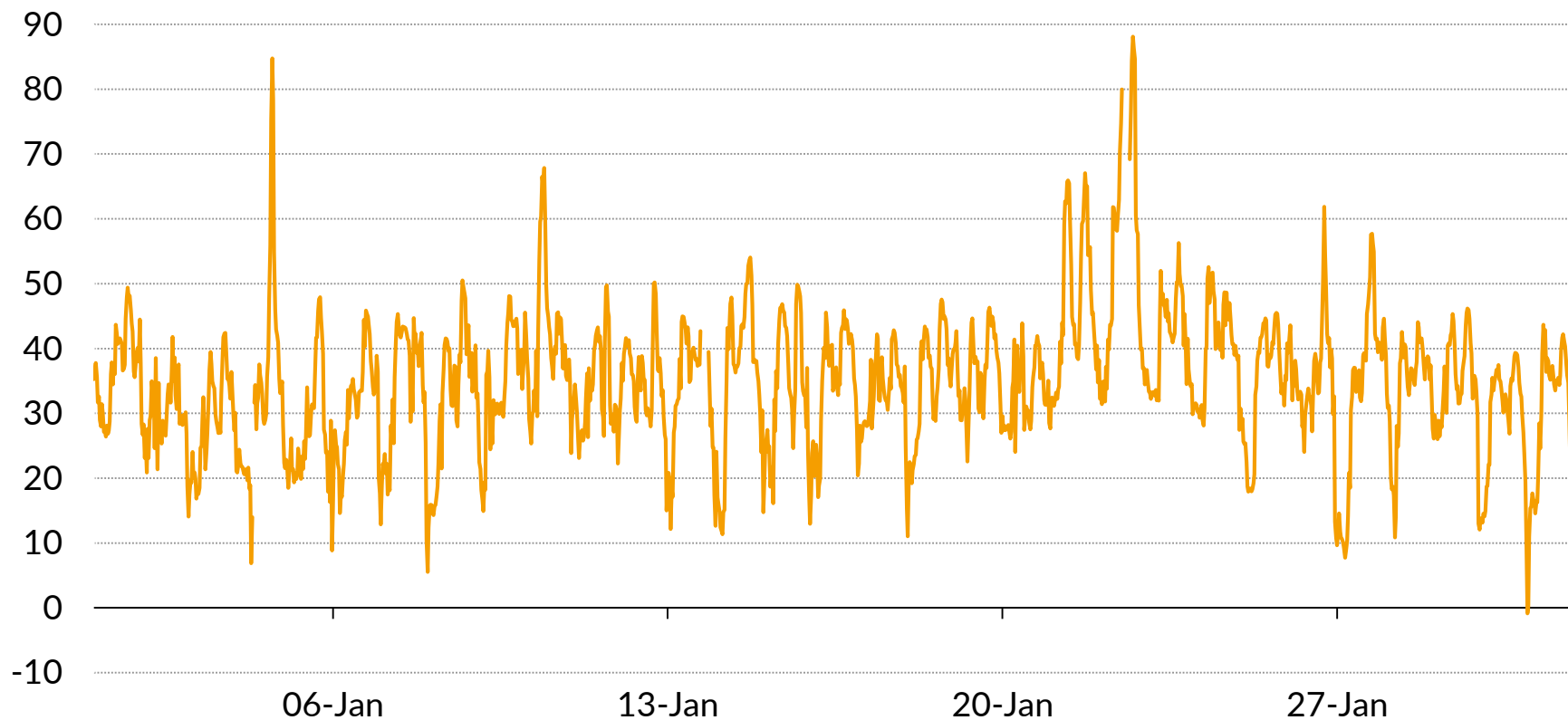
Contents

1. System performance
2. Company performance (available to subscribers only)
3. Plant performance

Half-hourly APX spot price for January

APX spot price¹,
£/MWh

Monthly average price
in January 2020:
£34.80 /MWh

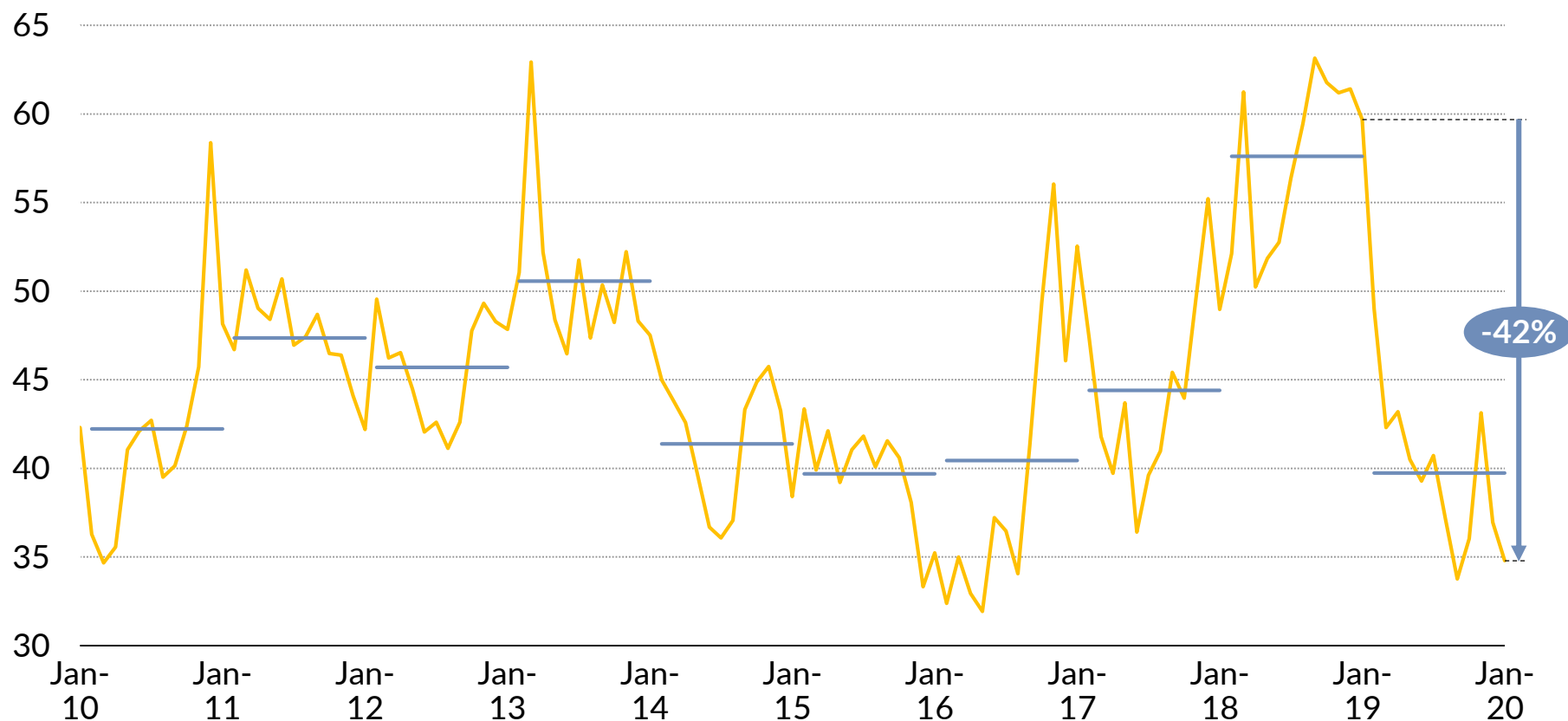


1. Half-hourly APX is the volume-weighted reference price over that half-hour interval, as provided by APX Power UK.

Historic monthly average APX spot price

Average APX spot price¹,
£/MWh

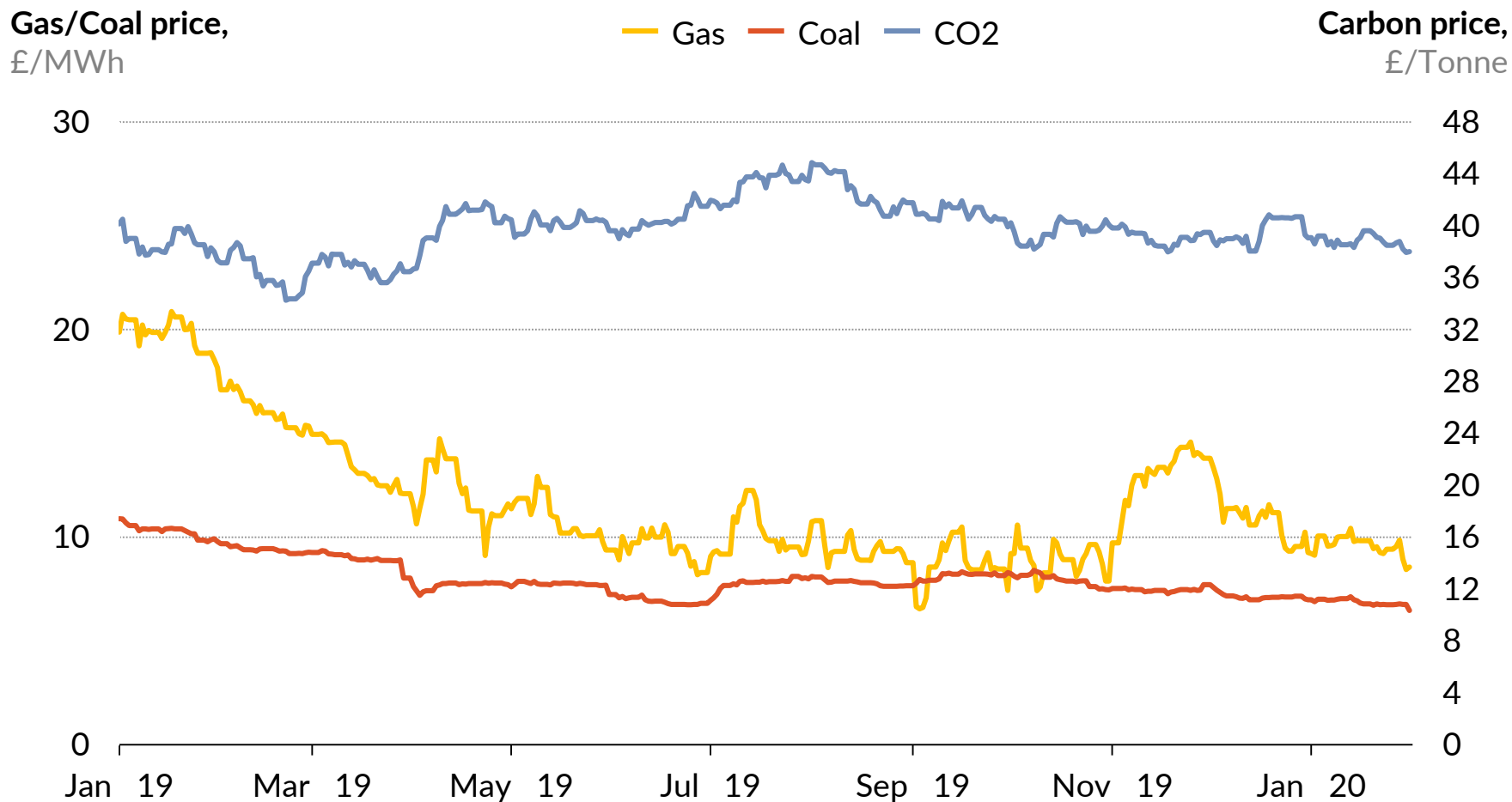
— Average monthly spot price — Annual average spot price



1. Average monthly APX is the average over the month of the volume-weighted reference prices for each half-hour interval.

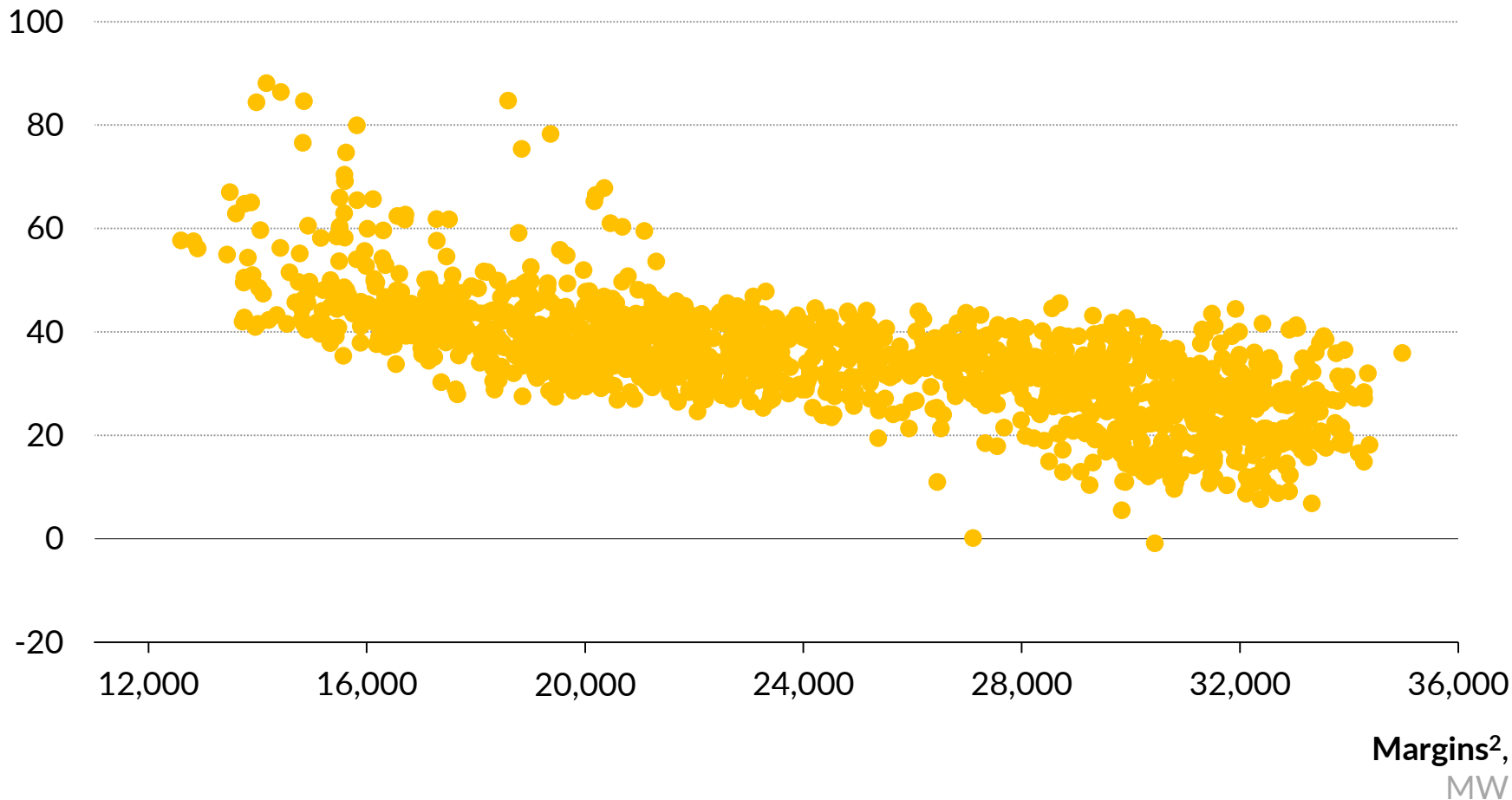
Historic fuel prices

Gas, Coal and Carbon daily prices



Half-hourly spot prices against half-hourly system margins for January

APX spot price¹,
£/MWh

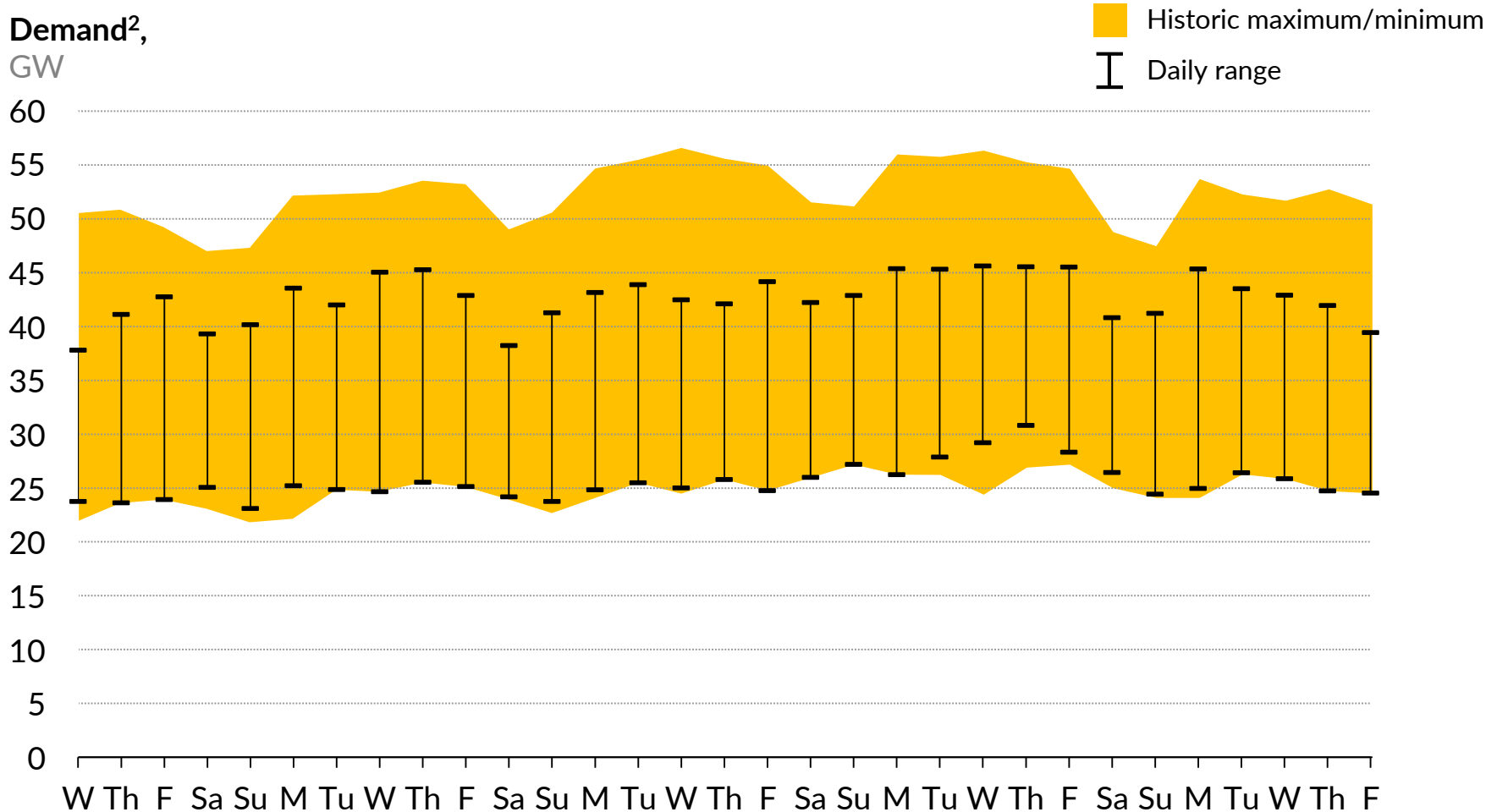


1. Half-hourly APX is the volume-weighted reference price over that half-hour interval, as provided by APX Power UK.

2. Margins are calculated as the difference between MEL and Demand for each half-hour period. Demand data presented here is Initial Transmission System Demand Out-Turn, and does not include embedded demand. MEL is calculated as the sum of all transmission BM units reporting MEL values in each half-hour. Where a BMU gives multiple values in a half-hour, only the least is taken.

Daily January max and min demand

Relative to historic January max and min demand since 2010¹



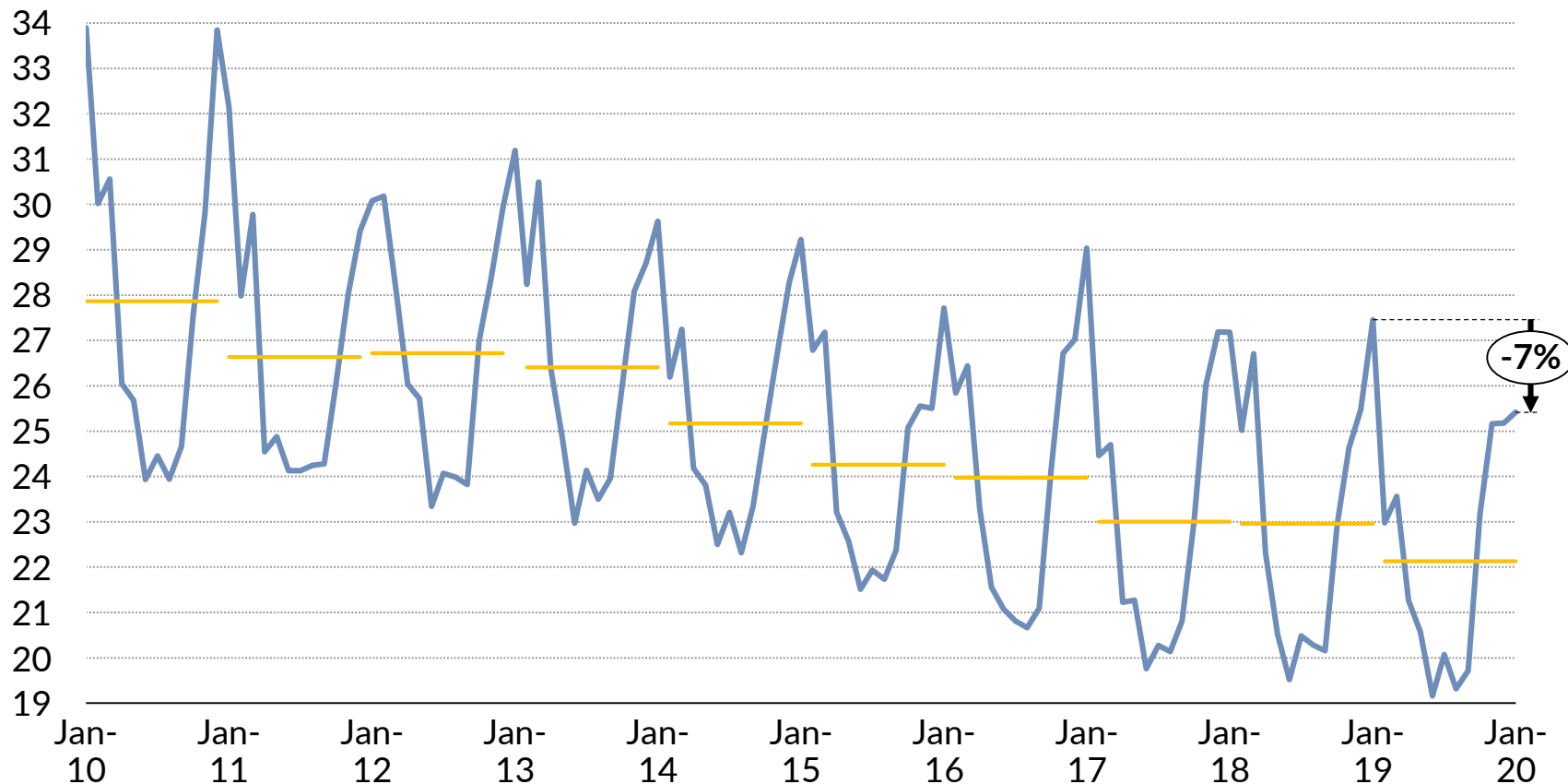
1. Data from previous years is matched to the nearest weekday within the current month, to maintain the weekly demand pattern.

2. Demand data presented here is Initial Transmission System Demand Out-Turn, and does not include embedded demand.

Monthly historical demand on the transmission system

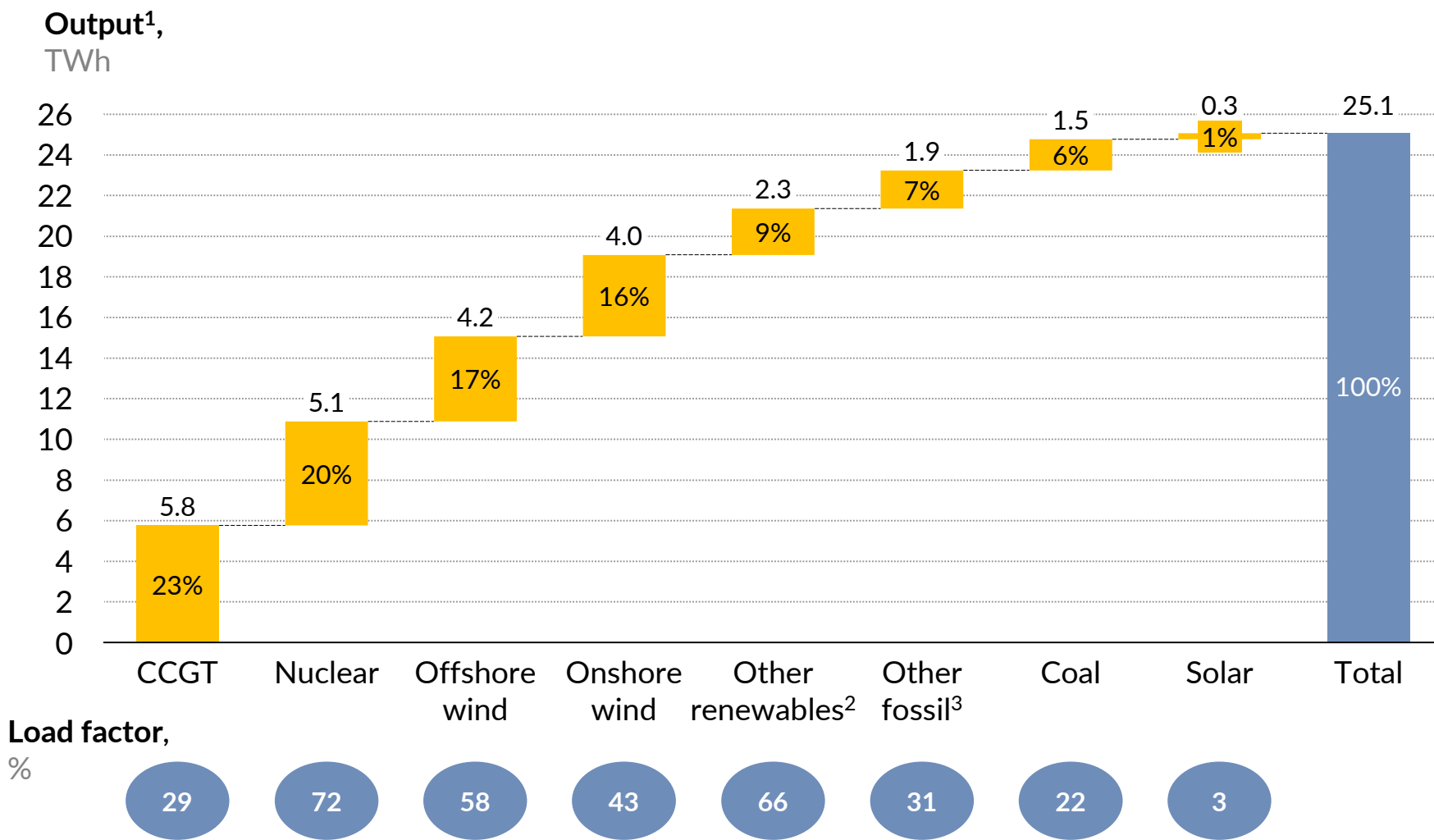
Total demand¹,
TWh

— Total monthly demand
— Annual average demand



¹, Demand data presented here is Initial Transmission System Demand Out-Turn, and includes station transformer load, pumped storage demand and interconnector demand, but does not include embedded demand.

Monthly fuel mix breakdown

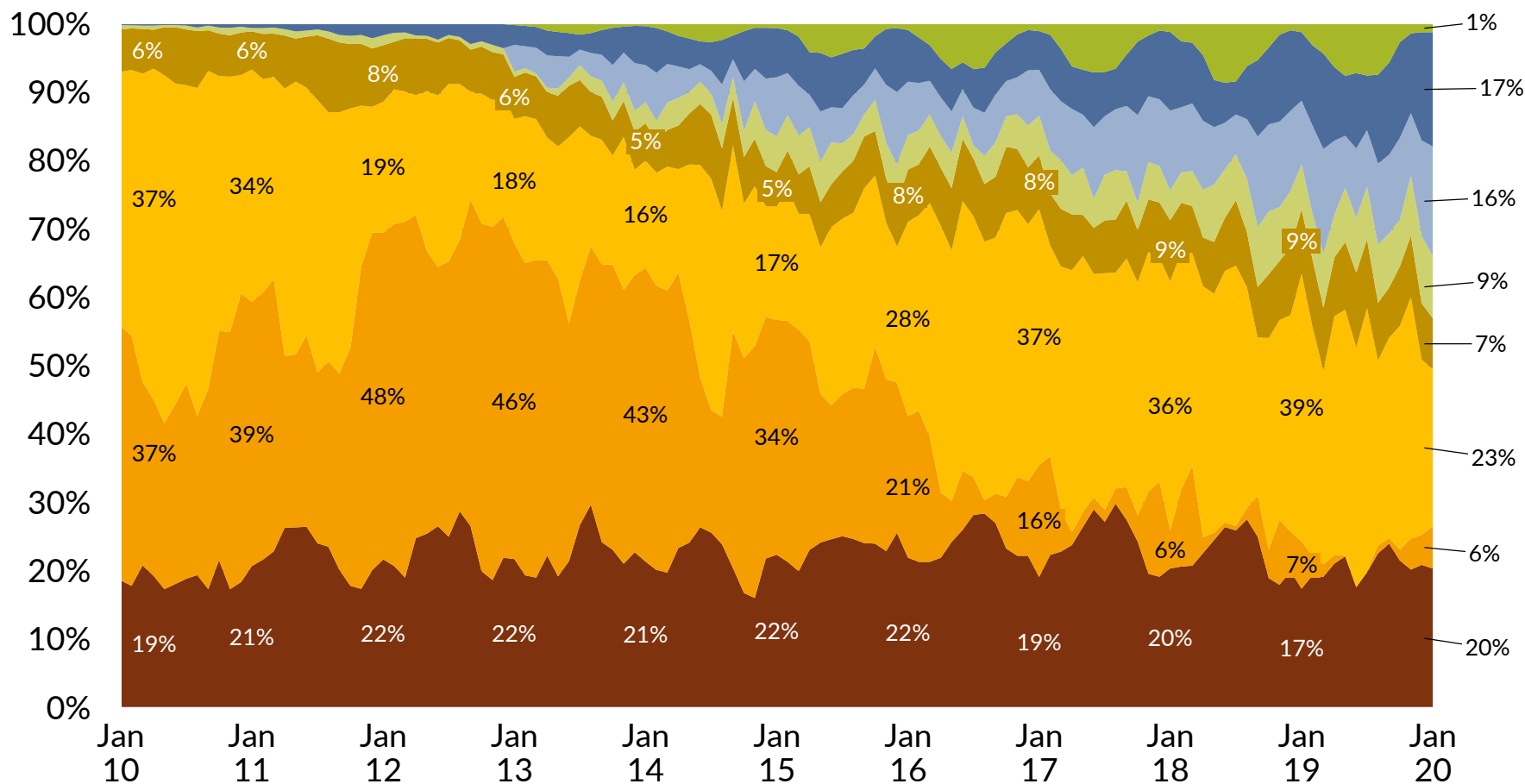


1) Includes outputs from generators registered as BM Units as well as embedded wind and solar PV assets. All numbers are rounded to 0.1 TWh which means that subtotals may not sum to total value. 2) Other fossil includes oil, CHP-CCGT and OCGT. 3) Other renewables includes biomass and hydro.

Historical fuel mix breakdown

Output¹,
% of total

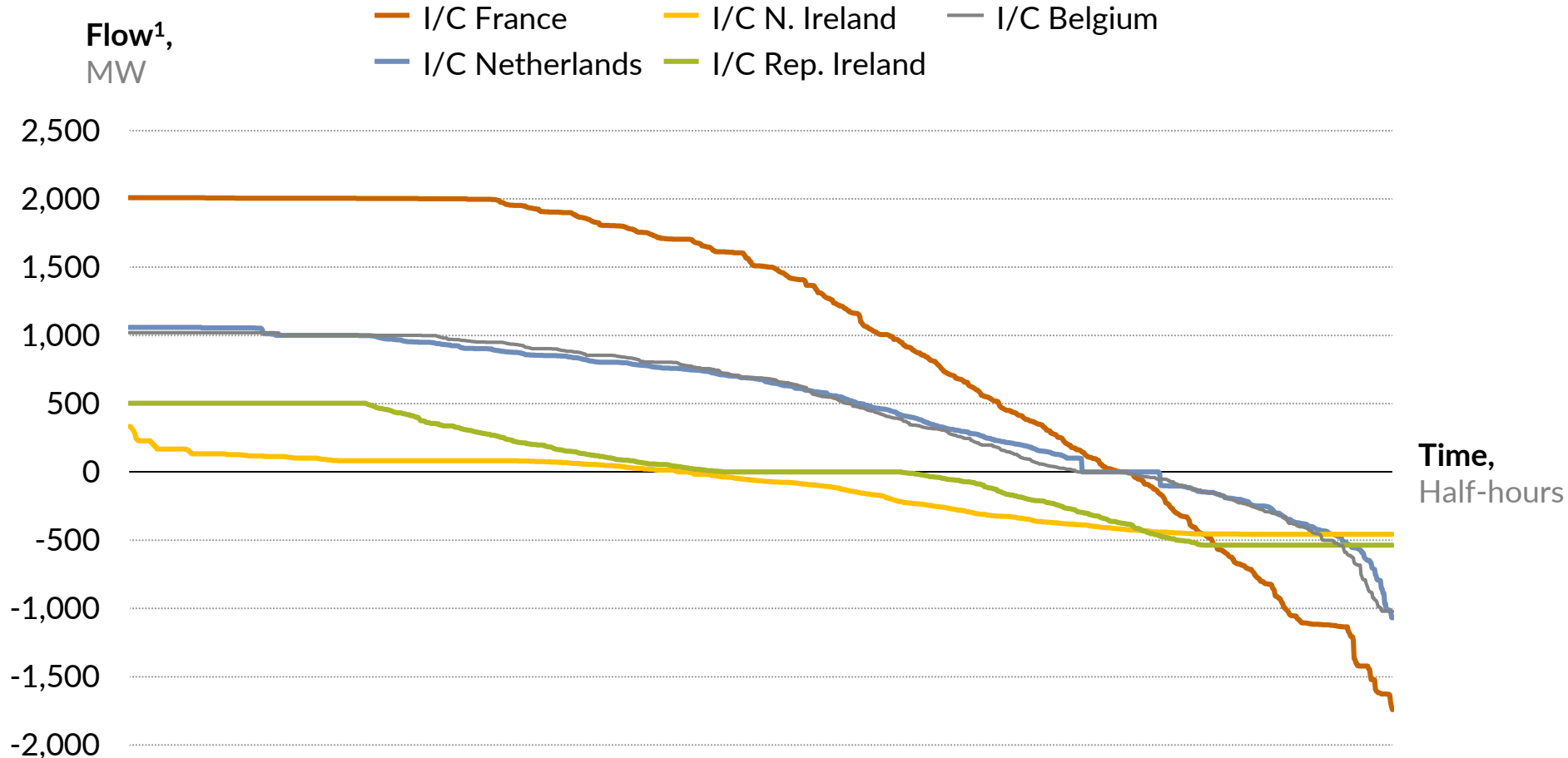
■ Nuclear ■ CCGT ■ Other renewables³ ■ Offshore wind
■ Coal ■ Other fossil² ■ Onshore wind ■ Solar



Notes: 1) Includes outputs from generators registered as BM Units as well as embedded wind and solar PV. 2) Other fossil includes oil, CHP-CCGT and OCGT. 3) Other renewables includes biomass and hydro.

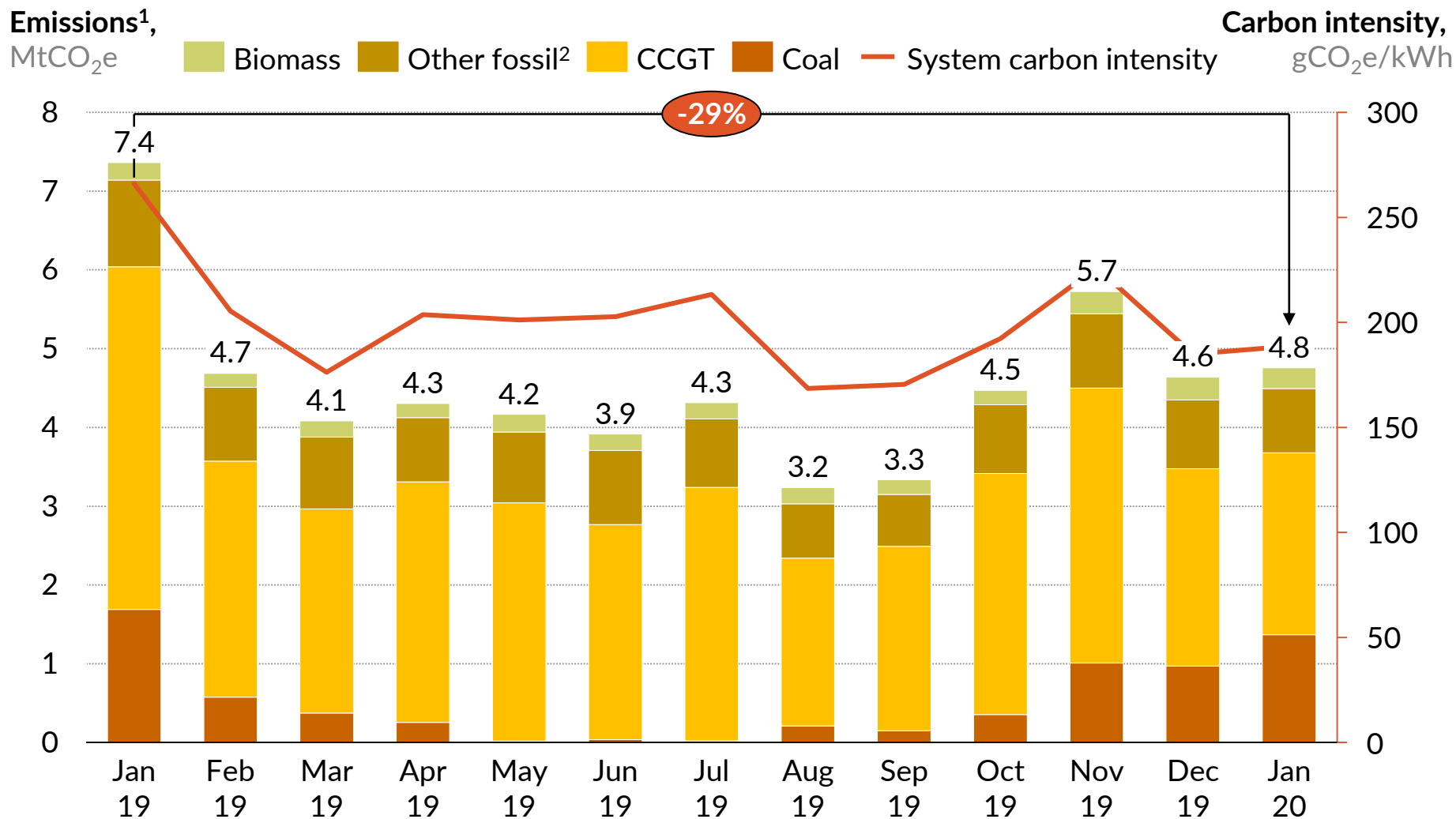
Monthly interconnector flow duration curve

Flow in each half-hour for GB interconnectors



1. Positive flow is imports into GB, negative flow is exports.

Monthly emissions by technology



1. Please refer to Appendix 1 for details of methodology employed to calculate emission amounts. Includes all Balancing Mechanism plants.

2. Other fossil includes oil, OCGT and gas CHP-CCGT.

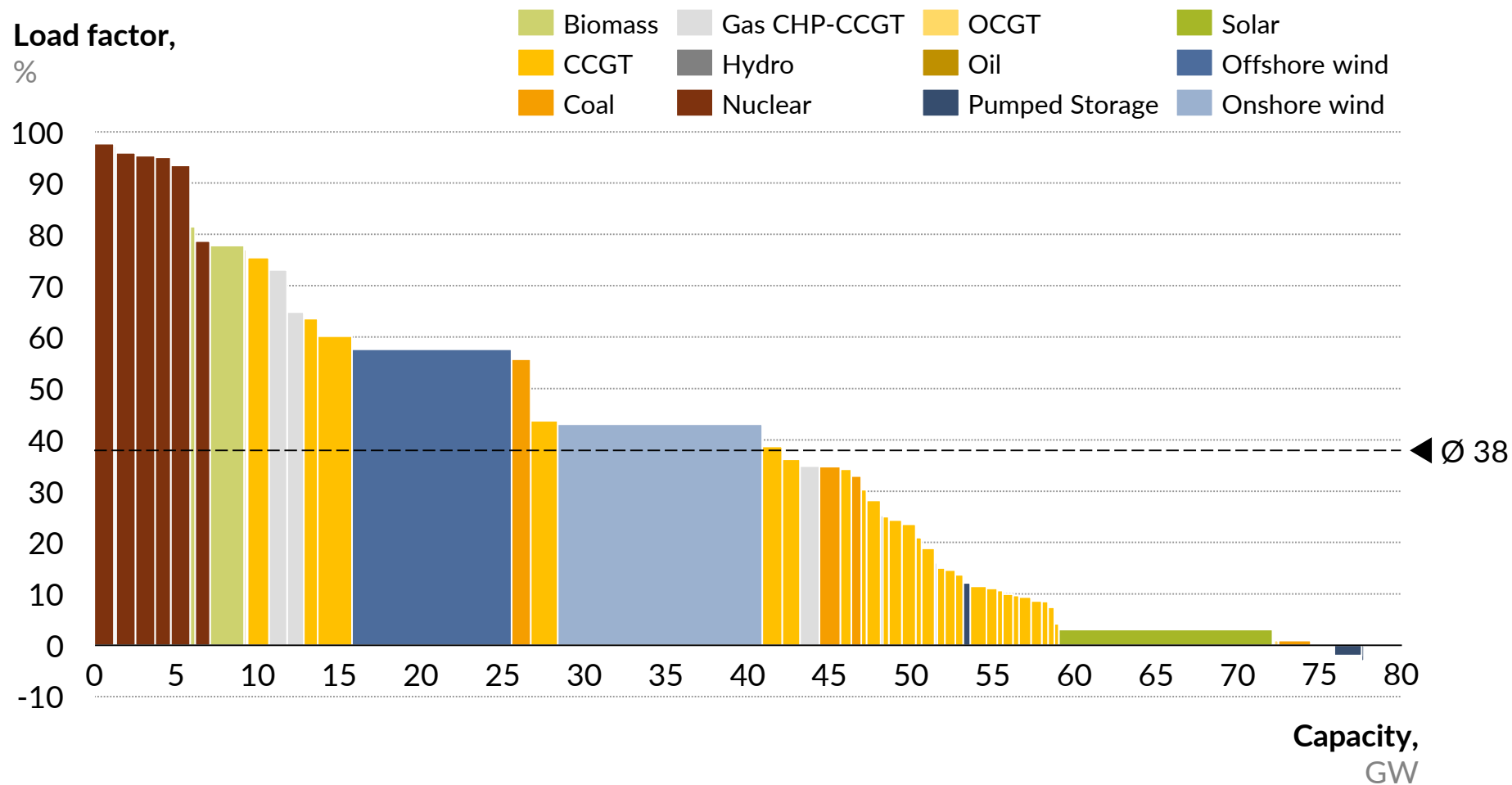
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Plant utilisation – load factors by plant (column width reflects capacity)



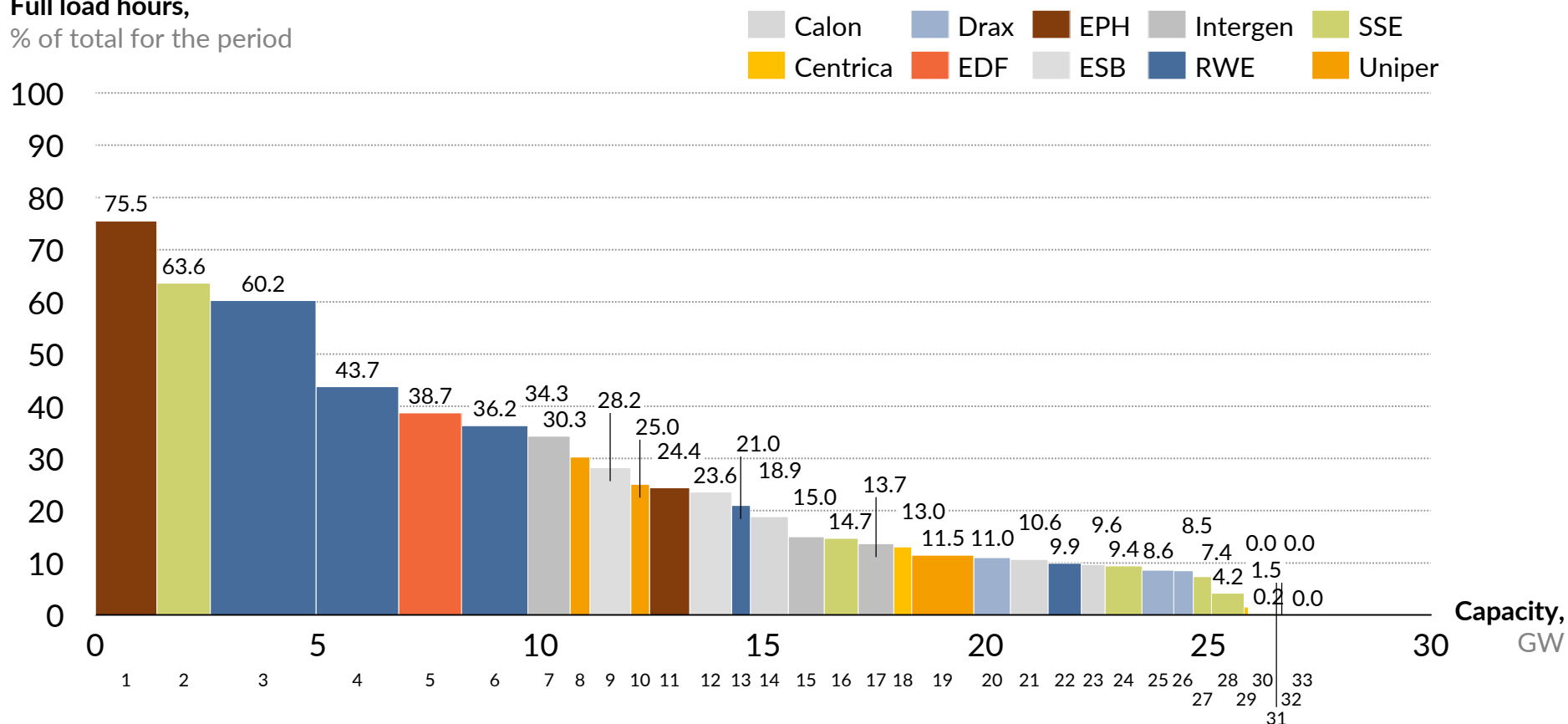
Represents 60 plants with highest capacity according to the Balancing Mechanism (BM) database, as well as aggregated data for wind and solar. Capacity of each plant represents the sum of capacities of all its generators that have been active at least once in the last three months.

Please refer to Appendix for a detailed description of the data used and categories presented.

CCGT plant utilisation – by plant, January 2020

Column width reflects capacity

Full load hours,
% of total for the period



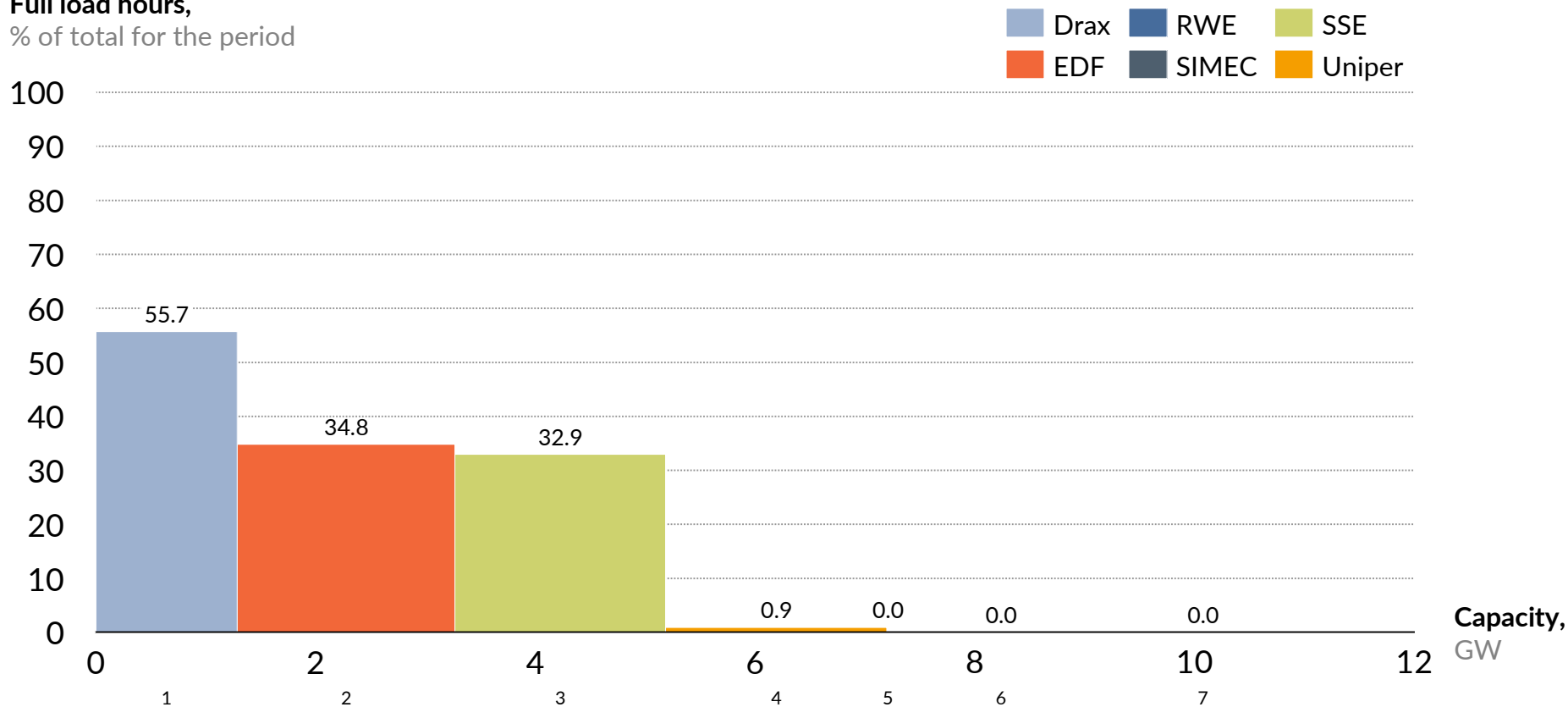
Plant Names: 1. South Humber Bank, 2. Peterhead, 3. Pembroke, 4. Staythorpe, 5. West Burton B, 6. Didcot B, 7. Spalding, 8. Cottam Dvpt Centre, 9. Marchwood, 10. Enfield Energy, 11. Langage, 12. Carrington, 13. Great Yarmouth, 14. Severn, 15. Rocksavage, 16. Keadby, 17. Coryton, 18. Kings Lynn, 19. Connahs Quay, 20. Damhead Creek, 21. Sutton Bridge, 22. Little Barford, 23. Baglan Bay, 24. Seabank 1, 25. Rye House, 26. Shoreham, 27. Seabank 2, 28. Medway, 29. Glanford Brigg, 30. Killingholme 2, 31. Killingholme 1, 32. Peterborough, 33. Corby.

Includes all CCGT plants of the presented companies that report to the Balancing Mechanism. Refer to Appendix B for ownerships in joint-ventured CCGT plants.

Coal plant utilisation – by plant, January 2020

Column width reflects capacity

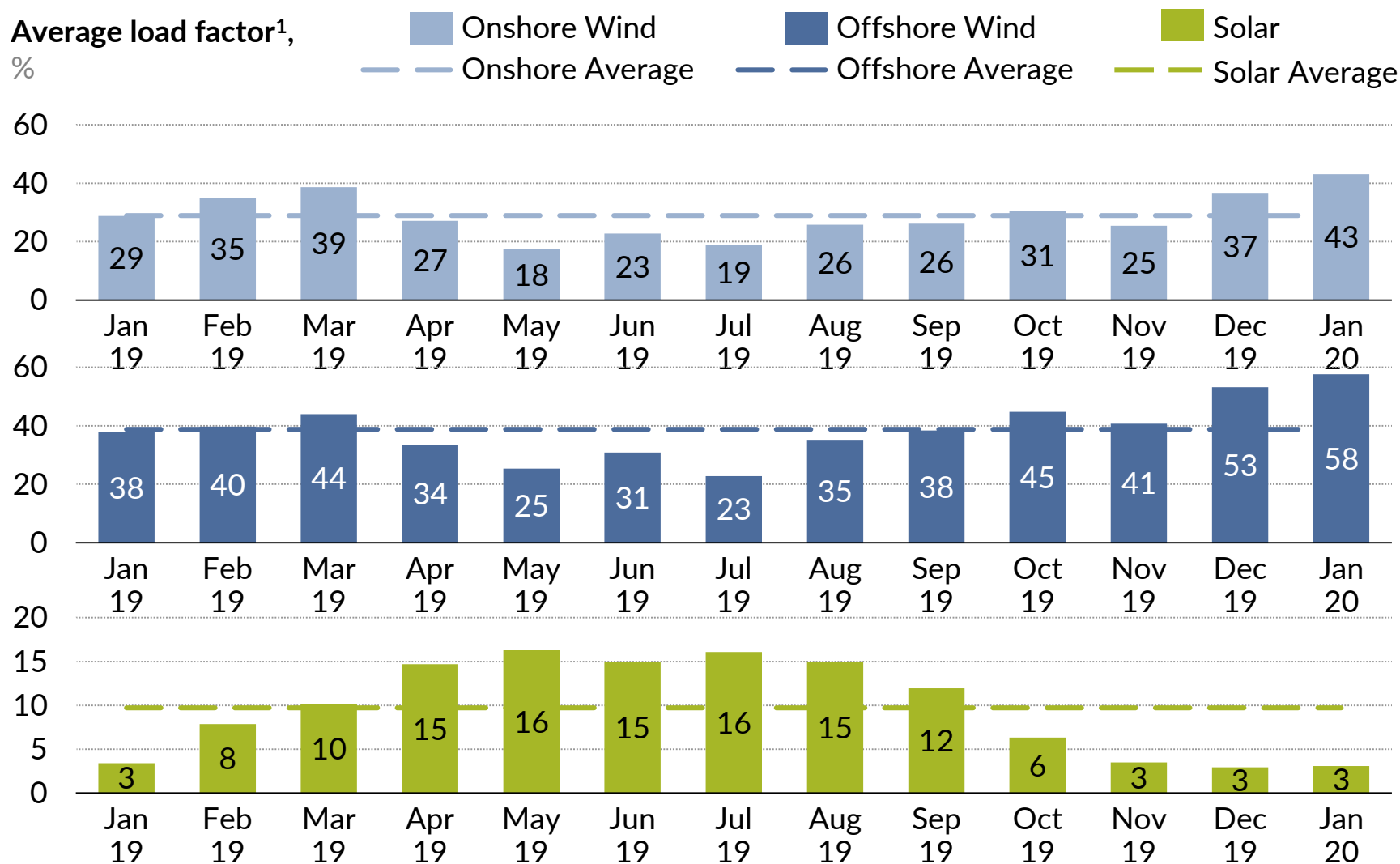
Full load hours,
% of total for the period



Plant Names: 1. Drax Coal, 2. West Burton, 3. Fiddlers Ferry, 4. Ratcliffe, 5. Uskmouth, 6. Cottam, 7. Aberthaw B.

Includes all coal plants of the presented companies that report to the Balancing Mechanism. Refer to Appendix B for ownerships in joint-ventured coal plants.

Monthly load factors by technology

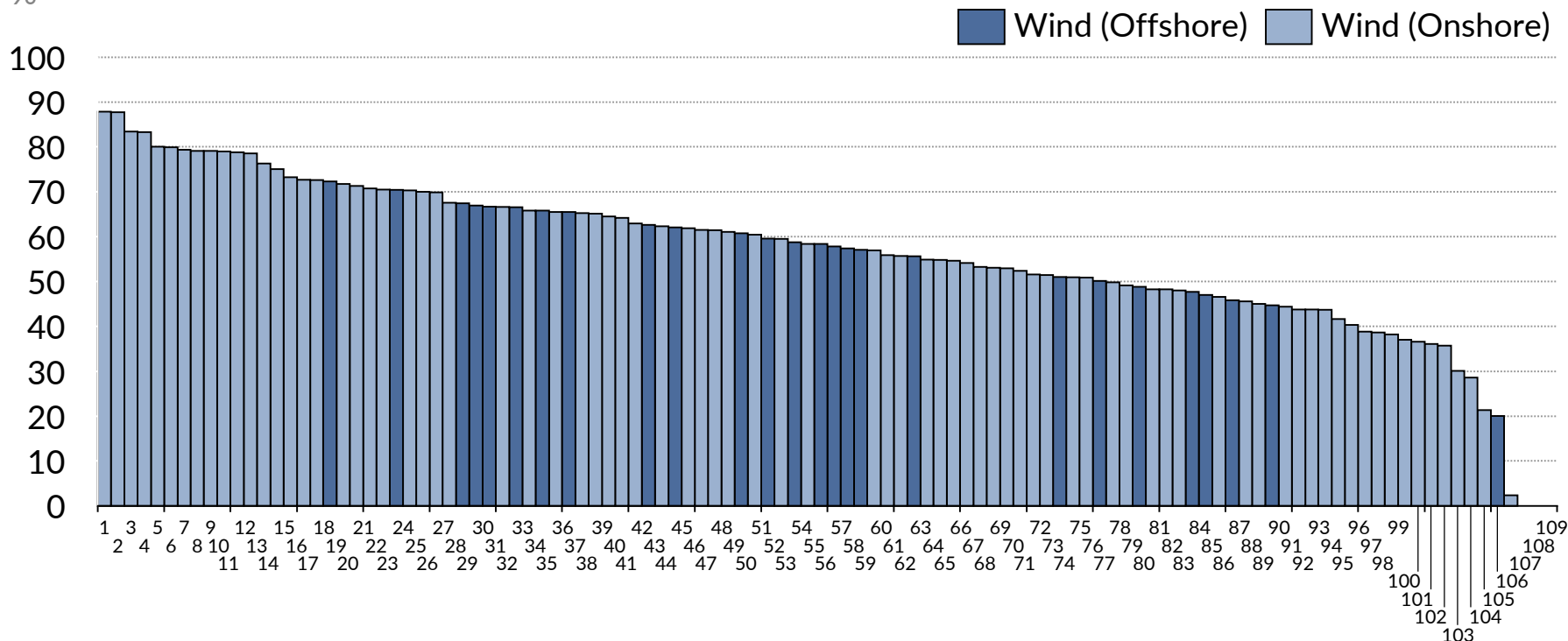


Notes: 1) Includes outputs from generators registered as BM Units as well as embedded wind and solar PV.

Wind farm utilisation – load factor by wind farm

Load factor,

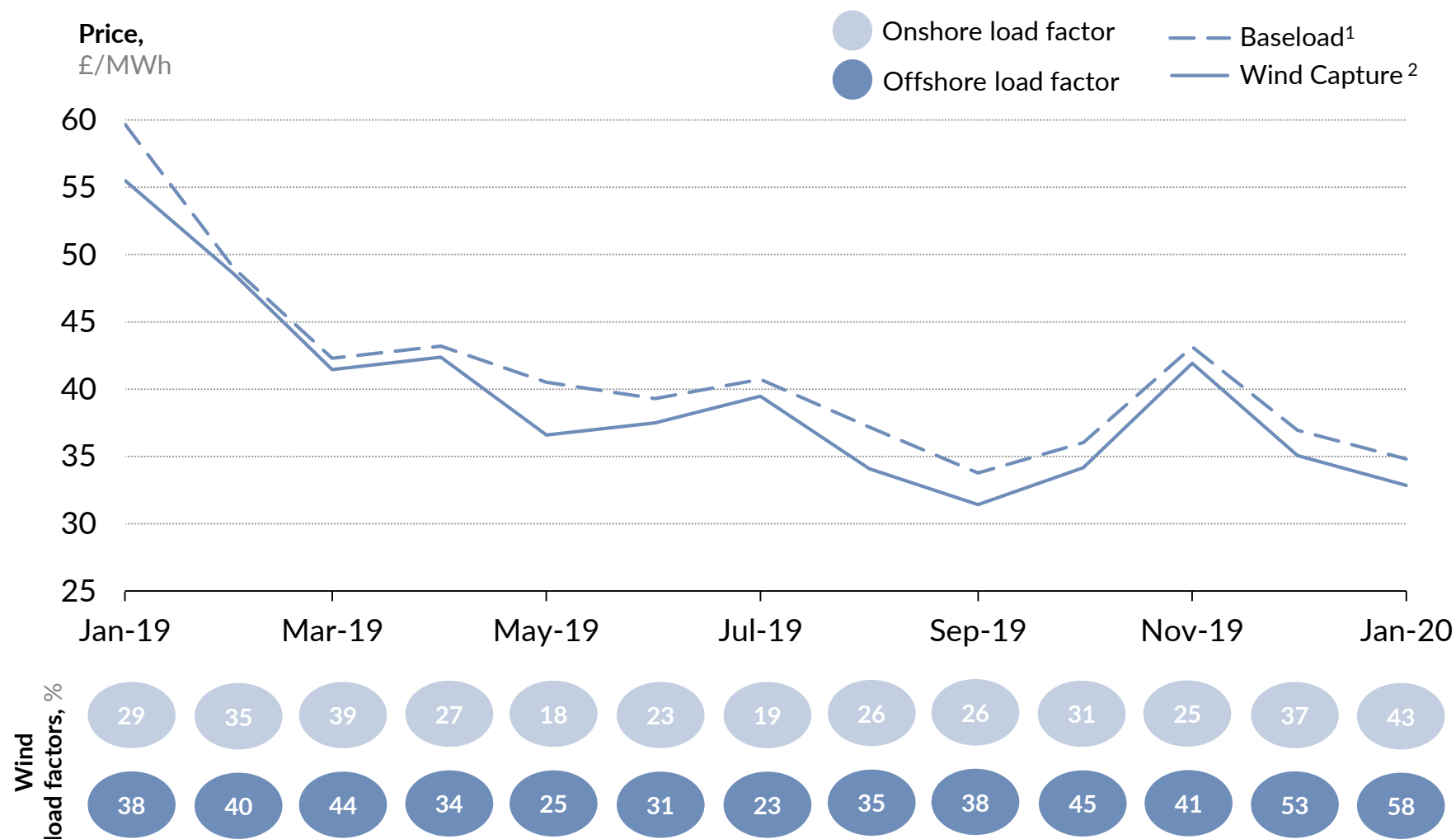
%



Plant Names: 1. Pauls Hill, 2. Corriegarth, 3. Dorenell, 4. Millennium, 5. Dunmaglass, 6. Aikengall 2, 7. Sanquhar Community, 8. Crystal Rig, 9. Fallago Rig, 10. Coire Na Cloiche, 11. Whiteside Hill, 12. Stronelairg, 13. Brockloch Rig 2, 14. Rothes, 15. Hill of Glaschyle, 16. Afton, 17. Middle Muir, 18. Hywind Scotland, 19. Auchrobert, 20. Carraig Gheal, 21. Cour, 22. Berry Burn, 23. Beatrice, 24. Bhlaraidh, 25. Andershaw, 26. Assel Valley, 27. Corriemoillie, 28. Dudgeon, 29. Hornsea 1, 30. Westernmost Rough, 31. Farr, 32. Sheringham Shoals, 33. Beinneun, 34. Walney Extension, 35. Blackcraig, 36. Race Bank, 37. Gordonstown, 38. Rothes Extension, 39. Kype Muir, 40. Galawhistle, 41. Bad a Cheo, 42. Humber, 43. Strathy North, 44. West of Duddon Sands, 45. Camster, 46. Brownieleys, 47. Lochluichart, 48. Kilbraur, 49. Walney, 50. Kilgallioch, 51. Galloper, 52. Toddleburn, 53. Greater Gabbard, 54. Edinbane, 55. Lincs, 56. London Array, 57. Gwynt y Mor, 58. Burbo Extension, 59. Minsca, 60. Tullymurdoch, 61. Freasdail, 62. Robin Rigg, 63. Baillie, 64. Clashindarroch, 65. Hare Hill Extension, 66. Griffin, 67. Harburnhead, 68. A Chruach, 69. Mid Hill, 70. Ewe Hill, 71. Dersalloch, 72. Beinn Tharsuinn, 73. Ormonde, 74. Tullo, 75. Gordonbush, 76. Gunfleet Sands, 77. Hill of Towie, 78. Arecleoch, 79. Aberdeen, 80. Whitelee, 81. Tullo Extension, 82. Beinn An Tuirc, 83. Burbo Bank, 84. Thanet, 85. Minnygap, 86. Rampion, 87. Burn of Whilk, 88. Clyde, 89. Barrow, 90. Black Law, 91. Pen y Cymoedd, 92. Dun Law Extension, 93. Glens of Foudland, 94. Glen App, 95. An Suidhe, 96. Braes of Doune, 97. Moy, 98. Dalswinton, 99. Harestanes, 100. Mark Hill, 101. Hadyard Hill, 102. Goole Fields, 103. Craig, 104. Clachan Flats, 105. Glenchamber, 106. East Anglia One, 107. Airies, 108. Kincardine, 109. Keith Hill.

Represents UK wind farms reporting Balancing Mechanism Unit data. Figures presented reflect Final Physical Notification (FPN) expectations reported to the grid, which are not always representative of actual production.

Wind capture price versus baseload price



1. Baseload price is the average monthly APX price.

2. Wind capture price is the load-weighted monthly average APX price across all wind Balancing Mechanism plants for all half-hourly periods.

Appendix A

Data used:

1. Output values used in this summary reflect the sum of Final Physical Notifications (FPN) submitted by all BM Units of a given plant that have been active over the last three months.
2. Capacity values used in this summary reflect the sum of capacities of individual BM Units, as reported to the Balancing Mechanism, that have been active over the last three months. They reflect long-term capacities and exclude temporary fluctuations due e.g. to plant failures or scheduled maintenance.
3. Prices used in this summary are the APX half-hourly Reference Prices for half-hourly, two-hourly and four-hourly spot products.

Categories presented:

1. Full-load hours represent the plants' load factors, calculated as the ratio of the output produced in a given month to the maximum possible output given the plants' capacity.
2. Running hours represent the proportion of time in a given month when a plant has been active, i.e. when at least one of its BM Units produced output greater than zero.
3. Capture prices (or average output-weighted prices) are calculated as an average of APX half-hourly prices per MWh weighted by the plants' corresponding half-hourly outputs for all periods.
4. Average gross margins are calculated as a sum of the uplift and inframarginal rent. Uplift is calculated as the difference between the APX price and the system marginal cost (SMC). SMC is the maximum marginal cost of all the plants with at least one generator producing above 80% of its installed capacity in a given half-hour.
5. Emissions are calculated as plant output divided by electrical efficiency, multiplied by theoretical carbon content of the fuel input. The carbon content of fuel inputs is sourced from DECC's *Greenhouse gas reporting – Conversion factors 2016*. System carbon intensity is calculated as the total emission divided by total electricity generated.

Appendix B

List of joint ventures in CCGT, coal and offshore wind:

CCGT plants:

Marchwood is co-owned by SSE (50%) and Munich Re (50%);
Deeside is co-owned by Engie (75%) and Mitsui (25%);
Seabank 1 is co-owned by SSE (50%) and Cheung Kong Infrastructure Holdings (50%).
Seabank 2 is co-owned by SSE (50%) and Cheung Kong Infrastructure Holdings (50%).

Coal plants:

Eggborough is co-owned by EPH (90%) and Engie (10%);
Rugeley is co-owned by Engie (75%) and Mitsui (25%).

Offshore wind farms:

Gwynt y Mor is co-owned by RWE (60%), Stadtwerke Muenchen (30%) and Siemens (10%);
Greater Gabbard is co-owned by SSE (50%) and RWE (50%);
London Array is co-owned by E.ON (30%), DONG (25%), the Caisse (25%) and Masdar (20%);
Gunfleet Sands is co-owned by DONG (50.1%), Marubeni (24.95%) and Development Bank of Japan (24.95%);
Walney is co-owned by DONG (50.1%), SSE (25.1%) and PGGM & Dutch Ampere Equity Fund (24.8%);
Sheringham Shoals is co-owned by Statkraft (40%), Statoil (40%) and Green Investment Bank (20%);
Lincs is co-owned by Centrica (50%), Siemens (25%) and DONG (25%);
West of Duddon Sands is co-owned by DONG (50%) and Scottish Power (50%);
Westermest Rough is co-owned by DONG (50%), Marubeni (25%) and Green Investment Bank (25%).

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