Programme Area: Energy Storage and Distribution

Project: 2030 Electricity Price Time Series

# Title: Modelling of hourly retail cost stacks in 2030 under three scenarios


## Abstract:

This deliverable is a slide pack which is the final technical report from the work carried out on this project.


## Context:

This knowledge building project aims to outline a number of price scenarios for the retail price of electricity across a number of different energy vectors in 2030. This project, delivered by Baringa, builds on their existing time series of hourly supplier electricity costs for 2030. They delivered an hourly electricity price series for 2030 based on traceable assumptions for three different 2030 supply-demand scenarios. The key objectives were:

- To investigate the costs that domestic electricity suppliers in Great Britain might face in 2030.
- To make projections on the assumption that, unless formally announced, no changes are made to the electricity market arrangements in place today
- To focus in particular on the hourly variation and seasonal shape of supplier costs

# GB Future Retail Electricity Supplier Costs

Technical Report:
Modelling of hourly retail cost stacks in 2030 under three scenarios

**ETI**

22/11/2018

# Executive summary

# Executive summary – Objective and approach

- **Study objectives**
  - This study investigates the costs that domestic electricity suppliers in Great Britain might face in 2030
  - Projections are made based on the assumption that, unless formally announced, no changes are made to today's electricity market arrangements
  - Particular focus is given to the hourly variation and seasonal shape of costs faced by suppliers
  - Hourly retail cost stacks in 2030 are modelled for the average domestic electricity consumer in the East Midlands
- Modelling was carried out under three scenarios:
  1. **National Grid Two Degrees (NG 2 Degrees):** *A relatively high demand scenario, with relatively high renewables, nuclear and imports, but reduced levels of CCGT*
  2. **ETI Long-Term Role of Gas (ETI LT ROG):** *The highest-demand scenario modelled, with high levels of renewables, CCGT and storage, but reduced nuclear capacity*
  3. **ETI Consumers, Vehicles and Energy Integration (ETI EVEI):** *With demand the lowest of the three, this scenario has the highest levels of nuclear, but the lowest levels of renewables and storage*
- These scenarios were drawn from public sources, and were chosen to represent a range of carbon intensities and levels of renewable generation, as well as different levels of electrification (e.g. of transport) and flexible demand
- The modelling outputs are intended to illustrate:
  1. **Trends in supplier costs** that might occur between 2017 and 2030 if market arrangements remain unchanged
  2. **Differences between scenarios** that can be seen, reflecting different technology and market assumptions
  3. **Issues that could result** if arrangements remain unchanged over horizon to 2030
- This Technical Report is one of the deliverables associated with this stage of the project. Associated deliverables are:
  - A word document providing interpretation of the findings in this slide deck
  - A high level viewpoint for senior stakeholders summarising the work, results and insights
  - An Excel workbook containing the key inputs and a full set of hourly outputs by scenario

# Executive summary – Headline results

| Scenario-average trends to 2030 (real 2017 prices) | | 2017 (£/MWh) | 2030 Δ (£/MWh) | 2030 Δ (%) |
|---|---|---|---|---|
| Overall | Load-weighted annual average supplier costs increase by 2030 | 141 | +43 | 30% |
| Wholesale price | The wholesale price component increases, primarily driven by commodity price rises, mainly for carbon permits and gas. | 48 | +12 | 25% |
| Network charges | Increases in both DUoS and, in particular, TNUoS. | 33 | +12 | 36% |
| Green & social levies | A small decrease in the RO is more than offset by support via CfDs. Combined with other smaller changes, the cost of these levies sees an increase. | 26 | +9 | 34% |
| CM charges | The Capacity Market went live in October 2017 at a price of £6.95/kW. The cleared volume is expected to remain steady but the price is expected to rise to £49/kW. | 1* | +8 | 877% |
| Other costs | BSUoS, T&D losses and supplier operating costs are projected to remain steady. | 33 | +2 | 6% |

| Scenario-specific results (real 2017 prices) | | | |
|---|---|---|---|
| Scenario | NG 2 Degrees | ETI LT ROG | ETI CVEI |
| Average 2030 cost | £184/MWh | £173/MWh | £194/MWh |
| Headline findings | High low-carbon capacity leads to the lowest wholesale costs, but also to high CfD and CM costs. Net imports (treated as zero carbon) are also increased significantly due to the higher interconnection and lower internal flexible gas capacity, resulting in the lowest carbon intensity of the three cases. | Lower nuclear and higher CCGT generation leads to greater wholesale costs than NG 2 Degrees but the lowest CfD costs. With the highest demand, this scenario spreads other costs (e.g. network charges and supplier operating costs) over a larger consumption base, reducing the per-unit cost. | Wholesale costs are the highest of the three scenarios, and enable lower bid prices in the CM. However, the low demand means that fixed costs (e.g. network costs and operating costs) are recovered through higher per-unit supplier charges. |

* CM charges only applied for the last 3 months of 2017

# Executive summary – Key findings

Hourly price variation is increasingly driven by administered charges such as Capacity Mechanism and Transmission Network Use of System charges. As a result, 2030 is dominated by cost signals that are static (fixed or time-based), overwhelming signals (e.g. wholesale prices) that are more dynamic.

The lowest demand scenario has the higher per-MWh supplier costs, since fixed and sunk costs need to be recovered.

Carbon intensity is lowest in the scenario with high installed capacity of low-carbon generation, particularly where that capacity has a high load factor (e.g. nuclear).

Imports are highest where there is a large interconnection capacity and low flexibility to address peaks, or where the GB wholesale price is relatively high. Imports are treated as zero carbon, but the overall impact on emissions will depend on the technologies and carbon budgets that apply in the exporting countries.

# Introduction, approach and scenario assumptions

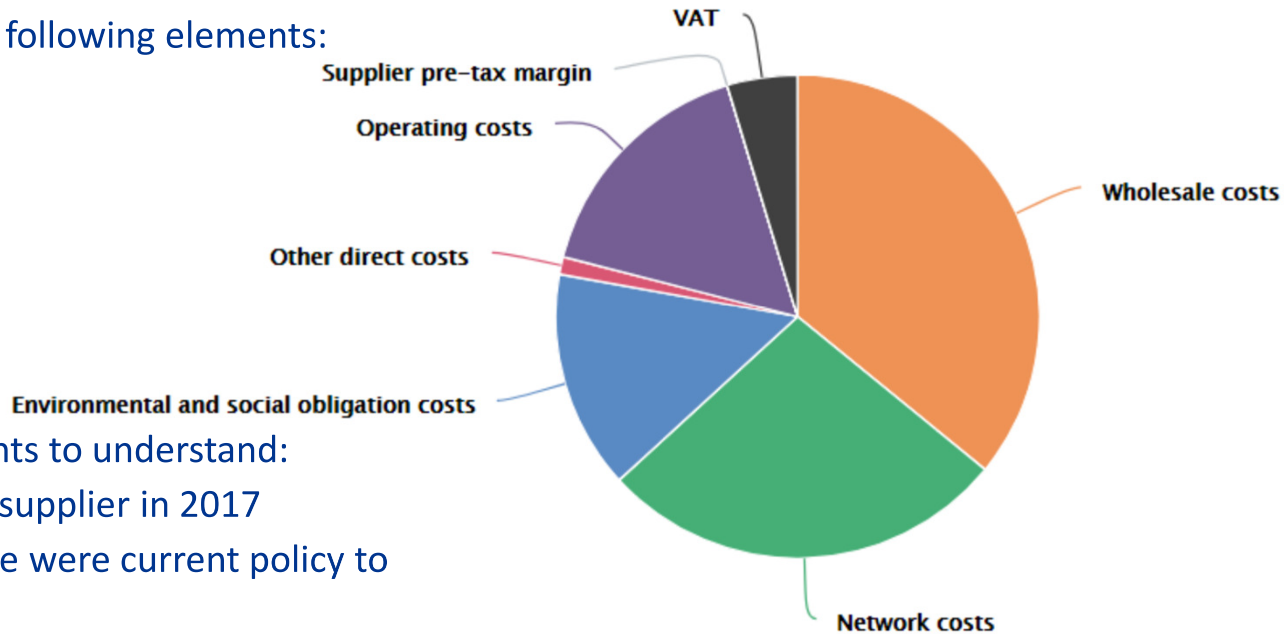
# Contents

Baringa

# Introduction

## This study seeks to understand supplier cost stack and provide projections for 2030

- The amount that a domestic consumer pays for electricity depends on the amount of electricity they consume and the tariff agreed with their electricity supplier
- Suppliers offer a range of tariffs, covering fixed and variable prices, and including different combinations of standing charges and per-kWh consumption charges
- Underlying all of these tariffs, however, are costs that a supplier must meet in order to supply electricity to its customers
- The larger suppliers are obliged to report on these costs
- Consolidated Segmental Statements identify the following elements:
  - Wholesale costs
  - Network costs
  - Environmental and social obligation costs
  - Other direct costs
  - Operating costs
- This study investigates each of these cost elements to understand:
  - The breakdown of costs faced by a domestic supplier in 2017
  - How each element might change in the future were current policy to remain in place
  - What a typical future supplier cost stack may look like in 2030 on this basis under a number of market scenarios

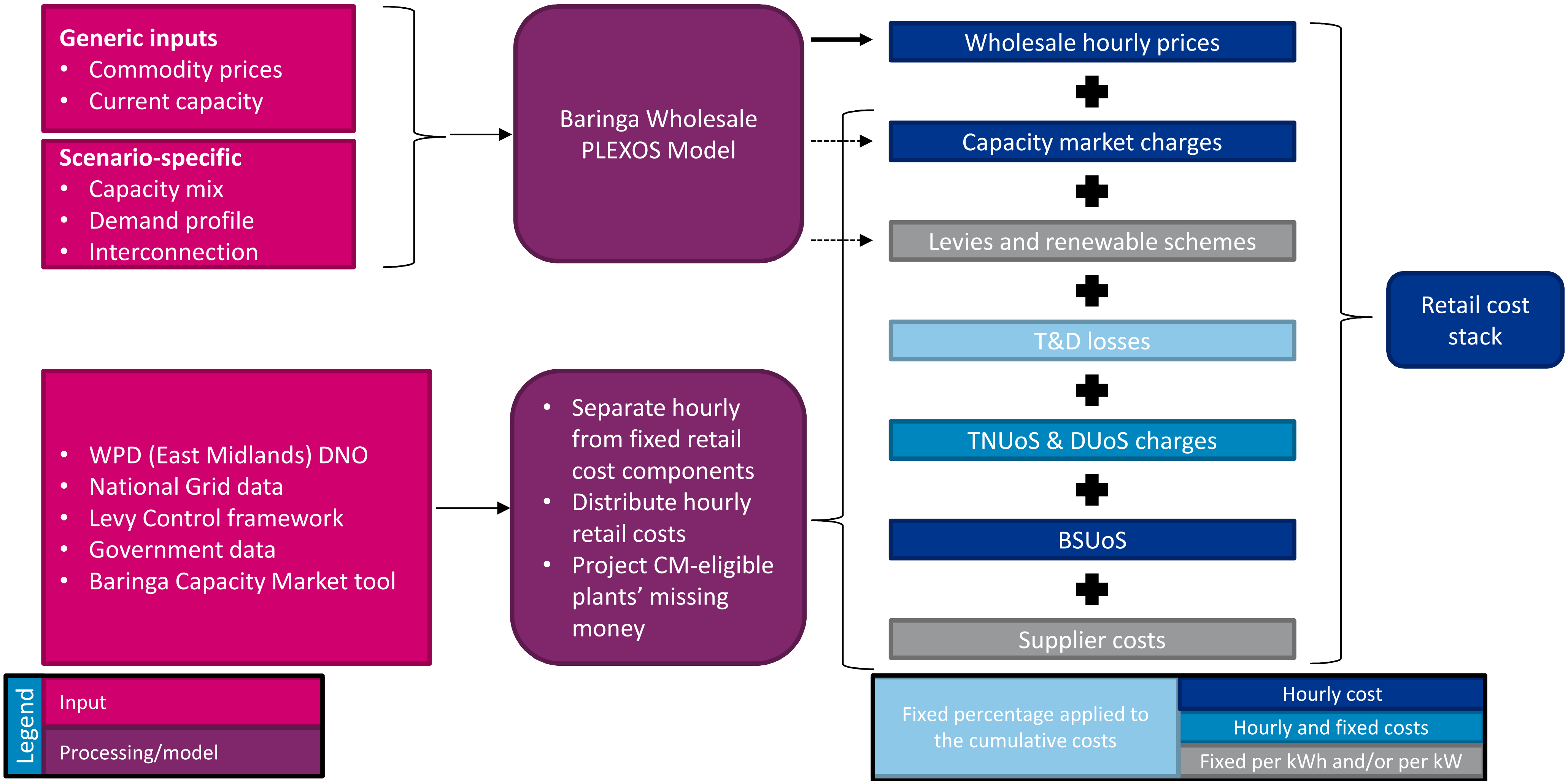



**2016 summary for 'Big 6' suppliers (2016/17 for SSE)**
Source: https://www.ofgem.gov.uk/gas/retail-market/retail-market-monitoring/understanding-profits-large-energy-suppliers

# Retail cost stack logic

## The retail cost stack components are generated by modelling wholesale costs then incorporating non-wholesale retail cost elements, some of which depend on the wholesale costs

- This diagram illustrates how the modelled retail cost stack was constructed from its constituent cost elements, and indicates at a high level the modelling used to generate the hourly cost data, and the sources of the inputs



# Introduction to scenarios

## Publicly available scenarios were selected that included a range of carbon intensities, renewable generation, levels of electrification (e.g. of transport) and flexible demand

### Current situation and back-cast 2017

- Publicly available information was used to estimate the hourly retail cost stack for the average domestic consumer in East Midlands in 2017 in order to be able to compare it with the three 2030 scenarios
- In 2017, gas capacity supplied half of demand, with renewables contributing almost one quarter
- Renewables are supported by a mix of RO, FiTs and CfDs with RO representing by far the largest cost of the three
- CM charge based on £6.95/kW clearing price but only applying for during Q4 of 2017, when the scheme began
- The average resulting retail cost was determined to be £140/MWh, which is similar to the 'Big 6' CSS figures

### National Grid Two Degrees

- National Grid Two Degrees scenario is the main decarbonisation scenario of National Grid
  - http://fes.nationalgrid.com/fes-document/fes-2017/
- The scenario assumes "a world where environmental sustainability is top priority". The scenario meets the 2050 carbon reduction targets for the UK.
- Annual demand is assumed to be 358 TWh with significant flexibility from EVs and HPs. Renewable sources supply the 60% of the load and nearly no new gas baseload capacity is built.
- CfD budget increases significantly in order to incentivise low carbon technologies. CM charge also adds to the retail cost stack.

### ETI Long-Term Role of Gas

- ETI LT ROG is a scenario that uses ESME v4.2 inputs and PLEXOS LT Plan to determine the cost-optimal pathway for GB towards 2050
- The assumed annual demand is the highest of the three scenarios (370 TWh)
  - Demand flexibility is lower compared to the NG 2 Degrees
- Renewable generation supplies nearly half of the load. Gas penetration remains at current levels. As a consequence, the carbon intensity is the highest amongst the three scenarios.
- The CfD costs are the lowest amongst the three scenarios

### ETI Consumers, Vehicles and Energy Integration

- This is an adapted version of the OEM Innovation scenario from the ETI CVEI scenario, based on ESME v4.0. The adapted scenario has taken into account recent deployments in intermittent renewable capacity and coal retirement.
- Annual demand is the lowest of the three scenarios (at 312 TWh) which has an impact on many of the retail cost elements which have a fixed budget/cost and are spread over a lower demand
- Renewable generation meets just above 40% of the load
- CfD costs are high due to significant nuclear capacity additions but the CM charge is the lowest of the three scenarios as generators are able to secure more revenue from the wholesale market

# Scenario demand assumptions

- The next three slides summarise the demand assumptions underpinning each of the modelled scenarios
  - Where available, assumptions about the sources of demand growth have been drawn from the public domain
  - In each scenario, the demand for electricity is higher than in 2017, driven primarily by the adoption of Electric Vehicles (EVs) and Heat Pumps (HPs)
  - Whilst these impose new loads on the electricity network, they also have the potential to be flexible, which has been reflected in the modelling

- In defining hourly system load for each scenario, the following variables have been considered:
  - **Annual demand:** the overall demand for electricity across 2030
  - **Inflexible hourly demand shape:** the way in which the majority of the load is shaped across each day and across the year, excluding the demand from flexible EVs and HPs
  - **Flexible EV and HP demand:** the number of EVs and HPs, and the proportion of these that can be considered as flexible, meaning that their load can be shifted across the day in response to price signals

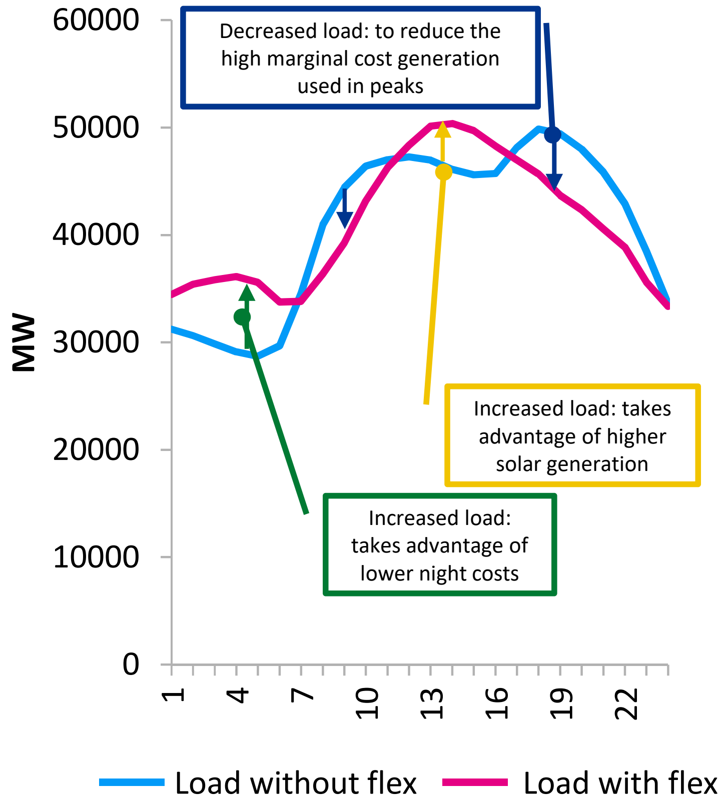
- The resulting **hourly demand**, therefore, sums up to the annual demand and has a largely predictable shape, but that shape is partly adjusted to reflect the fact that a proportion of the demand will be shifted dynamically from high-price periods to low-price periods

# Electricity demand assumptions – NG 2 Degrees

## Annual demand of 358 TWh with significant flexibility from EVs and HPs

- **Annual demand**
  - Annual demand assumptions consistent with the National Grid FES 2017 scenarios
  - Electric Vehicle (EV) and Heat Pump (HP) load is subtracted to be reintroduced as flexible demand
- **Hourly shape of demand excluding the EV and HP**
  - Hourly shape based on the NG 2 Degrees demand profile for 2012 (base year)
  - 8760 hour demand profile (excluding EV and HP) created by scaling to 312 TWh for annual demand and 57.4 GW for peak demand, in line with the scenarios assumptions
- **Flexibility**
  - It is assumed that there are two main sources of demand-side flexibility:
    - **EVs:** Based on the scenario assumptions, 80% of the EV load is flexible. This can be distributed across the day in a way that minimises the total system cost
    - **HPs:** 25% of the heat pumps are assumed to be flexible, in line with the scenario assumptions
- **Hourly demand**
  - 'Demand Requirement' represents the demand that would be observed if there were no flexibility on the system
  - The System Load is the resulting demand when the EV and HP flexibility is taken into account
  - The System Load plot effectively shifts demand into the night where there is lower demand and towards the midday hours where there is high solar generation

| | Annual Demand (GWh) |
|---|---|
| Total | 357,783 |
| Total (excl EVs & HPs) | 312,376 |
| EVs | 21,277 |
| HPs | 24,130 |

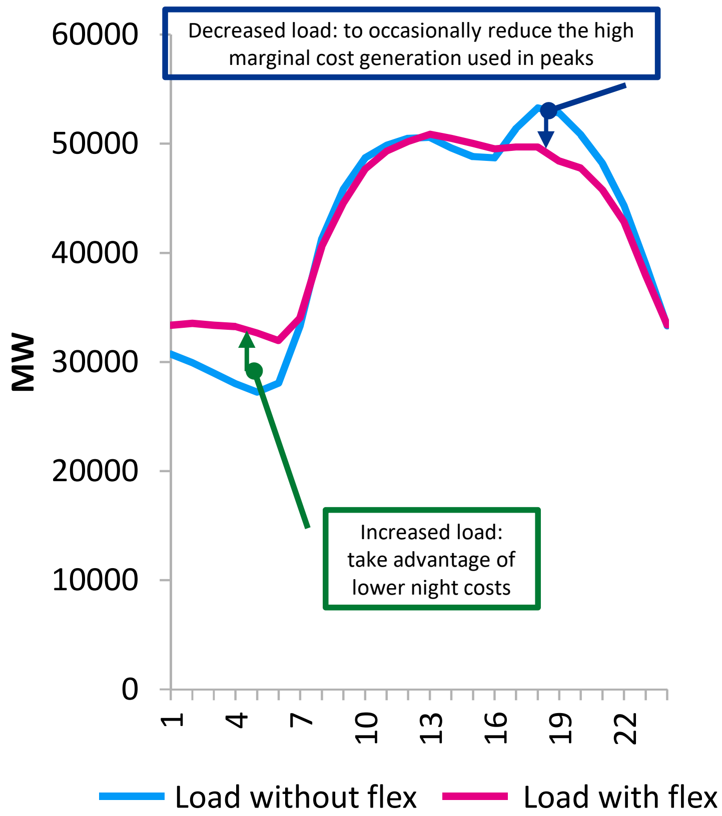


# Electricity demand – ETI LT ROG

## Highest annual demand (370 TWh) but demand flexibility is lower than NG 2 Degrees

- **Annual demand**
  - Annual demand is based on the central scenario of the CCC's report "Sectoral scenarios for the Fifth Carbon Budget", with the Northern Ireland component removed
  - EVs load is subtracted from the total electricity demand
- **Hourly shape of demand excluding the EV**
  - Hourly shape is based on the output electricity demand characteristic days from ESME v4.0. Historical demand profiles and the patterns of the ESME v4.0 demand are used to derive a 8,760 hour demand profile
- **Flexibility**
  - It is assumed that there are two main sources of flexibility:
    - **EVs:** Based on the scenario assumptions, 50% of the EV load is flexible. 50% of the EV daily load can be distributed across the day to minimise the total system cost
    - **HPs:** HP flexibility reflects broad Time of Use Shifting, rather than detailed hourly optimisation of load
- **Hourly demand**
  - The system load effectively shifts demand from the morning and evening peaks to the night time in order to reduce the high marginal cost generation

| | Annual Demand (GWh) |
|---|---|
| Total | 369,760 |
| Total (excl EVs) | 357,687 |
| EVs | 12,073 |

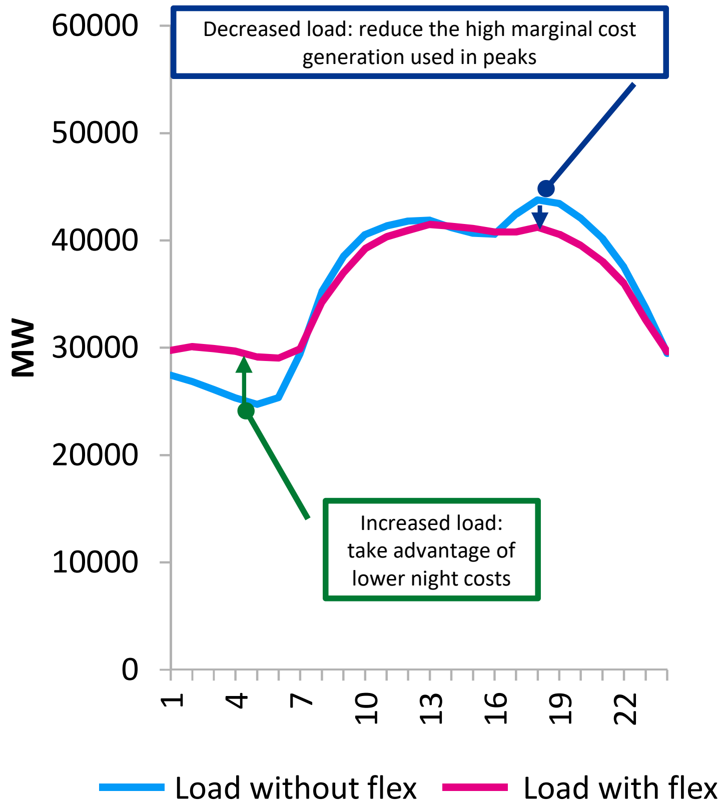


# Electricity demand – ETI CVEI

## Annual demand is the lowest of the three scenarios (at 312 TWh) which has an impact on many of the retail cost elements which have a fixed budget/cost and are spread over a lower demand

- **Annual demand**
  - Annual demand is based on the OEM Innovation scenario from ETI CVEI, based on ESME v4.0
  - EV load is subtracted from the total electricity demand
- **Hourly shape of demand excluding the EV**
  - The hourly shape of the non-EV demand is based on the ETI LT ROG scenario scaled to align with the annual demand assumptions under ETI CVEI
- **Flexibility**
  - It is assumed that there are two main sources of flexibility:
    - **EVs:** Based on the scenario assumptions, 50% of the EV load is flexible. 50% of the EV daily load can be distributed across the day to minimise the total system cost
    - **HPs:** HP flexibility reflects broad Time of Use Shifting, rather than detailed hourly optimisation of load
- **Hourly demand**
  - The system load effectively shifts demand from the morning and evening peaks to the night time in order to reduce the high marginal cost generation

| | Annual Demand (GWh) |
|---|---|
| Total | 312,088 |
| Total (excl EVs) | 292,099 |
| EVs | 19,990 |



# Inputs – Installed capacity

Electricity demand is higher than today in all 2030 scenarios, but the extent of electrification and the capacity mix differs

- **NG 2 Degrees**

  *High renewables, nuclear and imports, reduced CCGT*

  - Significant nuclear capacity additions in the late 2020s allow for capacity to remain at similar levels to 2017
  - Wind and solar capacity increase significantly, more than doubling between today and 2030
  - With no CCGT or OCGT additions by 2030, capacity reduces by approximately 10 GW, driven by the large low carbon capacity additions.

- **ETI LT ROG**

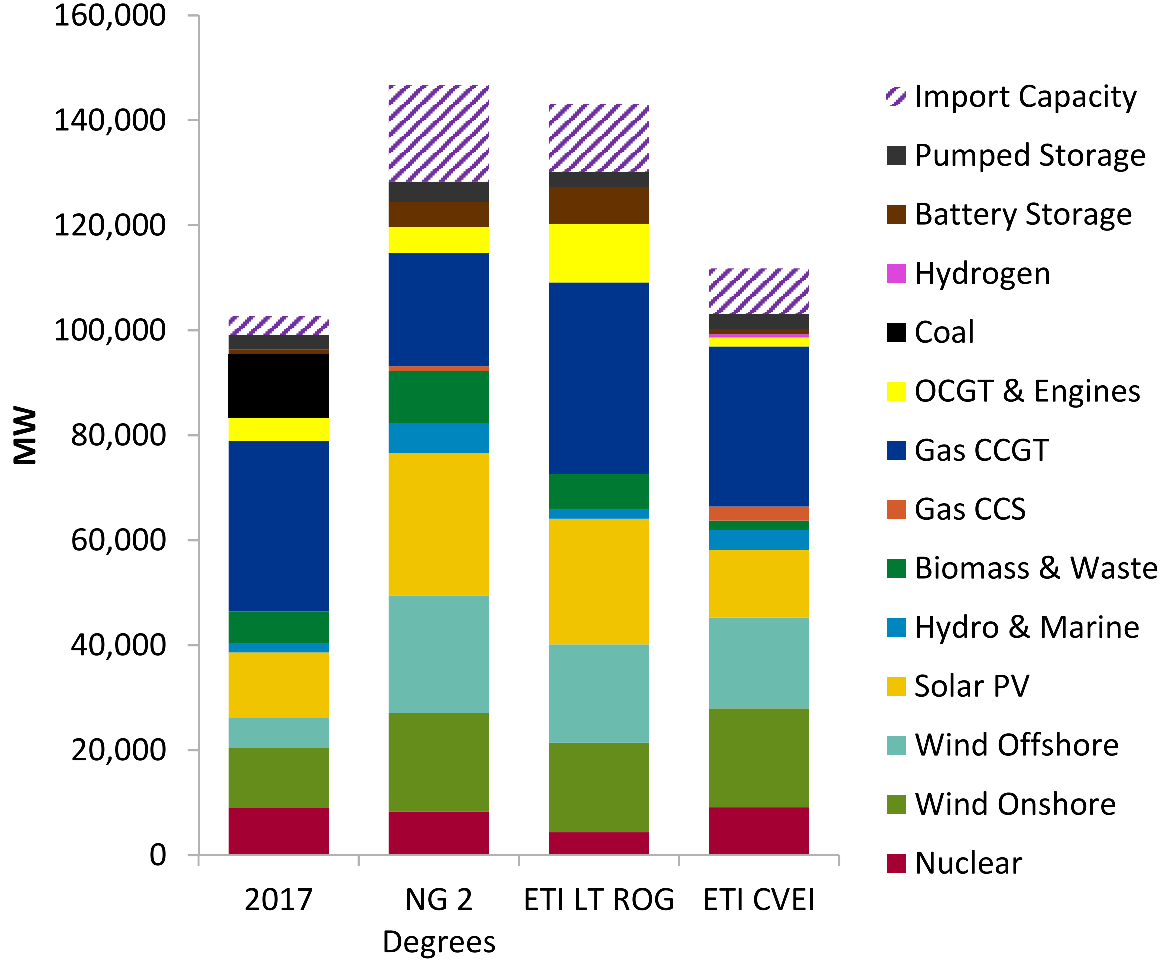
  *High renewables, CCGT and storage, reduced nuclear*

  - Nuclear: Only Hinkley Point C is built by 2030 and as a result capacity reduces to 4.3 GW
  - Wind and solar capacity increase to similar but slightly lower levels compared to NG 2 Degrees
  - CCGT new build raises capacity to 36 GW, whist OCGT capacity more than doubles to 11 GW
  - Storage capacity reaches 7 GW by 2030

- **ETI CVEI**

  *Highest nuclear case, lowest renewables and storage*

  - Nuclear capacity is assumed to reach 9.1 GW by 2030
  - Solar capacity remains at low levels and wind capacity similar to the other cases
  - Gas CCGT capacity decreases slightly by 2030 to 30 GW, putting it between the other two scenarios



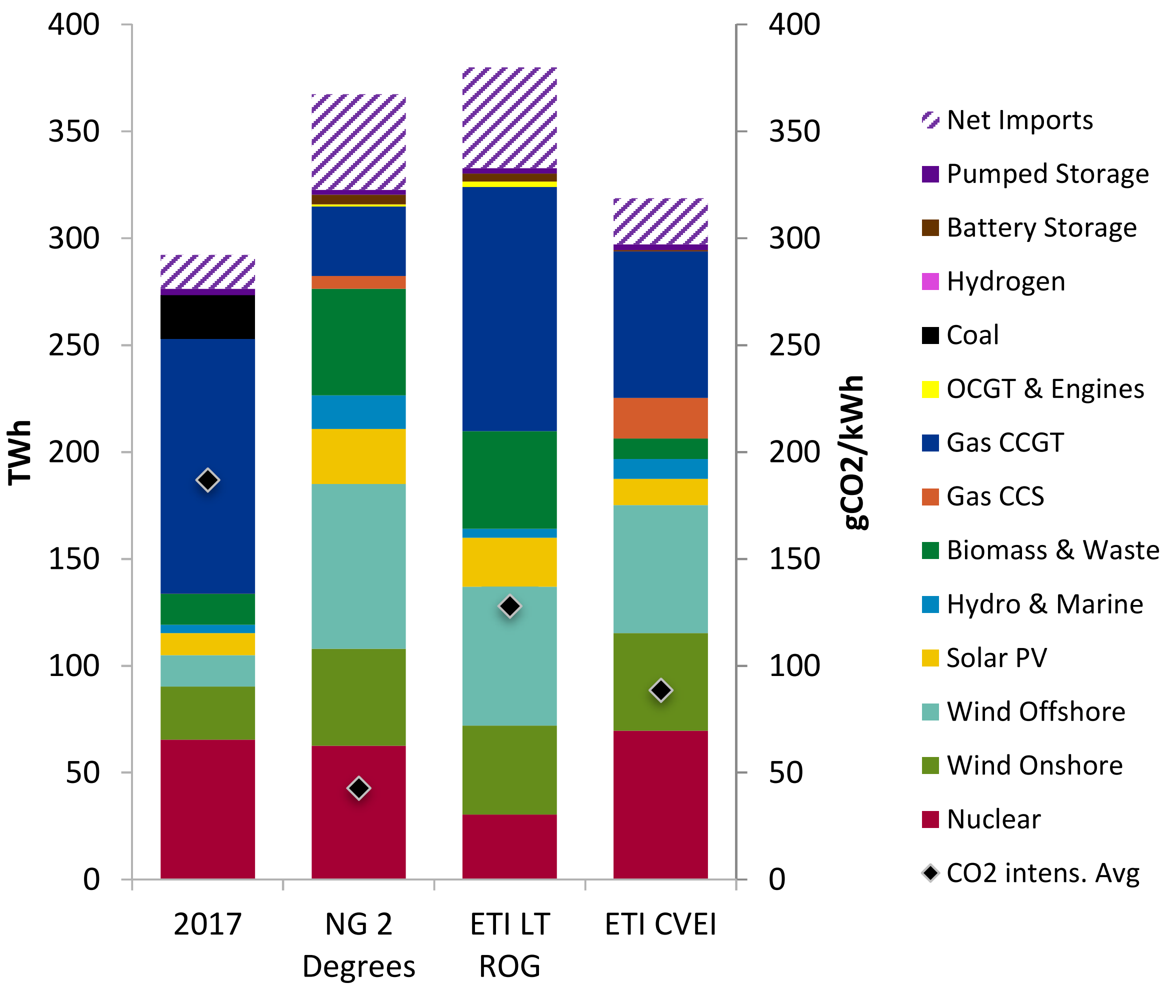
# Summary of cost element assumptions

| | 2017 | 2030 |
|---|---|---|
| **Wholesale cost** | Combination of public data and Baringa's own assumptions | Consistent with each scenario where explicit, incorporating other public sources where available and otherwise using Baringa's own assumptions |
| **BSUoS** | Actual hourly Balancing Services Use of System (BSUoS) data provided by National Grid | Average BSUoS from 2016/17 with hourly shape derived from 4 years' historic data. Assumed to be unchanged between today and 2030 |
| **Losses** | Transmission losses partly reflected in wholesale price, and partly taken from ELEXON Transmission Loss Multipliers. Distribution Loss Factors taken from WPD East Midlands. | Assumed unchanged from today |
| **DUoS** | Published 2017/18 WPD East Midlands Distribution Use of System (DUoS) charges for domestic customers | WPD RIIO-ED1 Business Plan used to estimate increase in allowed revenue, showing increases in reinforcement and condition-related expenditure, holding other costs flat |
| **TNUoS** | Transmission Network Use of System (TNUoS) Zone 7 (East Midlands) 2017/18 NHH tariffs | NG 5-year non-half-hourly projections used to estimate growth rate. First year excluded in order to discount step change in approach. |
| **AAHEDC** | Assistance for Areas with High Electricity Distribution Costs (AAHEDC) tariff provided by National Grid | Assumed unchanged from today |
| **CMSC** | £380m 2017/18 budget based on £6.95/kW clearing price and modelled demand, only applies from October onwards | Baringa model uses Wholesale Price model, and assumes plant use Capacity Market bids to attempt to recover 'missing money' |
| **RO** | Historical data from OFGEM to calculate the annual Renewables Obligation (RO) budget | RO budget for 2030 considers capacity first accredited after 2010, reflecting the 20 year limit on support |
| **FiT** | Historical data from the 2016 government document "Consumer Funded Policies" and Ofgem FiT annual reports | Projection based on 20 year FiT period for most systems, 25 years for pre-August 2012 solar PV and 10 years for micro-CHP |
| **CfD** | Asset data from CfD register combined with wholesale modelling to generate CfD Reference Price | Offshore Wind receives CfD to allow upfront cost recovery, and nuclear receives 20% less than Hinkley Point C. No other technologies eligible. |
| **ECO** | Government statistics on historic data | Assumed unchanged, based on intention to retain until at least 2028 |
| **Operating costs** | Supplier operating costs from Consolidated Segmental Statements submitted to Ofgem | Delta on CSS based on projected impact of smart metering. Impact of changing supplier mix not modelled. |

# Results overview

# Annual generation

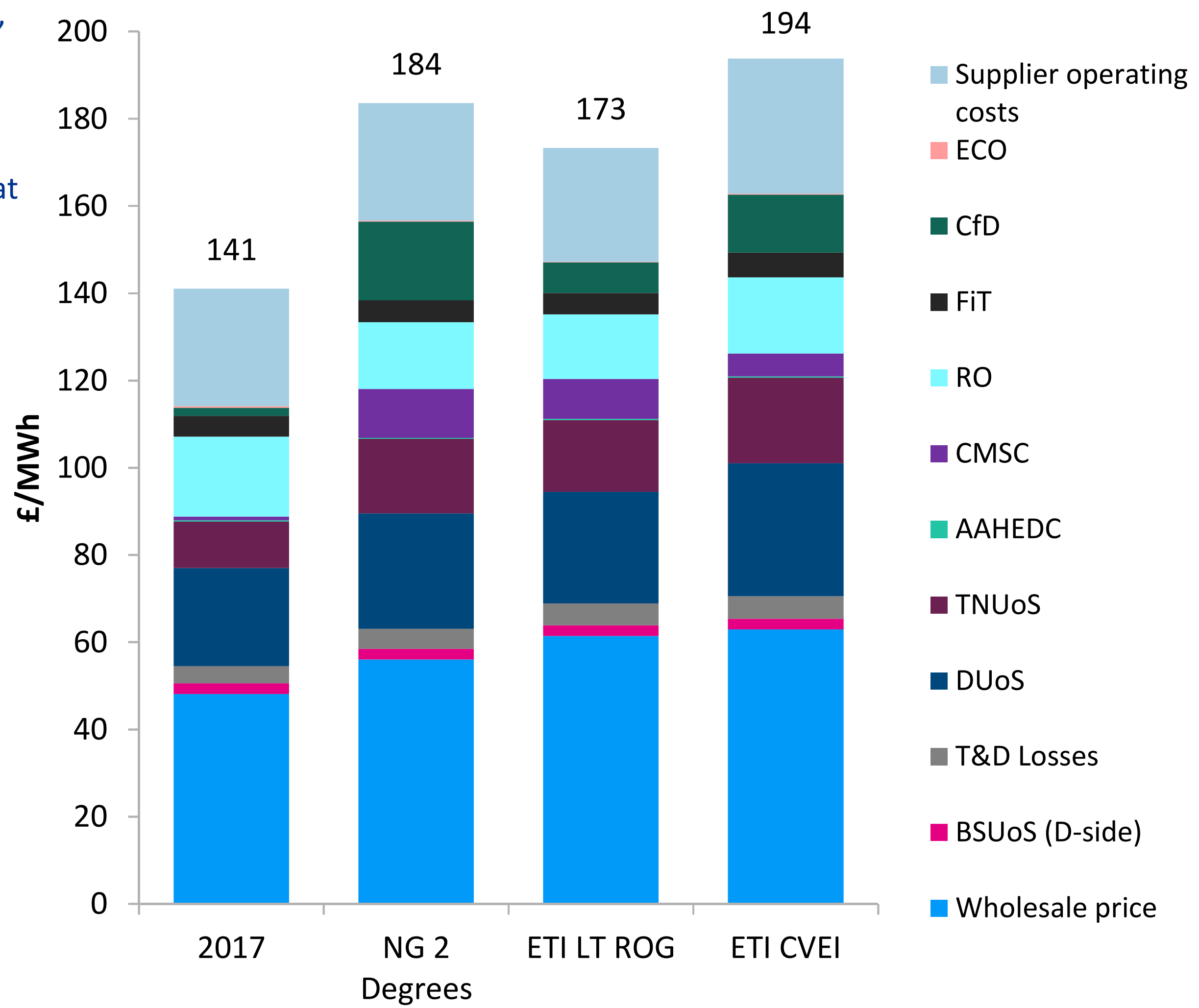
- **NG 2 Degrees**
  - Most of the GB supply comes from low carbon technologies, especially wind and nuclear
  - Total renewable generation is over two times higher than current levels
  - Net imports (which are reflected as zero carbon) are also increased significantly due to the higher interconnection and lower internal flexible gas capacity
  - Results in the lowest carbon intensity of the three cases
- **ETI LT ROG**
  - Nuclear generation the lowest of the scenarios
  - CCGT output only slightly down on current levels at over 110 TWh per annum, driving relatively high carbon intensity
  - Despite lower interconnection than NG 2 Degrees, net imports are higher because of higher prices caused by lower nuclear and renewable generation
- **ETI CVEI**
  - Nuclear generation slightly above current levels
  - Wind generation is similar to ETI LT ROG
  - CCGT output below current levels but higher than NG 2 Degrees, which is reflected in the carbon intensity




* 2017 carbon intensity is an estimate based on the BEIS UEEP 2017 projection published in November 2017

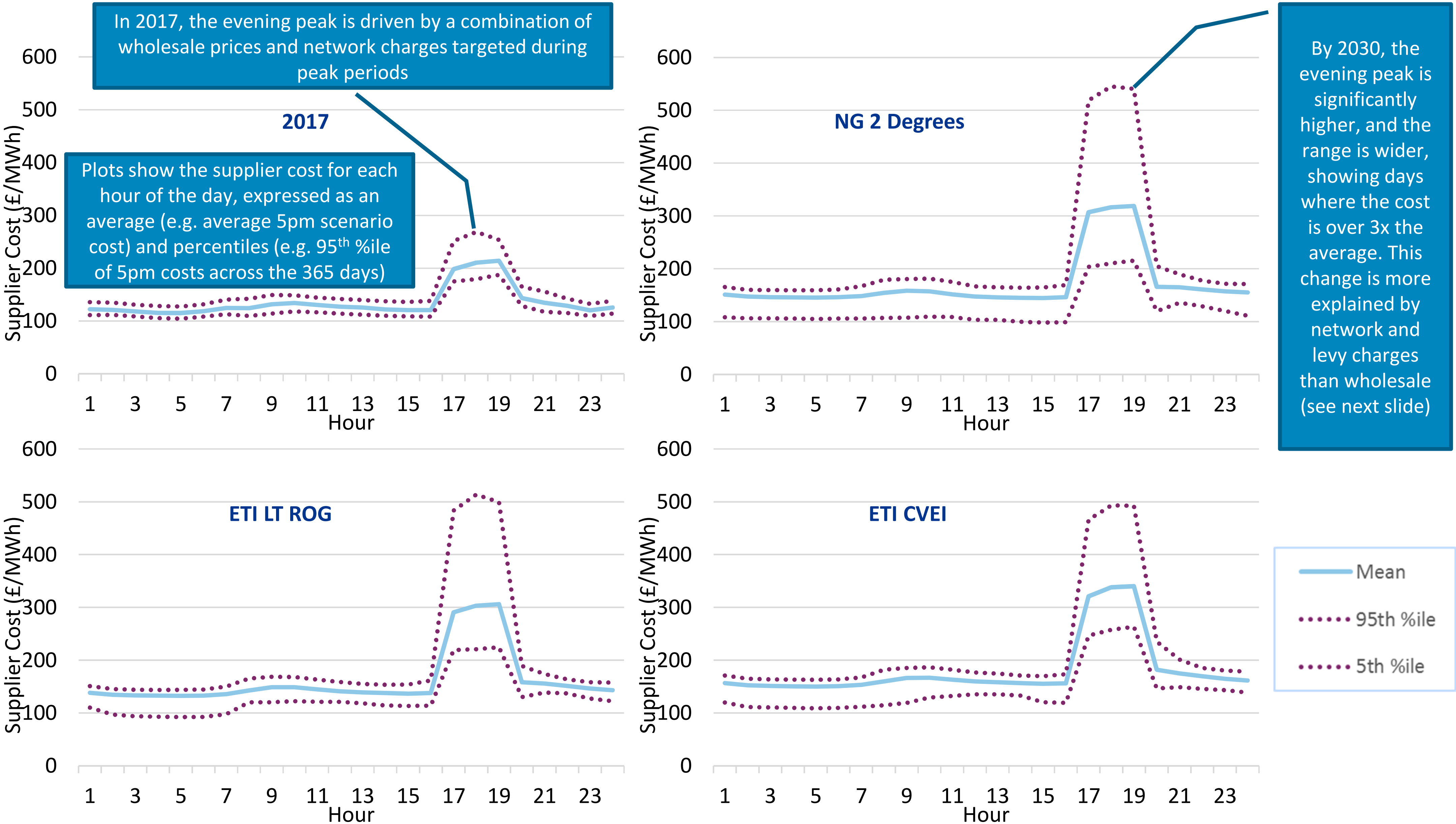
# Load-weighted average retail cost stack

- In 2017 the largest cost components are wholesale price, DUoS, renewable obligation costs and the supplier operating costs
- In 2030 and in all the scenarios:
  - The supplier operating costs, DUoS and FiTs remain at similar levels to 2017
  - AAHEDC, ECO and BSUoS are assumed to remain at the same level as 2017
  - TNUoS charges show an average 67% increase, extrapolating from near-term projections, partly driven by offshore wind expansion
  - Renewable obligation decreases from £18MWh to approximately £15MWh
- In **NG 2 Degrees**, load-weighted wholesale cost is the lowest of the three scenarios due to high renewable output and import capacity. However the low wholesale prices cause both CfD expenses and CMSC to be higher, resulting in a £184/MWh retail cost
- In **ETI LT ROG**, the wholesale price is significantly higher but nearly all retail cost components are lower either because of higher demand or lower price-supported capacity. As a result, the retail cost is on average lower compared to NG 2 Degrees (£173/MWh)
- In **ETI CVEI**, the wholesale price is at similar levels to ETI LT ROG but higher support costs and lower demand over which to recover network costs result in a per-MWh retail cost that is the highest of the three (£194/MWh)



# Hourly supplier costs – Daily distribution

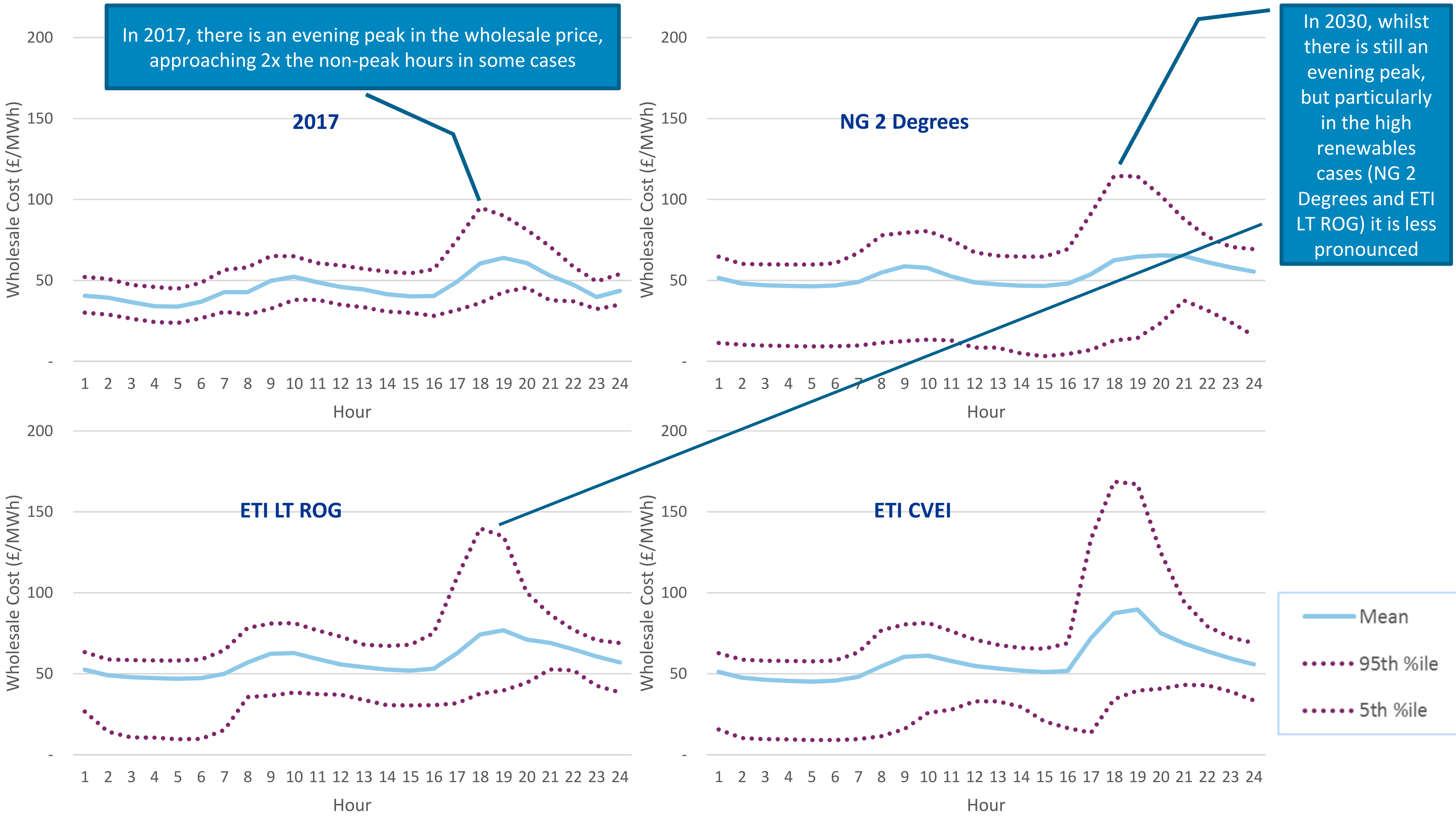
## Volatility and hour-of-day cost distribution indicate high variability in NG 2 Degrees and ETI LT ROG



# Hourly supplier costs – Daily distribution (wholesale only)

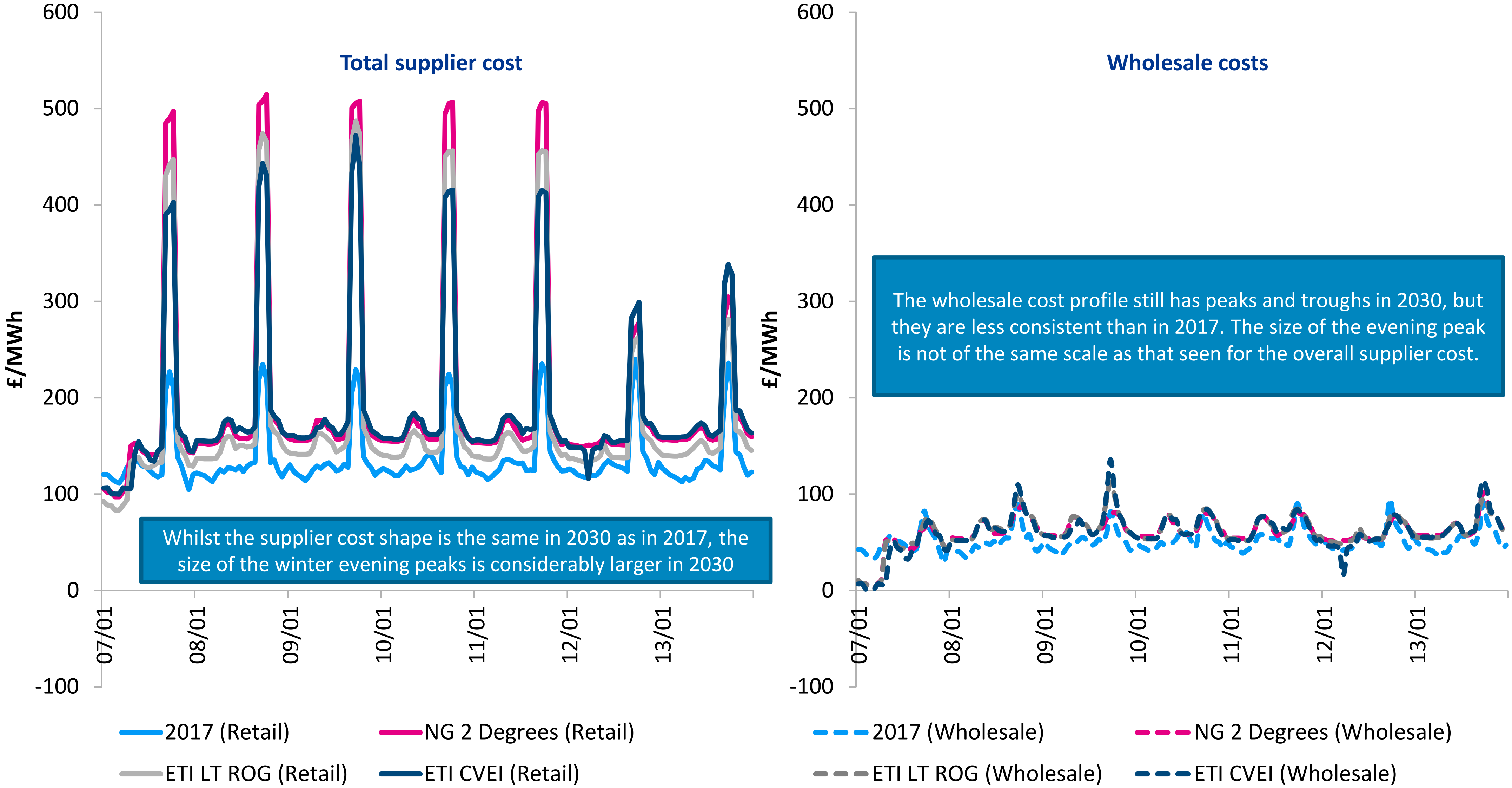
Baringa

## Volatility and hour-of-day cost distribution indicate high variability in NG 2 Degrees and ETI LT ROG



# Sample total supplier and wholesale costs (Winter)

## Sample week in January*,**

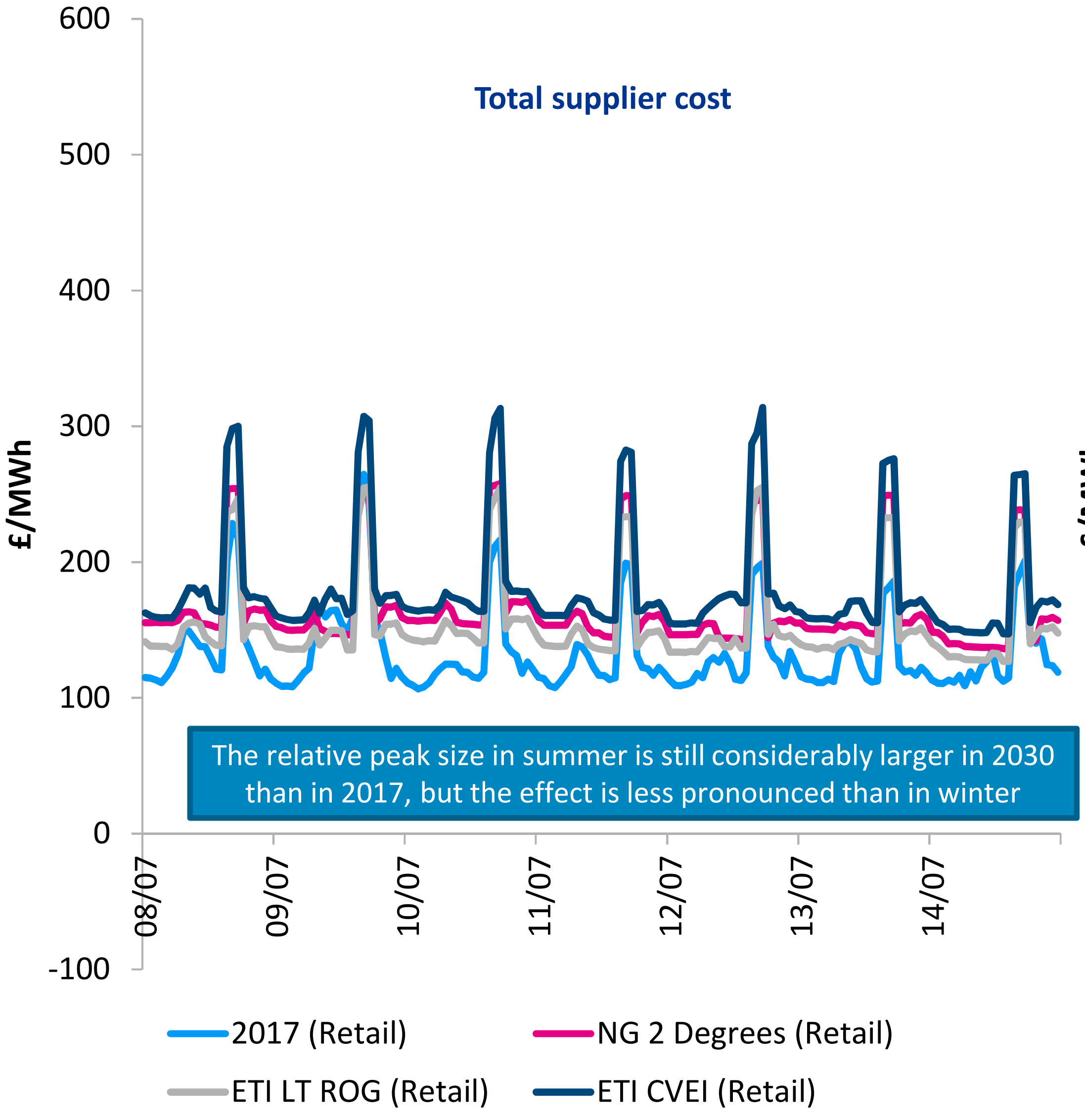


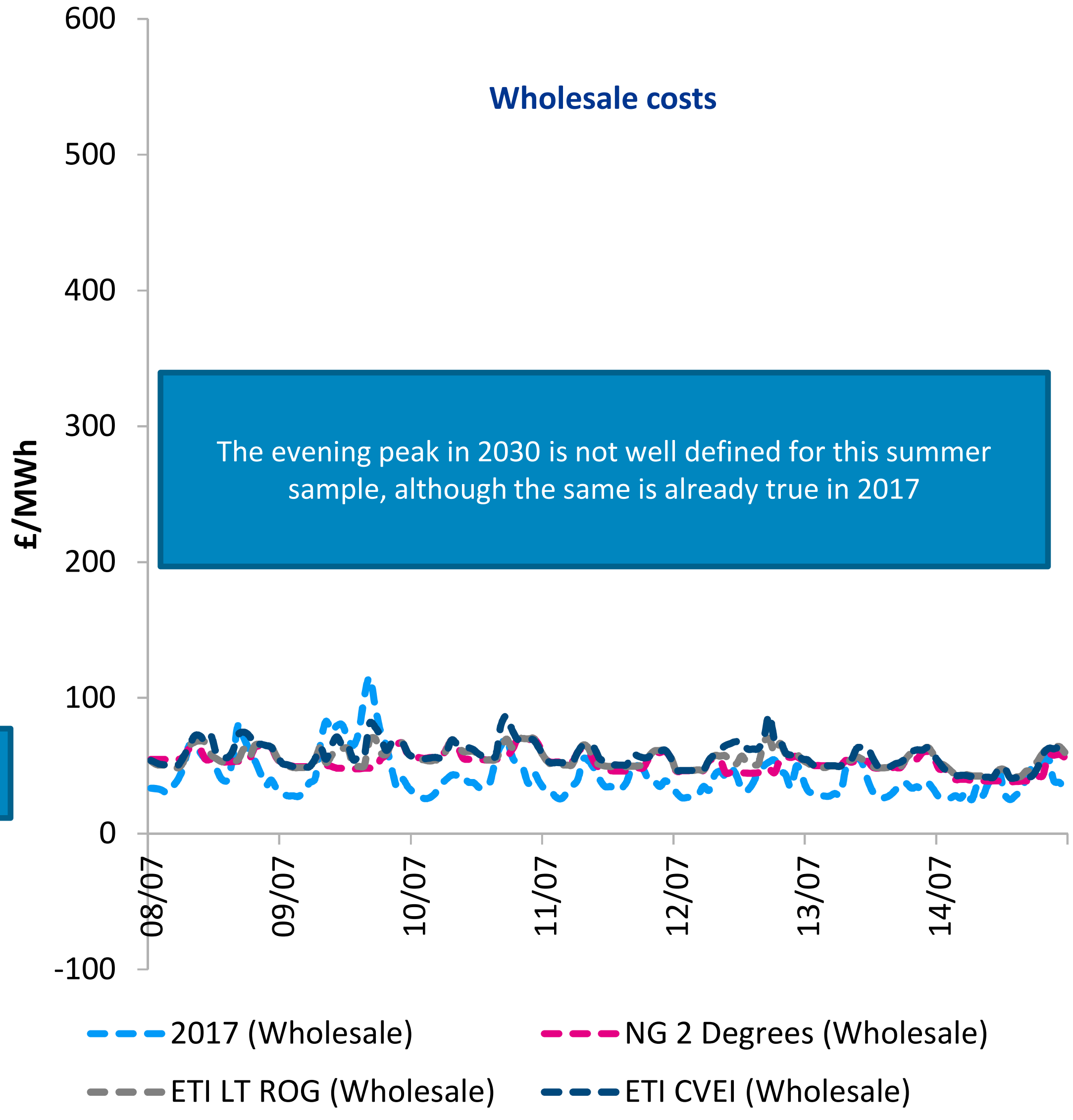

*Note that this does not include the 2017/18 CM supplier charge, which did not become material until October 2017

**The 2017 plot has been shifted by two days in order to align the days of the week for comparison with 2030

# Sample total supplier and wholesale costs (Summer)

## Sample week in July*




*The 2017 plot has been shifted by two days in order to align the days of the week for comparison with 2030

# Key findings

- Hourly price variation is **driven more by administered charges** such as CM and TNUoS
  - The winter evening supplier cost peaks in 2030 are disproportionately large when compared to the wholesale cost
- 2030 wholesale prices give a weaker and less predictable **signal for flexibility**
  - Whilst the average wholesale share only decreases slightly in the low carbon scenarios, this is more stark during January evening peak
- **The lowest demand case has the higher per-MWh charges**
- **Carbon intensity** is lowest in a scenario with high installed capacity of low-carbon generation, particularly where that capacity has a high load factor (e.g. nuclear)
- **Imports** are highest where there is a large interconnection capacity and low flexibility to address peaks (NG 2 Degrees) or where a relatively high wholesale price encourages flows into GB
  - High imports also decrease the carbon intensity since they are treated as zero carbon
  - This is an appropriate treatment for carbon emitted across borders, since the emissions will be accounted for elsewhere
  - However the overall impact on emissions will depend on the technologies and carbon budgets in the exporting countries

| Wholesale cost as % | 2017 | NG 2 Degrees | ETI LT ROG | ETI CVEI | 2030 average |
|---|---|---|---|---|---|
| **Annual** | 34% | 32% | 37% | 32% | **33%** |
| **4-7pm January** | 40% | 26% | 31% | 30% | **29%** |

# Appendix 1

Wholesale cost assumptions

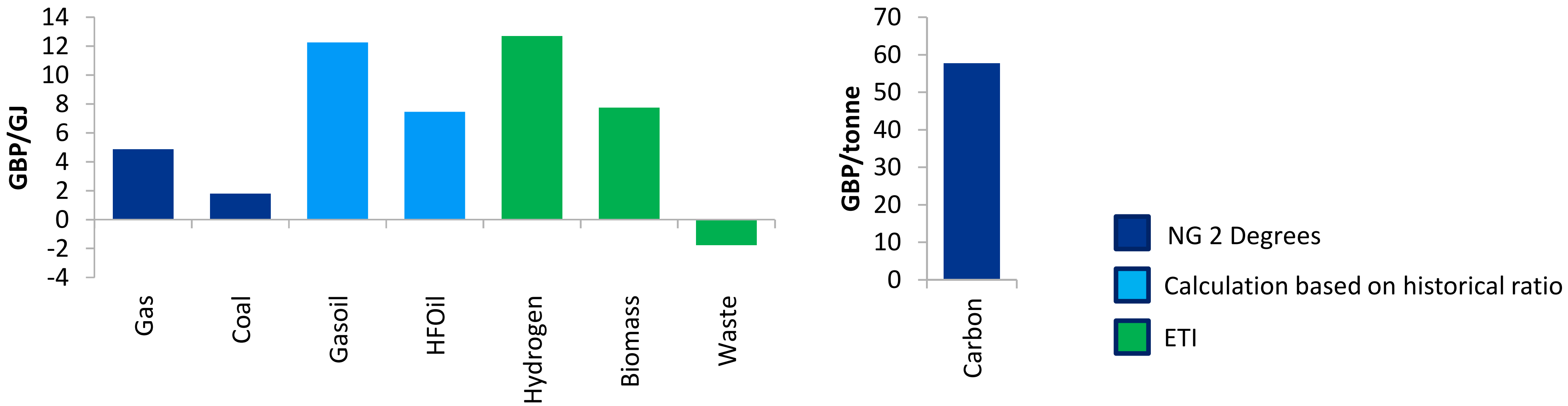
# Inputs – wholesale price model

| Input | Description | Source/methodology |
| --- | --- | --- |
| Commodity prices | Gas, coal, carbon, biomass prices used to determine dispatch and wholesale prices | NG 2 Degrees for gas, coal, carbon and ETI for H2, biomass. For gasoil we will use a ratio over gas |
| Demand – annual | Electricity demand that needs to be met | Scenario assumption |
| Demand – shape | Demand by hour that needs to be met | Use a historical shape of demand and adapt it by removing flexible demand and achieving the assumed peak and annual demand |
| Demand – flexibility | What is the flexibility provided by EVs and HPs | Scenario assumption for flexible load. The model will optimise the hourly distribution of the flexible daily load |
| Capacity - existing - properties | Heat rates, start costs, VOM and plant operational constraints | Baringa wholesale model |
| Capacity - future | Projections of installed capacity by 2030 | Scenario assumption |
| Capacity - future - properties | Heat rates, start costs, VOM and plant operational constraints | Baringa wholesale model |
| Renewable profiles | Non-dispatchable renewable hourly generation is an input to the model | Baringa wholesale model for wind and solar, ETI for tidal |
| Interconnection - capacity | Projection of the import and export connection capacity with neighbouring markets | Scenario assumptions |
| Interconnection - prices | Projection of hourly prices of the neighbouring markets which determine direction of flows each hour | Baringa wholesale model results |
| Scarcity function | Function used to determine the premium above the marginal cost that is added to the wholesale price each hour | Baringa wholesale model scarcity function |

# Inputs – wholesale price model (1) – commodity prices

- **Commodity prices in 2030**
  - The main commodity prices (gas, coal and carbon) were taken from the National Grid FES assumptions published in July 2017 because they are publicly available and also have been used already in one of these scenarios
  - Oil products prices (used only exceptionally from peaking plants) were calculated using the average ratio observed in between them and natural gas in the period 2010-2018 in GB
  - Baringa's view is that gas and coal assumptions are sensible but on the low-side, carbon price is sensible but on the high-side which is reasonable given that the scenario's aim is to decarbonise the GB power sector faster than BAU
  - Biomass and hydrogen prices were taken from the ETI LT RoG model

- **Commodity price charts**



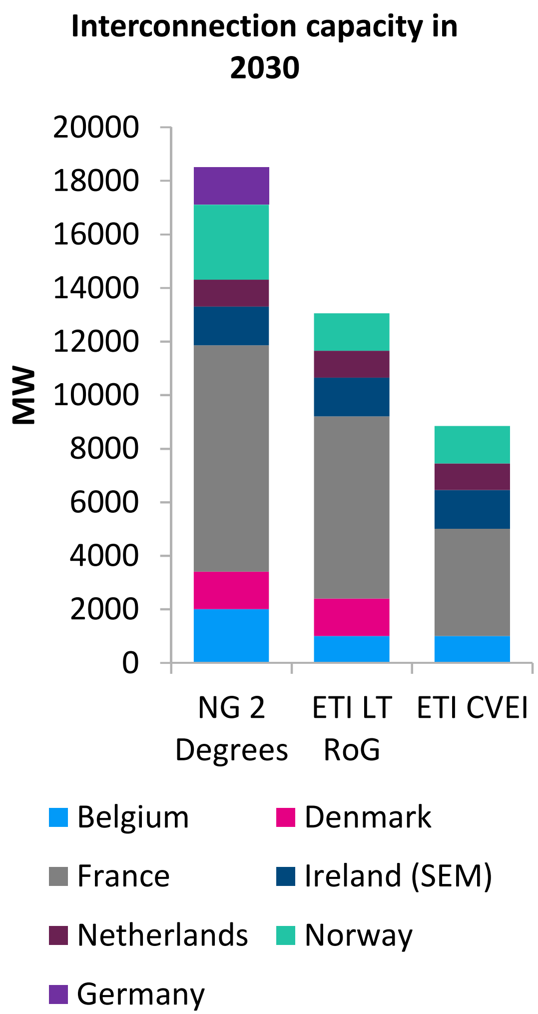
# Inputs – wholesale price model (2) – capacity

- **Capacity**
  - The properties of the generators such as heat rates are part of the Baringa wholesale model
  - Intermittent renewable generation is non-dispatchable and pre-determined:
    - Wind: We have used historical wind speed data at intervals of 3 hours for 3 offshore and 6 onshore locations in GB (we used 2012 as the base year). We have fed those wind speeds to our in-house model that includes a power curve in order to generate wind load factors by hour for a full year
    - Solar: We have used historical solar load factor from 2012
  - The profiles used for tidal/wave generation will come from ESME
  - We will use the scenario-specific capacity mix assumptions (provided in slide 4 but also in excel format)
- **Properties in the PLEXOS model**

| Property | Unit | Explanation |
|---|---|---|
| Capacity | MW | Capacity of each unit of that plant |
| MSL | MW | Minimum Stable Level of generation. The plant needs to generate at least at that level when open |
| Ramp Up | MW/min | Constraint of how quickly can a plant increase its generation |
| Ramp Down | MW/min | Constraint of how quickly can a plant decrease its generation |
| Min Up Time | Hours | Constraint of how many hours at minimum must a plant remain open before closing again |
| Min Down Time | Hours | Constraint of how many hours at minimum must a plant remain closed before opening again |
| Start Cost | GBP | Cost of starting the plant from zero generation levels |
| Rating Factor | % | Maximum allowed generation per hour – used to constrain intermittent renewable output |
| VO&M | GBP/MWh | Non-fuel variable cost to produce a unit of electricity |
| Heat Rate Base | GJ | Fuel required for the start to remain open regardless of output |
| Heat Rate Incremental | GJ/MWh | Fuel required for the production of an extra unit of electricity (marginal fuel cost) |
| Maintenance Rate & frequency | % | The model can optimise/choose the time when the plant is on planned maintenance |
| Forced Outage Rate & frequency | % | The model assigns forced outages randomly and does not optimise for those |

# Inputs – wholesale price model (3) - interconnection

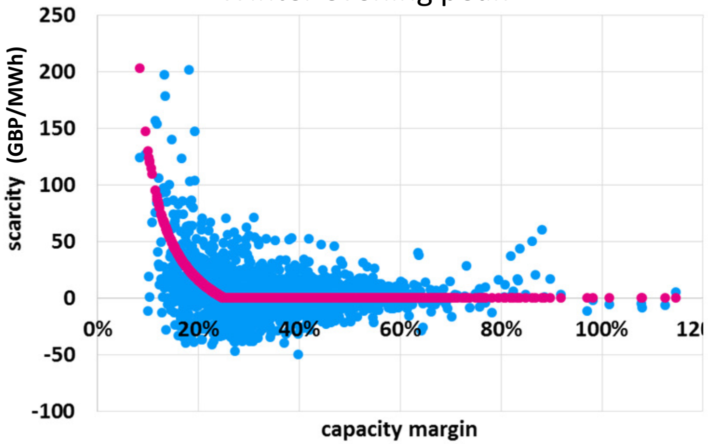
- **Operation of interconnectors**
  - Interconnectors allow the flow of electricity between two different price zones / markets
  - The main properties of interconnector are the import and export capacity that they have – what is their maximum allowed flow. Their flow may also be limited by internal transmission constraints in each of the connected markets
  - In coupled markets (like GB and France) interconnector flows will depend on price spread at each interval. For example, if price is lower in France (e.g. 40 €/MWh) compared to GB (e.g. 50€/MWh), then the flow of power will have the direction from France to GB because the GB-based suppliers can buy cheaper electricity in France and the French generators can sell electricity to GB at a higher price
  - As more generation from France is required to supply GB demand though interconnectors, the price in France increases. Price in GB decreases as less domestic generation is required. If the interconnector capacity is very high, prices will converge and their spread will be determined by the line losses. If the interconnector capacity is fully utilised, price spreads can remain significant
- **Assumptions on interconnector capacity**
  - Capacity per interconnection will come from the scenario-specific assumptions
  - NG 2 Degrees only gives a total interconnection capacity. We have spread that over GB and the neighbouring markets based on our assumptions and known potential projects
  - The hourly interconnected prices, which are Baringa commercial IP, will be the output of our pan-EU wholesale price model using the same commodity prices
  - Line loss factors: Publicly available for existing lines. For future lines, they are Baringa estimates based on type of connection, distance and existing information
- **Interconnector prices**
  - The flows of interconnectors are dependent on the prices of the neighbouring markets
  - We used our in-house Pan-Europe PLEXOS wholesale model and the commodity price assumptions of this project to generate the hourly interconnector prices for 2030



# Inputs – wholesale price model (4) - scarcity

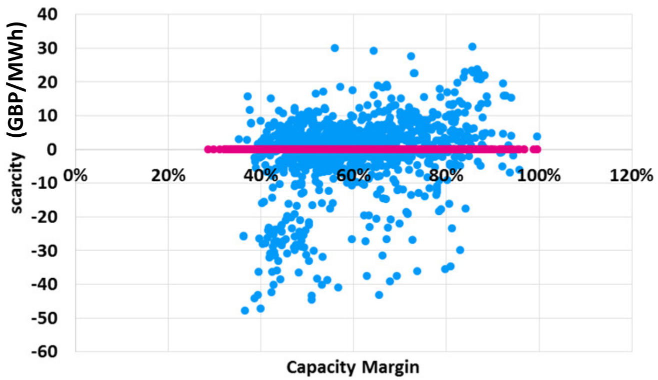
- **Scarcity premia**
  - We will assume that when the capacity margin is tight, generators will be able to bid prices higher than their SRMC. This creates additional rent that is received by all plants that generate during those hours and makes up the scarcity revenues. The scarcity premium can increase the wholesale prices and benefits plants that are able to generate during these times with tight capacity margin
- **Calibration of scarcity**
  - We calculated the actual capacity margin in each of the hours of 2016 based on availability of plants and actual demand
  - We simulated the SRMC-only prices by running our model for 2016 using the relevant renewable and commodity price assumptions from that historical year
  - We compared the capacity margin observed with the spread of actual out-turn prices and the simulated SRMC-only prices
  - We used that comparison to calibrate the relationship between scarcity premia and capacity margin
  - We use different scarcity function for different time blocks throughout the year
- **Indicative scarcity function:**

Winter evening peak




Spring/autumn evening peak


Summer evening peak

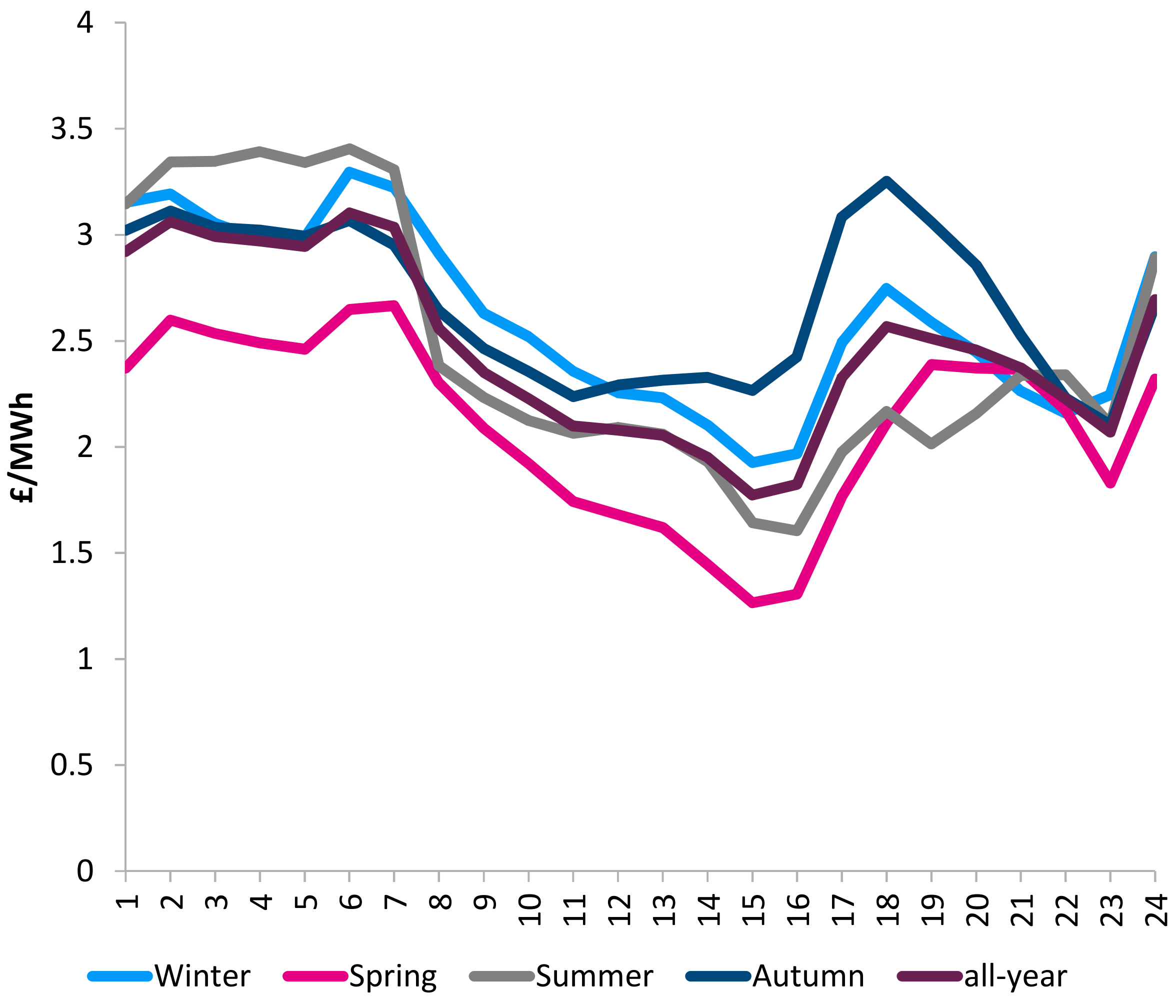


# Appendix 2

Non-wholesale costs: detailed assumptions and results

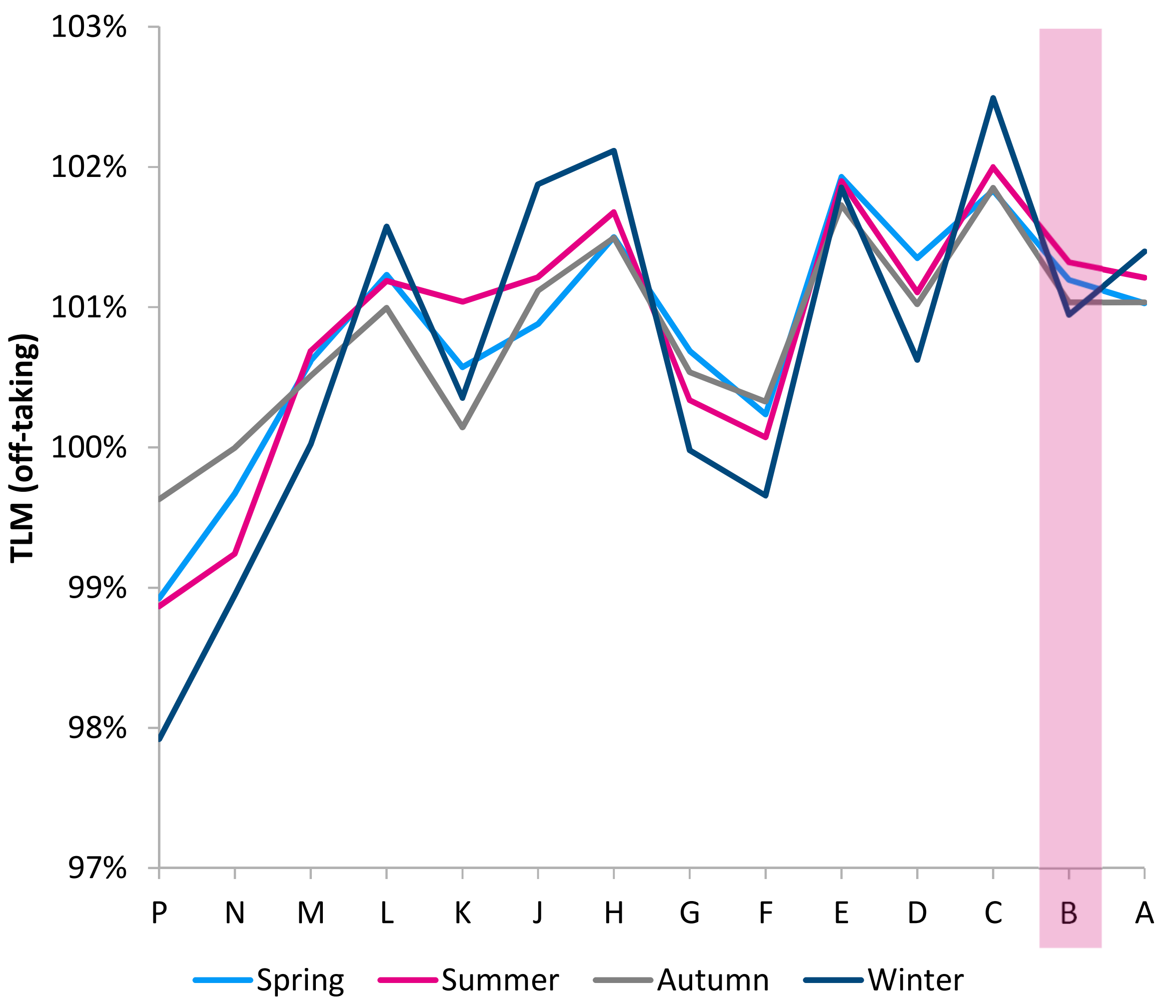
# BSUoS

- Forecasting BSUoS charges is challenging since it depends on both flexibility supply and demand
  - Less inertia, resulting from reduced thermal capacity, should increase the need for enhanced balancing services
  - Constraint management, in lieu of network capacity build, is expected to increase
  - However, the availability of flexibility from distributed energy resources (batteries, controllable DG) and demand response (e.g. EVs) may offset these trends
- We have assumed that the BSUoS charges in 2030 will be on average £2.46/MWh which was the average BSUoS in the financial year 2016/2017
- We have applied seasonal-hourly adjustment factors to shape the BSUoS in accordance to historical data
- For that purpose, we have used historical data published by National Grid from four recent consecutive financial years (2013/2014 – 2016/2017) to derive an hourly average shape in each of the seasons of the year
- All seasons have very similar hourly shape: BSUoS is high during the night time and during the evening peaks while it is lower during the morning and early afternoon
- On average, BSUoS is lower during spring and summer and higher in the autumn and winter months



# Loss factors

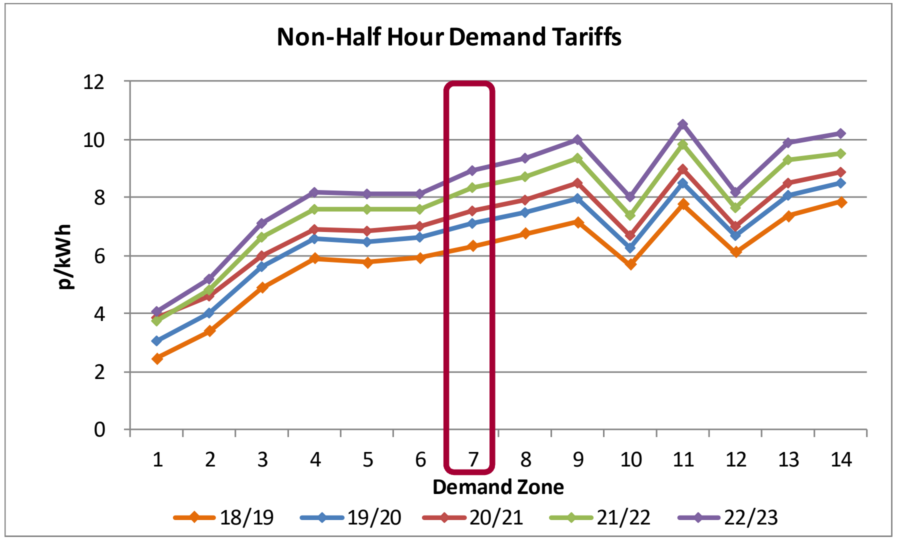
- There are three loss factors applied in these study:
- Transmission loss factors (generation-side):
  - The generation-side losses are factored in the wholesale NBP power price. They are assumed to be 0.9% of the NBP price
- Transmission loss factors (demand-side):
  - We have used the off-taking seasonal-zonal transmission loss multipliers based on published values by ELEXON (TLM = TLMO + TLF)
  - In East Midlands (the focus area of this study), the factor varies from 100.9% in winter to 101.3% in summer
- Distribution loss factors:
  - Latest WPD East Midlands Line Loss Factor estimate is taken, representing 2018/19, which defines four different periods during the week
  - Although there are programmes to reduce losses (e.g. installing lower-loss transformers), and Ofgem may reintroduce direct incentives on DNOs to reduce losses, no forecasts of the impact exist so a flat assumption is taken to 2030
- Impact on costs: The loss factors adjust the consumption to take into account the actual load to the system. These factors differ by GSP zone, season and time of the day



# Network Charges

- **DUoS**
  - Projections based on the 2017/18 DUoS charges applicable to the East Midlands (Western Power Distribution)
  - Simple extrapolation from WPD's RIIO-ED1 business plan,* assuming that domestic DUoS scales with DNO allowed revenue
  - Allowed revenue expected to increase from £460m to £552m in 2030
  - Future price controls could impose more stringent targets, which would result in a lower rate of increase
- **TNUoS**
  - TNUoS zone 7 (East Midlands) used as a representative location
  - It is our view that the TRIADs will be replaced by another system before 2030
    - Other changes such as removal of the 2.5 EUR/MWh floor on generators and/or greater proportion of demand-side TNUoS are likely
  - However, due to the absence of certainty of what the system will be (at the time of writing), we assume current policy will remain
  - Tariff increases driven by allowed revenue associated with Offshore and Onshore networks, and exacerbated by the generation tariff floor
  - We convert National Grid's projections to 2022/23 into real terms and extrapolate to 2030 based on the CAGR (calculated to be 4.9%)
    - Consistent with estimated OFTO cost of £71k/MW
    - Offshore wind alone contributes 3.5-4.3p/kW to depending on scenario
  - 2018/19 is excluded from this calculation for two reasons:
    - CMP283 introduces a step change in cost recovery of interconnector costs
    - NG identifies four OFTO asset transfers in that year, which it considers a "significant increase"**, so unlikely to be representative
  - TNUoS charged on each MWh that occurs between 4-7 PM throughout the year
  - This reflects the current approach for domestic customers, and since half-hourly settlement for smart meter customers is not yet mandatory we assume this remains unchanged for 2030

| Tariff name | Unit charge 1 (NHH) or red/black charge (HH) p/kWh | Unit charge 2 (NHH) or amber/yellow charge (HH) p/kWh | Green charge(HH) p/kWh | Fixed charge p/MPAN/day |
|---|---|---|---|---|
| Domestic Unrestricted | 2.060 | | | 3.03 |

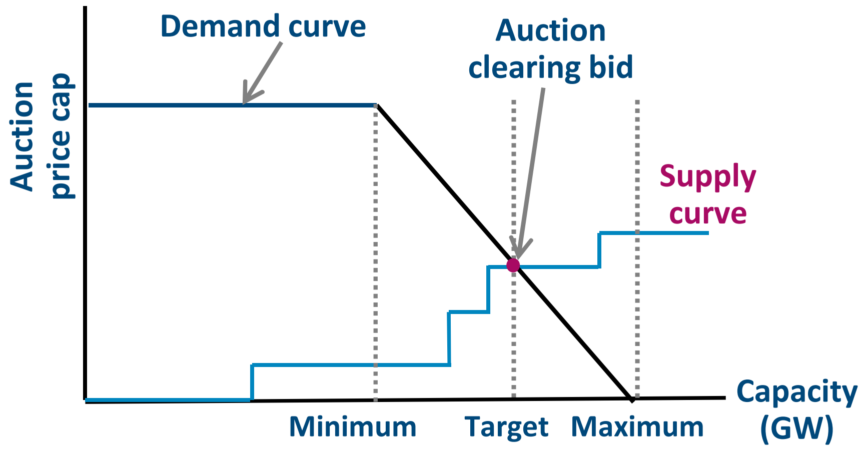



* https://www.westernpower.co.uk/docs/About-us/Stakeholder-information/Our-future-business-plan/Seperate-documents/Expenditure.aspx

** https://www.nationalgrid.com/sites/default/files/documents/Forecast%20TNUoS%20Tariffs%20for%202019-20%20-%20Report_0.pd

# Capacity market auctions mechanism

## High-level CM auction design




- Auction design: Descending clock, and "pay as clear" rather than "pay as bid"
- Price makers: new plants, DSR capacity, existing plant (by choice)
- Price takers: existing plant (by default) cannot bid higher than £25/kW
- New plants are eligible for a 15 year contract at a fixed CM price

## Eligibility

- Generation capacity providers: remaining unabated coal, new and existing gas, existing nuclear, CHP
- Non generation capacity providers: DSR and storage
- Ineligible plant: ss-FiT, RO, RHI, CfD plant, plant <2MW

## Key Considerations

| | |
|---|---|
| **Market Access** | Contact with Capacity Market Delivery Body (National Grid) although energy needs to be accounted for either through trading directly or via a supplier |
| **Tech Limits** | 2 MW de minimis threshold (possibly aggregated). Need to be dispatchable during periods of system stress. (Can contract for other ancillary services) |
| **Key Risks** | The out-turn price in the clearing price is unknown and may be volatile within years. The number of auctions is also unknown |
| **Competitors** | Y+4 and Y+1 auctions will be competitive pay as clear auctions |

## Delivered energy obligation

- Providers must deliver energy in a 'system stress' period (defined via a four hour ahead warning), or face penalties
- The obligation will be scaled to peak demand in the period with penalties based on the value of the capacity agreement obtained
- Penalty exposure are capped at twice the monthly capacity payments (for a single event), and providers can lose no more than the annual CM revenue across the year
- Participants providing ancillary services at the time of system stress event are exempt from penalties

# Capacity market supply charge

- Suppliers are obliged to pay the Capacity Market Supplier Charge (CMSC) to cover the total CM revenues paid to the generators
  - With the exception of administrative costs, the CM imposed no charges on suppliers until October 2017
- The CMSC is spread over the winter months (November, December, January and February) on weekdays between 16:00 and 19:00
- The CMSC is calculated as following:
- $CMSC[£/MWh] = \frac{Total\ CM\ annual\ cost[£]}{Demand\ during\ CMSC\ hours[MWh]} = \frac{\sum_g \left( CM\ Price(g,t)\left[\frac{£}{kW}\right] \cdot De\text{-}ratedCapacity(g,t)[kW] \right)}{Demand\ during\ CMSC\ hours[MWh]}$
- The CM auction prices are output from Baringa's CM Model, taking account of the future volume requirement, power station costs and expected returns, interconnector participation, the wholesale market results for asset revenues, and other sources of income including balancing services
- The de-rating factors determine the part of the capacity that a plant can receive CM revenues for. The contracted plant must be able to deliver energy during "system stress" (defined via a four hour ahead warning), or face penalties
- For this project we have only modelled the year 2030 and we have assumed that all generators bid based on their revenues of this year
- For each of the scenarios we have:
  - calculated one CM clearing price equal to the highest price bid for that year. The CM clearing price is an output of the Baringa CM model. Capex, FO&M and lifetime figures are based on ESME 4.4 inputs
  - multiplied the CM clearing price of each of the scenarios with the total eligible de-rated capacity
  - divided the product above with the CMSC hours demand

| Item | Units | 2017 | NG 2 Degrees | ETI LT ROG | ETI CVEI |
|---|---|---|---|---|---|
| CM Clearing Price | £/kW | 6.95 | 60 | 55 | 33 |
| CM annual cost | £bn | 0.4 | 2.9 | 2.8 | 1.3 |
| CMSC | £/MWh | 33* | 204 | 170 | 99 |

*This is only applied from October 2017 onwards

# RO support projections

- The Renewables Obligation (RO) closed to all new generating capacity on 31 March 2017
- ROCs will not be issued after the 31st March 2027 for all capacity first accredited before the 25th of June 2008
- In regards to the capacity first accredited after the 25th of June 2008, they will be issued ROCs up to their 20th anniversary since accreditation (not later than the 31st of March 2037)
- The suppliers pay the total cost of the RO scheme by buying a specified number of ROCs for each MWh of consumption at the ROC buy-out price. Both figures are updated and published by OFGEM on an annual basis. ROC buy-out prices are updated using the Retail Prices Index (RPI). Therefore the annual RO spent is determined by the following formula:
- $RO\ budget[£] = RO\ buy - out\ price \left[\frac{£}{ROC}\right] \cdot RO\ obligation\ level \left[\frac{ROCs}{MWh}\right] \cdot Annual\ Supply[MWh]$
- We have collected historical data from OFGEM to calculate the annual RO budget figures:
- https://www.ofgem.gov.uk/publications-and-updates/renewables-obligation-ro-buy-out-price-and-mutualisation-ceilings-2018-19-ro-year
- https://www.ofgem.gov.uk/environmental-programmes/ro/contacts-publications-and-data/public-reports-and-data-ro
- We have projected the 2030 RO budget taking into account capacity that was first accredited after 2010
- We have adjusted the historical nominal figures by inflating them every year by RPI
  - Annual inflation rate measured by RPI has ben consistently higher compared to inflation rate measured from CPI (except a few outlier years such as 2009)
  - We have assumed that RPI will continue being on average higher compared to CPI by 0.6% based the compound annual growth rates of RPI and CPI between 2005 and 2017
- Based on the methodology above, the RO budget has been estimated to be £4.7bn (real 2017) in 2030 from £5.2bn in 2017 (real 2017) (both calendar years rather than financial years)
- Each scenario has the same assumption for RO budget but different cost per MWh due to different consumption figures

# FiT support projections

- Approximately 4.4 GW of capacity receive Feed-in-Tariffs for their generation. The FiT levels vary depending on type, size and year of accreditation. The FiT levels are guaranteed for the duration of the FiT period. FiT levels are indexed using RPI like the RO
- The FiT period is 20 years for most systems. Solar PV receive FiTs for 25 years if they were installed before August 2012 and micro-CHP receive FiTs for 10 years
- We have used data from the government document “Consumer Funded Policies” published in November 2016 as well as the FiT annual reports published by OFGEM in regards to historical and projected FiT budget
- We have projected these values to 2030 using the RPI in the same way as the RO projections
- Based on the methodology above, the FiT budget has been projected to be £1.36bn in 2030 from £1.32bn in 2017 (real 2017) (both calendar years rather than financial years)
- Each scenario has the same assumption for RO budget but different cost per MWh due to different consumption figures

# CfD support introduction

- Contracts-for-Difference is a mechanism introduced by the Electricity Market Reform. There have been two allocation rounds of CfDs.
- CfD contract lengths vary:
  - Many biomass plants' CfD contracts (e.g. Drax biomass conversions) will be terminated in March 2027
  - Wind contracts will be terminated 15 years after the commissioning date
  - Nuclear contracts (i.e. Hinkley Point C) last 35 years
- The strike price of the CfD contracts is inflated using the CPI rather than the RPI. Therefore the strike prices of the existing CfD contracts remain fixed in real terms in contrast to the FiT and RO schemes
- The plants that have CfD contracts receive the difference between the Strike Price and the Reference Price which is the determined in a different ways for different technologies:

$$CfD\ cash\ flow(g,t)\ [£] = (Generation(g,t)[MWh]) \cdot \left(StrikePrice(g)\left[\frac{£}{MWh}\right] - ReferencePrice(g,t)\left[\frac{£}{MWh}\right]\right)$$

The plants have the incentive to run when the $Hourly\ price\ is\ \geq\ StrikePrice(g)\left[\frac{£}{MWh}\right] - ReferencePrice(g,t)\left[\frac{£}{MWh}\right]$

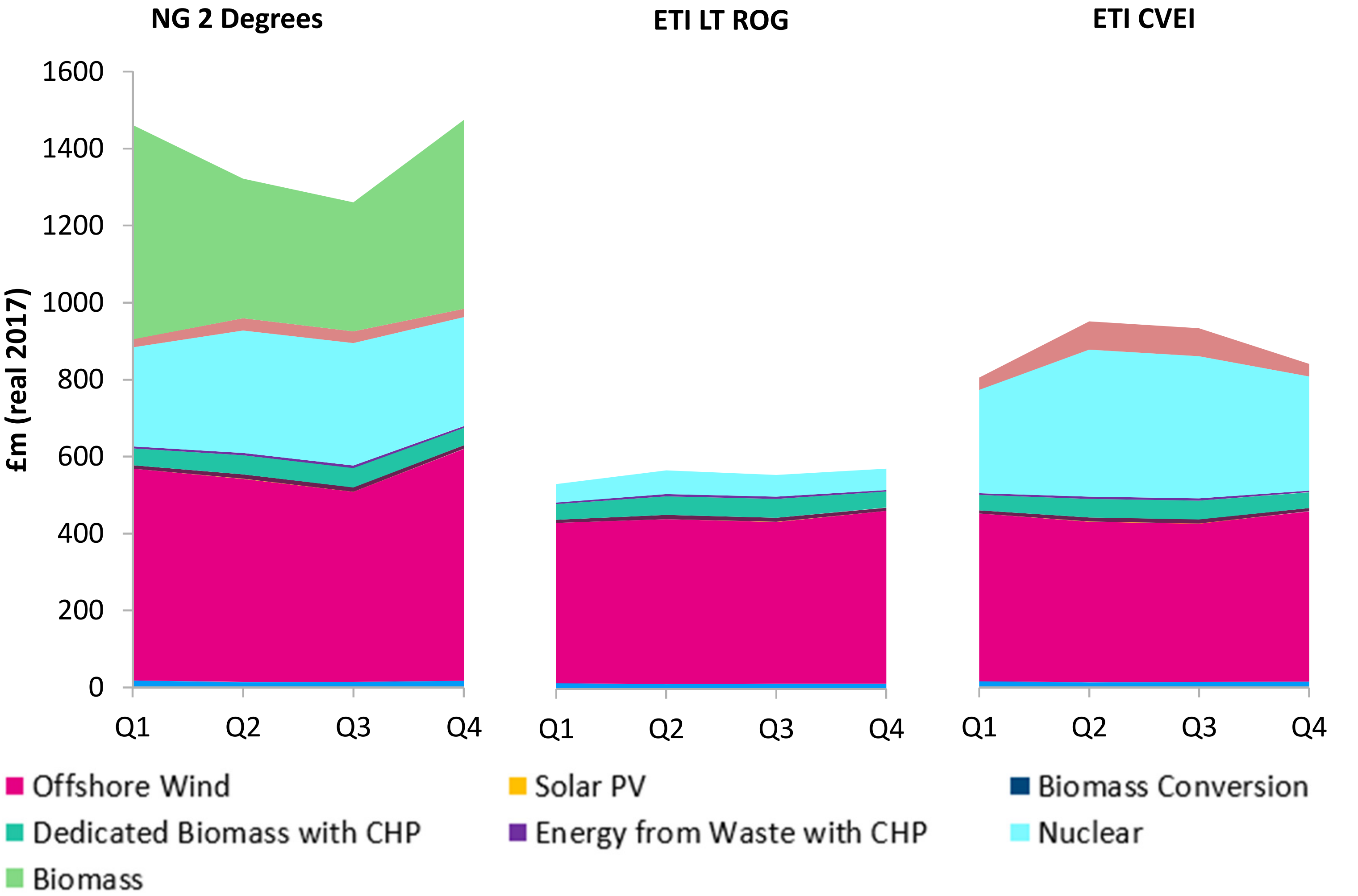
- No payments are made when the day-ahead price is negative for more than six hours. Therefore plants are exposed to renewable over-generation
- Reference Price calculation:
  - Nuclear, biomass and potentially CCS in the future: The Reference Price is the average season-ahead wholesale price
  - Onshore, Offshore wind: The Reference Price is the average day-ahead wholesale price
- The CfD budget is allocated based on a quarterly basis based on the suppliers electricity demand and difference payments

# CfD support calculations and projections

- Reference Price:
  - For each plant/technology under a CfD contract, the Reference Price must be calculated based on the modelling results
  - The wholesale price are known for 2017 (historical values) and have been projected using the model for 2030 for each of the scenarios. For the period 2018-2029 we have used linear interpolation to determine the Reference Prices for each of the scenarios
- Existing CfD contracts:
  - The following types of plants have won CfD contracts: Onshore Wind, Offshore Wind, Solar PV, Biomass Conversion, Advanced Conversion Technology, Dedicated Biomass with CHP, Energy from Waste with CHP and Nuclear (Hinkley Point C)
  - Data related to CfDs can be found in the CfD register including capacity, type and commissioning date
- New CfD contracts:
  - Based on the announcements by the UK government, we have assumed that only Offshore Wind and Nuclear will be able to win new CfD contracts in the future
  - All offshore wind and nuclear capacity that is added to the system but does not have an existing CfD, is assumed to be awarded a new CfD
  - Nuclear plants have been assumed to win CfDs with the strike price awarded at Hinkley Point C discounted by 20% based on an announcement from EDF on the potential of cost savings for the plants following Hinkley Point C
  - Offshore plants have been awarded CfD strike prices based on the minimum value required by them to cover their costs during their project lifetime
- CfD budget projection
  - We have used the assumptions/projections above to calculate the quarterly total difference of strike prices and reference prices for all the plants under CfD
  - The CfD spent per quarter as well as the electricity supplied (charged) per quarter is different for each of the scenarios

# CfD support calculations and projections

- NG 2 Degrees has the most nuclear, offshore wind and biomass build by 2030 and therefore it has the highest CfD budget of all three scenarios (£5.5bn)
- ETI CVEI has a significant expenditure on nuclear CfDs but there is no new biomass plants and therefore the total budget is lower than the NG 2 Degrees (£3.5bn)
- ETI LT ROG has the lowest CfD expenditure (£2.2bn). The largest share of CfD spend in this scenario is attributed to Offshore Wind. Only part of the Hinkley Point C is assumed to have been built by 2030 in this scenario

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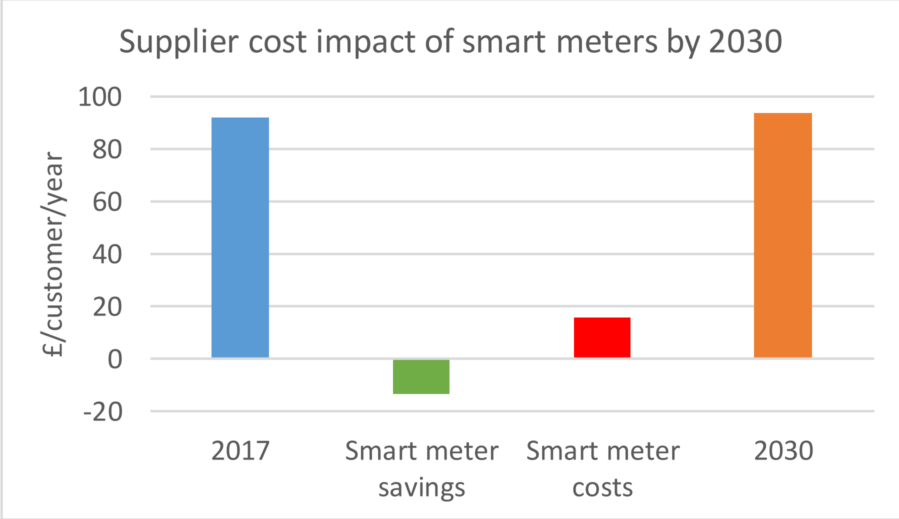
# ECO scheme expenditure

- Background
  - The Energy Company Obligation (ECO) is a government scheme in GB intended to increase the energy efficiency of domestic customers
  - ECO includes several measures such as gas boiler replacement, loft insulation, micro-CHP generation
  - Suppliers that have more than 250,000 domestic customers and provide more than 400 GWh of electricity or 2,000 GWh of gas are legally obliged to contribute to the ECO scheme
  - Most of the measures affect the gas consumption of homes rather than the electricity consumption
- Projection
  - For the ECO expenditure, we have used the government's statistics in regards to historical data:
    - https://www.gov.uk/government/statistics/household-energy-efficiency-national-statistics-headline-release-may-2018
    - The average spent for the financial year 2017/2018 was ~ £300m
  - We assume that the average annual spent will be the same based on the government's announced intention to keep the budget the same up to 2028
  - On the basis that 6.7% of expenditure is targeted at reducing electricity consumption, we have assumed that 6.7% of the scheme costs should be allocated to the electricity bills
  - We have spread the cost of the ECO scheme across all domestic consumption and have added this as a fixed charge to the retail cost stack
  - Even though the total spent is assumed to be the same in all scenarios, the domestic consumption differs and therefore the fixed cost element varies in £/MWh basis between the three scenarios
    - The fixed cost is very small all three scenarios (~£0.18/MWh)

# Supplier operating costs

- 2017 costs are estimated from 'Big 6' suppliers' latest Consolidated Segmental Statements*
- Maps to Ofgem's "other direct costs" and "indirect costs"**
  - Other direct costs: "Supply should in addition include, brokers' costs and intermediaries' sales commissions and any 'wider' smart metering programme costs (eg Data Communications Company (DCC)-related costs)"
  - Indirect costs: "Indirect costs should be defined as licensees' own internal operating costs including sales and marketing costs, bad debt, costs to serve, IT, staffing costs, billing and all meter costs, including smart meter costs (eg linked to rollout or asset rental, not DCC)."
- **Cost amounts to £91.7 per customer in 2017**
- Quantified supplier cost delta focused on impact of smart metering, using 2030 based on BEIS Smart Meter Roll-Out CBA Part II – Technical Annex***
  - Supplier **savings of £13.4/customer/yr** from reduced site visits, fewer and more effective inbound enquiries, lower debt management costs and theft reduction
  - **Costs of the meters themselves represent £15.5/customer/year** in 2030
  - Note that the report suggest an overall benefit of smart meters for network users as a whole, but the 2030 supplier impact is a net cost
- The impact of new supplier market entrants has not been quantified, but could be significant:
  - Competition could drive efficiencies for all suppliers
  - Reduced number of customers per supplier could reduce economies of scale




**Annual profile of monetised costs and benefits (undiscounted)***

| £m | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|
| Total annual costs | 121 | 110 | 267 | 444 | 594 | 881 |
| Total annual benefits | 55 | 67 | 97 | 163 | 342 | 723 |
| **£m** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** |
| Total annual costs | 1,120 | 1,153 | 1,022 | 987 | 983 | 950 |
| Total annual benefits | 1,162 | 1,430 | 1,539 | 1,675 | 1,699 | 1,769 |
| **£m** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| Total annual costs | 950 | 950 | 951 | 757 | 721 | 740 |
| Total annual benefits | 1,839 | 1,886 | 1,899 | 1,897 | 1,931 | 1,971 |

* https://www.ofgem.gov.uk/publications-and-updates/energy-companies-consolidated-segmental-statements-css
** https://www.ofgem.gov.uk/sites/default/files/docs/2015/05/css_guidelines_jan_2015.pdf
*** https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/567168/OFFSEN_2016_smart_meters_cost-benefit-update_Part_II_FINAL_VERSION.PDF

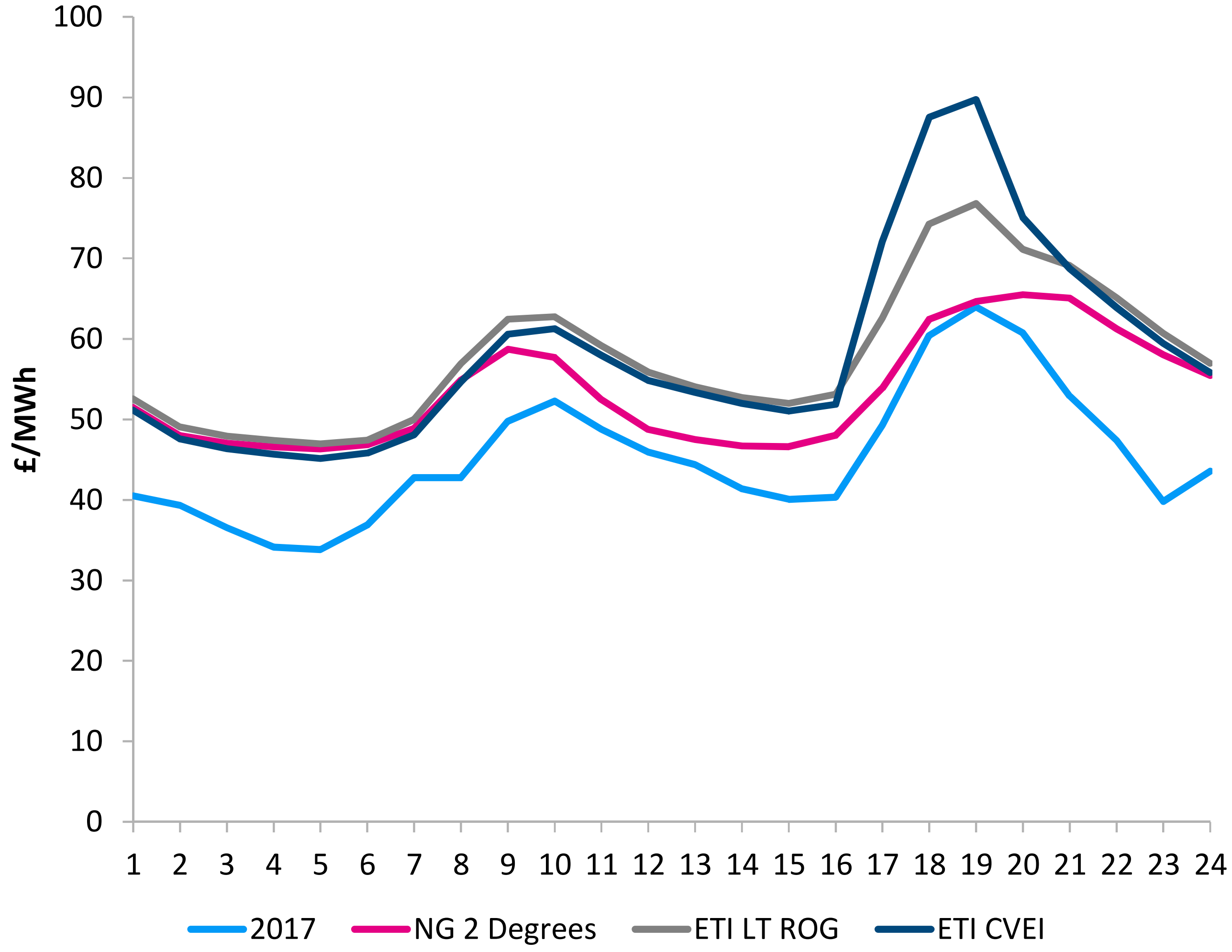
# Appendix 3

Electricity generation detailed outputs

# Time-weighted average hourly wholesale price

Baringa

- All scenarios result in a similar wholesale hourly shape with the historical 2017 shape with high morning and evening price peaks
- All three 2030 scenarios have the same commodity price assumptions which are higher compared to 2017 and as a result they have higher on average wholesale power prices as well
- The ETI CVEI scenario results in the most volatile power prices due to the low interconnection capacity, lower demand side response and storage compared to the other two scenarios. For that reason the evening load peaks result in very high prices on average
- The NG 2 Degrees scenario's prices are lower and less volatile compared to the ETI CVEI scenario due to the larger interconnection, demand-side response and storage despite the lack of new baseload gas capacity
- Finally, the ETI LT ROG scenario's prices in between the two other scenarios in terms of average hourly shape. ETI LT ROG has however slightly lower volatility in wholesale power prices (measured by standard deviation) compared to NG 2 Degrees due to the significant gas baseload capacity and the lower renewable output

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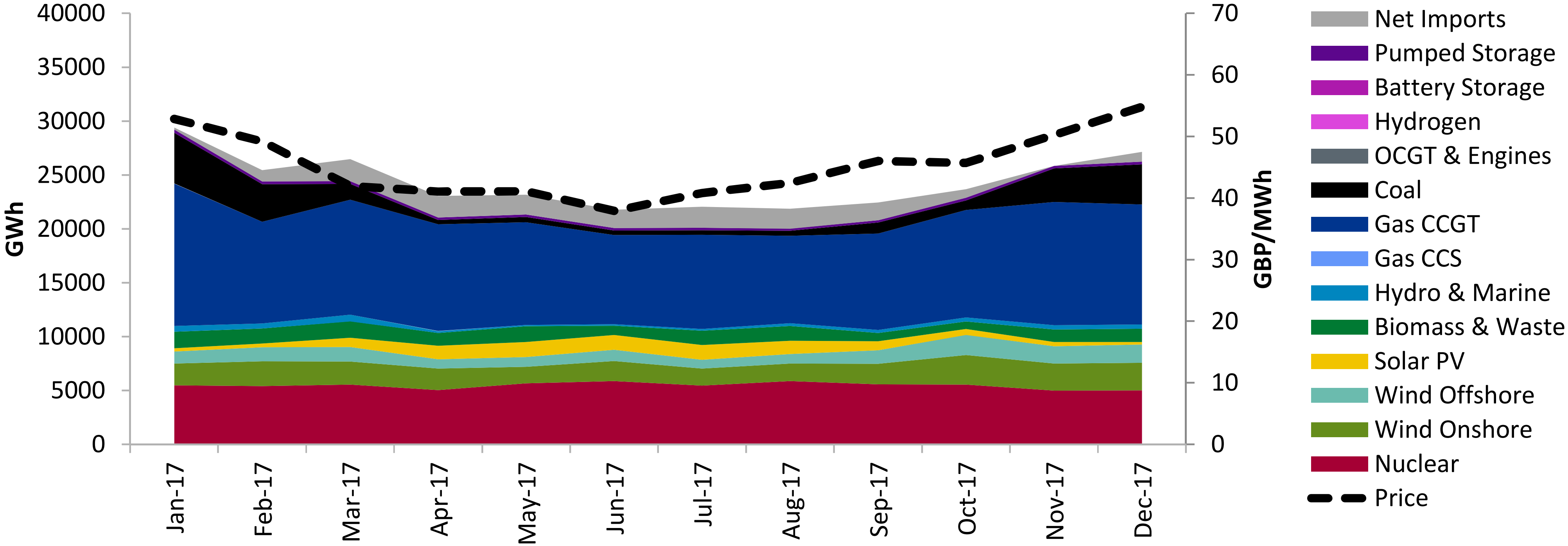
# Monthly generation – 2017

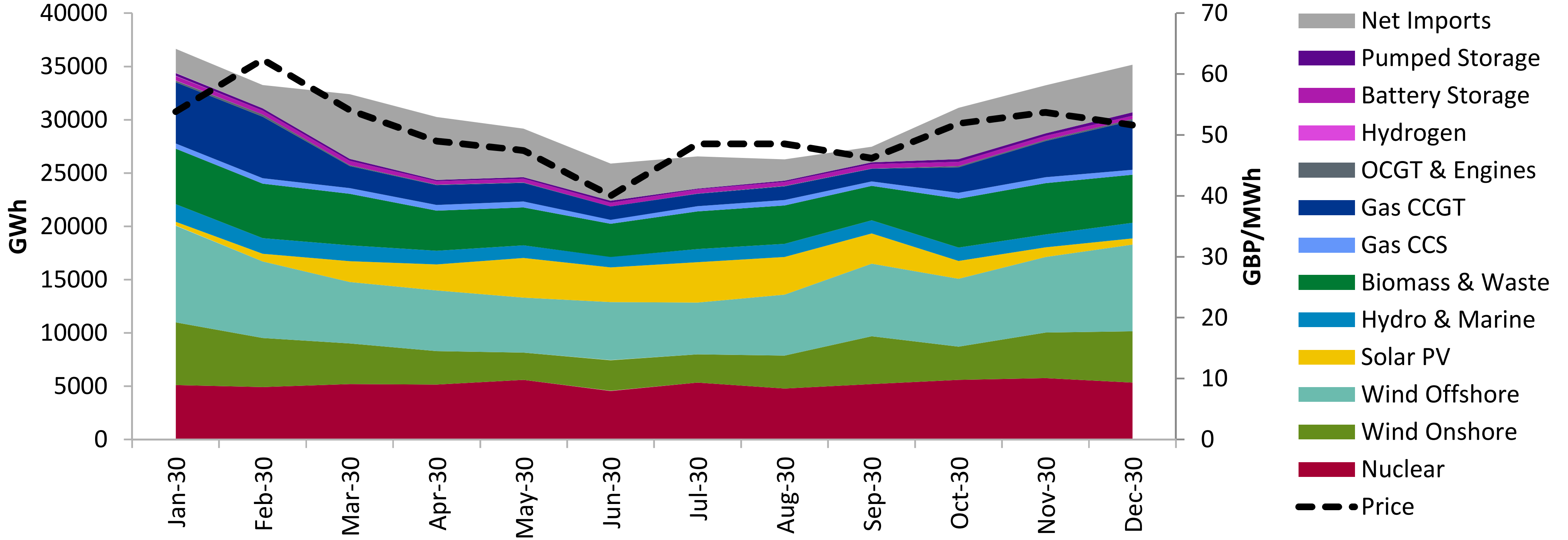
- Nuclear generation is roughly equal throughout the year while renewables vary throughout the year with wind generating more during winter and solar generating more during summer
- Gas CCGT generated at 40-50% average load factors during the winter and ~30-40% during the summer. Coal plants generated almost exclusively in winter times
- Net imports were particularly high during summer with line load factors exceeding 70% in July
- Wholesale price varied throughout the year (£38-55/MWh) and was higher during the winter due to the higher electricity demand and gas prices



# Monthly generation – NG 2 Degrees

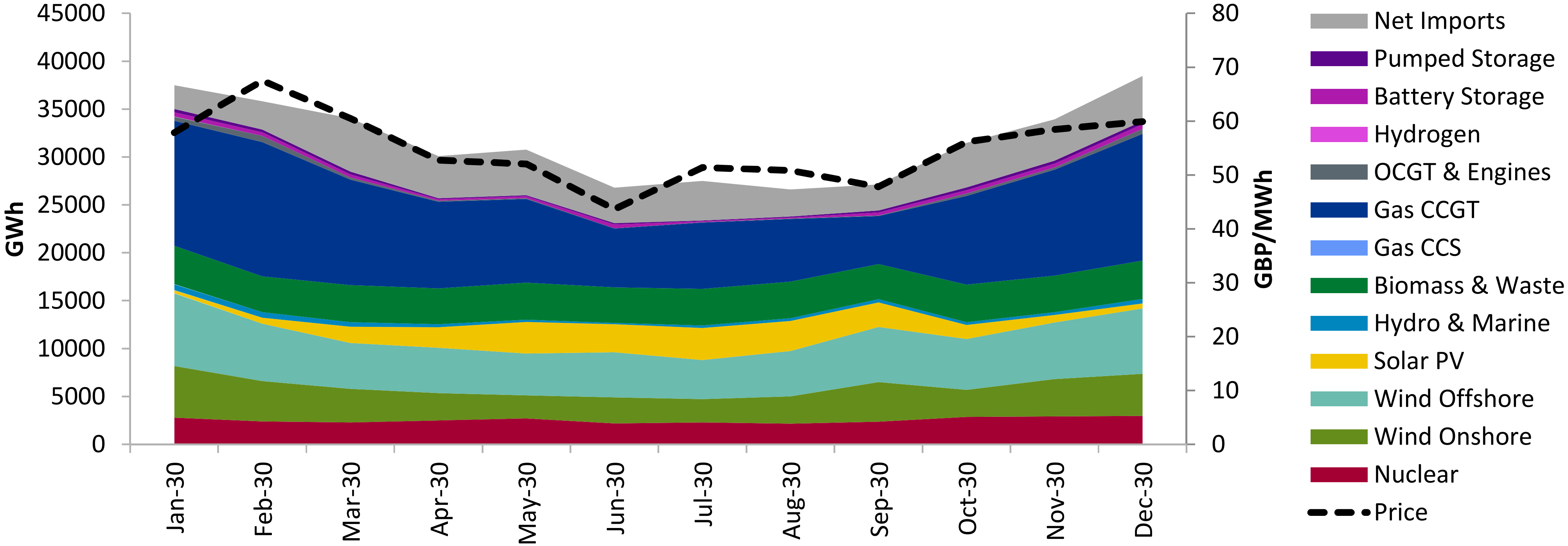
Baringa

- Nuclear generation is roughly equal throughout the year while renewables vary throughout the year with wind generating more during winter and solar generating more during summer
- Gas CCGT generates at 20-40% average load factors during the winter and ~10% during the summer
- Net imports are positive and high throughout the year especially spring when the reach on average 40% line load factor
- Wholesale prices varies throughout the year (£40-62/MWh) and are higher during the winter due to the higher electricity demand and gas prices



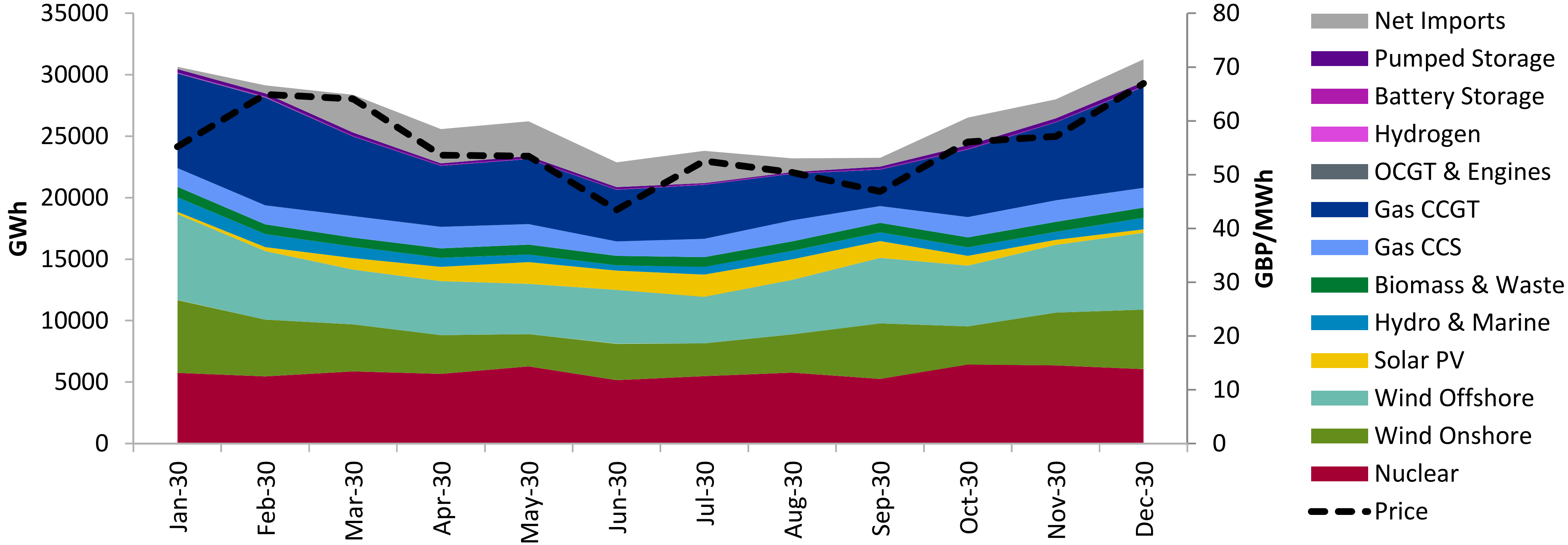
# Monthly generation – ETI LT ROG

- Nuclear generation is roughly equal throughout the year while renewables vary throughout the year with wind generating more during winter and solar generating more during summer
- Gas CCGT generates at 40-60% average load factors during the winter and 20-30% during the summer
- Net imports are positive and high throughout the year
- Wholesale prices varies throughout the year (£44-67/MWh) and are higher during the winter due to the higher electricity demand and gas prices



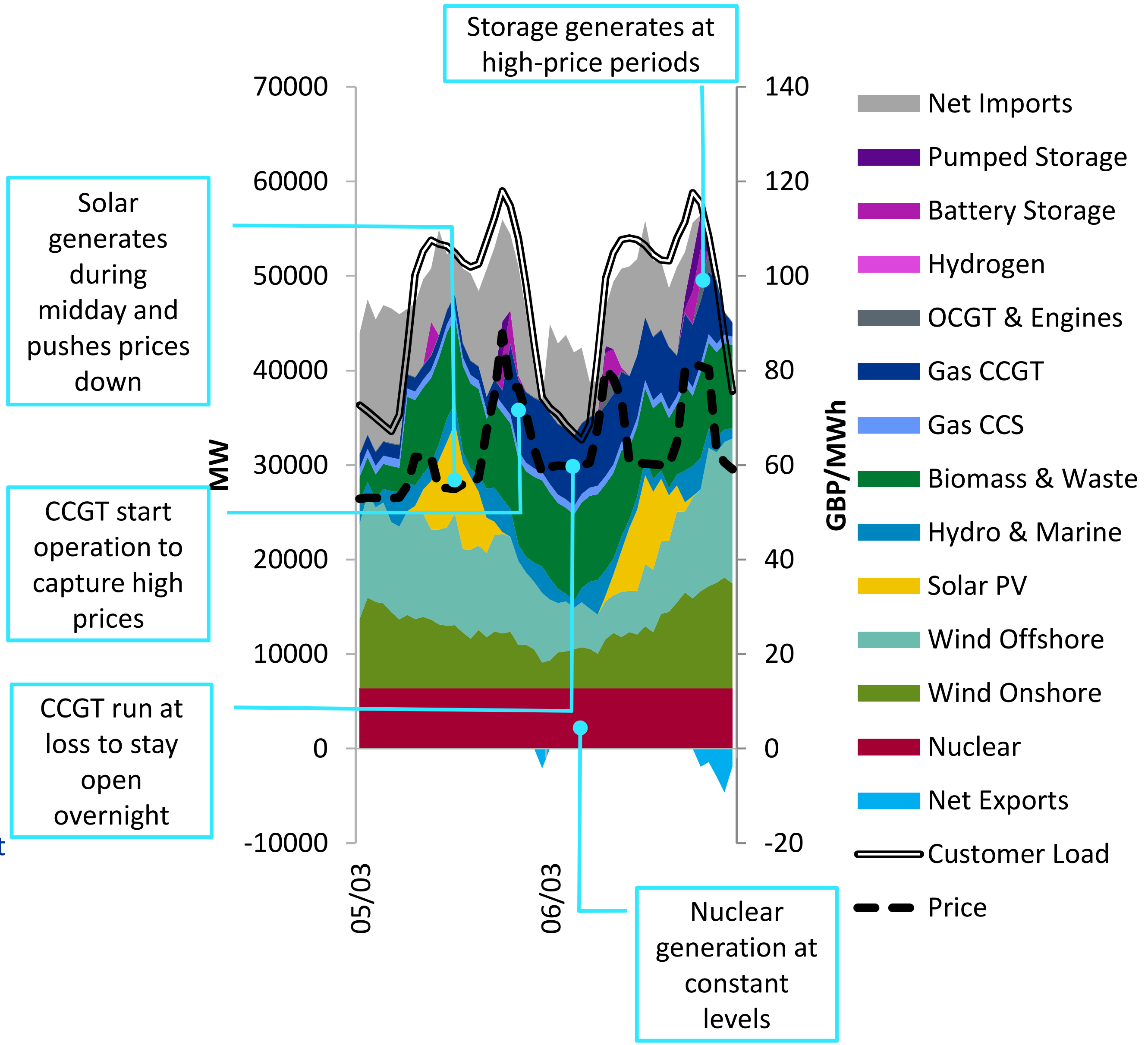
# Monthly generation – ETI CVEI

- Nuclear generation is roughly equal throughout the year while renewables vary throughout the year with wind generating more during winter and solar generating more during summer
- CCGT generates at 25-40% average load factors during the winter and at 15-25% during the summer. Gas CCS generate at high load factors throughout the year
- Net imports are high only during the summer due to the lower solar output compared to neighbouring markets
- Wholesale prices varies throughout the year (£43-67/MWh) and are higher during the winter due to the higher electricity demand and gas prices



# Dispatch & price charts explanation

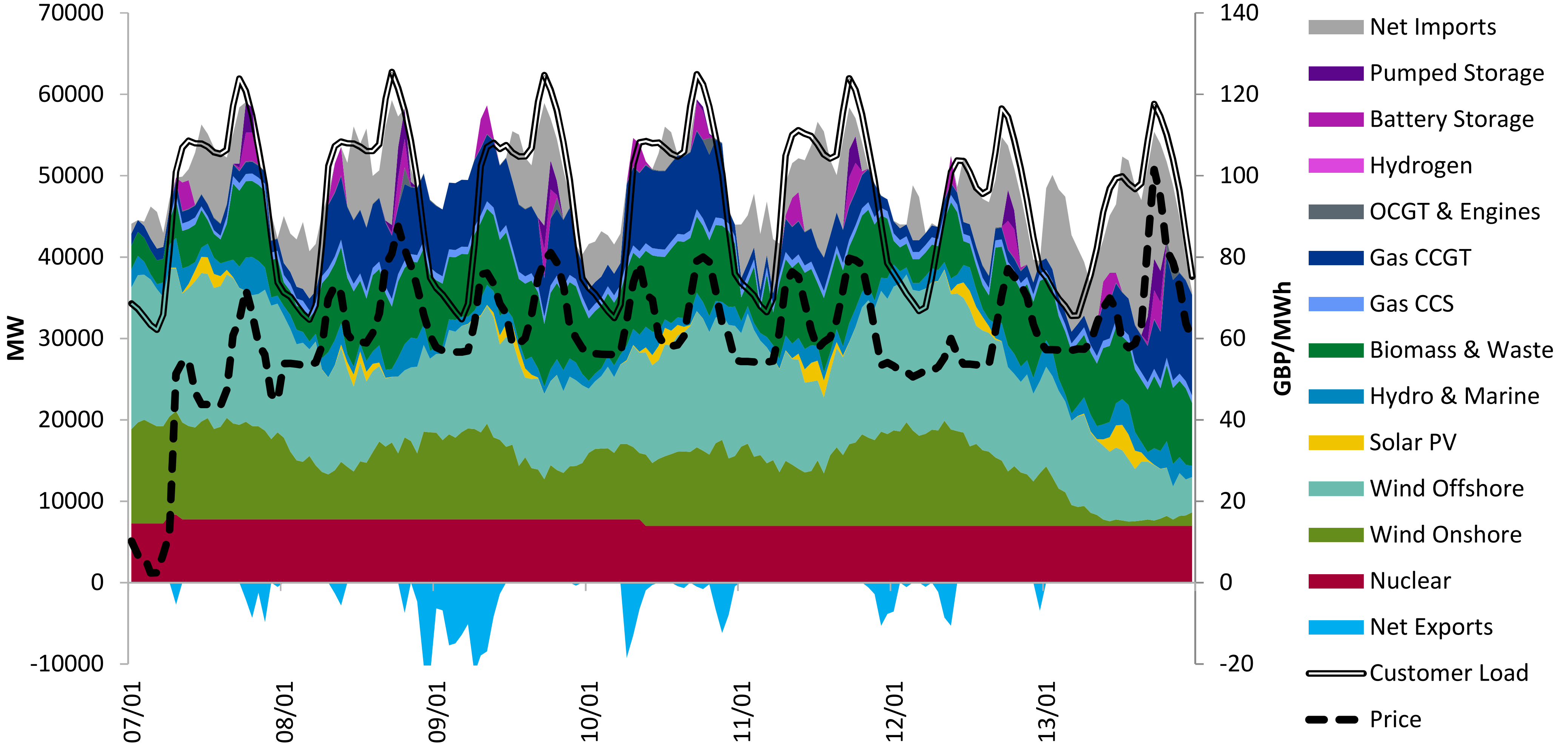
- In the following two slides, the hourly dispatch results and associated wholesale prices from two sample weeks are presented illustratively for the NG 2 Degrees scenario
  - The data for other sample weeks and the other scenarios can be found in the accompanying excel file
- The hourly dispatch results include the hourly
  - Generation by type in MW
  - Net imports and net exports in MW
  - Customer Load in MW is the demand without taking into account demand shifting and pump/battery storage load
  - Price (wholesale) in GBP/MWh (real 2017)
- The total hourly supply (generation + net imports) does not always match the Customer Load:
  - When the supply is higher that indicates that there is additional consumption in those hours either from storage units, from EV/HPs and/or exports
  - When the supply is lower that indicates that there is consumption shifted from this hour to other hours of the day/week
  - On average hourly supply is shown higher than inflexible load due to the net exports and storage load



# Dispatch & price – NG 2 Degrees – sample week in January

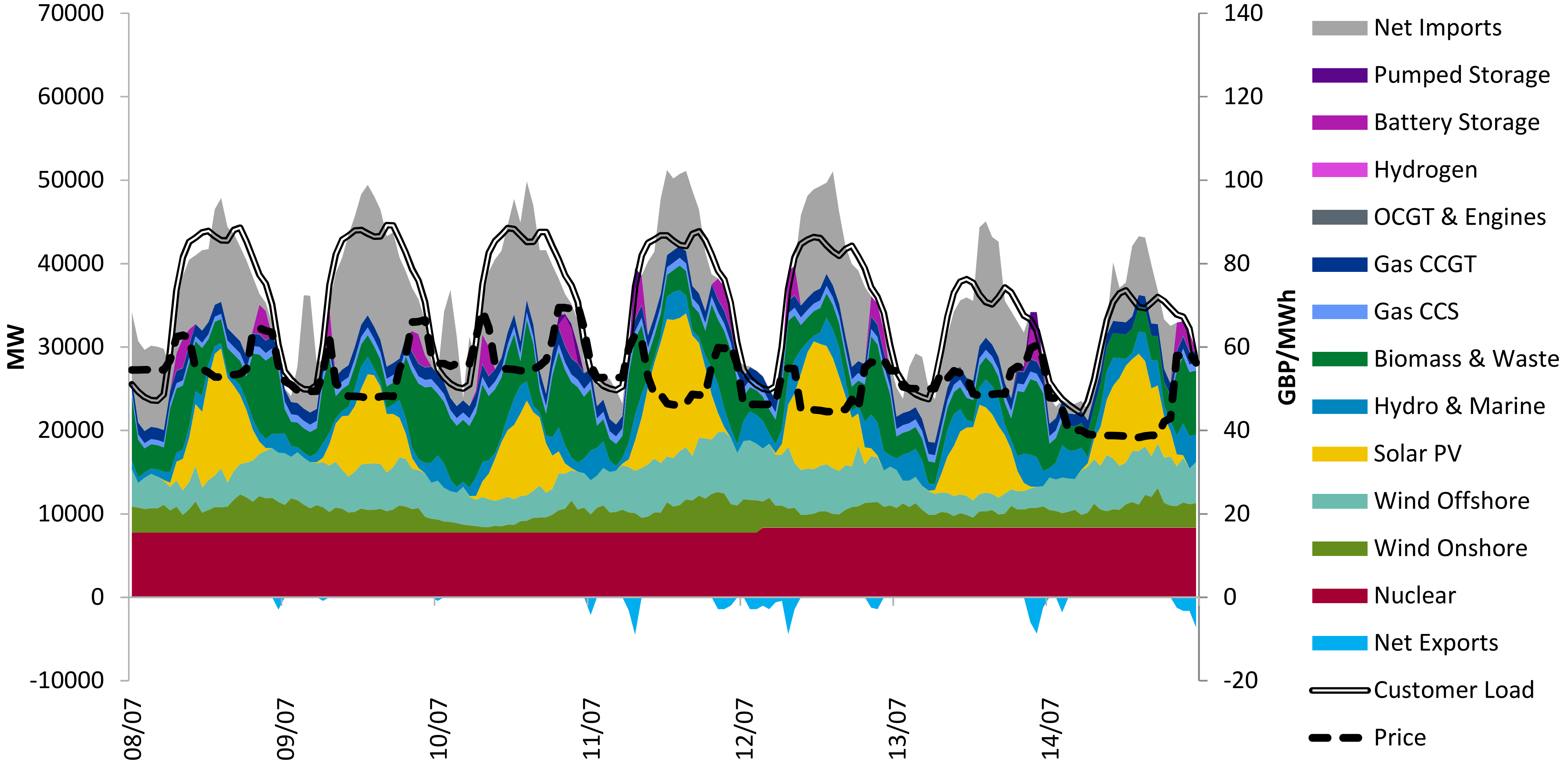
Baringa

Imports and low carbon generation supply most of the time the load. Storages supply several GW during the morning and evening peaks. Supply has mismatches to the customer load



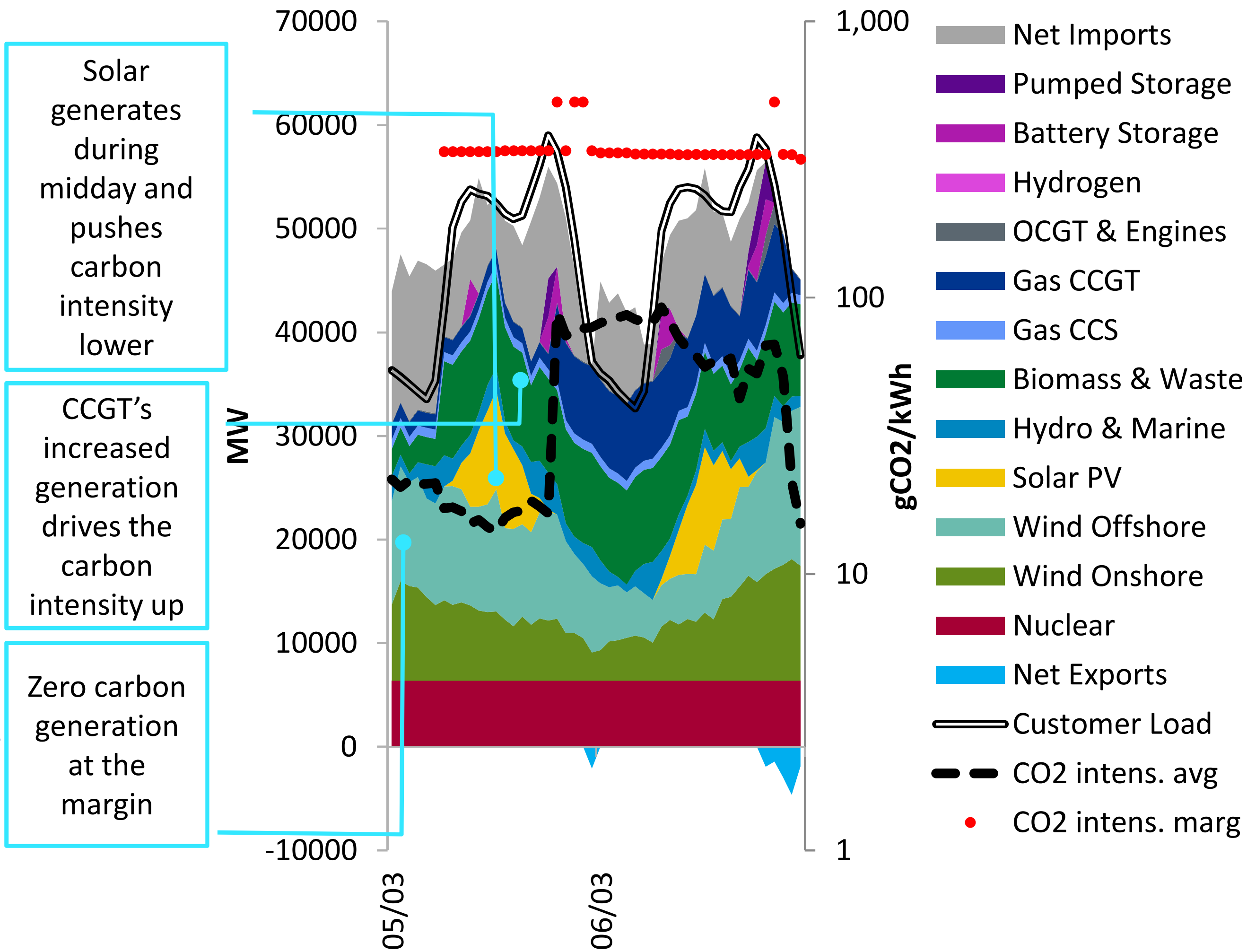
# Dispatch & price – NG 2 Degrees – sample week in July

Storage and gas generation are very low compared to winter times. Solar generation shifts the flexible demand to the midday hours



# Dispatch & carbon charts explanation

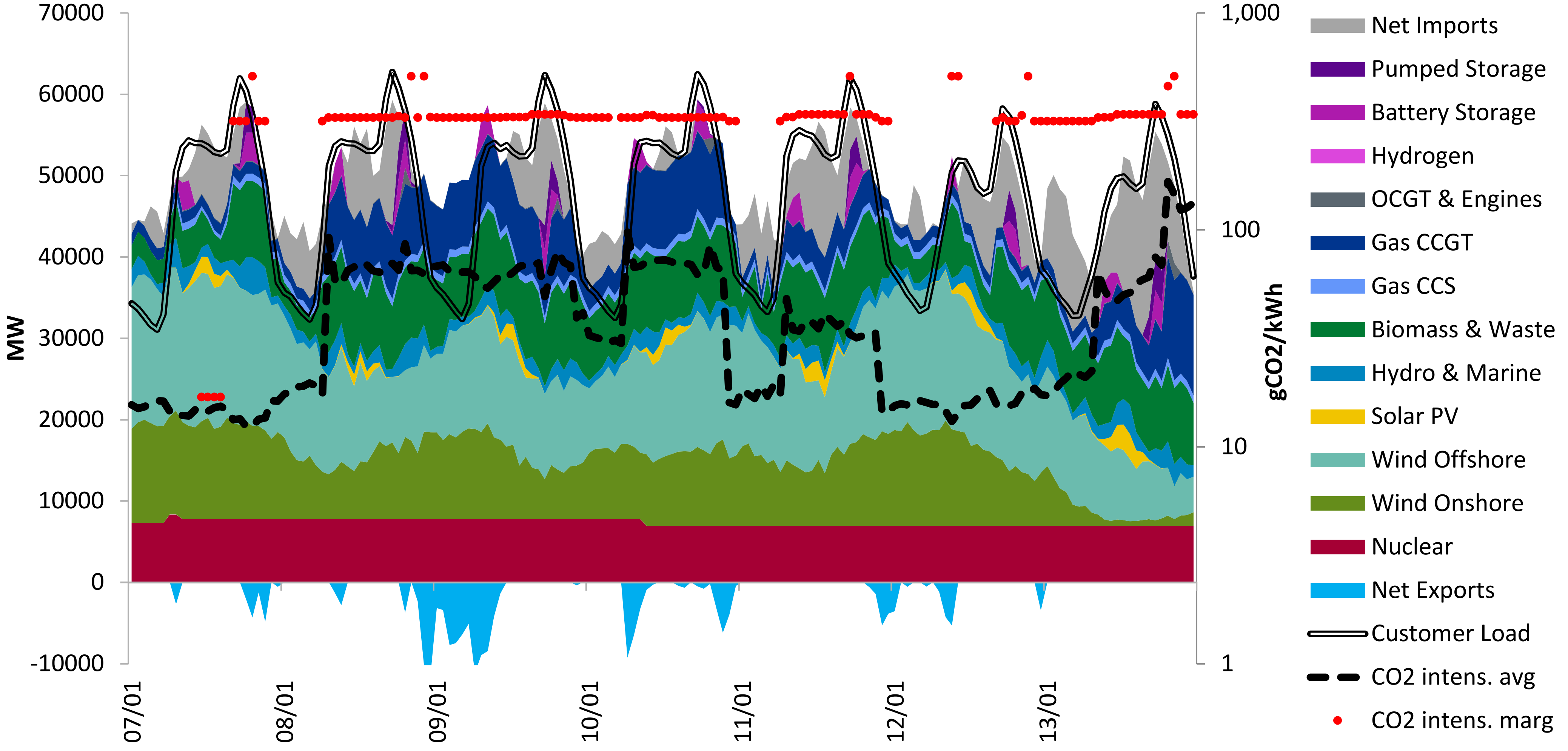
- In the following two slides, the hourly dispatch results and associated **carbon intensity** from two sample weeks are presented illustratively for the NG 2 Degrees scenario
  - The data for other sample weeks and the other scenarios can be found in the accompanying excel file
- Carbon intensity
  - Average carbon intensity is calculated by dividing the total carbon emissions to the total domestic power generation
  - Net imports are not accounted but are considered carbon neutral
  - Marginal carbon intensity is the change of carbon emissions when demand is incremented by one small amount. It is equal to the marginal carbon intensity of the marginal plant in the GB system. When the marginal carbon intensity is zero, it is not shown in the logarithmic secondary axis in the chart
  - Marginal carbon intensity is on average higher than the average carbon intensity because carbon intensive plants are more often at the margin



# Dispatch & carbon – NG 2 Degrees – sample week in January

Baringa

Gas plants are in the margin for over 50% of the time with their marginal carbon intensity being ~330gCO2/kWh. Average carbon intensity is far lower even in winter



# Dispatch & carbon – NG 2 Degrees – sample week in July

Gas plants are in the margin for around 50% of the time. In summer, the most efficient gas plants run more which result in a lower carbon intensity. Average carbon intensity is lower than winter