Programme Area: Energy Storage and Distribution

Project: 2030 Electricity Price Time Series

Title: Methodology & key inputs

Abstract:

This deliverable is a slide pack which explains the assumptions used and methodology panned for this work. There is an accompanying spreadsheet of key input data.

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

Projection of hourly retail cost stacks in 2030 for three scenarios

Stage 1: Methodology and key inputs

ETI

02/02/2018

Introduction

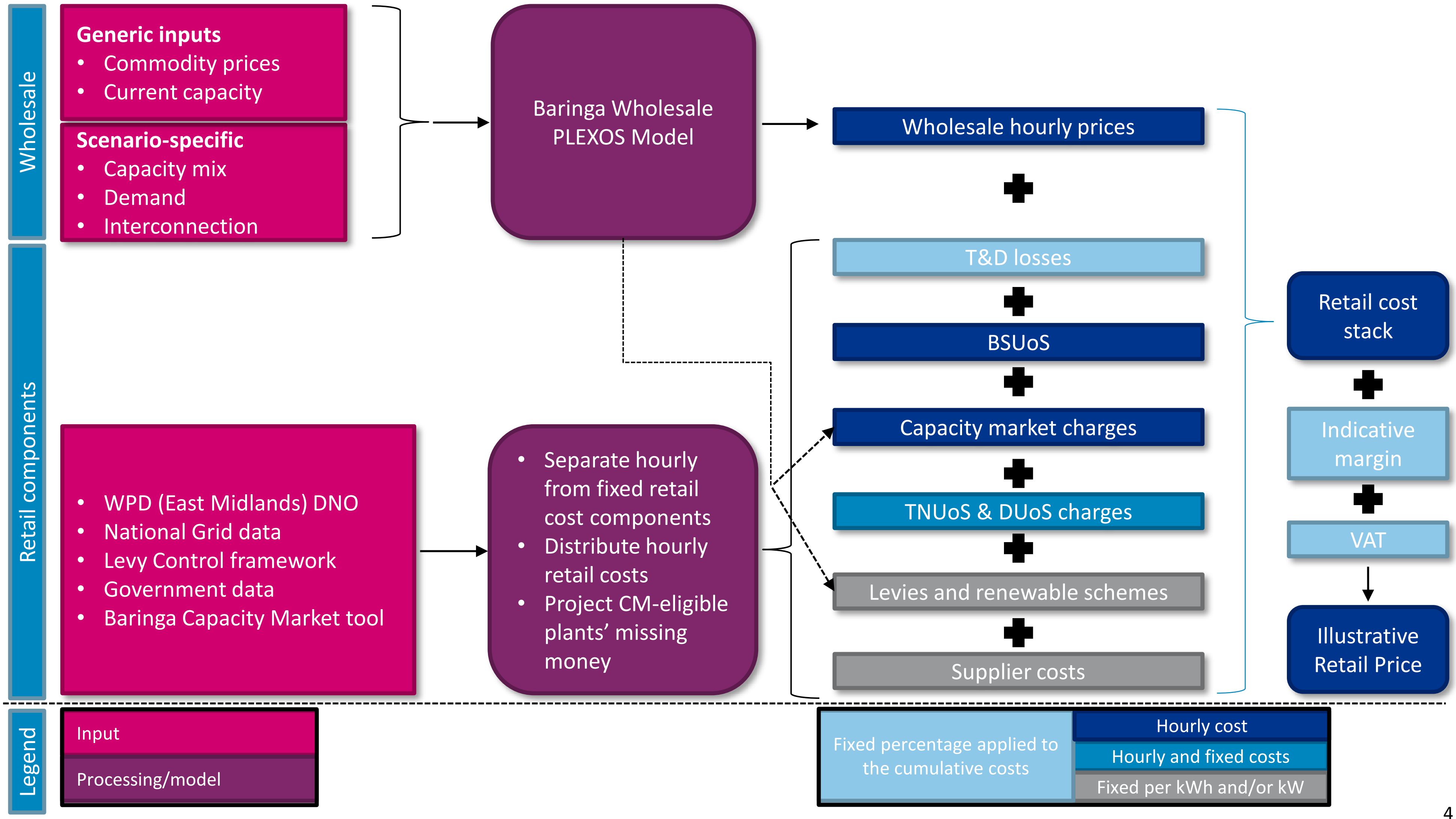
- **Scope:** The ETI would like to undertake detailed analysis of the potential shape of the cost components of future domestic retail electricity supply in 2030, based on a number of scenarios of capacity mix, some externally published and some generated by the ETI
  - We will project the direct costs for the supplier (excluding VAT)
  - The estimation of supplier margin is out of scope, and would depend on each supplier's hedging and retail strategy. However, we will present indicative margins and show the addition of VAT
  - In Great Britain there is differentiation on part of the retail costs based on region. We will select East Midlands as the region for which the retail cost stacks will be projected
- **Project stages:** The project is divided in three stages:
  - In Stage 1, Baringa and ETI will agree the methodology and key inputs used to construct the final hourly retail cost stacks. This document is the main deliverable of Stage 1 and contains Baringa's proposed main methodology and inputs. It is also accompanied by an excel deliverable with some of the proposed key input assumptions
  - In Stage 2, Baringa will undertake the main part of the analysis of the retail cost stack. Initially, Baringa will construct the retail cost stack for 2017 using actual historical data for wholesale price and retail cost components. We will use this as a benchmark to compare the 2030 scenario retail cost stacks. Then, we will construct the scenario-specific wholesale models, process the available data on retail cost inputs and generate the first set of results for each of the scenarios
  - In Stage 3, we will finalise the key results of the scenarios, and will produce a detailed technical report and a short viewpoint that explores the key insights and summarises messages for policy makers and other stakeholders
- **Methodology:** The wholesale price comprises just over one third of the total retail cost stack and several other components, mainly network costs and levies, make up the rest
  - Wholesale: We will project the hourly wholesale price separately using our existing in-house wholesale model and inputs agreed with ETI in Stage 1 of this project. The capacity and demand assumptions will be scenario-specific. We will use three different scenarios and their differences are described in slide 4: National Grid Two Degrees (NG 2 Degrees), the ETI Long Term Role of Gas (ETI LT RoG) scenario and the ETI CVEI scenario
  - Retail cost components: Most retail costs will be independent of the wholesale results and scenarios. They will be projected to 2030 when possible given publicly available information or they will be kept flat if this is not possible. The modelling will assume current policies (as reasonably extrapolated into the future), or new policies where these are already known. We will allocate the costs to an hourly level when appropriate such as in TNUoS charges (TRIADs) and DUoS (blocks)

Approach to Stage 1

Core scenario selection	▪ Consider a range of energy market scenarios, reviewing capacity mix, demand and outcomes (e.g. carbon intensity)
Identify retail cost elements	▪ Identify the elements that comprise the retail cost stack ▪ Determine any interactions between them (e.g. wholesale prices drive CM bidding behaviour)
Adapt scenario inputs	▪ Where a scenario has an assumption that is out of date, adapt accordingly to reflect current market ▪ Where scenarios provide insufficient detail (e.g. demand flexibility) infer/estimate appropriate parameters
Define approach by cost item	▪ For each cost element, determine whether to differentiate by scenario ▪ For each cost element, define the data source to be used ▪ Determine the modelling approach for each element (if applicable)
Map scenarios to cost items	▪ Collate data applicable to each scenario

Methodology to deduce retail stacks

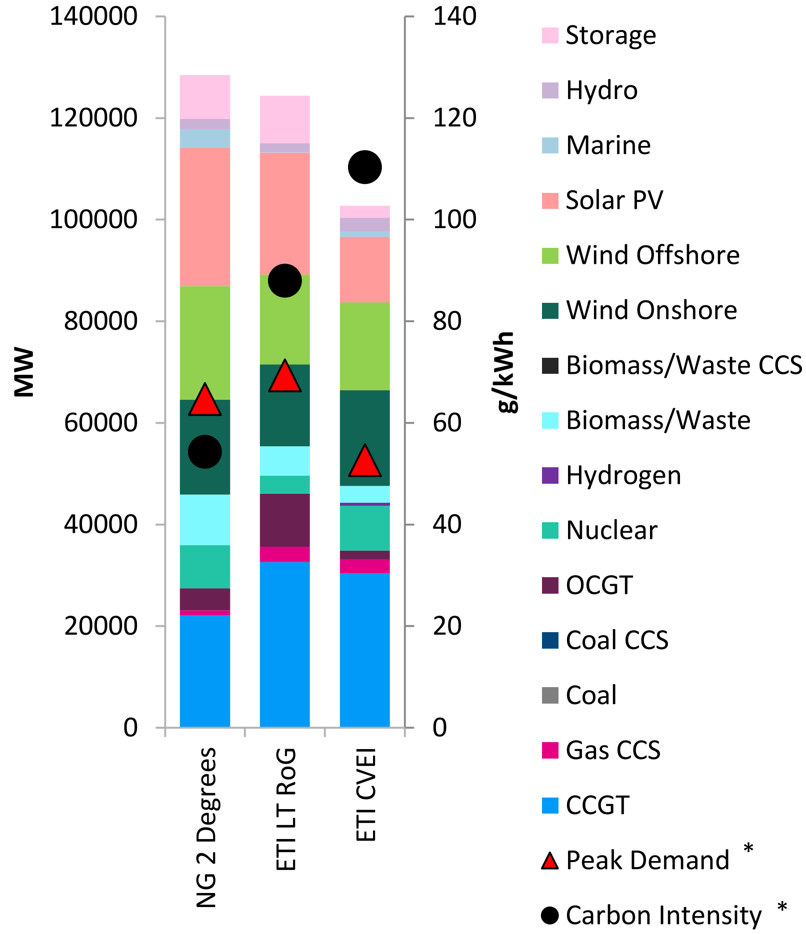
Wholesale component is generated independently from the retail cost components. Some retail cost components will be affected by the wholesale results



Inputs – selection of scenarios

The three selected scenarios assume different degrees of decarbonisation by 2030 as well as different ways of accomplishing the decarbonisation of the grid

- **National Grid Two Degrees (NG 2 Degrees) – original / not adapted**
  - National Grid published four long-term electricity scenarios, the most decarbonised of them being the “Two Degrees”
  - The capacity mix in 2030 includes 41 GW of wind, 27 GW of solar, 8.5 GW of nuclear as well as nearly 4 GW of marine technologies
  - As a consequence, carbon intensity drops to nearly 50 g/kWh by 2030
  - Includes 18 GW of interconnection in total
- **ETI Long-Term Role of Gas (ETI LT RoG) – original / not adapted**
  - Based on inputs from ESME, this scenario was developed for ETI by Baringa in order to derive the cost-optimal pathway for GB to achieve carbon reduction targets by 2050
  - The 2030 capacity mix has lower penetration from low carbon technologies than “Two Degrees”, with 34 GW of wind, 24 GW of solar and 3.5 GW of nuclear but higher conventional baseload CCGT capacity of 33 GW
  - At 90 g/kWh, the carbon intensity is higher than “Two Degrees”
  - Includes 13 GW of interconnection
- **ETI Consumers, Vehicles and Energy Integration (ETI CVEI) – adapted**
  - 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
  - Demand and capacity are lower than in the other two scenarios. Wind, solar and nuclear capacity are 25 GW, 13 GW and 9 GW, respectively
  - The original carbon intensity for this scenario is 110 g/kWh
  - A total of just 8.5 GW of interconnection



* Peak demand and carbon intensity may change in the model due to 1) different commodity price assumptions compared to the original models 2) different interconnector prices/flows and 3) different treatment of flexible demand

Inputs – wholesale price model

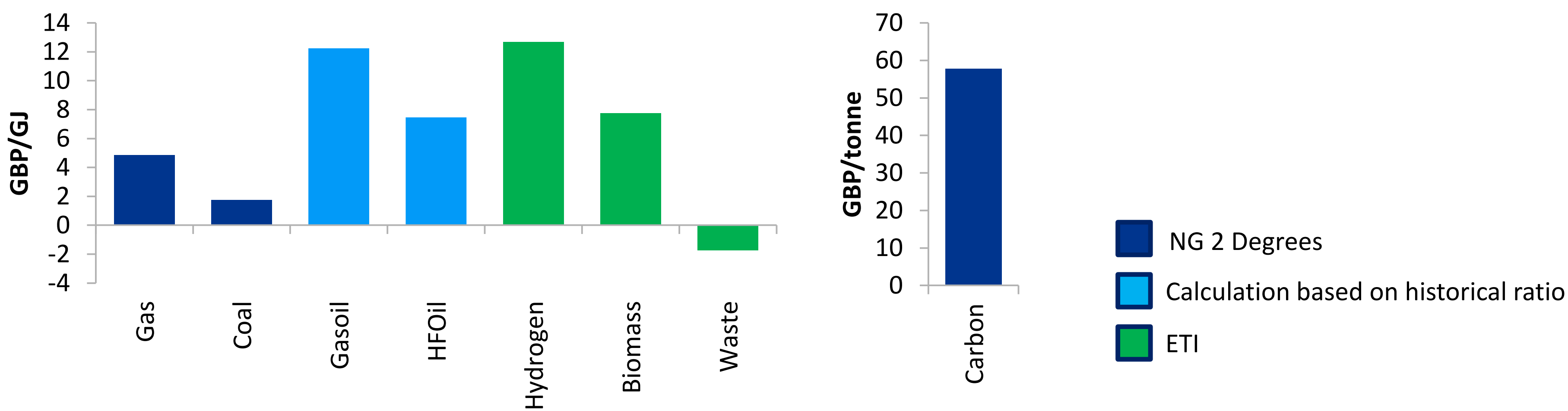
Baringa

Input	Description	Source/methodology	Baringa IP
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	**Yes**
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	**Yes**
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	**Yes**
Renewable profiles	Non-dispatchable renewable hourly generation is an input to the model	Baringa wholesale model for wind and solar, ETI for tidal	**Yes**
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	**Yes**
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	**Yes**

Inputs – wholesale price model (1) – commodity prices

- **Commodity price in 2030**
  - The main commodity prices (gas, coal and carbon) will be 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 will be taken from the ETI LT RoG model

- **Commodity price charts**



Inputs – wholesale price model (2) – demand

- **Inflexible demand**
  - Annual and peak demand are scenario-specific assumptions and they are provided in the excel file that accompanies this report
  - We will use the actual historical load shape (based on the year 2012) in order to derive the 2030 load shape
  - We will a tool provided within PLEXOS that allows us to shape demand based on a base year (2012) using different annual demand and peak demand figures. These annual demand and peak demand figures will be net of flexible demand as it is described below. Therefore the remainder will be the inflexible demand
  - ETI LT RoG already has its own 2030 hourly load profile which can be used directly and has taken into account HP operational flexibility (Time of Use blocks)

- **Flexible demand**
  - A part of the electricity demand in 2030 will be flexible (managed charging/consumption via demand aggregators/suppliers or directly from large customers)
  - We will include two types of flexible demand:
    - Electric Vehicles (EVs): The assumptions for the total EV consumption and the proportion of the EVs under managed charging will come from the scenarios. The inflexible part of the EV consumption will be added in the inflexible demand above. The flexible part of the demand will be optimised by the model: The daily load from EVs is assumed to be fixed and the model can optimise the time of consumption with the constraint that the load in each hour cannot exceed 15% of the daily load
    - Electrified heat: The assumption on electrified heat annual consumption and number of heat pumps will come from the scenarios. We have assumed that each unit of (flexible) heat pump has a capacity of 3.4 kWe and 7 hours of heat storage. We will assume that 50% of the heat pumps will be flexible

Inputs – wholesale price model (3) – capacity

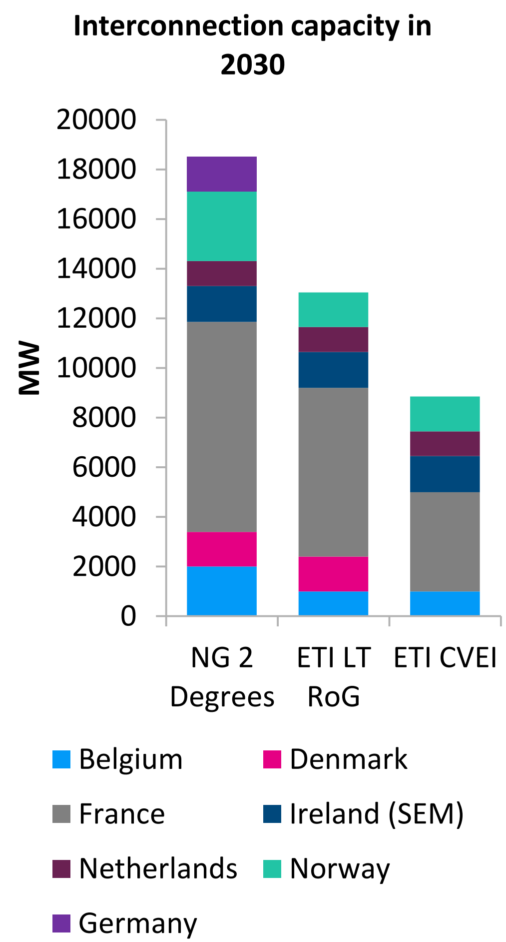
Baringa

- **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 (4) - 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 will be dependent on the prices of the neighbouring markets
  - We will use our in-house Pan-Europe PLEXOS wholesale model and the commodity price assumptions of this project to generate the hourly interconnector prices for 2030

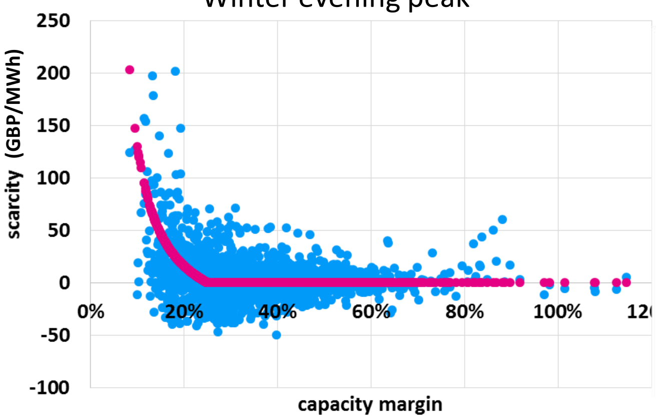


Inputs – wholesale price model (5) - scarcity

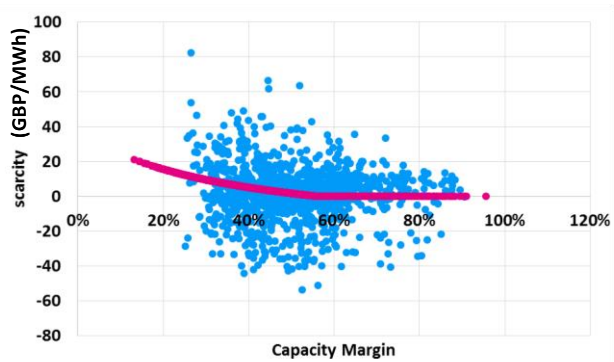
- **Scarcity premia**
  - We will assume that when the capacity margin is tight, generators will be able to bid prices higher than their SRMC. This creates additional rent that is received by all plants that generate during those hours and makes up the scarcity revenues. The scarcity premium can increase 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

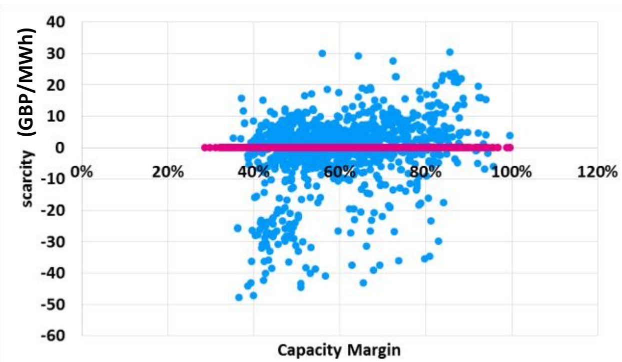
Winter evening peak



Spring/autumn evening peak



Summer evening peak



Inputs – retail cost components (network and peak charges)

Input	Description	Source/methodology	Baringa IP
Demand - consumer profile	10-year average domestic consumer profile that will be used to determine the settlement of some of the charges below (e.g. DUoS)	ELEXON consumer profiles	-
Losses (generator-side)	Charge to generators for part of transmissions losses (location and time specific)	CMA's P350 (45% share of T-losses)	-
BSUoS (generator-side)	Charges to generators for balancing the system	Average and shape based on NG historical data	-
BSUoS (demand-side)	Charges to suppliers for balancing the system	Same as the generator-side charge	-
T&D losses (demand-side)	Charges to suppliers for the network losses of their customers	P350 (55% share of T-losses) and WPD for D losses	-
TNUoS charges	Charges to cover the transmission network costs	Extrapolation of current policy	
DUoS charges - variable	Charges to the suppliers for the use of distribution network (time-variable)	DNO (East Midlands)	-
DUoS charges - fixed	Charges to the suppliers for the use of distribution network (fixed per kW)	DNO (East Midlands)	-
AAHEDC	Charge to provide "Assistance for areas with high electricity distribution costs" to the region of Northern Scotland	National Grid	-
ELEXON charges	Charges to suppliers to cover part of ELEXON costs	ELEXON annual reports	-
CMSC (Capacity Market Supply Charge)	Charge to recover the capacity revenues of the CM-participating plants	Missing money for CM-cleared plants	Yes *

*We can share the final figure as it will be scenario specific but many assumptions feeding into that figure are our commercial IP

Inputs – retail cost components (levies, taxes, supplier fees)

Input	Description	Source/methodology	Baringa IP
Renewables Obligation	Recovery of the Renewables Obligation scheme costs	Existing capacity into RO, RO contract length, RO buy-out price, assumption on premium over the buy-out price at 10%	-
Feed-in tariff	Recovery of the Feed in Tariff scheme costs	OFGEM FiT report, applying LCF cap	-
CfD / Supplier Obligation	Recovery of the Contracts for Difference scheme costs	Existing and projected (only offshore) capacity	-
ECO (Energy Company Obligation)	Pass-through of costs related to Energy Company Obligation investments that affect the electricity consumption/bill	OFGEM, BEIS statistics	-
Management fee	Charge to recover the suppliers' costs of preparing the bill, arranging payments and providing customer service/support, as well as imbalance charges	Assumption and Baringa modelling	**Yes**
Meters and meter reading	Cost for the supplier for metering and processing consumption data as well as pass-though of the costs for smart-meter rollout	BEIS Smart meter roll-out cost-benefit analysis	-
VAT	Value Added Tax imposed by government. This is not a retail cost component but we will add an illustrative retail price that includes the VAT on top of the retail cost stack	Government VAT Notice 700: at 5% for domestic/small users	-

Inputs – retail cost components – detail (1)

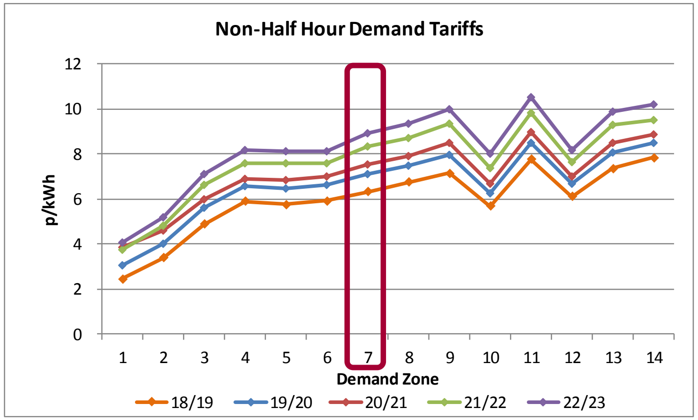
- **Consumer profile**
  - We will use the average domestic hourly profile (Profile 1) from ELEXON in order to determine the settlement of many of the retail cost components such as BSUoS, TNUoS, DUoS and CMSC

- **Inputs to missing money calculations fed to Capacity Market (CM) and Contracts for Difference (CfD) calculations**
  - In order to deduce the Capacity Market charge and the CfD spent (detail descriptions in the following slides), we will need to calculate the missing money of the plants that will benefit from those revenue streams
  - We will estimate the annualised fixed costs of all the main types of generators participating in CM and CfDs using ESME v4.4 assumptions on capex, fixed operating costs and lifetime. We will assume that the WACC of all these projects will be at 6% in real terms
  - We will also use our in-house and plant type-specific assumptions for other revenues of generators such as ancillary services and balancing market revenues. These figures will be added to the calculations of missing money for CM-participating plants. The only technology assumed to be awarded CfDs in the future (according to current policy) will be offshore wind which do not receive ancillary revenues

- **Losses**
  - We will include transmission losses of 2.33% based on National Grid's Introduction of a seasonal Zonal Transmission Losses scheme (P350). We will use season-varying loss factors as they are provided publicly
  - Distribution losses include both technical (copper and iron losses) and non-technical losses (theft, meter errors, other inaccuracies)
    - Loss Load Factors provided taken from WPD East Midlands, to be consistent with TNUoS and DUoS
    - Latest WPD estimate is taken, representing 2018/19, which defines four different periods during the week for loss calculations
    - 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

Inputs – retail cost components – detail (2)

- **BSUoS**
  - BSUoS covers response, reserve, constraint management and other smaller services (e.g. Reactive power, e.g. Black Start)
  - Upward drivers, such as more intermittency and lower inertia may be offset by an increase in the supply of flexibility
  - We will base our BSUoS projections on 2016/17 settlement data from National Grid
  - The 2030 average BSUoS charge will be assumed at the same average level (2-2.5 £/MWh)
  - We will vary the BSUoS charge based the hourly profile shape (24 data points) using the same historical data
- **TNUoS**
  - We will use TNUoS zone 7 (East Midlands) as a representative location
  - It is our view that the TRIADs will be replaced by another system well before 2030. We also believe that other changes such as removal of the floor of 2.5 £/MWh for TNUoS on generators and/or greater proportion of demand-side TNUoS are likely to happen. However, due to the absence of certainty of what the system will be (at the time of writing), we will assume current policy will remain in place in regards to cost recovery
  - National Grid's NHH demand projections to 2022/23 show an increase for three reasons:
    - Figures expressed in nominal terms, reflecting inflation at RPI
    - Decline in chargeable zonal NHH volumes, requiring higher tariffs to cover costs
    - Projections of embedded renewable generation
  - We will convert National Grid's projections to 2022/23 into real terms and extrapolate to 2030 based on the CAGR (calculated to be 6%)
  - TNUoS will be charged on each MWh that occurs between 4-7 PM throughout the year which is the way that is currently recovered for domestics

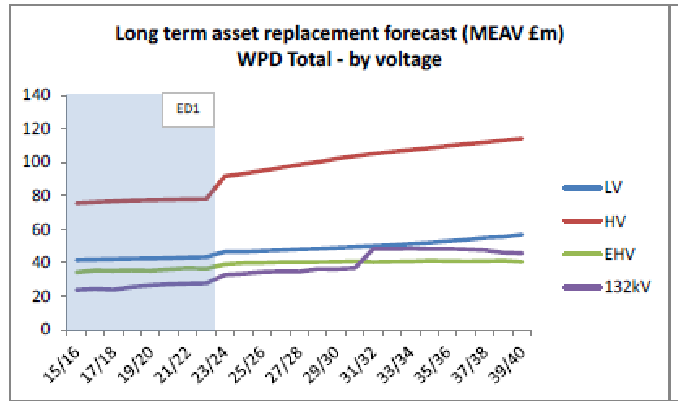


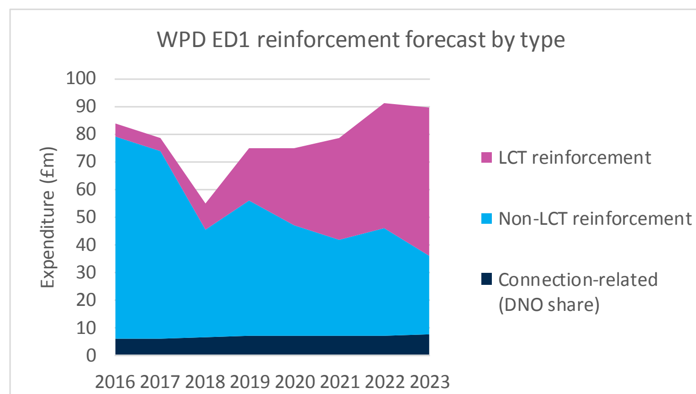
Inputs – retail cost components – detail (3)

Baringa

- **DUoS**
  - We will base our projections on the 2019 DUoS charges applicable
    the East Midlands (Western Power Distribution)
  - Projections will be based on WPD's RIIO-ED1 business plan,* assuming that domestic DUoS scales with DNO allowed revenue
    - Condition-based asset replacement costs (representing 25% of total expenditure) estimated by WDP to 2030
    - Reinforcement cost (representing 10% of total) projections given to 2023, split into LCT-related increase and efficiency-related decrease. Efficiency savings may decline, in which case LCT increase could dominate, although this will be offset by increase in Flexible Connections and DNO-tendered flexibility services
    - All other cost components that feed into DUoS calculate are assumed flat from 2019

T	Tariff name	Open LLFCs	PCs	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 char p/MPAN/d
Domestic Unre	Domestic Unrestricted	1	501	2.060		3.03	3.03





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

Inputs – retail cost components – detail (4)

- **CMSC (Capacity Market Supply Charge): total charge**
  - We will assume that CM eligible generators are bidding into the CM market with the purpose of recovering the costs that they cannot recover from the wholesale, balancing and ancillary services markets
  - $\mathbf{TotalCapacityMarketSupplyCharge(y)} = \sum_{g,Y} \boldsymbol{DeratedCapacity(g)} \cdot \boldsymbol{CapacityClearingPrice(Y)}$, Y includes all previous years
  - Therefore for each of the plants that participate in the CM market, we will calculate/estimate their revenues and costs:
    - Costs: discounted-annualised fixed costs, their TNUoS costs and gas capacity charges
    - Revenues: Their wholesale margins for each scenario using the three sets of scenario-specific wholesale market model results as well as their non-energy revenues such as balancing market and ancillary services
  - We will calculate the minimum required capacity revenues per plant and therefore the minimum capacity charge for each of plants based on the following equation:
  - $\boldsymbol{MinCapacityRevenues(g,y)} = \boldsymbol{TotalCosts(g,y,)} - \boldsymbol{TotalRevenues(g,y,)} = \boldsymbol{AnnualisedCapex(g,y)} + \boldsymbol{TNUoS(Gen_{Side})(g,y)} + \boldsymbol{GasCapacityCharge(g,y,)} + \boldsymbol{FOM(g,y)} - \boldsymbol{WholesaleMargin(g,y)} - \boldsymbol{OtherRevenues(g,y)}$
  - $\mathbf{CapacityBidPrice(g,}\boldsymbol{y}\mathbf{)} = \boldsymbol{MinCapacityRevenues(g,y)/DeratedCapacity(g)}$
  - With current CM rules, the clearing price is determined each year by the maximum bid that is required to clear the auction required volumes: $\mathbf{CapacityClearingPrice(y)} = \mathbf{Min(75, Max(CapacityBidPrice(}\boldsymbol{g,y}\mathbf{)))}$
  - CM clearing prices will differ each year and the total charge paid each year will depend on previous prices as well. We will investigate if the clearing price can be determined using the three scenarios and 2030 as the indicative year of wholesale revenues. In case that the price is set by an outlier plant, we will investigate other ways of capturing the volatility of CM clearing prices from previous years
  - The de-rated capacity assumption for each plant will depend on its type based on the relevant publication from the EMR delivery body
- **CMSC: distribution and hourly shape of cost**
  - The total CMSC will be spread equally on each MWh of demand that occurs during 4-6 PM on working days in the months of January, February, November and December. That demand corresponds to about 4% of the total annual demand

Inputs – retail cost components – detail (5)

- **Environmental levies:**
  - There are three schemes aimed to promote renewable generation that are charged to suppliers. All these three are limited by the cap as described in the Levy Control Framework
  - Renewables Obligation: All plants that will benefiting from this scheme are already existing. Their capacity and contract length is known from public sources. The RO buy-out price is flat at 45.58 £/MWh (in real terms) and we assume that on average there will be a 10% uplift on RO spend
  - Contracts for Difference: The funds allocated to CfD will be based on:
    - Historical CfD and capacity contracts won (public information)
    - Projection of funds required to recover the costs of the scenario-specific assumed offshore wind capacity. Therefore that component will vary by scenario
  - Feed in Tariffs: We will use the latest government's projection for FiT spend in 2020/2021 and publicly available data on capacity FiT contract lengths and prices to calculate the reduction of FiT expenditure towards 2030 (available from OFGEM)

- **Obligations:**
  - Energy Company Obligation (ECO): most of the costs associated with ECO are charged to the gas bills rather than the electricity bills. We will use historical data published by OFGEM/BEIS in order to find the allocation ratio for gas and electricity bills. We will use the latest projection from the government in regards to forecast of total ECO expenditure and keep it flat for 2030

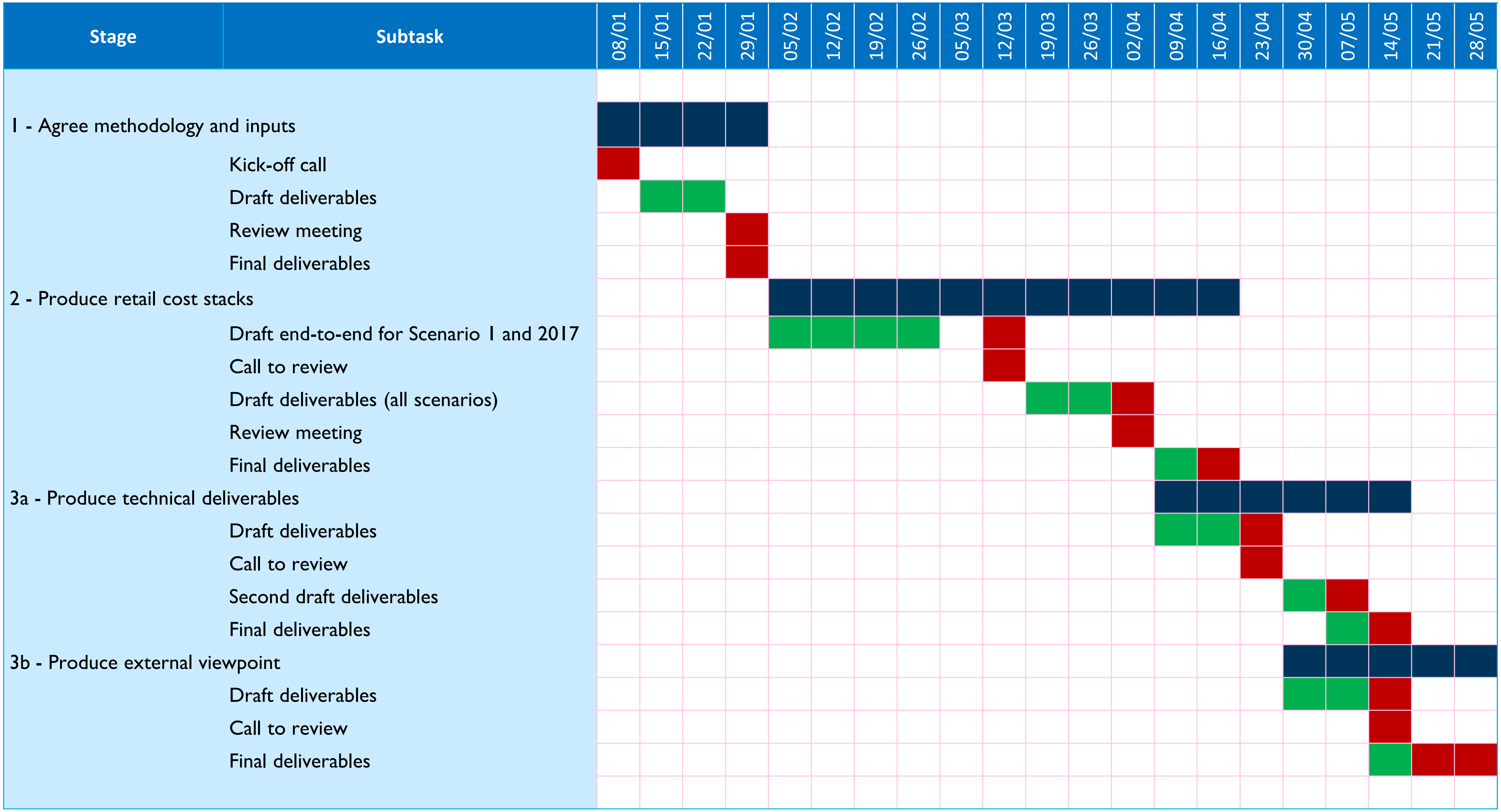
- **Hourly shape of levies and obligations:**
  - All levies and obligations will be charged as a fixed rate (at annual level) on consumption except CfD charge
  - The CfD charge will be charged at a fixed rate which differentiates by quarter

Inputs – retail cost components – detail (6)

- **Supplier costs**
  - Management fee: We will add a fixed cost per MWh management fee (around 0.5 £/MWh - may be altered during Stage 2) that will be used to cover the costs associated with preparation of the bill and customer service as well as imbalance costs. The imbalance costs cost refer to the load forecasting uncertainty and these costs are charged to the supplier. These will be based on our in-house Reference case projections
  - Metering fee: We will use the BEIS study ("Smart meter rollout: cost and benefit analysis") to derive a fixed annual charge to recover the costs of metering (including smart meter, IED, installation and data processing)
  - Supplier margin and risk management: We will not include these charges to the retail cost stack because it is not a direct cost to the supplier but it depends on practice and the structure of the consumer proposition as well as the business model

Project plan and deliverables for stages 2 and 3

Plan largely unchanged except for shifted start date and inclusion of 2017 scenario



Baringa
Brighter together