Programme Area: Carbon Capture and Storage

Project: Hydrogen Turbines Follow On

Title: Scenario 0 Results Pack

Abstract:

Various scenarios for the UK's power fleet composition in 2030 and 2040 were developed. Dispatch modelling in Plexos was carried out by Baringa on these fleets to investigate the role gas fed plants might have in future. This includes the ability to study load factors, stop/starts etc, and together with concomitant pricing, provide a picture of investment remuneration. The effect of key drivers is studied e.g. gas price.

Context:

Increasing amounts of subsidised renewable power is reducing load factors of gas fired power generation. This work set out to get a view on whether new gas GT looked investible, and if GTs with CCS could expect reasonable load factors. The work concludes with a comparison of gas usage in three scenarios , the first being a continuation of current trends in fleet composition, the second where renewable lead the decarbonisation , and a third where baseload plants lead decarbonisation. Slidepack and excel formats are provided.

Role of Gas/H2 in the GB power sector

Initial analysis

Client: ETI
Date: 24 October 2016
Version: V1_1

Reputation built on results

Contents

- Introduction
- Overview of approach
- Baringa Reference Case assumptions
- Role of gas in the GB power sector
- Missing money for Gas CCS plant
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Introduction

Requirements and objectives of the initial analysis

Overview

- ETI would like to characterise better the fundamental dispatch of different types of gas and H2 electricity plant in future GB electricity systems (from ~2020-2030/40 (the later date sufficient to enable meaningful consideration of the role of CCS).
  - This would provide an understanding of e.g. load duration curves, hourly operating profiles, number of starts, etc for different plant types across a number of spot years. This would look to understand the different potential roles related to baseload, more flexible balancing or ancillary service provision for different types of plant: Gas CCS, Flexible Gas Turbines (GTs), Flexible Hydrogen GTs with salt cavern storage
  - For this purpose, as used previously for ETI and as part of Baringa's standard electricity market modelling suite, we have used PLEXOS to simulate the half-hourly dispatch of plant across each spot year and scenario/sensitivity under consideration

- An initial piece of work as been undertaken to provide some preliminary insight into the operation of GB gas fleet prior to more detailed modelling work.
  - For this initial analysis we have considered a base model and three additional scenarios in 2030: looking at the impact of the different cooling states for gas generators and associated technical parameters (e.g. start times, costs, ramp rates), the impact of the length of perfect foresight (e.g. how far into the future generators have visibility over) on the flexibility requirements and the impact of adding 3 GW of new Gas CCS in the system (also evaluating the missing money for such a plant as a proxy for required CfD level)
  - We have used our Baringa Reference Case as the basis for these initial scenarios. The underlying assumptions of this scenario are presented further in the following slides

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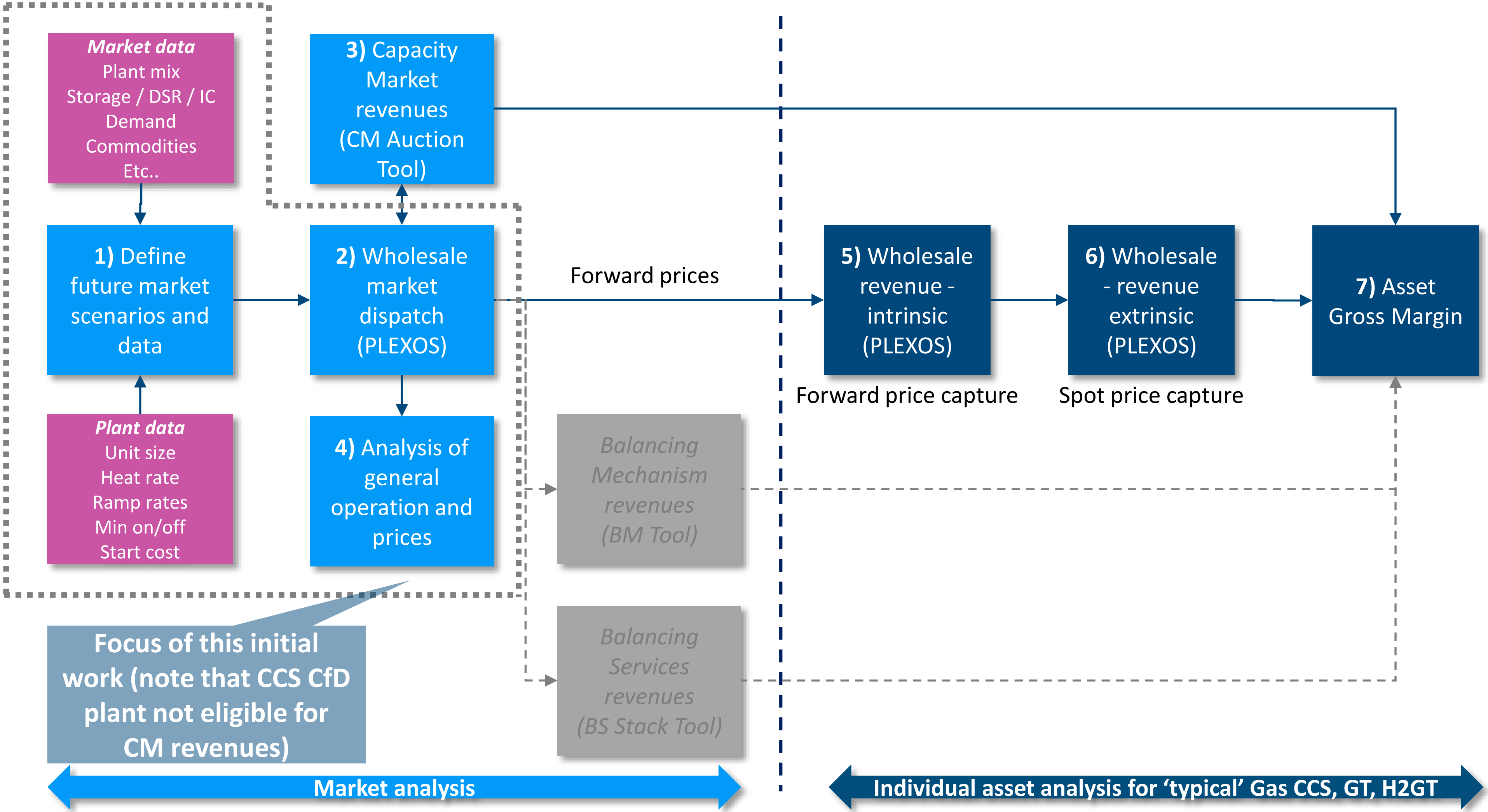
Overview of approach

The core project will focus on wholesale and CM markets as most material, post-GC balancing markets are more complex and generally ‘thinner’ but could be investigated at a later stage. However, for this initial analysis only the whole market dispatch has been considered



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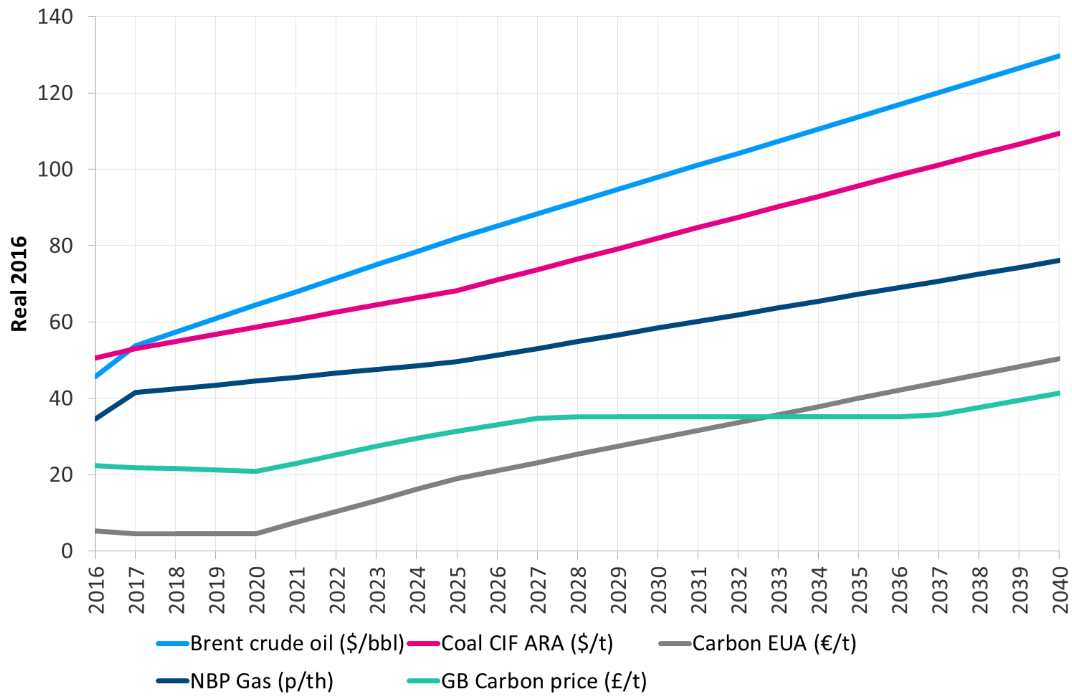
Commodity prices

Baringa Reference Case assumptions

Commodity price trajectories in the Baringa Reference Case



Background

Commodity Price Curves Methodology

- In the December 2015 update, oil, gas and coal price curves were projected by taking current forward curves as of 9th of November 2015 and projecting towards a long-term target price in 2040 in real 2016 money
- This July 2016 update uses forward curves as of 29th June 2016 and trends to the same 2025 prices as in December 2015. Prices from 2025-2040 remain unchanged

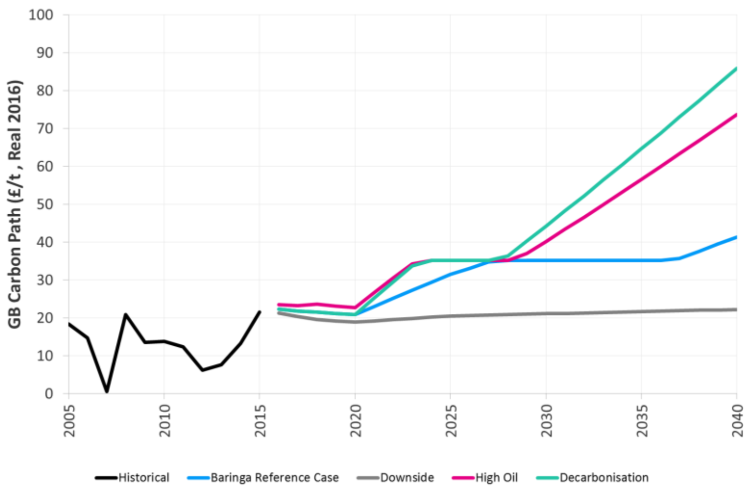
Baringa Reference Case

- The Brent oil price in the Baringa Reference case is based on the Intercontinental Exchange (ICE) forward curve through to 2017 and then interpolates to a price of 130 $/bbl in 2040
- This long term price target is based on the International Energy Agency's (IEA) "New Policies" Case presented in their 2015 World Energy Outlook (WEO)
- The Baringa Reference case follows the forward curve to 2017 based on Platts NBP and TTF forwards (NBP for GB and TTF for EU gas prices), then trends to 76 p/th in 2040
- This long term price target is based on the IEA's 2015 WEO "New Policies" scenario (Europe imports) price
- In the Baringa Reference case the coal price follows the current EEX ARA coal forward curve through to 2017, then trends to 109 $/t in 2040
- This long term price target is based on the IEA's 2015 WEO "New Policies" scenario price
- The long run carbon price is driven by fuel switching in the power sector in response to an eventual shortage of carbon allowances
- This switching is from the less efficient operational coal stations to the more efficient gas stations in Europe: the carbon price rises to the level necessary to make these gas stations competitive

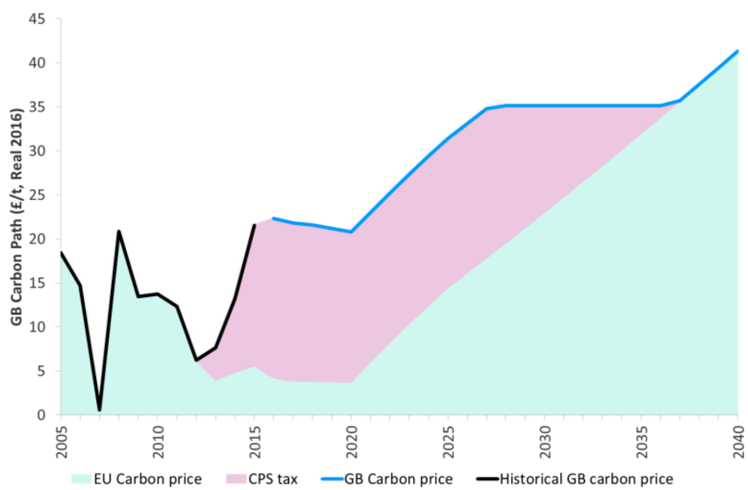
GB carbon price

Baringa Reference Case assumptions

GB Carbon price (£/tCO2, Real 2016)



GB Carbon price (£/tCO2, Real 2016)



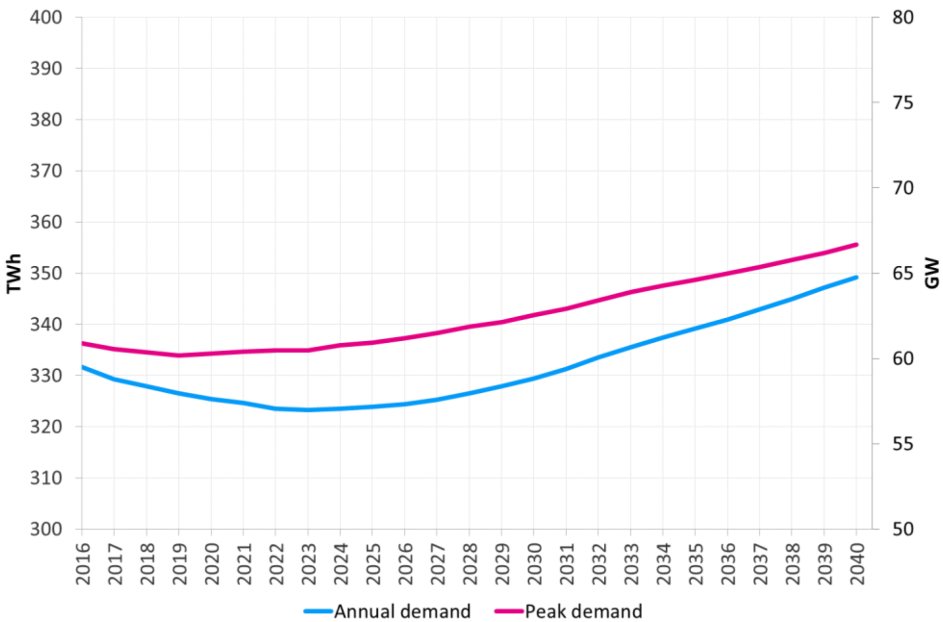
GB Carbon price

- The government carbon tax (the Carbon Price Support (CPS)) implemented from April 2013 is 4.94 £/t in financial year 2013/14, 9.55 £/t in 2014/15 and 18.08 £/t in 2015/16 (all nominal)
- This CPS tax is "added" to the EUA carbon price to get the Carbon Price Floor, which is the effective GB Carbon price
- In the March 2014 Budget it was announced that the CPS would be capped at the 2015/16 level of 18 £/t from April 2016 to March 2020 in nominal terms; subsequent Budgets in March and July 2015 did not alter CPS legislation
- In the March 2016 Budget the Chancellor announced that the CPS would be inflated in real terms in the year 2020/21. The government has announced that it will set out the long-term direction for CPS rates and the Carbon Price Floor at the Autumn Statement, expected in Q4 2016
- In each scenario, our modelling incorporates this tax, frozen in nominal terms until 2020/21. From 2020/21 the CPS is inflated in real terms each year until the GB Carbon Price (EUA + CPS) reaches the 2020 CPF target of 30 £/t (real 2009). The CPS is then phased out
- We assume that the full costs of carbon are passed through into the power price, and carbon prices are therefore a major value driver, particularly for non-fossil-fired generation plant

Demand growth projections

Baringa Reference Case assumptions

Annual energy and peak demand trajectories



Background

Annual energy requirements

- In the Baringa Reference Case, the average demand of the four National Grid Future Energy Scenarios (FES) 2016 scenarios is adopted

Peak demand

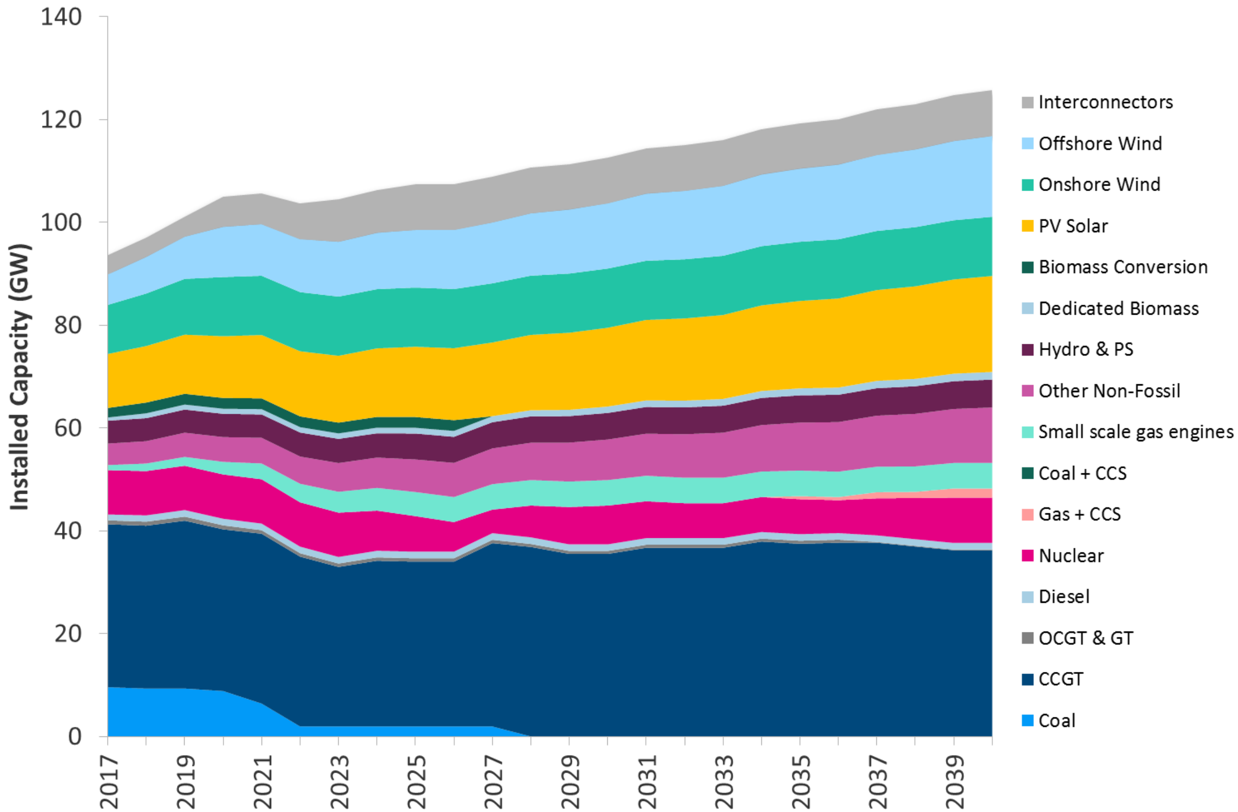
- Peak electricity demand is assumed to grow at the same rate as in the corresponding FES scenarios. Peak demand grows at approximately the same rate as energy demand growth in the Reference Case

Capacity mix

Baringa Reference Case assumptions

Installed Capacity (GW) (Baringa Reference case)

- The GB capacity mix in the Reference Case is shown below. The capacity build out represents the current market policy and regulatory environment and considers the economic viability of both new and existing generation plants from the operators' perspective. This is a different perspective to ESME, where the capacity build is based on a least cost optimisation from the point of view of the overarching energy system.



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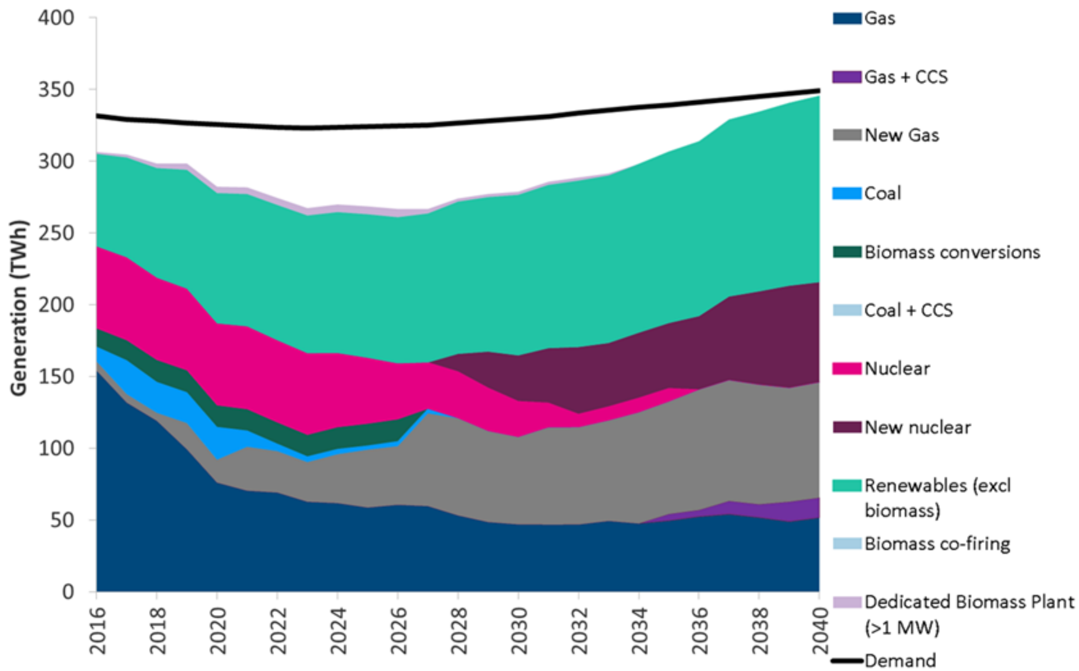
Role of gas in the GB power sector

Evolution of generation output in the Reference Case

Generation mix in the Reference Case



Evolution of existing plant de-rated capacity

- Generation from coal declines significantly in 2016 as plant retires or are converted to biomass and the rising carbon price combined with depressed commodity prices push remaining plant out of merit.
- By 2040 the market share of unabated gas is 38.3% (indigenous generation excluding interconnectors), with OCGTs and older CCGTs tending to operate as peaking plant with low capacity factors, and new entrant CCGTs two-shifting to operate at higher capacity factors
- Renewables share of generation is 36.7%, nuclear is 20.3%, with the remainder made up of some gas CCS in 2040
- Overall, gas generation remains the main marginal price setting plant

Reference Case results

Wholesale power price outlook

Factors driving higher wholesale electricity prices

- We forecast an increase in GB wholesale electricity prices in real terms over the medium term. The main drivers behind this trend are rising commodity prices, tighter capacity margins and higher profit margins for conventional plant

Natural Gas Price

- Natural gas prices were relatively low in 2014 and 2015 due to high storage levels, mild weather and oversupply due to weak global demand. Increasing competition for LNG and higher global demand are expected to lead to higher prices in the future. IEA forecasts natural gas price to reach 76 p/th by 2040 (New Policies scenario)

Carbon Price

- The Carbon Price Support level is currently 18.1 £/t, which is fixed until April 2021. We expect the CPS mechanism to be maintained post 2021. Meanwhile, the EUA price is trading at around 5 €/t in summer 2016. We expect this price to increase substantially in the long-run as Europe pursues its emission reduction targets

Capacity Margins

- The last couple of years were characterised by mild winters and high capacity margins, reducing the scarcity premium received by generators in the market. Capacity margins are now much tighter and will remain so for the next few years due to the retirement of some unprofitable generators, continuing delays in investment decisions for new thermal projects and the impact of the Industrial Emissions Directive

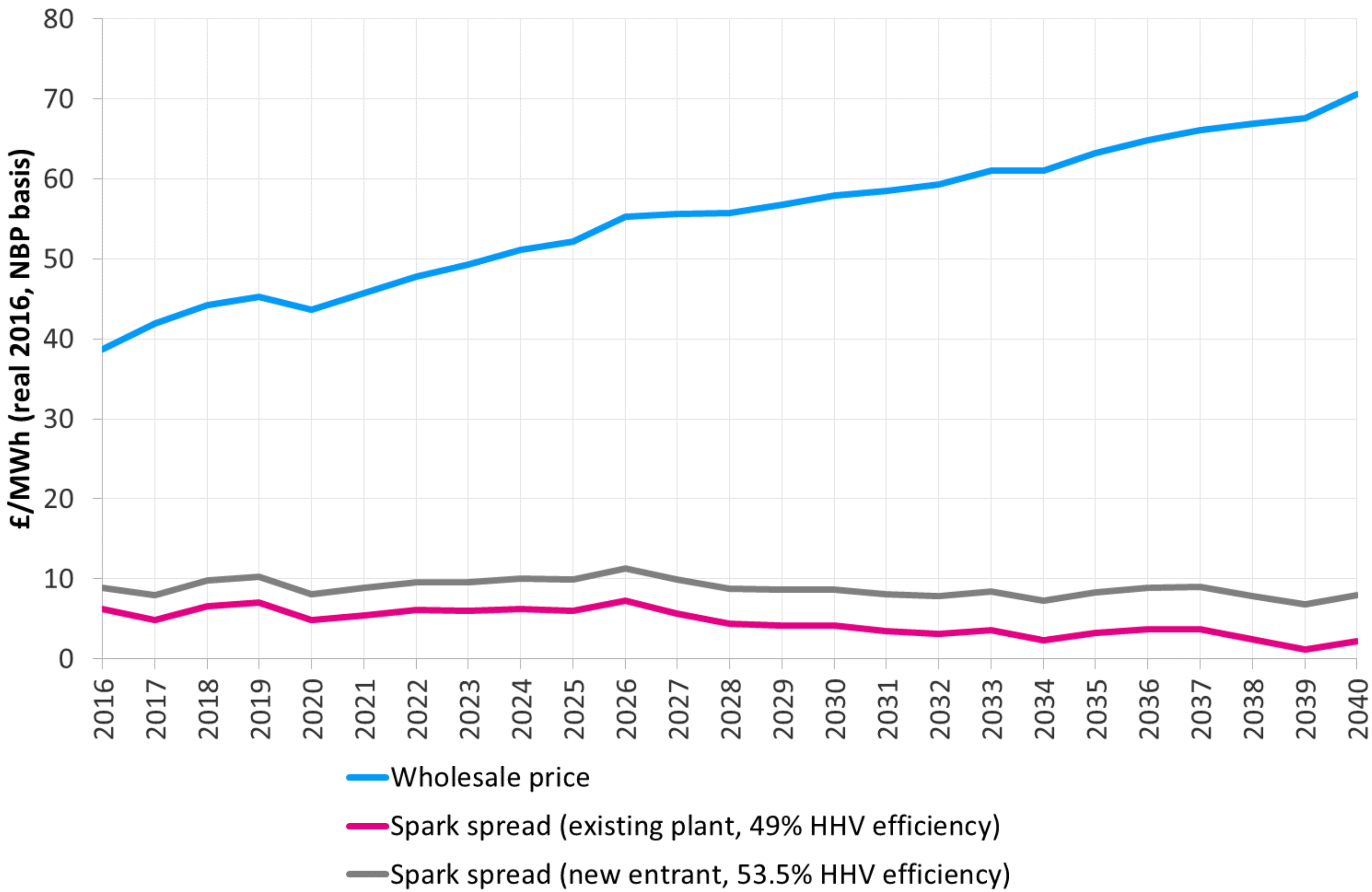
Generators Profits

- Low electricity prices due to weak demand and increased production from renewable energy sources have negatively affected the profit margins of big utilities in Europe. A significant quantity of capacity has been running at a loss. This situation is unsustainable in the long-term and we expect profit margins to increase for existing generators to recover their costs

Reference Case results

Wholesale power price outlook

Factors driving higher wholesale electricity prices



Role of Gas in the GB Power Sector

Baringa

Closer exploration of the dispatch profiles of the GB gas fleet in 2030 by modelling a number of scenarios based around our Reference Case

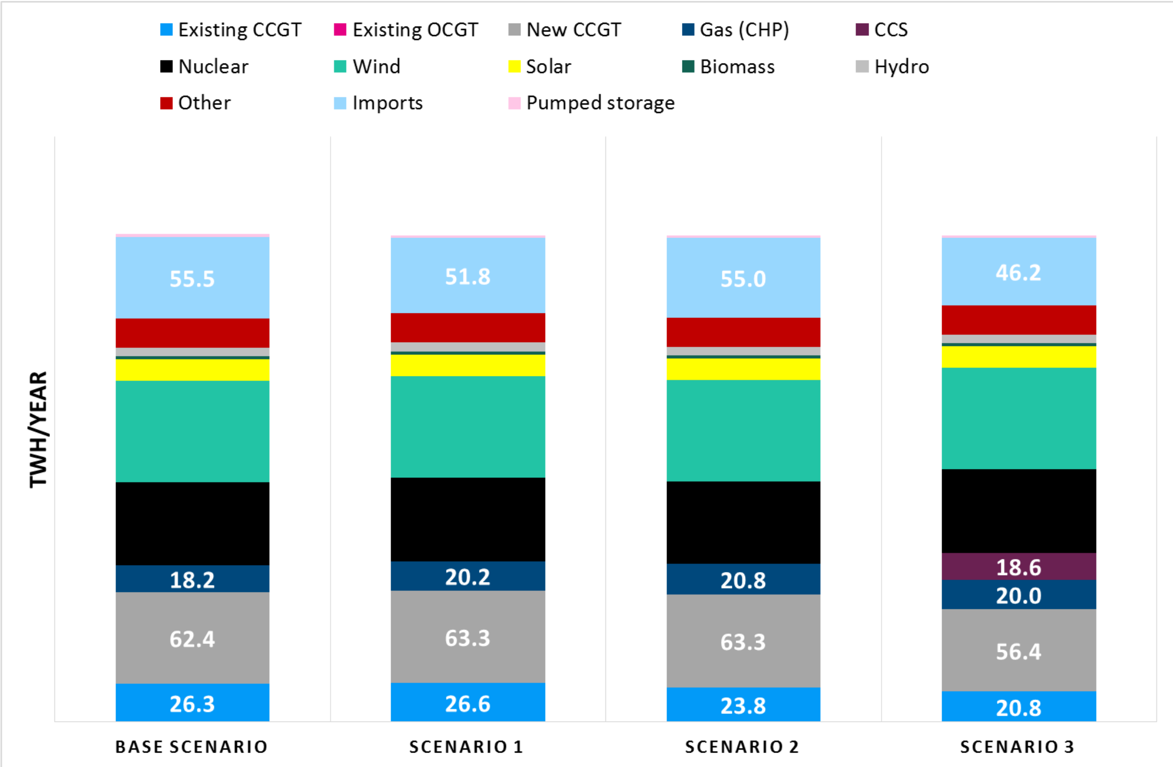
Overview of scenarios	Description
Base scenario	Baringa Reference Case (half hourly input data and dispatch profiles, daily optimisation step with 12 hour look-ahead period)
Scenario 1	More detailed operational parameters for thermal capacity, including hot/warm/cold start costs, start times, run up rates and ramp rates based on the (DECC) 2014 Technical Assessment of Operation of Coal and Gas Fired Plants report by Parsons Brinckerhoff report
Scenario 2	As per Scenario 1 with a shorter optimisation window (4 hours + 2 hour look-ahead). The purpose of this scenario is a quick proxy to understand better the role of gas generation providing flexibility when there is less visibility over future demand, wind, other conditions. This issue will be explored in more detail in a subsequent analysis. Note that the storage operation profile has been fixed to that seen in Scenario 1 to avoid the shorter window distorting the ability to cycle across the day.
Scenario 3	Scenario 1 with 3 GW of gas CCS capacity added. The purpose of this scenario is to see the impact of the CCS capacity on the rest of the gas fleet in the system and to evaluate the missing money for such as plant as a proxy for the required CfD level.

- In 2030 in the Reference Case, the GB gas capacity includes:
  - 23.2 GW of existing CCGTs: 4.6 GW of this capacity operates in “must-run” CHP mode and has been excluded from the results (average efficiency of the remaining new CCGT fleet on HHV basis is 51.5% in 2030)
  - 0.6 GW of existing OCGTs (average efficiency of the whole existing OCGT fleet on HHV basis is 27.0% in 2030),
  - 12. 3 GW of new CCGTs (average efficiency of the whole new CCGT fleet on HHV basis is 53.3% in 2030),

Gas generation in the power mix

2030 Generation mix overview in the four scenarios

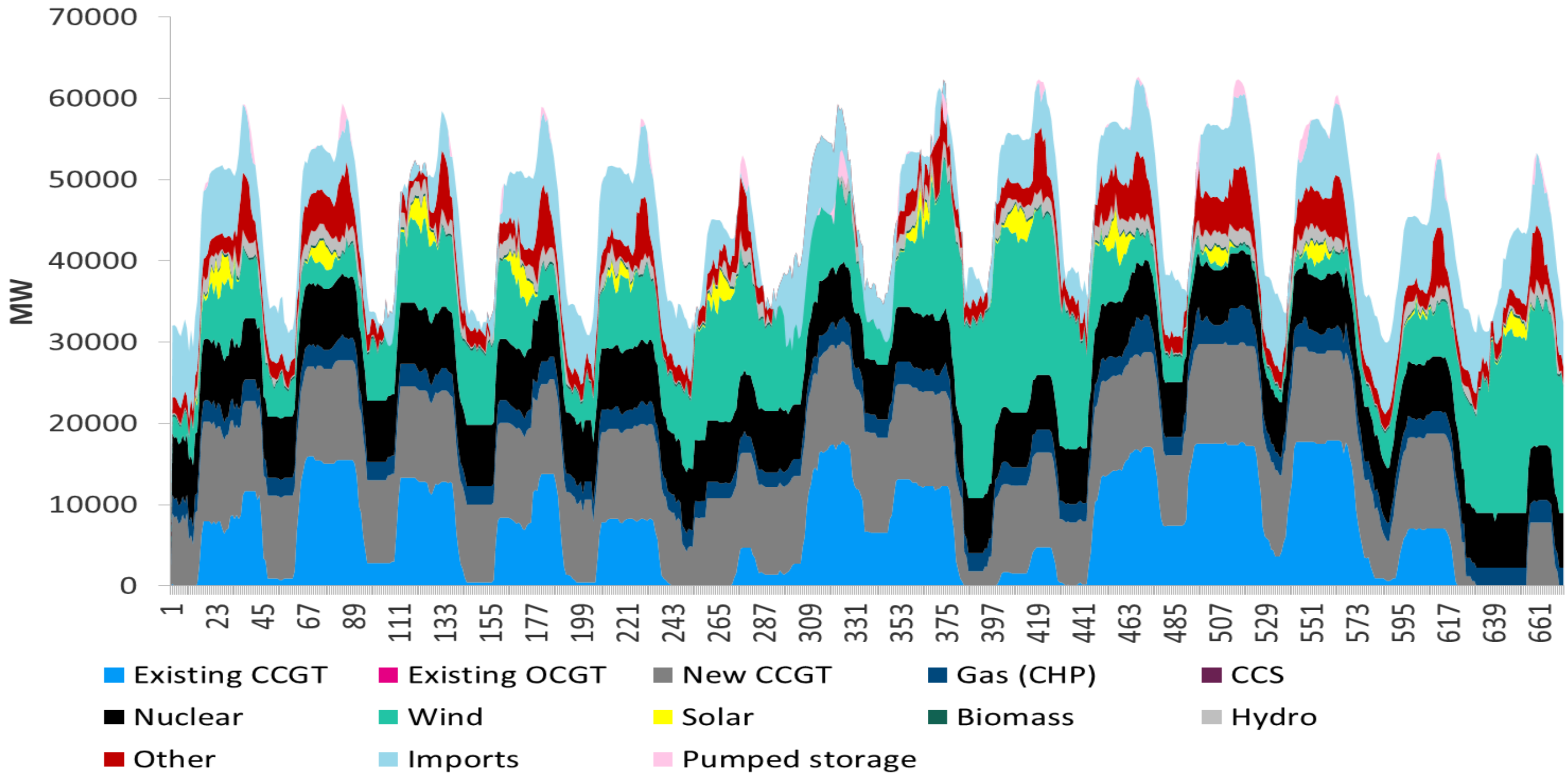
- Below is the generation by type under the four scenarios in 2030. Overall generation levels are similar in the base scenario, scenario 1 and scenario 2, however, in scenario 2 the need for additional flexibility means that some of the existing gas CCGT output is displaced to a combination of new CCGT and additional interconnector imports. In scenario 3, the new gas CCS generation displaces some CCGT generation and imports.



Generation dispatch profile in a winter fortnightly period

Winter fortnightly generation profile in Scenario 1 (02/12/2030-16/12/2030)

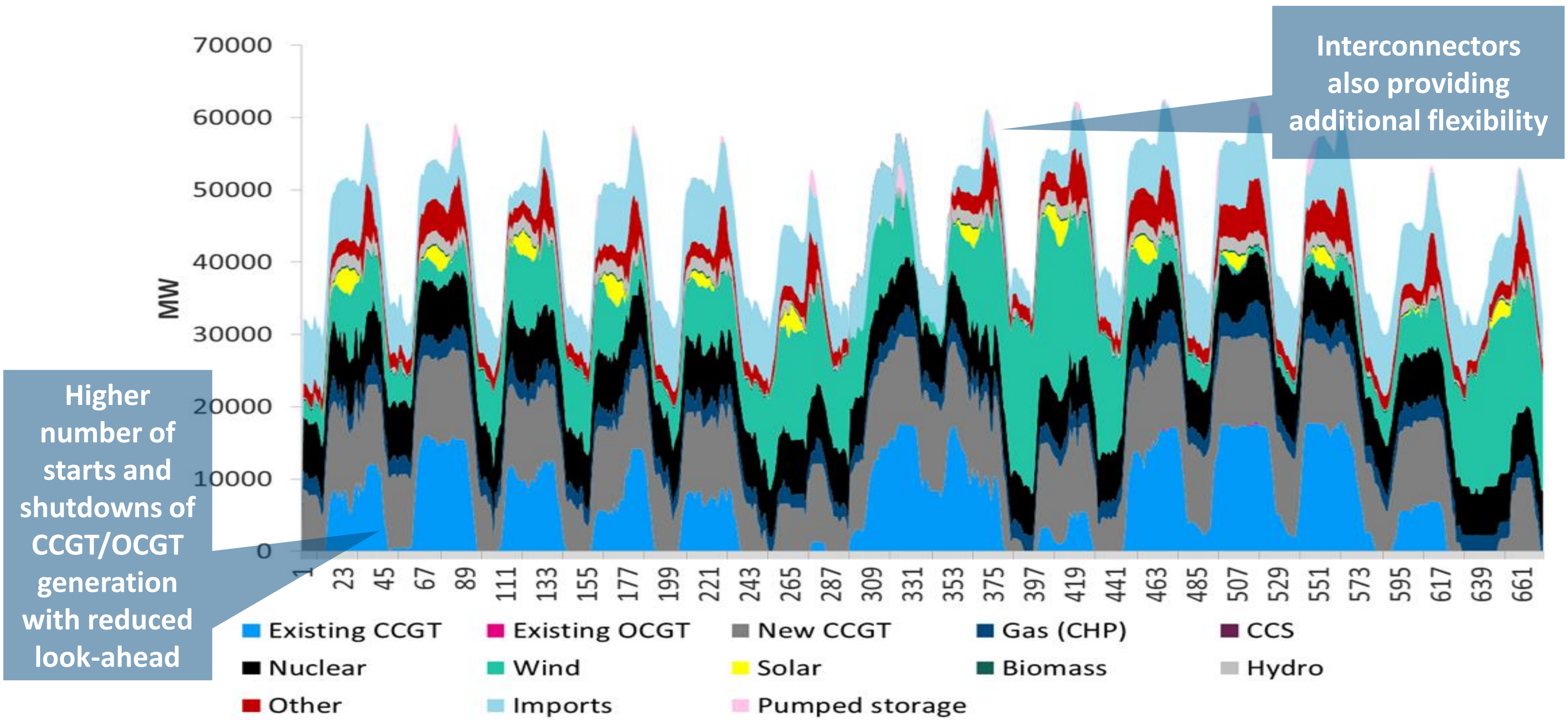
- Below is a typical generation profile in Scenario 1 over a winter fortnightly period. Nuclear provides baseload power for most of the time, wind and solar provide intermittent generation with gas generation excluding Gas CHP and pumped storage increasing generation over high price periods



Generation dispatch profile in a winter fortnightly period

Winter fortnightly generation profile in Scenario 2 (02/12/2030-16/12/2030)

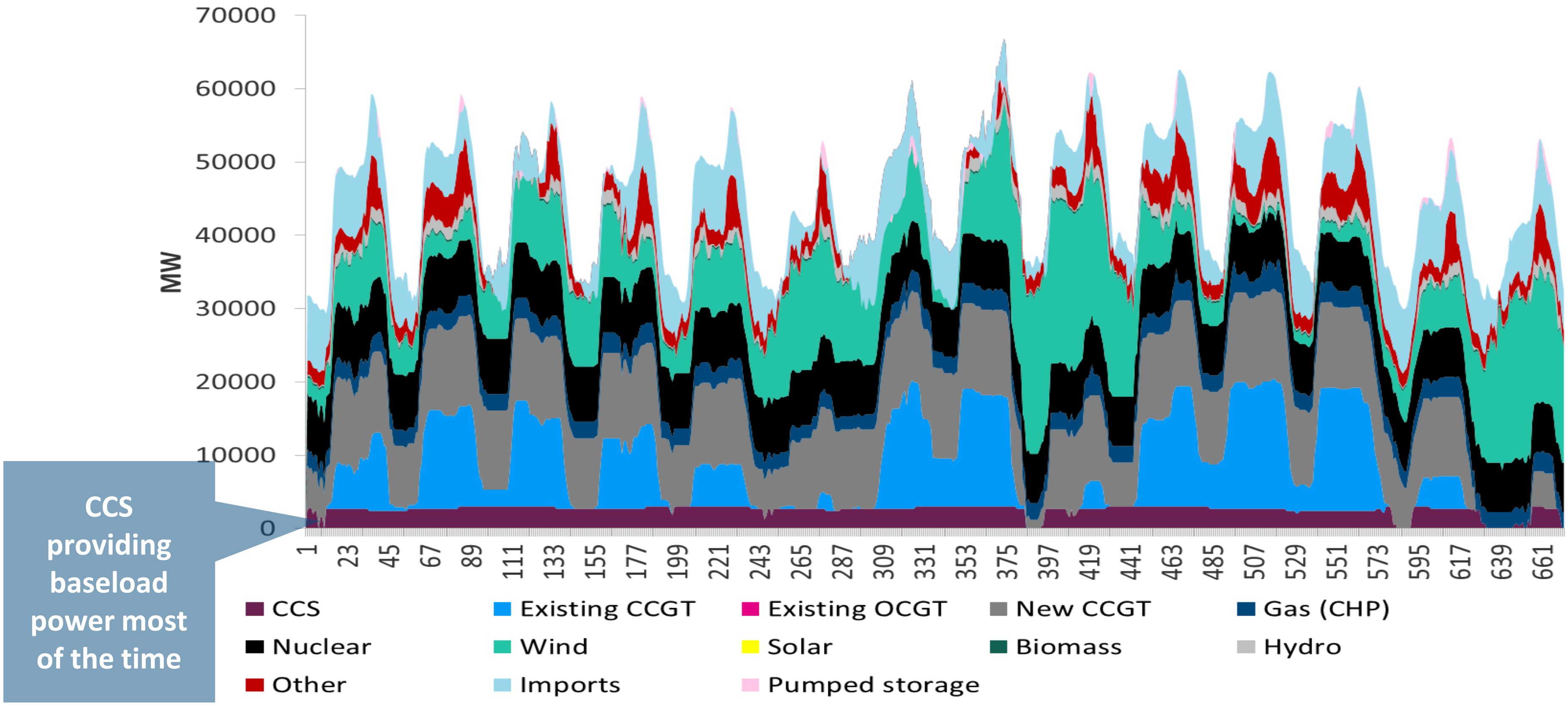
- We see a greater 'cycling' effect in the CCGT/OCGT generation with the reduced perfect foresight in Scenario 2 as below . The total generation from new CCGTs remain at a similar level to scenario 1 but they provide higher flexibility. Imports also provide higher flexibility to compensate for the reduced generation from existing CCGTs compared to Scenario 1



Generation dispatch profile in a winter fortnightly period

Winter fortnightly generation profile in Scenario 3 (02/12/2030-16/12/2030)

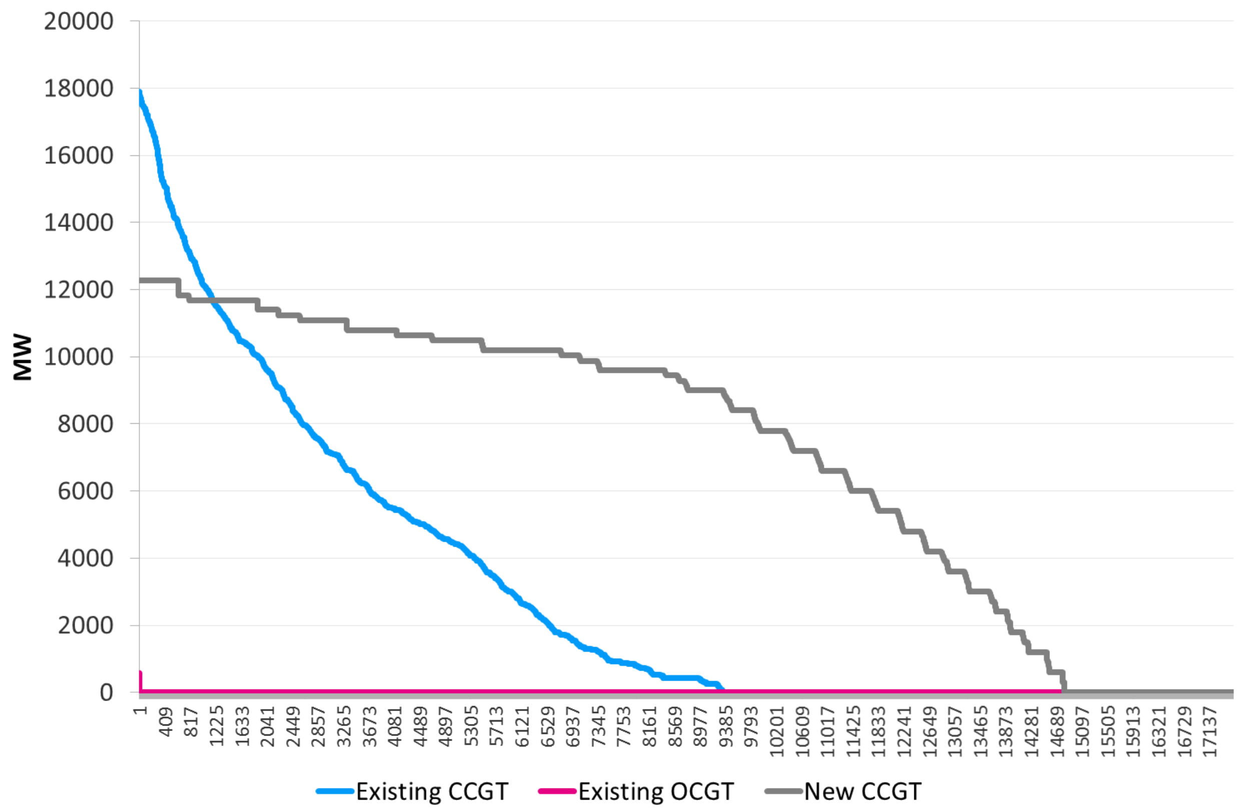
- In scenario 3, the new Gas CCS capacity provides baseload power for most of the time, resulting in reduced generation from CCGTs/OCGTs as well as reduced imports



Duration curves for flexible gas generation

Generation duration curve of flexible gas generation in Scenario 1 in 2030

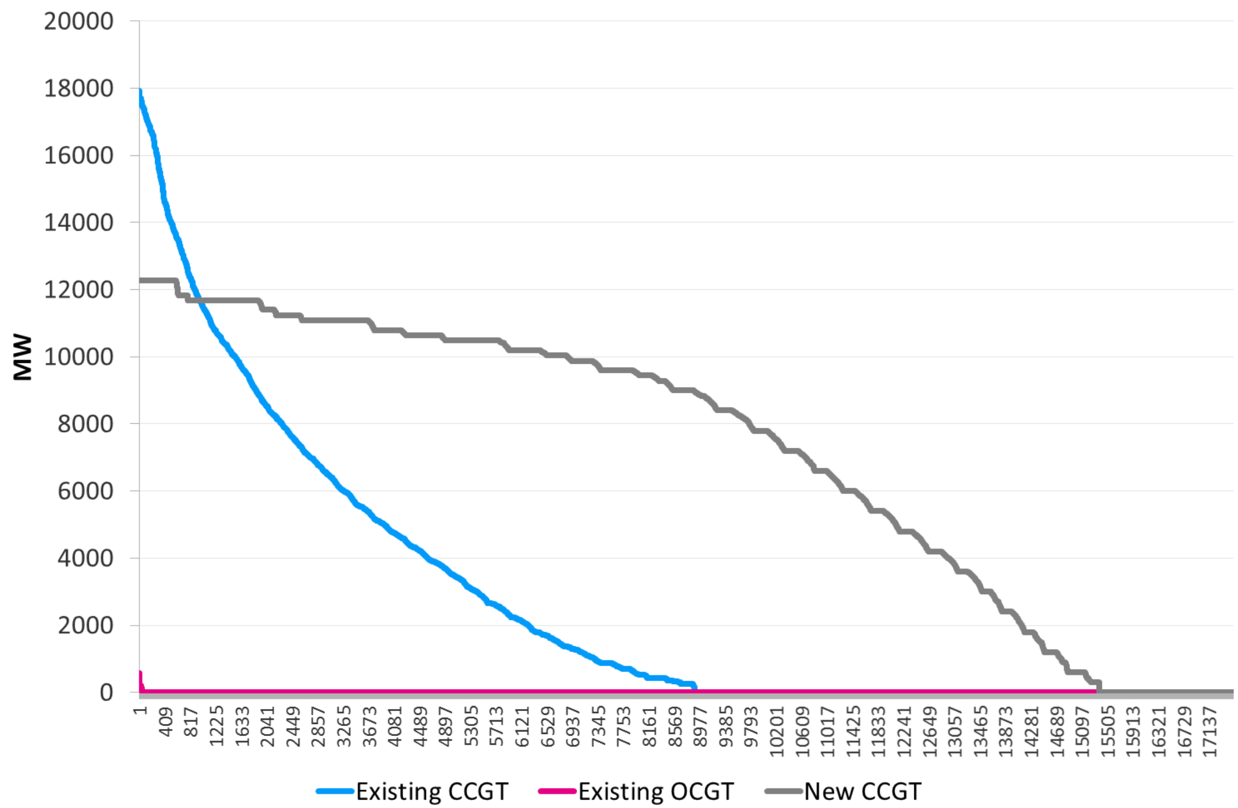
- Below is the half-hourly generation duration curves for existing and new CCGTs and existing OCGTs in scenario 1 in 2030. Existing and new CCGTs provide most of the flexibility on the gas side with generation from OCGTs being limited to a very small number of running hours.



Duration curves for flexible gas generation

Generation duration curve of flexible gas generation in Scenario 2 in 2030

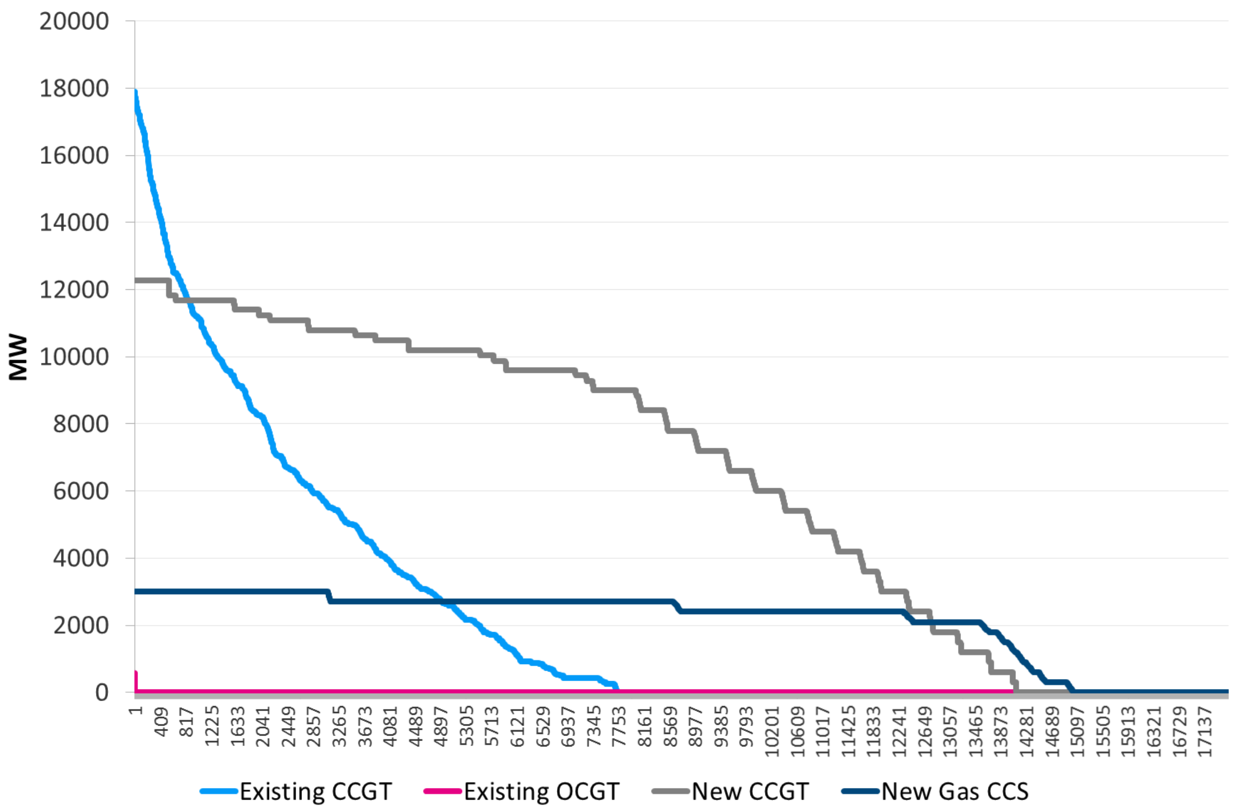
- The greater ‘cycling’ of the new CCGT/OCGT generation is visible in scenario 2 with the reduced perfect foresight, however some of the additional flexibility is also being provided by interconnectors.



Duration curves for flexible gas generation

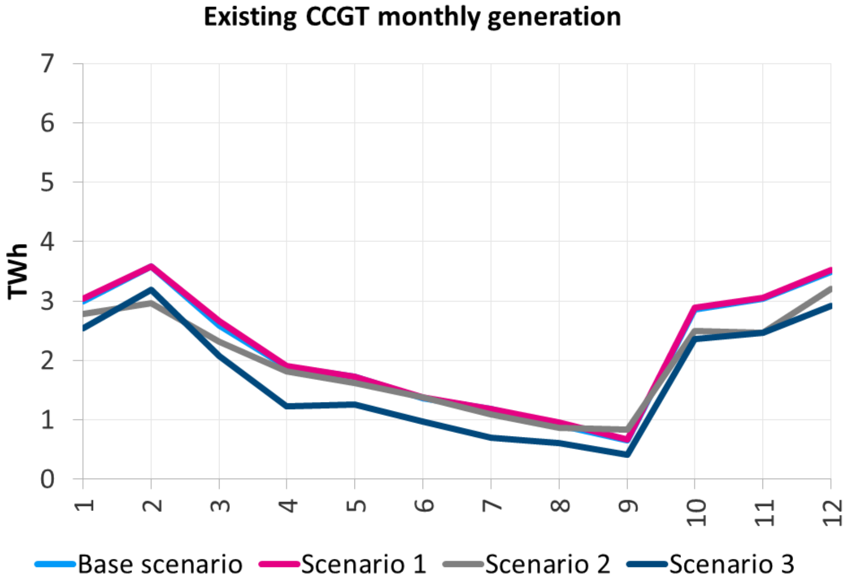
Generation duration curve of flexible gas generation in Scenario 3 in 2030

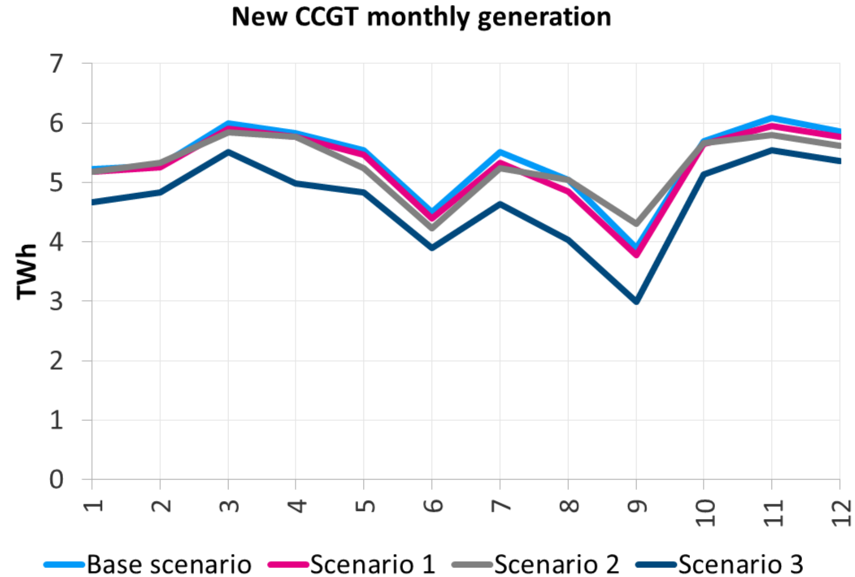
- CCS provides baseload power in most of the high demand periods reducing the required generation from CCGTs/OCGTs



Annual and seasonal dispatch of gas generation

Annual and seasonal dispatch in the four scenarios in 2030, more efficient new CCGT provides a more consistent level of generation across the year





Average annual load factor/run time in hrs	Existing CCGTs	Existing OCGTs	New CCGTs
Base scenario	16.1% / 1,409 hrs	0.0% / 3hrs	60.0% / 5,252 hrs
Scenario 1	16.3% / 1,424 hrs	0.0% / 3hrs	58.8% /5,153 hrs
Scenario 2	14.6% / 1,278 hrs	0.1% / 8hrs	58.8% / 5,152 hrs
Scenario 3	12.7% / 1,113 hrs	0.0% / 3hrs	52.4% /4,592 hrs

Hot/cold/warm starts of gas generation

Average annual number of starts per gas generation by type in each scenario – increased cycling is seen within scenario 2 given the additional requirement for flexibility

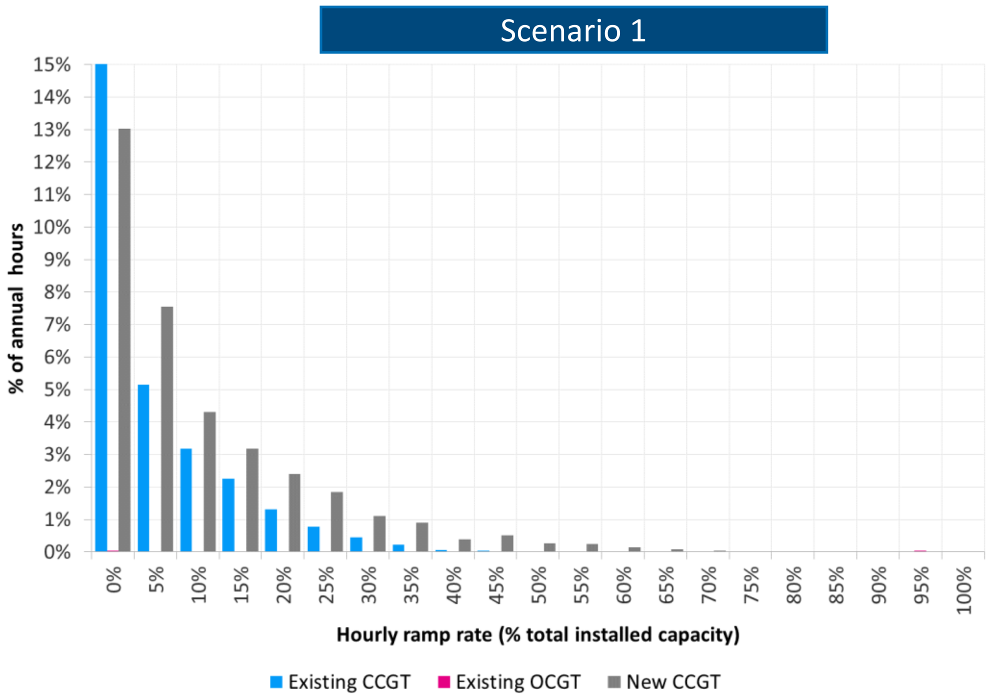
Average number of annual starts per unit	Existing CCGTs	Existing OCGTs	New CCGTs
Base scenario	85	3	143
Scenario 1	93	3	167
Scenario 2	114	9	231
Scenario 3	75	2	161

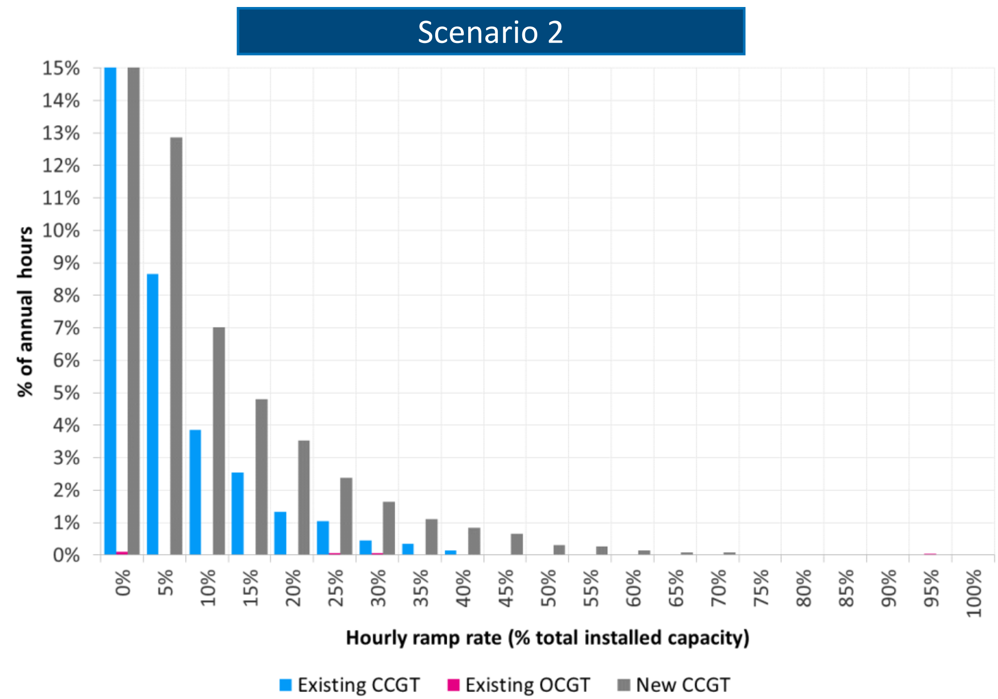
Total number of starts per unit for Existing CCGT/New CCGT	Hot	Warm	Cold
Scenario 1	23/68	45/85	25/14
Scenario 2	30/136	58/88	26/7
Scenario 3	15/59	36/82	24/20

Ramping of flexible gas generation

Scenario 1 and Scenario 2 in 2030

- The distribution of the absolute swings in flexible gas generation in each hour *as a percentage* of installed capacity is shown below. The ramping is higher for the more efficient new CCGTs compared to existing CCGTs, with higher contribution to overall generation
- The hourly ramping is higher in Scenario 2, with reduced visibility into the future due to the look-ahead being reduced from 12 hours to 4 hours, as a proxy for greater flexibility requirements on the system. In this scenario more flexibility is required from all gas plant (as well as indicators), but the increase is most pronounced for new gas plant. As noted previously, storage operation has been fixed to that seen in scenario 1 so cannot provide additional flexibility in this simple proxy.





Flexible gas generation and fuel consumption

Total generation and fuel consumption for the flexible generation in each scenario

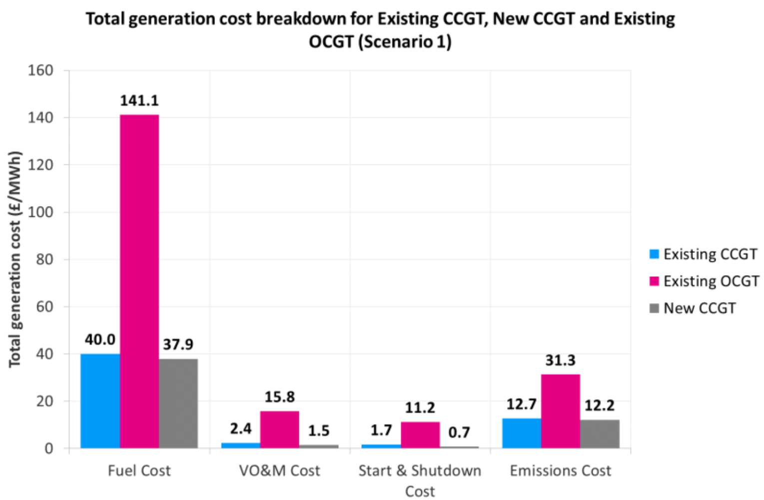
- Total fuel consumption changes in line with the power generation from flexible gas plants as below

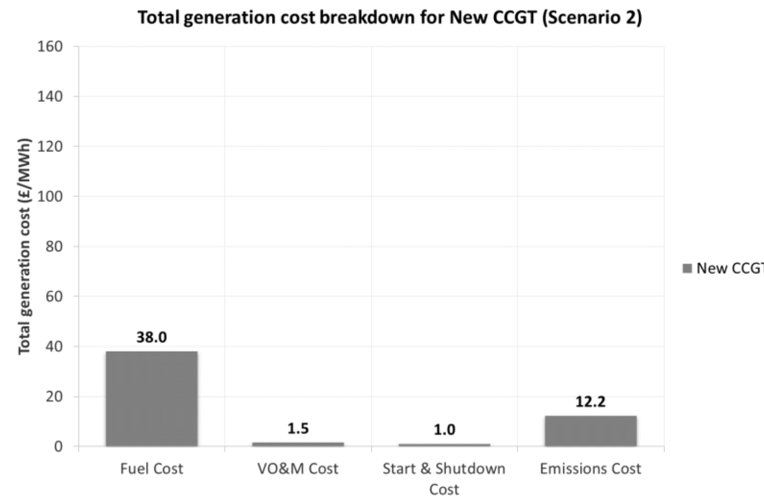
Total fuel consumption (TWh / year)	Existing CCGTs	Existing OCGTs	New CCGTs
Base scenario	47.6	0.0	117.7
Scenario 1	52.2	0.0	119.1
Scenario 2	47.1	0.0	119.4
Scenario 3	40.7	0.0	106.1

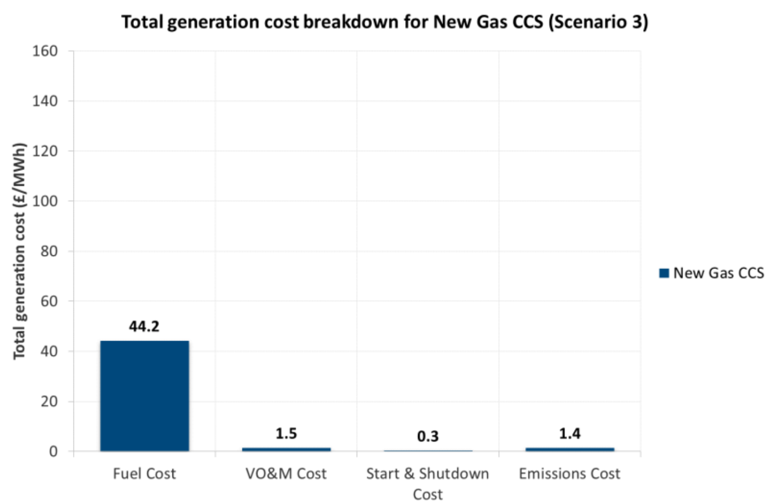
Total generation (TWh/year)	Existing CCGTs	Existing OCGTs	New CCGTs
Base scenario	24.2	0.0	62.4
Scenario 1	26.6	0.0	63.3
Scenario 2	23.8	0.0	63.3
Scenario 3	20.8	0.0	56.4

Total generation cost breakdown for gas plant types

Breakdown of average generation cost per MWh of output in 2030







We have excluded an estimate of CCS transport and storage costs in this initial analysis to avoid unduly distorting dispatch, but can consider in more detail in subsequent work

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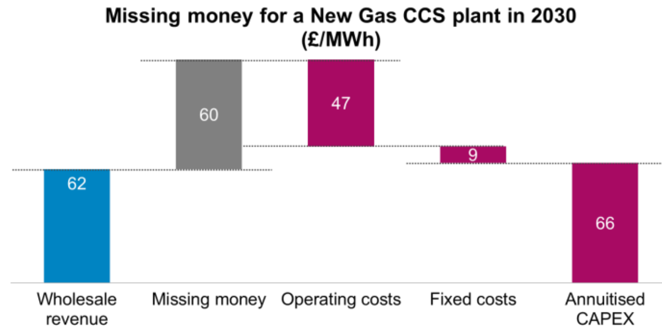
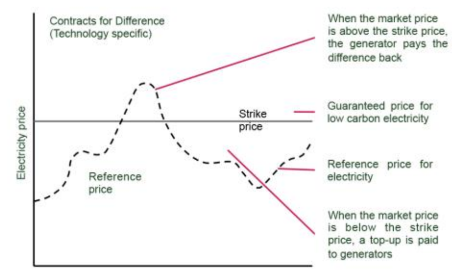
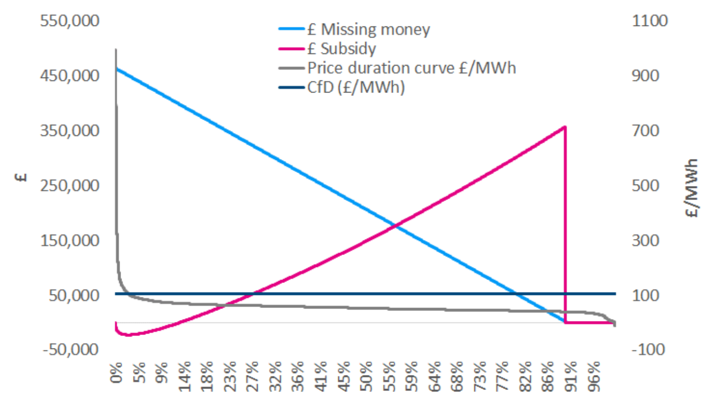
Missing money for CCS plant

Missing money and LCOE for a new Gas CCS plant in 2030

- The missing money for a new 3 GW Gas CCS plant is shown in the table on the right. This is based on the actual load factor of 70.7% seen in the Scenario 3 results.
- The missing money is derived from the difference between the gross margin of the plant in the wholesale market (i.e. the money it makes net of short run operating costs) and the sum of its annuitised capital and fixed costs. Note that a plant receiving a CfD is not eligible to participate in the Capacity Market
- The underlying cost assumptions for a CCS plant is based on the DECC Electricity Generation Costs Report (2013). The underlying commodity prices are based on Baringa Reference Case assumptions.
- Setting a CfD directly at £122/MWh (based on the outturn load factor) may then lead to extended running hours and a higher level of overall subsidy than is strictly necessary to provide the missing money.
- As the CfD is 2-way we have estimated what CfD would cover the missing money and minimise the total amount of subsidy provided at an assumed maximum load factor (e.g. 90%), which is broadly ~£106/MWh







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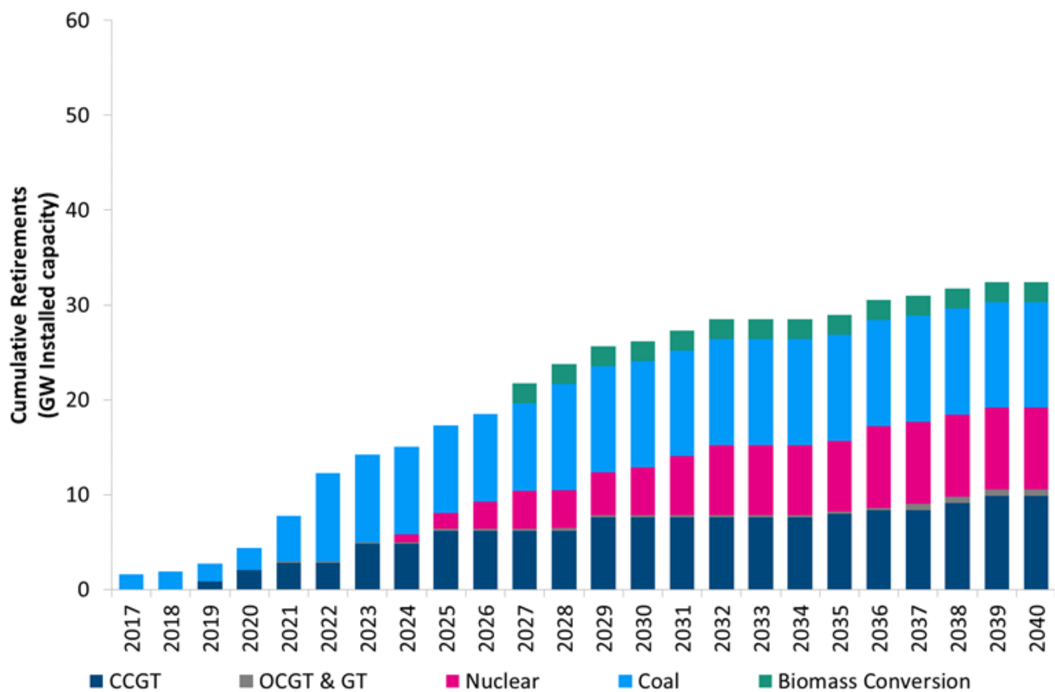
Capacity assumptions

Cumulative plant retirements

Cumulative Plant Retirements (GW) (Baringa Reference Case)



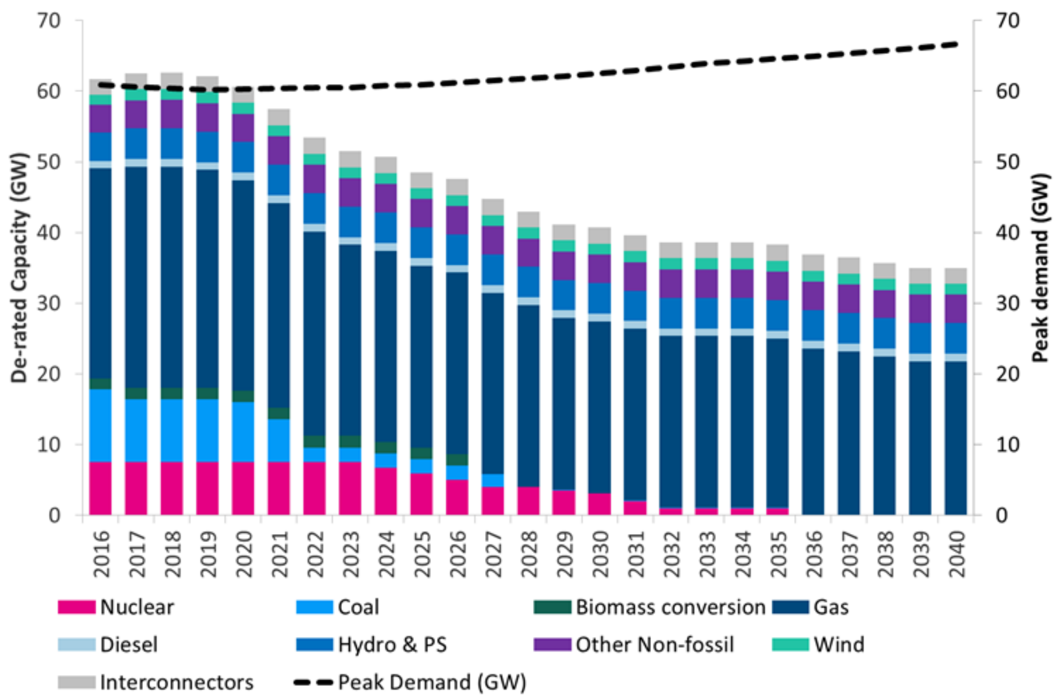
Cumulative Plant Retirements

- Approximately 7 GW of coal plant has either closed during 2016. This is comprised of Ferrybridge, Longannet, Rugeley and Eggborough.
- We have estimated the coal plant retirement dates based on market announcements regarding their **Industrial Emissions Directive** (IED) compliance and projected profitability
- Low gas prices, combined with the GB CPS, make coal plant less economic, which would tend to accelerate retirement decisions.
- A large volume of the existing nuclear generation is set to retire over the next 15 years. Of the 8.6 GW of existing nuclear capacity on the GB system, 5 GW is currently scheduled to be decommissioned by 2030
- Towards the end of the scenario, some of the remaining older **CCGT plant** is steadily pushed out of the merit order, and also retires from the system
- Subsidy support for biomass conversions (both RO & CfD) is scheduled to end in 2027. On the expiry of these contracts we expect these plant to close

Capacity assumptions

Evolution of existing plant

Evolution of existing plant de-rated capacity (GW) (Baringa Reference case)



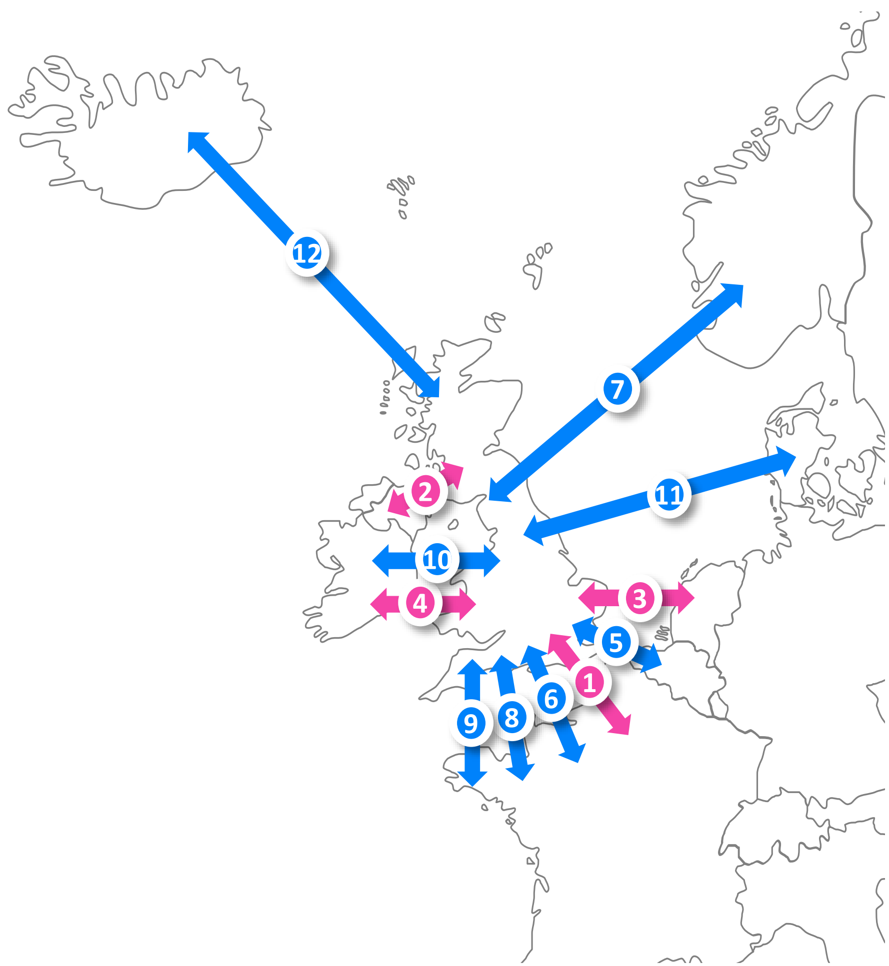
Evolution of existing plant de-rated capacity

- The graph on the LHS shows the evolution of the GB demand / supply gap (on a de-rated basis i.e. taking into account the possible plant availability during peak demand) as it would develop without any new plant build and incorporating the known retirement of plant
- Existing interconnectors are included in the chart and provide an additional 2.3 GW of de-rated capacity, based on the interconnector de-rating factors published by government in July 2016
- The requirement to close coal plant that have 'opted out' of the IED will cause peak demand exceeds de-rated capacity by ~2020, indicating that without new projects being initiated, security of supply will be threatened by this point.
- The UK is also required, in common with its partners in the EU, to deploy a significant capacity of renewables by 2020
- Increasing amounts of variable supply (wind) to meet these targets will increase the requirement for plant that can operate flexibly to balance the system

Capacity assumptions

Interconnectors

Interconnectors projects



Baringa Reference Case assumptions

	Country	Capacity (MW)	Status	Target[2]	Baringa Ref Case
1	France	2000	Existing	1986	1986
2	Northern Ireland	500[1]	Existing	2001	2001
3	Netherlands	1000	Existing	2012	2012
4	Ireland	500	Existing	2012	2012
5	Belgium	1000	Proposed	2019	2020
6	France	1000	Building	2017	2020
7	Norway	1400	Proposed	2021	2023*
8	France	1000	Proposed	2020	2022
9	France	1400	Proposed	2021	-**
10	Ireland	500	Proposed	2025	2025
11	Denmark	1400	Proposed	2022	-***
12	Iceland	1000	Proposed	2027	-

[1] Currently operating with reduced capacity of 250 MW
[2] Target go-live years based on project developer announcements
*Commissioned in 2022 in the High Oil and Decarbonisation scenarios
**Commissioned in 2023 in the High Oil and Decarbonisation scenarios
***Commissioned in 2030 in the High Oil, Downside and Decarbonisation

Capacity assumptions

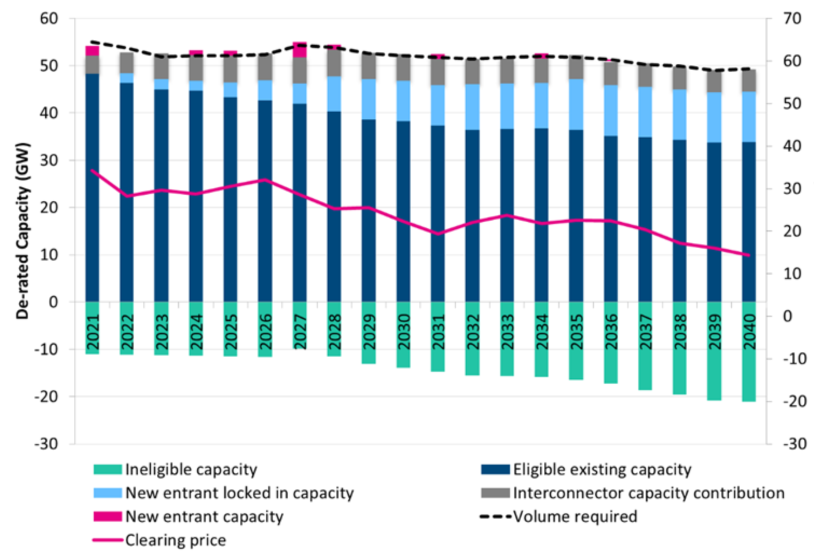
New plant build

New build renewable capacity

- New renewables capacity is only commissioned if it is in a receipt of a subsidy payment, be it an advanced CfD FiD, RO, CfD or ss-FiT
- Expenditure in these schemes is capped by the Levy Control Framework, which is described in detail in later slides
- We use a bottom up model of CfD auction and forecast RO build to inform renewable capacity assumptions up to 2020, again within the bounds of the LCF expenditure cap
- Post 2020 we assume growth rates for the respective technologies that are in line with National Grid's Future Energy Scenarios capacity growth assumptions and well as recent positive announcements on Offshore Wind CfD auctions for delivery as late as 2026.

New build thermal capacity

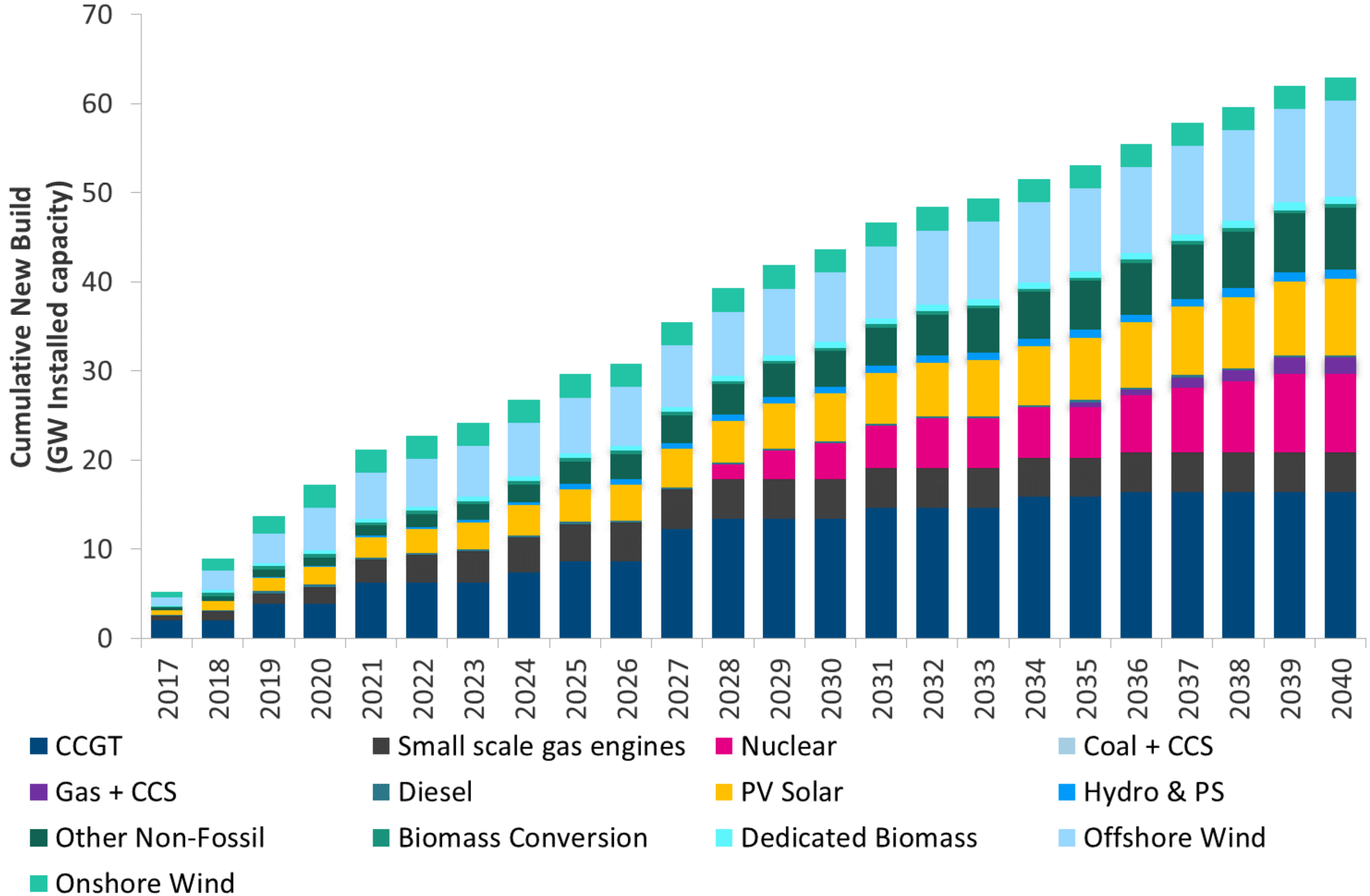
- With the exception of nuclear capacity, in the near term new build thermal capacity is only commissioned if it is in receipt of a 15 year Capacity Market (CM) contract
- As such new build capacity that clears in our CM auction modelling is commissioned in the market models of the respective scenarios
- This is an iterative process in that the wholesale market energy revenues feed through to the missing money which is used to derive the CM auction bids



Capacity assumptions

Cumulative plant new build

Cumulative Plant New Build (GW) (Baringa Reference case)



Baringa