Programme Area: Carbon Capture and Storage

Project: Hydrogen Turbines Follow On

Title: Scenario 5 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.

Power sector CCS and H2 Turbine Asset Modelling

Final results

- **Client** ▶ ETI
- **Date** ▶ 04/08/2017
- **Version** ▶ V3_0

Executive summary

Significant financial support is likely to be needed for low carbon CCS and H2 turbines and conditions are more challenging where substantial subsidised nuclear is also being deployed

- This project has been commissioned to help the ETI characterise better the operation of CCGT/OCGT and new CCGT CCS / H2 Turbine assets in the GB electricity system in 2030 and 2040. This provides support to separate internal programmes on the financial viability of new low carbon generation and an understanding of the desirability of different technical characteristics (e.g. flexibility) within the wider electricity system.
- We have modelled *three distinct market scenarios*: a Business as Usual "*ModDecarb"* (with only modest decarbonisation) which reflects a central view of expected market conditions and two alternative pathways to achieving more significant decarbonisation. The two alternatives have significantly higher carbon prices by 2040 but with substantially different capacity mixes: one is *nuclear baseload focused* (HiBaseDecarb) with the other *focused around significant further expansion of intermittent renewables (HiRenDecarb).* For each asset type we have assessed the Gross Margin given likely wholesale and Capacity Market Revenues.
- For existing and new unabated fossil plant conditions becoming more challenging (in terms of wholesale market revenues) as they move from 2030 to 2040 and from ModDecarb to the intermittent-focused and subsequently baseload-focused scenarios. This is due to a combination of increasing carbon price (which directly affects their short run operating costs), which is compounded in the case of the baseload-focused scenario by a significant expansion of subsidised low carbon baseload plant which helps to depress average wholesale prices. In ModDecarb new CCGT is close to the money with limited need for CM revenues, whereas by 2040 in the other scenarios it requires CM support at near to - or above - the £75/kW limit. This level of support appears highly unlikely given expected CM clearing prices.
- For CCS and H2GTs wholesale revenues broadly improve over time, but from a low base for H2GT due to the limited number of economic operating hours in 2030. Wholesale revenues for CCS plant in 2040 are materially higher in the intermittent-focused scenario compared to ModDecarb and the baseload-focused scenario. This is due to the higher carbon price pushing up wholesale prices more generally, but without the impact of subsidised low carbon baseload depressing prices for a significant portion part of the year, as seen in the baseload-focused world. However significant financial support for both CCS and H2GT would still be needed in the 2040s in all scenarios.
- H2GTs appear more valuable as a low carbon mid-merit plant than a baseload or pure peaking unit. Supporting these via a CfD would tend to over-incentivise running hours whilst the current CM does not adequately reflect the value of low carbon capacity versus capacity more generally. A higher carbon price would be one option but this is already high in 2040 (~£119/tCO_2).

Contents

Introduction

Requirements and objectives of the analysis

Overview

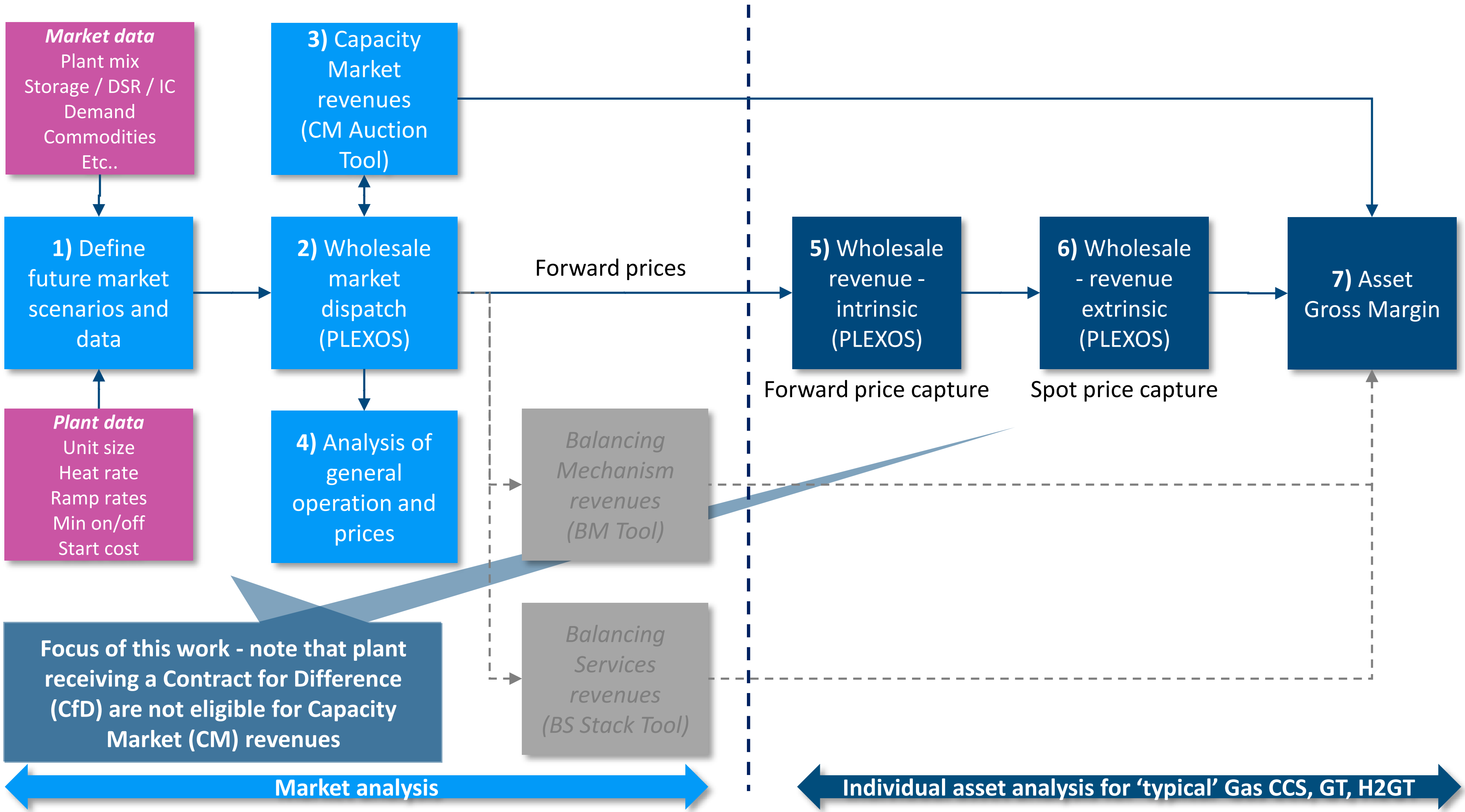
- ETI would like to characterise better the fundamental operation of different types of gas and H2 electricity plant in future GB electricity systems in 2030 and 2040 (the later date sufficient to enable meaningful consideration of the role of CCS) to support their internal programmes on financial viability of new low carbon generation and an understanding of the desirability of different technical characteristics (e.g. flexibility) within the wider electricity system.

- A number of scenarios have been analysed and for each the analysis is comprised of 3 core components
  - Wholesale electricity market modelling using a commercial half-hourly dispatch model (PLEXOS) to understand system operation (e.g. hourly operating profiles, number of starts, etc of different plants) and day-ahead wholesale prices
  - An estimate of Capacity Market Clearing prices consistent with the above
  - Individual asset modelling using the same dispatch model to estimate the Gross Margins (GM) based on intrinsic and extrinsic wholesale market revenues for CCGT, OCGT, CCGT CCS and H2 Gas Turbine (H2GT) plants
  - *The underlying approach is described in more detail in Appendices A and B*

- The analysis has been undertaken in a number of phases with ETI; exploring different scenarios/sensitivities and refining these based on the results at each step. This has culminated in the three final scenarios presented in this pack (technically all part of scenario "5" in the contract definition). Earlier analysis is included in the final Appendices for reference and covers
  - *Appendix C* - Scenarios 'Base' to '3' explored a range of wholesale market scenarios in 2030 based around Baringa's in-house reference case
  - *Appendix D* – 'updated Scenario 3 and 4' collectively explored two separate wholesale market scenarios for 2030 and 2040 and undertook the first set of asset modelling analysis, prior to their refinement in the final scenario 5 analysis
  - Supporting excel results files have been provided for all model runs

Overview of approach

Core project focuses on wholesale and CM markets as most material, post-Gate Closure balancing markets are more complex and generally ‘thinner’ but could be investigated at a later date

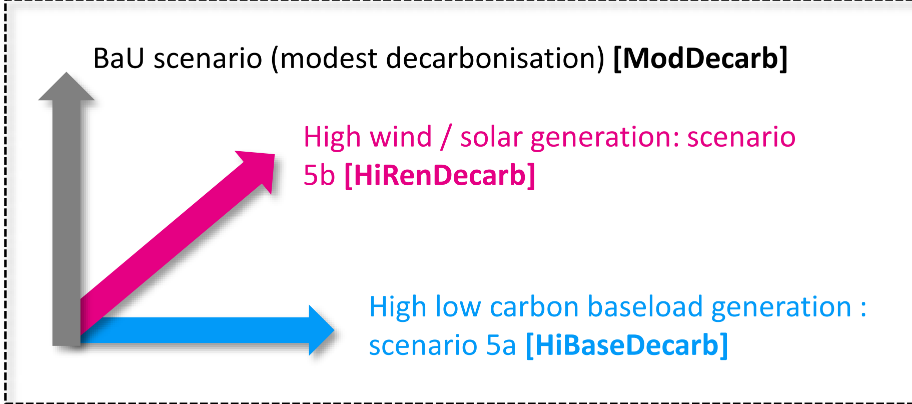


Overview of final scenarios

A 'BaU' and two alternative pathways to achieving significant power sector decarbonisation

Overview

- The final scenarios presented in this analysis draw on a combination of ETI and in-house Baringa assumptions (summarised in the table below) and present a range of significantly different, but plausible decarbonisation routes in which the different asset types would need to operate.
- **BaU scenario [ModDecarb]** represents Baringa's core view of how the market will evolve - based on our July 2016 Reference Case (RC) - given private investment decisions and central assumptions around e.g. demand, commodity prices and expectation of how current market/policy arrangements will evolve. As a result it only achieves relatively modest decarbonisation.
- **Scenario 5a [HiBaseDecarb]** is based on an ESME (v4.1) cost-optimized electricity system solution (from the pathway simulation mode). This is a world with high baseload low carbon generation focused around nuclear and CCS and achieves substantial early decarbonisation by 2030 and 2040.
- **Scenario 5b [HiRenDecarb]** is based on Baringa's (July 2016) Decarbonisation case, where a higher penetration of intermittent wind / solar drives further reduction in emissions - beyond that seen under ModDecarb. The pace of decarbonisation is between HiBaseDecarb and ModDecarb.



Overview of key assumptions

Scenarios	ModDecarb	HiBaseDecarb	HiRenDecarb
Capacity mix	Baringa RC	ESME	Baringa Decarb
Demand	Baringa RC	ESME	Baringa Decarb
Commodity prices	Baringa RC	Baringa RC	Baringa RC
Carbon price	Baringa RC	Baringa Decarb	Baringa Decarb
Target capacity margin	3.4%	3.4%	3.4%
New build gas efficiency	ESME	ESME	ESME
CfDs influencing dispatch	Yes	Yes	Yes

Contents

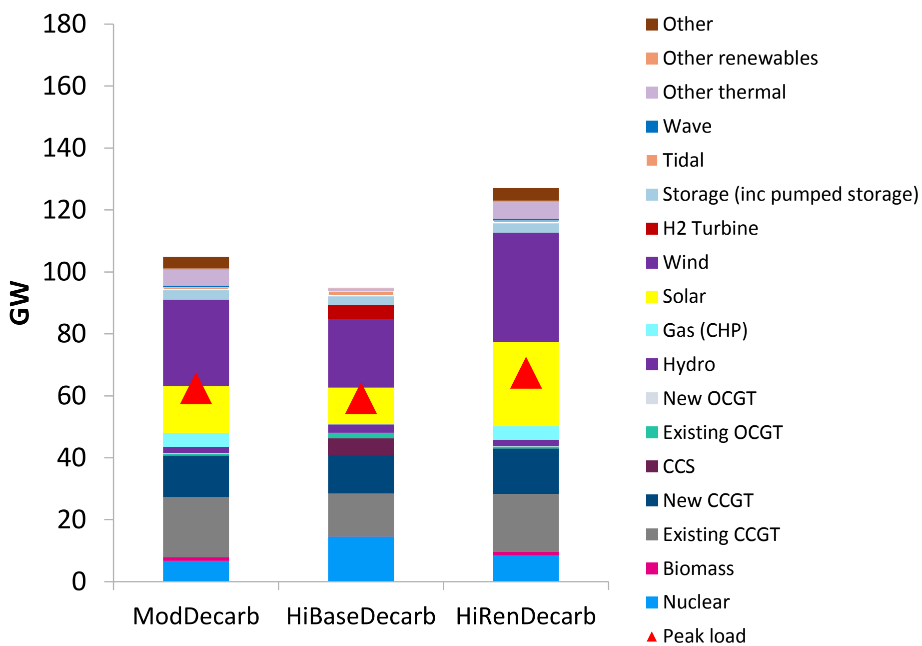
Capacity mix and demand

Comparison of supply and demand for 2030 and 2040 between the three scenarios

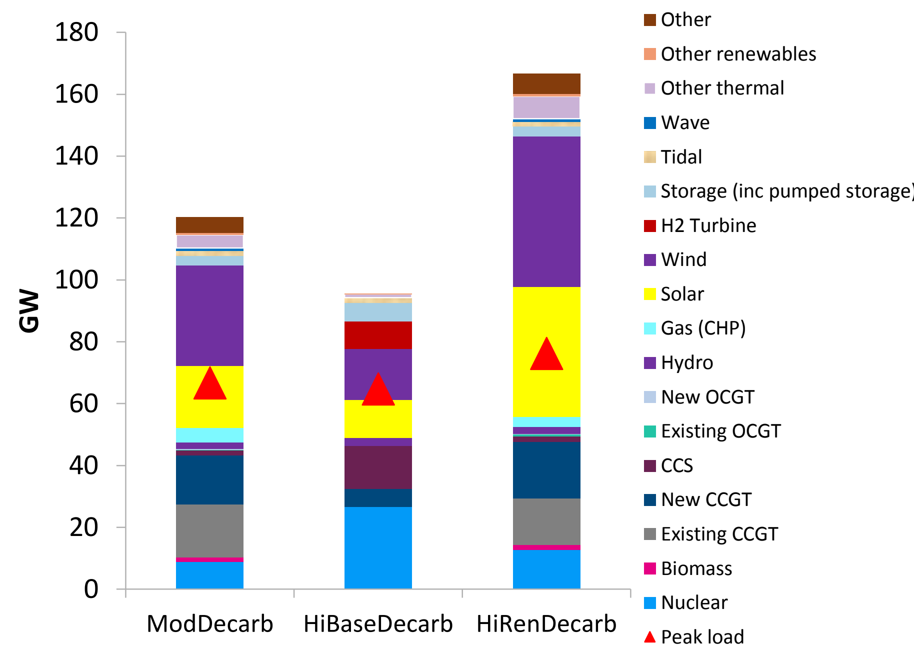
Installed Capacity (GW) (Scenarios: ModDecarb, HiBaseDecarb and HiRenDecarb)

- The comparison of GB supply and demand in the three scenarios in 2030 and 2040 is shown in the charts below, a de-rated capacity margin of 3.4% has been targeted in all cases consistent with the current Capacity Market assumptions (but noting in the Baringa-based ModDecarb and HiRenDecarb scenarios that there can be small fluctuations in outturn margin from year to year).
- HiBaseDecarb has a substantial share of lower carbon baseload nuclear and CCS plant whilst HiRenDecarb has a higher share of intermittent low carbon generation such as wind and solar, requiring more installed capacity in relation to peak demand is required to achieve a similar capacity margin to the two other cases.

2030 supply and demand



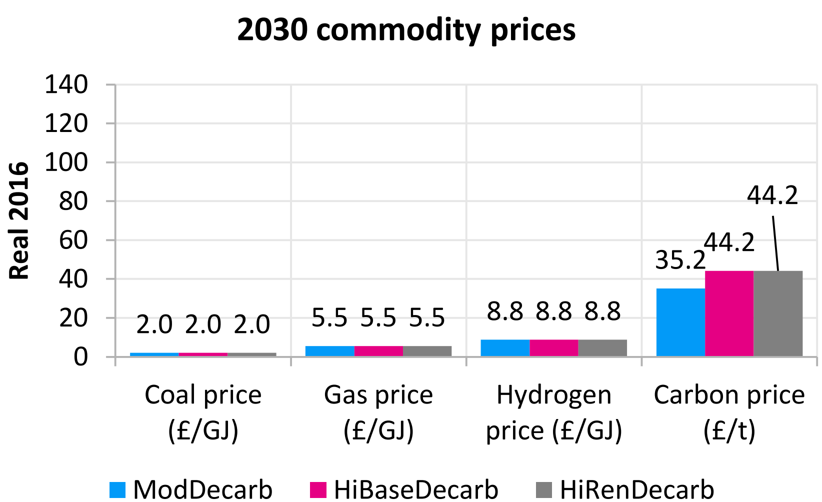
2040 supply and demand

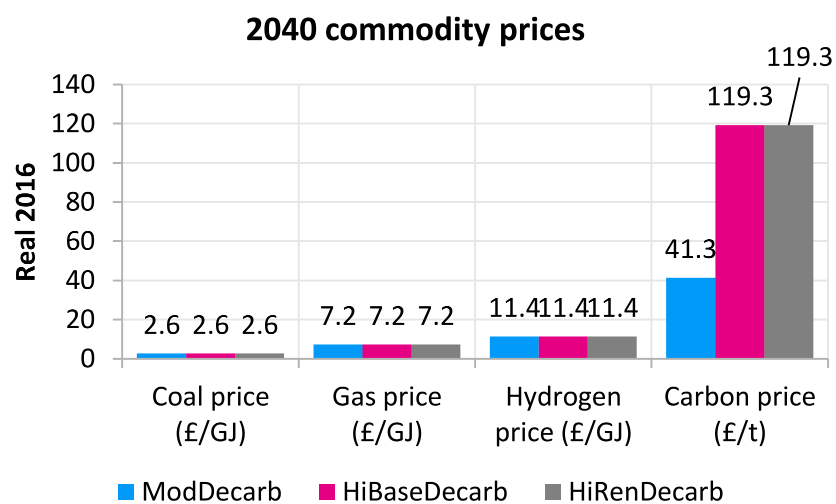


Commodity prices (real 2016 prices)

Comparison of commodity prices in the three scenarios

- Baringa RC commodity prices (based on IEA assumptions) have been used in all the three scenarios apart from carbon price. Baringa RC carbon price has been used for the ModDecarb scenario whereas Baringa Decarbonisation price for carbon has been used in scenarios HiBaseDecarb and HiRenDecarb as shown below.
- Baringa Decarbonisation carbon prices are higher compared to Baringa RC prices in both years as below, representing a higher ambition towards achieving decarbonisation targets. We have assumed the same carbon price in the interconnected markets as in GB and prices for these markets have been generated using Baringa's Pan-European Electricity Market Model.
- The long term carbon price in 2040 in the Baringa RC and Decarbonisation scenarios is based on a Pan-EU coal-to-gas switching principle, reflecting a world in which abatement is achieved largely in the power sector through switching from coal generation to gas. Note that these carbon prices are generally lower than the shadow prices provided by ESME (reflecting the marginal cost of meeting the economy wide carbon targets) which are broadly ~£100 and ~£150/tCO2 in 2030 and 2040, respectively
- Hydrogen prices reflect natural gas prices (via Steam Methane Reforming with CCS) and ETI assumptions on conversion efficiency





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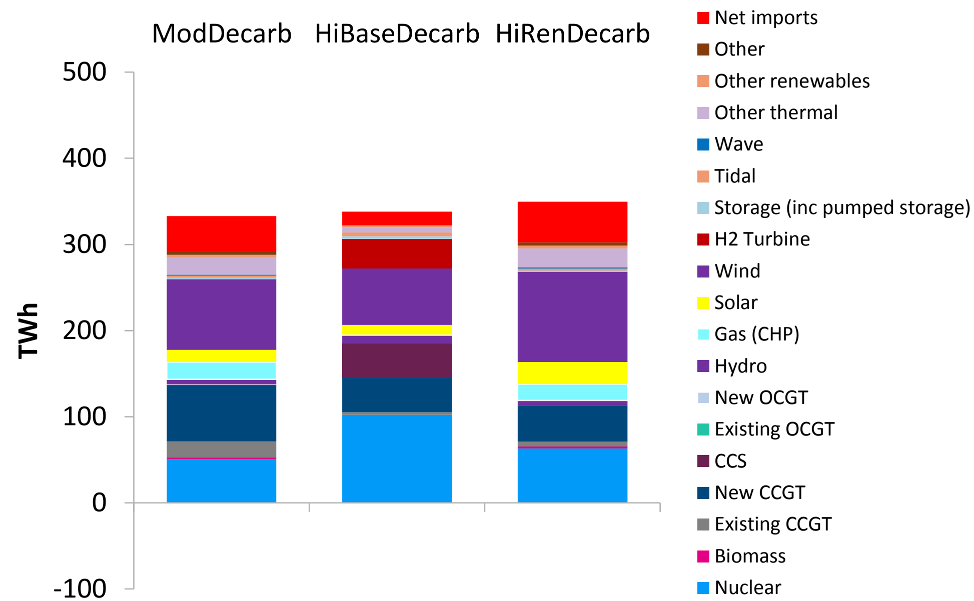
Gas generation in the power mix in 2030

2030 Generation mix overview across scenarios

- We have included an estimate of CfD prices for eligible generation types in 2030 and 2040 in all the three scenarios (based on BEIS administered strike prices with adjustments for changes future technology and commodity costs). These can influence the plant dispatch (and resulting electricity prices) in some periods, due to plant who would normally turn down bidding below their short run costs (negatively in some cases) to remain on the system and receive their subsidy payment
- In 2030, due to the high share of baseload low carbon generation (e.g. nuclear and CCS) in HiBaseDecarb, imports to GB are significantly reduced compared to the two other cases
- Higher low carbon generation in HiBaseDecarb and HiRenDecarb scenarios result in a reduction of the new CCGT load factors to 35-40% from 56% in the ModDecarb scenario
- Existing CCGTs are slightly more competitive in the ModDecarb scenario (running slightly harder) compared to HiBaseDecarb and HiRenDecarb due to lower carbon price and lower share of low carbon generation
- In HiBaseDecarb with the high carbon price and CfD levels for H2 GT and CCS, they run baseload at an annual level. There is no CCS or H2 GT capacity in scenarios ModDecarb and HiRenDecarb in 2030, which are based on Baringa RC and Decarbonisation capacity mix scenarios, respectively
- There is also very little new OCGT capacity in the ModDecarb and HiRenDecarb cases, which does not run in the wholesale market but provides peaking backup capacity



Gas generation (TWh) and load factors	ModDecarb	HiBaseDecarb	HiRenDecarb
Existing CCGT	18.6 (11%)	2.8 (2%)	5.6 (3%)
New CCGT	66.2 (56%)	40 (37%)	42.1 (33%)
Existing OCGT	0 (0%)	0 (0%)	0 (0%)
New OCGT	0 (0%)	0 (0%)*	0 (0%)
CCS	0 (0%)*	40.4 (85%)	0 (0%)*
H2 Turbine	0 (0%)*	34.4 (90%)	0 (0%)*

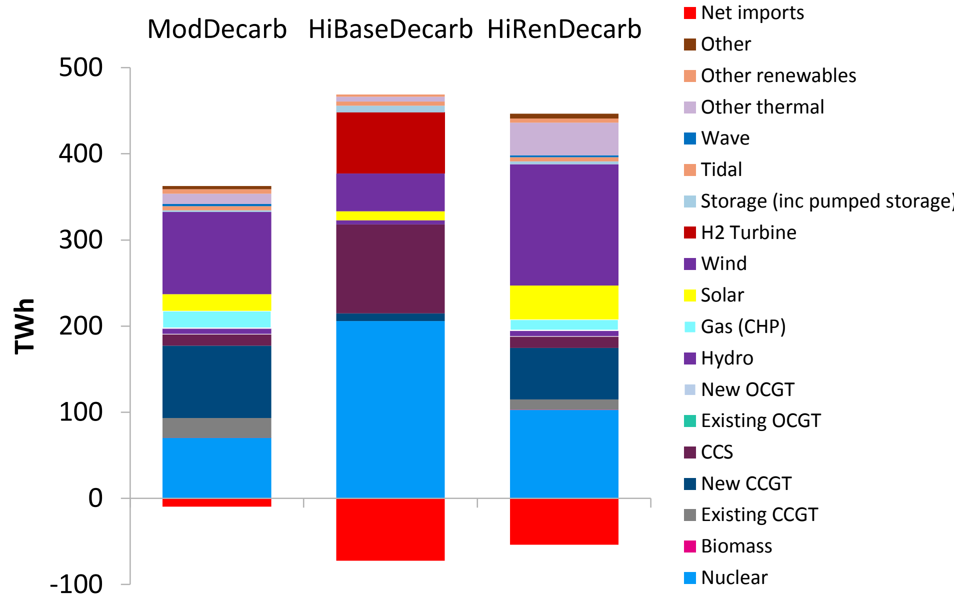
Gas consumption (TWh/year)	ModDecarb	HiBaseDecarb	HiRenDecarb
Existing CCGT	36.2	5.4	10.9
New CCGT	118.8	70.8	75.4
Existing OCGT	0	0	0
New OCGT	0	0*	0
CCS	0*	81.7	0*
H2 Turbine	0*	64.8	0*

**The installed capacity is 0, so the load factor, generation and gas consumption are 0%*

Gas generation in the power mix in 2040

2040 Generation mix overview across scenarios

- Moving from 2030 to 2040, the increasing share of low carbon generation is significant in both scenarios HiBaseDecarb and HiRenDecarb, but more so in HiBaseDecarb due to the significant expansion of new baseload nuclear and CCS plant. As a result, GB becomes a net exporter in 2040 from being a net importer in 2030
- In 2040, GB exports to a significantly higher extent in HiBaseDecarb and HiRenDecarb with high share of low carbon generation (to a higher extent in HiBaseDecarb due to high nuclear and CCS generation, which generates baseload)
- Existing CCGT runs low load factors (~10-15%) in the ModDecarb and HiRenDecarb scenarios - albeit increasing slightly compared to 2030 – mainly due to lower carbon price in the ModDecarb case and higher requirement for back up capacity in the HiRenDecarb world with a high share of intermittent generation
- New CCGT load factors are the highest in the ModDecarb case, primarily due to lower carbon prices, increasing slightly compared to 2030. New CCGT load factors also increase slightly in HiRenDecarb helping to accommodate more intermittent wind and solar, however, they are significantly reduced in HiBaseDecarb as their operation is displaced by hydrogen turbines.
- CCS runs baseload in all cases, with the CfD being in place. Similarly, H2 GTs run baseload in HiBaseDecarb (no H2 GT comes online in the ModDecarb and HiRenDecarb cases)



Gas generation (TWh) and load factors	ModDecarb	HiBaseDecarb	HiRenDecarb
Existing CCGT	23 (15%)	0 (0%)*	12.1 (9%)
New CCGT	83.8 (60%)	9 (18%)	59.8 (37%)
Existing OCGT	0 (0%)	0 (0%)*	0 (0%)
New OCGT	0 (0%)	0 (0%)*	0 (0%)
CCS	13.6 (86%)	103.1 (84%)	13.7 (87%)
H2 Turbine	0 (0%)*	70.7 (90%)	0 (0%)*

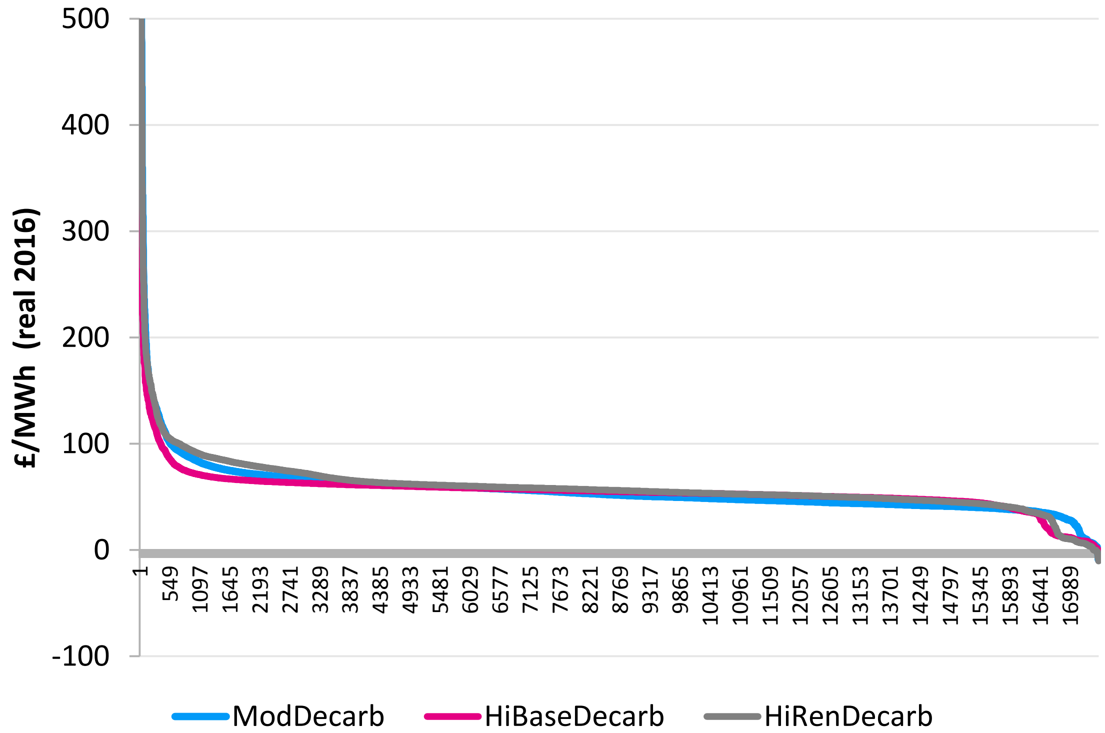
Gas consumption (TWh/year)	ModDecarb	HiBaseDecarb	HiRenDecarb
Existing CCGT	44.8	0*	23.5
New CCGT	150.9	16.1	107.7
Existing OCGT	0	0*	0
New OCGT	0	0 *	0
CCS	27.2	207.4	27.3
H2 Turbine	0*	131.3	0*

The installed capacity is 0, so the load factor, generation and gas consumption are 0%

Comparison of GB price duration curves in 2030

GB (day-ahead wholesale station gate basis) power price in 2030 (real 2016 prices) including scarcity and technical uplift

- The comparison of the price duration curves for GB in 2030 is shown below. There are fewer numbers of hours with very high power prices in the HiBaseDecarb scenario with significant CCS and nuclear baseload generation compared to the other scenarios
- Annual price levels are similar in ModDecarb compared to the two other scenarios due to the impact of higher carbon price in HiBaseDecarb and HiRenDecarb partially offsetting the impact of higher share of low carbon intermittent generation
- The level of decarbonisation achieved in the power sector is highest in HiBaseDecarb and lowest in ModDecarb



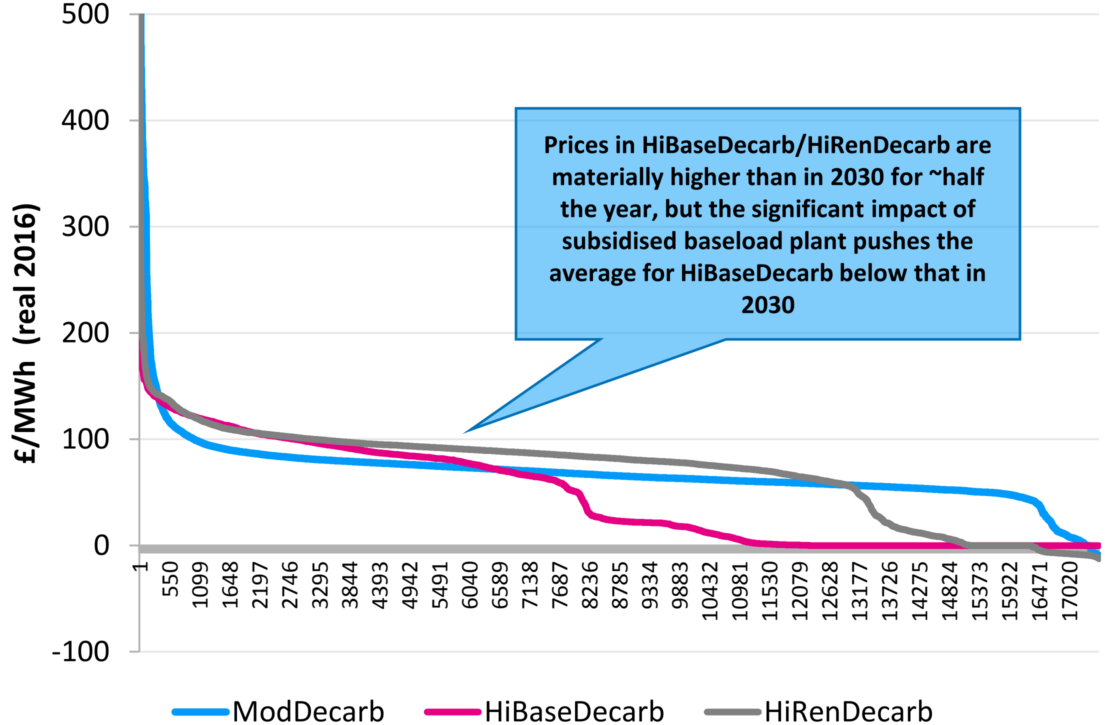
Scenarios	GB time weighted price (£/MWh)	Carbon intensity (gCO2/kWh)
ModDecarb	57.4	130.6
HiBaseDecarb	56.0	50.2
HiRenDecarb	60.4	82.3

Scenarios	No of hours with negative prices	No of hours with prices above 500 £/MWh
ModDecarb	12	37
HiBaseDecarb	20	19
HiRenDecarb	46	32

Comparison of GB price duration curves in 2040

GB (day-ahead wholesale station gate basis) power price in 2040 (real 2016 prices) including scarcity and technical uplift

- The difference in the price duration curves in the three scenarios becomes more significant in 2040 compared to 2030 as shown below. The number of hours with low or near zero prices is highest in HiBaseDecarb with a significant increase in baseload nuclear, CCS and H2 GT generation in the long term, which are also eligible for CfDs which broadly acts to depress prices.
- As expected, the power sector is highly decarbonised in HiBaseDecarb in 2040. HiRenDecarb sees a more limited decline in carbon intensity compared to 2030, however, this is affected by significant export volumes. Carbon intensity considering only supply to meet domestic demand - excluding exports - would be lower in this world.



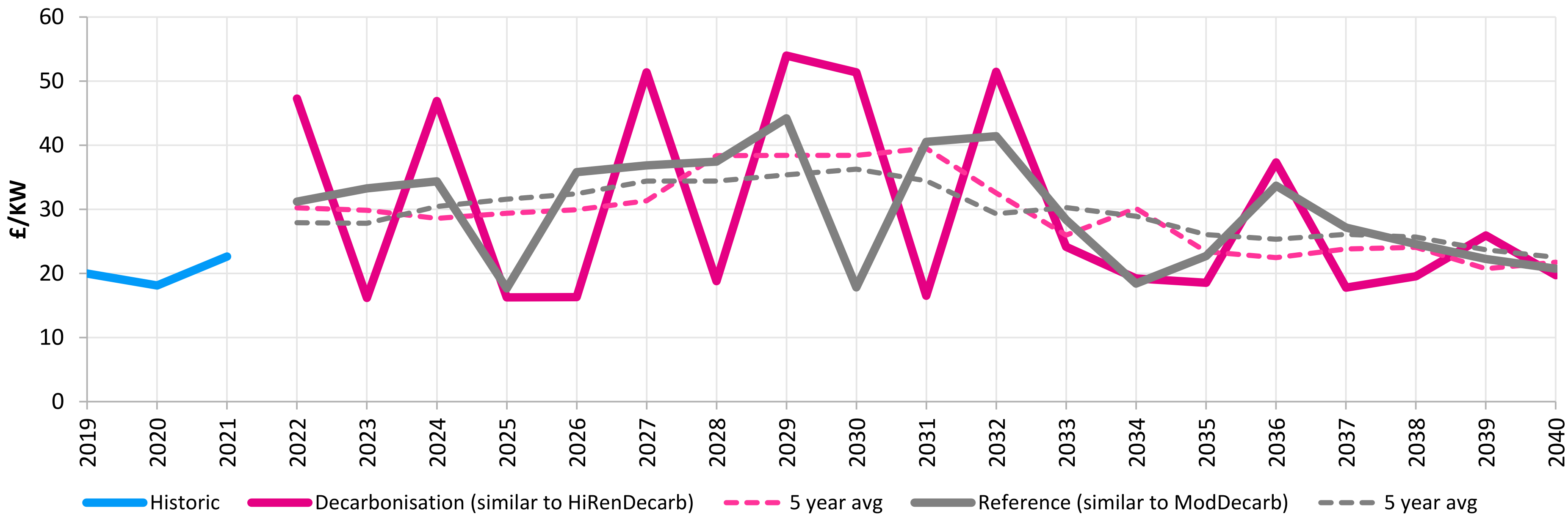
Scenarios	GB time weighted price (£/MWh)	Carbon intensity (gCO2/kWh)
ModDecarb	69.4	127.3
HiBaseDecarb	46.2	15.3
HiRenDecarb	69.9	69.3

Scenarios	No of hours with negative prices	No of hours with prices above 500 £/MWh
ModDecarb	170	25
HiBaseDecarb	2,002	0
HiRenDecarb	1,254	7

Potential Capacity Market revenues

Outturn CM clearing prices may be quite volatile from year to year

- It should be noted that the analysis of CM clearing prices across the three scenarios has only been assessed for snapshots of the system consistent with the assumptions in the 2030 and 2040 spot years (i.e. the expected energy market revenues for existing and new plant brought onto the system and what the marginal plant would need to bid to make its required return)
- In practice CM prices on a year-to-year basis may be quite volatile as illustrated by the chart below (from in-house Baringa analysis) given how steep the auction supply stack is around the capacity requirement and may spike to a max of £75/kW (a backstop assuming that the new entrant is an OCGT with minimal energy market revenues)
- *Note that the Reference and Decarbonisation results below are similar (but not identical) to the specific ModDecarb and HiRenDecarb scenarios within this project, but are presented to provide an illustration of volatility across the pathway*



Estimated Capacity Market clearing prices

Clearing prices for three scenarios in the 2030 and 2040 spot years

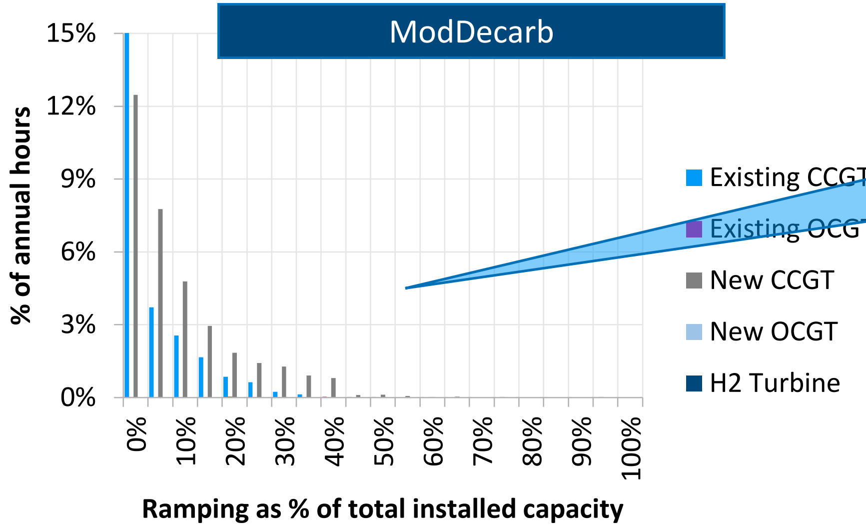
- All scenarios are broadly targeting a de-rated capacity margin of 3.4%. HiBaseDecarb targets this explicitly in each spot year (as it is a constraint within the ESME solution that informs it) whilst the ModDecarb and HiRenDecarb are targeting this on average basis across the pathway, but may experience small movements away from this target depending on the new capacity that is brought forward by the CM in each individual year.
- Whilst acknowledging the potential for year to year variations the scenarios show a broad trend towards declining clearing price (consistent with the previous slide) which is driven by a combination of cheaper technology options in the supply stack (e.g. declining costs of batteries or DSR) and/or the marginal new entrant earning more the wholesale (or other) markets which reduces the amount they need to bid into the CM.
- The clearing prices in HiBaseDecarb are the most volatile. This is accentuated by both the optimised underlying capacity mix (flipping between the marginal new plant being built purely for backup reasons in 2030 and a new plant which is providing significant energy supply and indirectly provides virtually free peak capacity in 2040); and a much smaller auction supply stack (e.g. over 80% of the installed capacity in 2040 ineligible as it is receiving low carbon support)

Scenarios	2030 (£/kW)	2040 (£/kW)
ModDecarb	22.0	11.5
HiBaseDecarb	75	1.9
HiRenDecarb	54.4	24.3

Technology	GB CM de-rating factors
Nuclear	90.0%
Biomass	86.9%
Existing CCGT	90.0%
CCS	90.0%
Existing OCGT	94.2%
Other	86.9%
Hydro	86.2%
Gas (CHP)	90.0%
Solar	0.0%
Wind	10.0%
Pumped storage	96.6%
Interconnection	26-78% (varies by IC)

Ramping of flexible gas generation in 2030

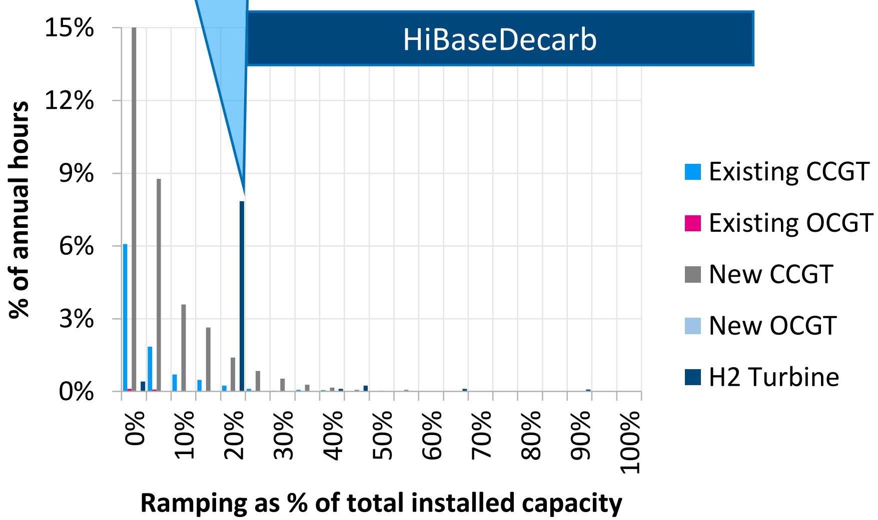
Ramping as a percentage of installed capacity for flexible gas generation in 2030

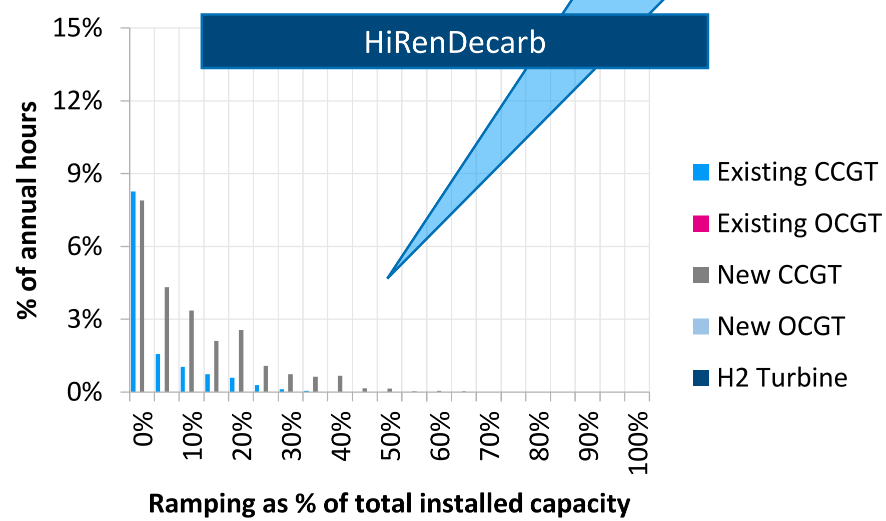


Flexibility provided by existing / new CCGT, but relatively few hours where significant ramping is required

Some additional ramping provided by H2 turbines, but noting that the assumed CfD incentivises baseload running

Similar to ModDecarb, but additional wind/solar leads to small number of periods where ramping requirements are more significant



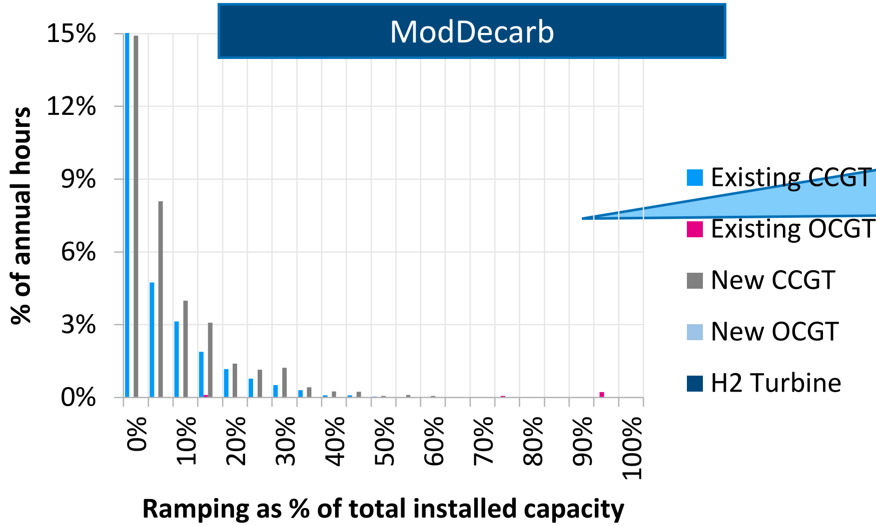


**The x-axis in the charts refers to ramping defined as the change in generation level from one hour to the next as a percentage of the total installed capacity. The y-axis refers to the total number of hours in a year during which each of these ramping levels are observed (as a percentage of the total number of hours in a year). The ramping level buckets are in increments of 5%. The 5% bucket refers to ramping levels from 5% to 10% and so on.*

Ramping of flexible gas generation in 2040

Baringa

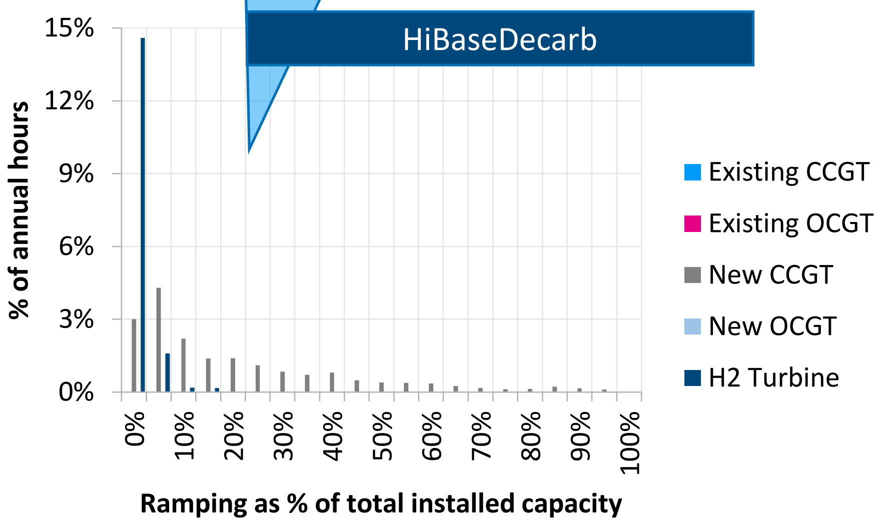
Ramping as a percentage of installed capacity for flexible gas generation in 2040

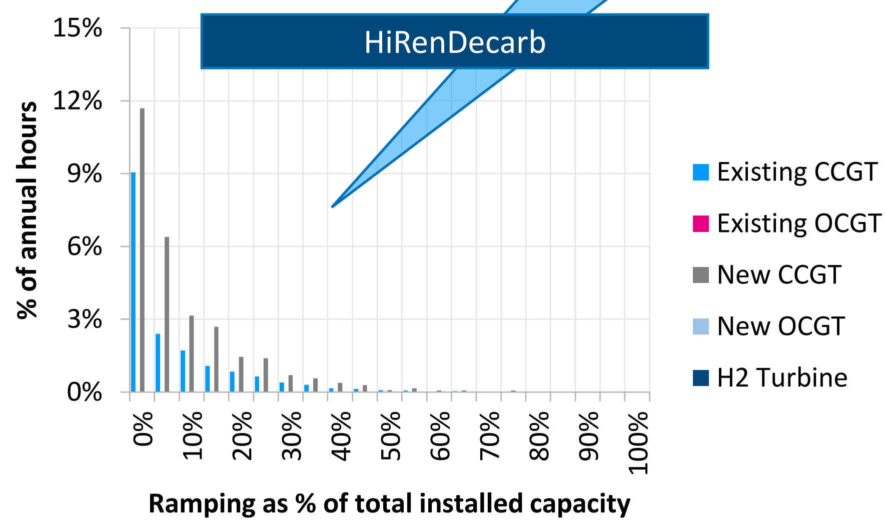


CCGT operation is broadly similar to 2030

New CCGTs squeezed out by a combination of New CCGT and H2 turbine and more limited intermittent renewables reduces balancing requirements

Higher carbon prices start to squeeze role of gas plant for providing flexibility with more cycling of e.g. storage (nb installed new CCGT capacity is ~15% higher compared to ModDecarb





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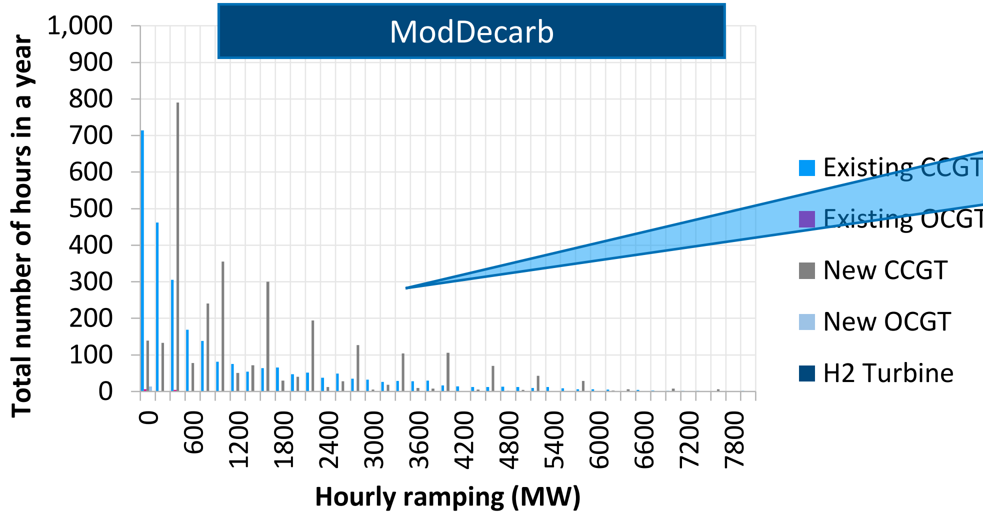
Ramping of flexible gas generation in 2030

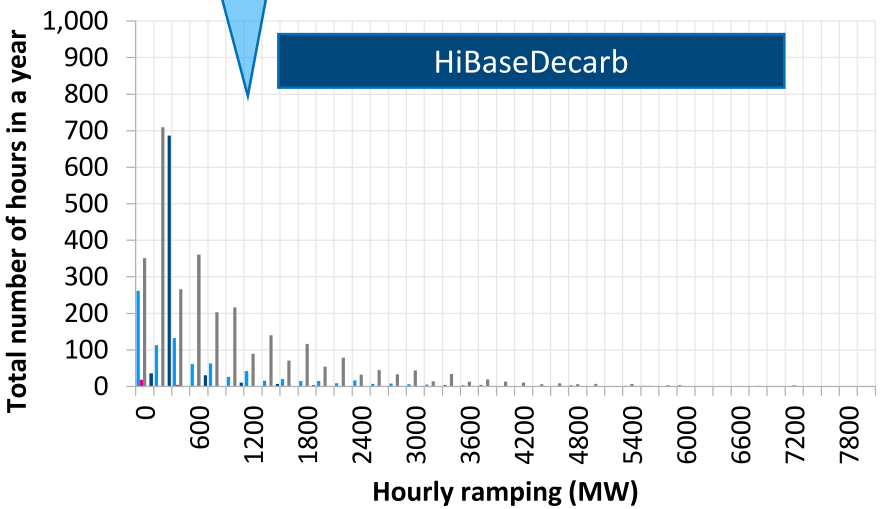
Baringa

Ramping in MW for flexible gas generation in 2030

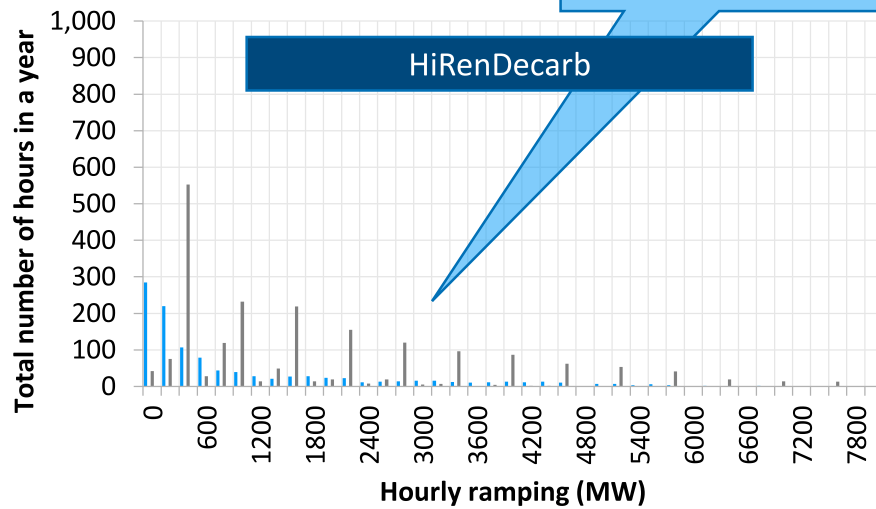


Flexibility provided by existing / new CCGT, but relatively few hours where significant ramping is required

Some additional ramping provided by H2 turbines, but noting that the assumed CfD incentivises baseload running



Similar to ModDecarb, but additional wind/solar leads to small number of periods where ramping requirements are more significant

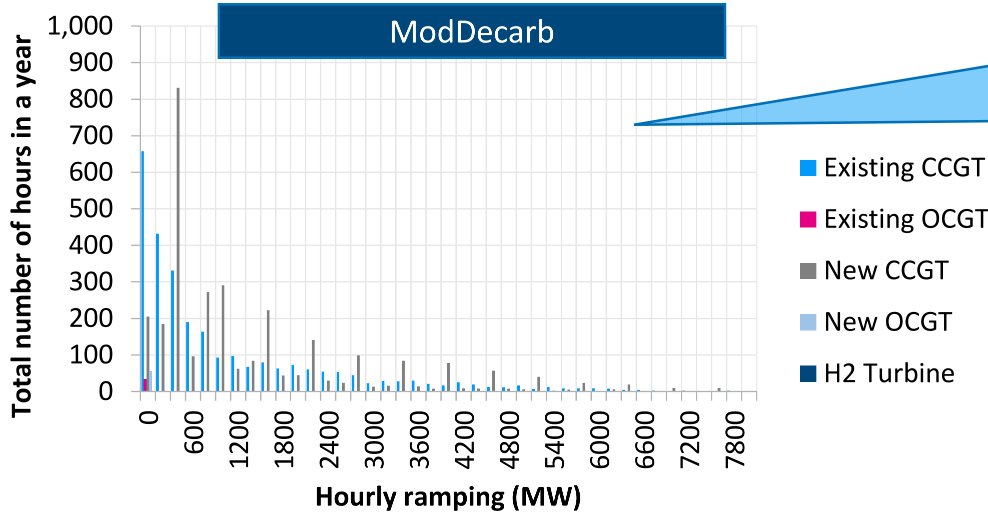


**The x-axis in the charts refers to ramping defined as the change in generation level in MW from one hour to the next. The y-axis refers to the total number of hours in a year during which each of these ramping levels are observed. The ramping level buckets are in increments of 200 MW. The 200 MW bucket refers to ramping levels from 200 MW to 400 MW and so on. This is another representation of the ramping shown as % of total installed capacity in the previous slides.*

Ramping of flexible gas generation in 2040

Baringa

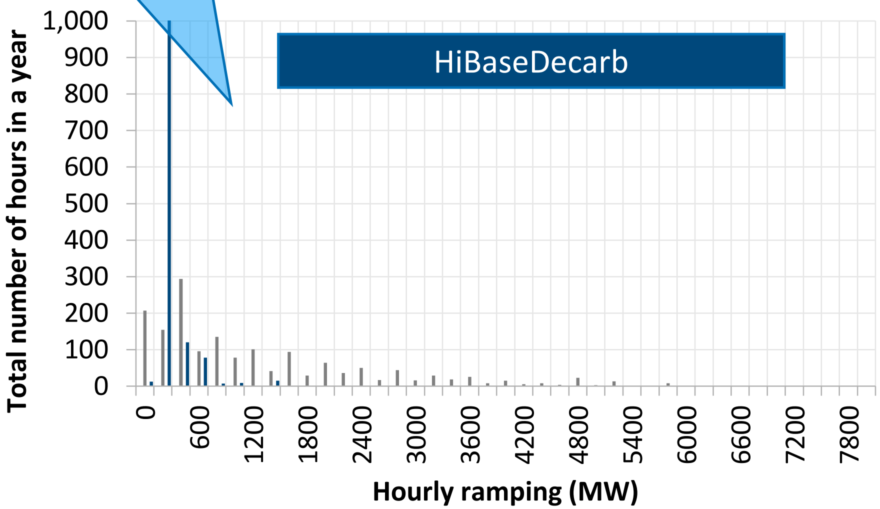
Ramping in MW for flexible gas generation in 2040

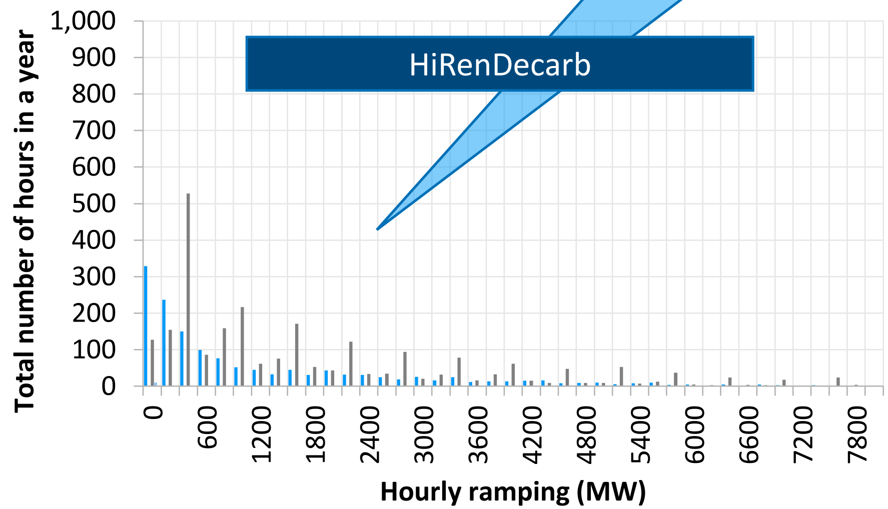


CCGT operation is broadly similar to 2030

New CCGTs squeezed out by a combination of New CCGT and H2 turbine and more limited intermittent renewables reduces balancing requirements

Higher carbon prices start to squeeze role of gas plant for providing flexibility with more cycling of e.g. storage (nb installed new CCGT capacity is ~15% higher compared to ModDecarb





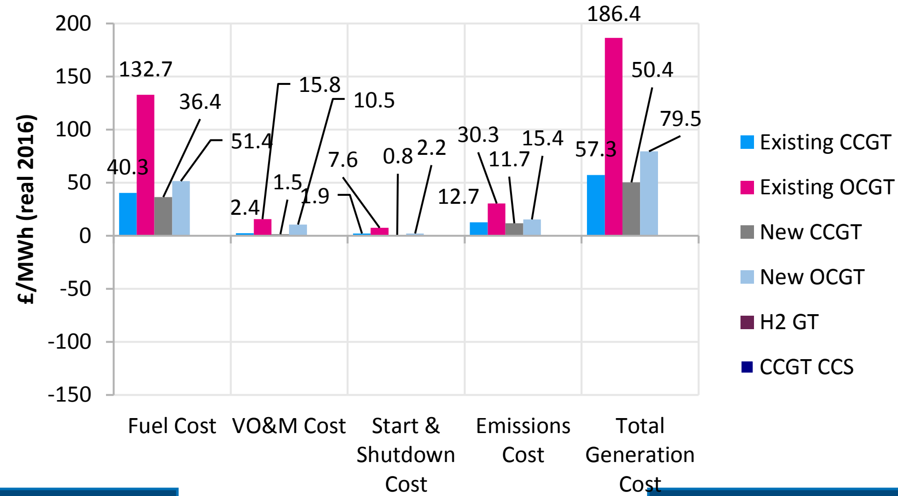
**The x-axis in the charts refers to ramping defined as the change in generation level in MW from one hour to the next. The y-axis refers to the total number of hours in a year during which each of these ramping levels are observed. The ramping level buckets are in increments of 200 MW. The 200 MW bucket refers to ramping levels from 200 MW to 400 MW and so on. This is another representation of the ramping shown as % of total installed capacity in the previous slides.*

Operating costs in 2030

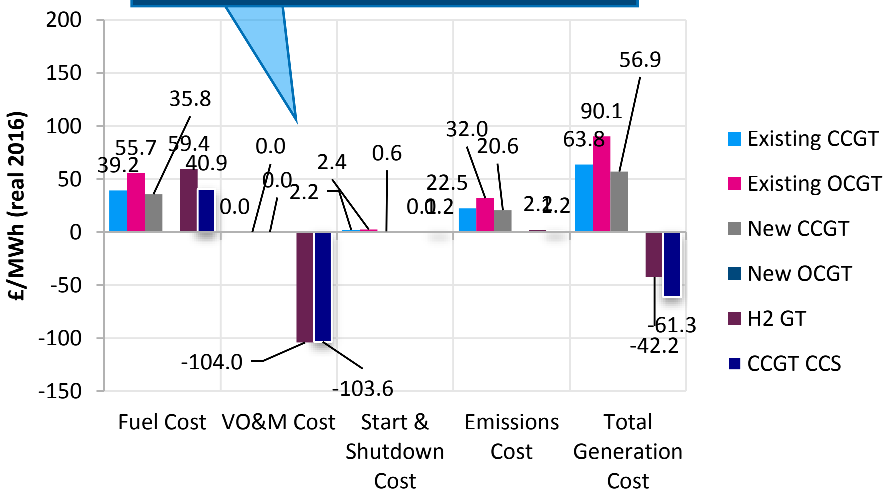
Breakdown of operating costs for gas plant in 2030

Negative VOMs reflect implied subsidy from CfDs (net of actual variable operating costs such as CCS transport and storage)

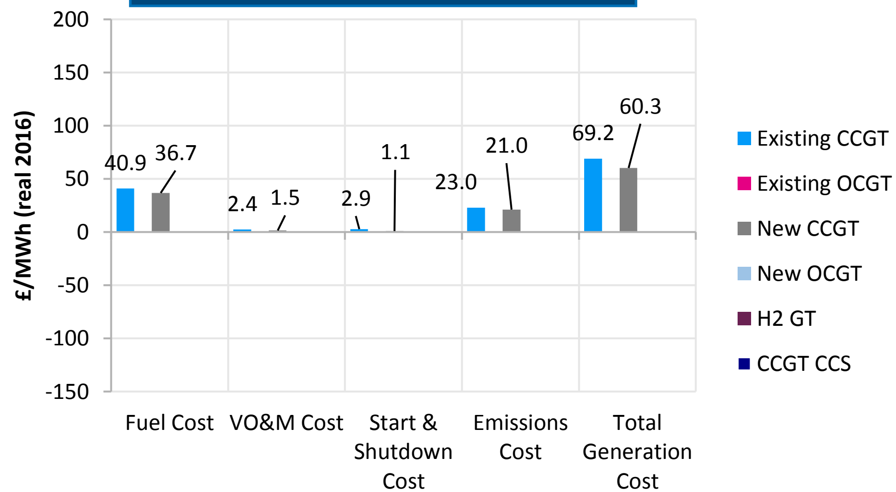
ModDecarb



HiBaseDecarb



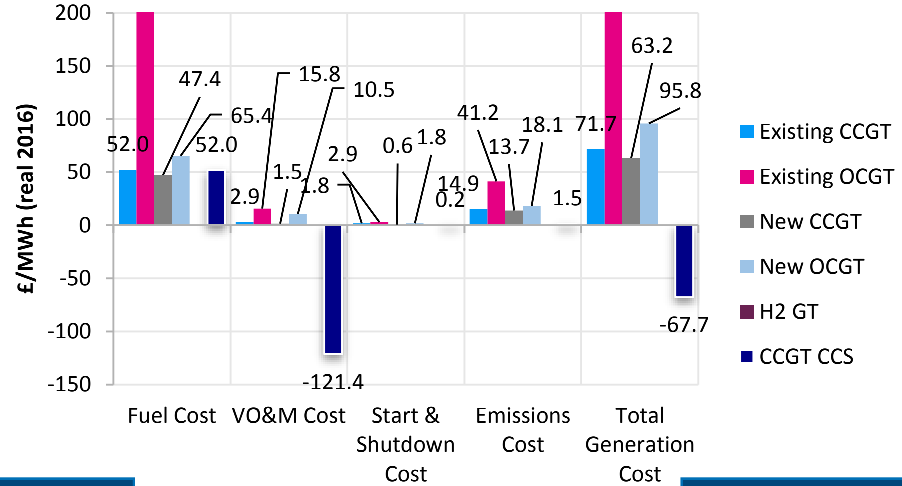
HiRenDecarb



Operating costs in 2040

Breakdown of operating costs for gas plant in 2040

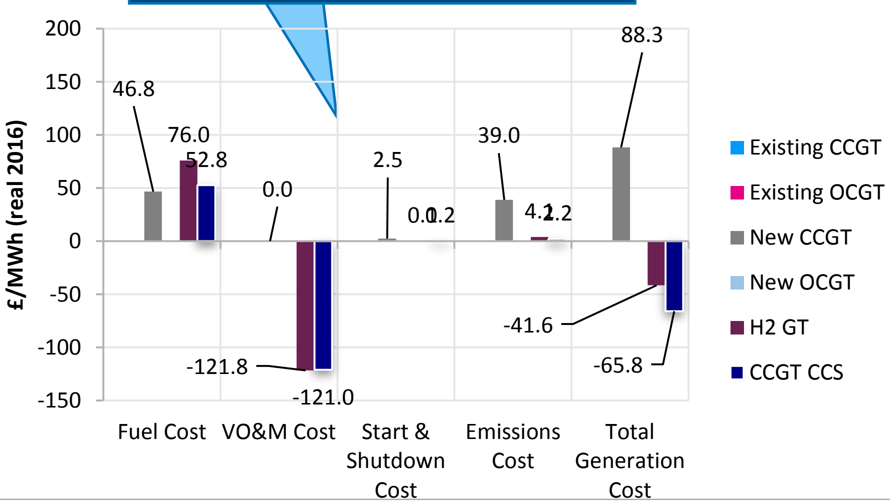
ModDecarb



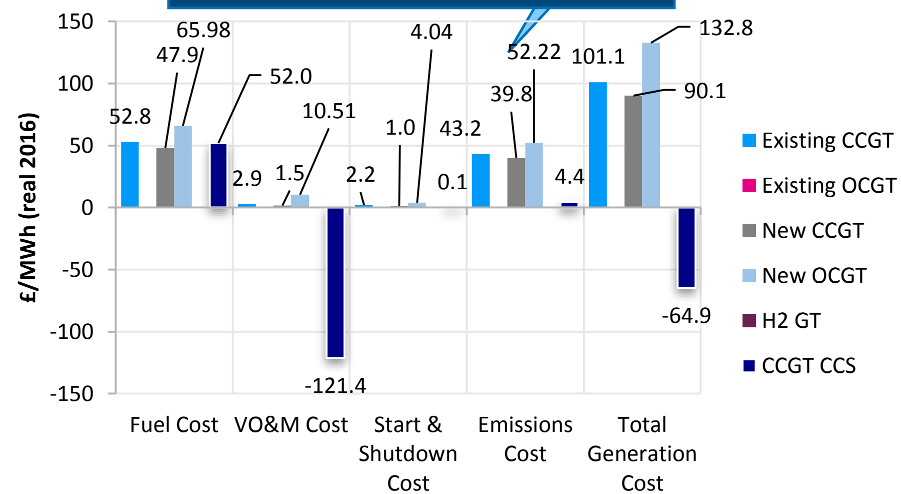
Negative VOMs reflect implied subsidy from CfDs (net of actual variable operating costs such as CCS transport and storage)

Significant increase in emissions cost

HiBaseDecarb

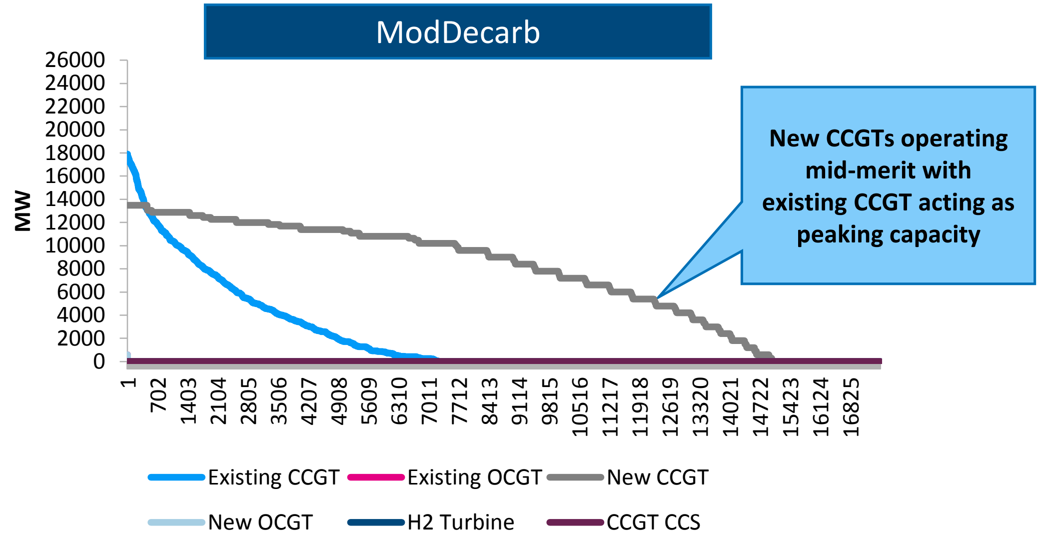


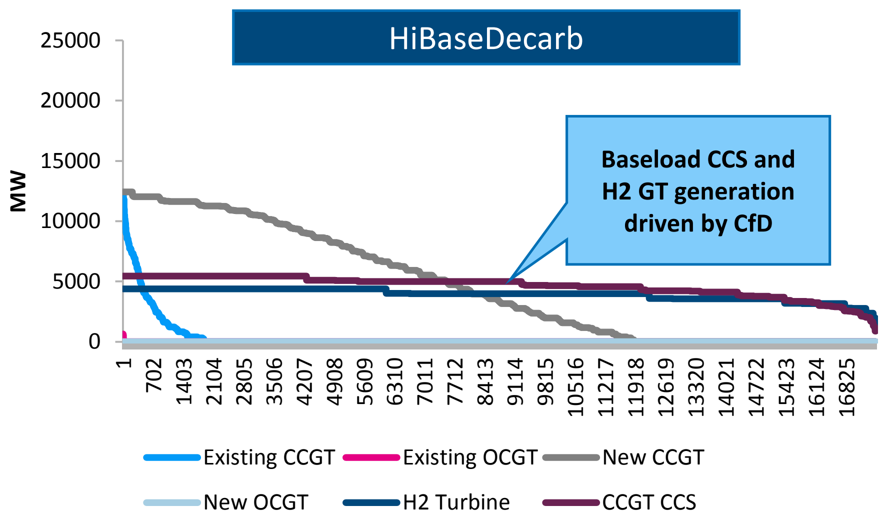
HiRenDecarb

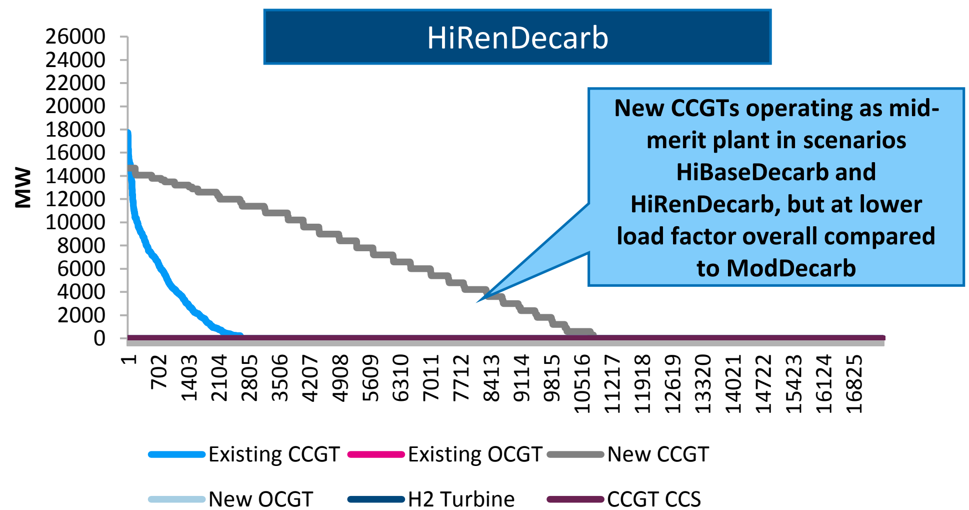


Generation duration curves 2030

Flexible gas generation

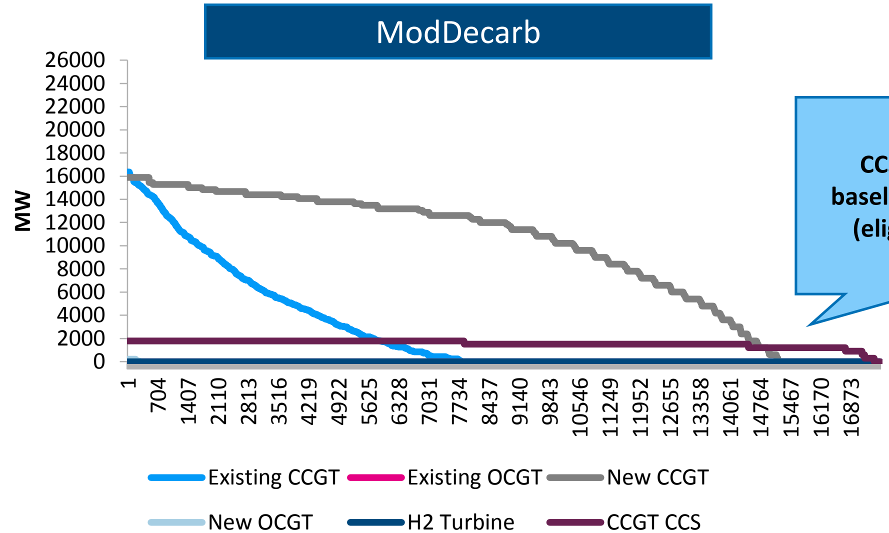






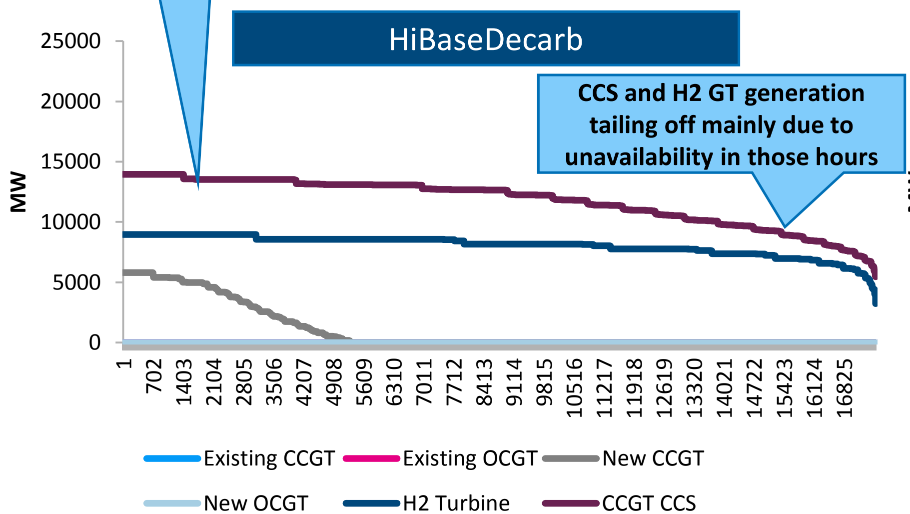
Generation duration curves 2040

Flexible gas generation

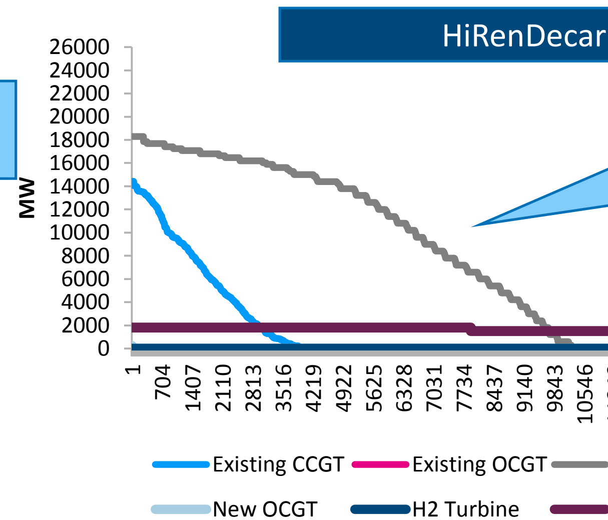


CCS generating baseload in all cases (eligible for CfD)

Approx. doubling of H2 GT and CCS generation in 2040 compared to 2030



CCS and H2 GT generation tailing off mainly due to unavailability in those hours

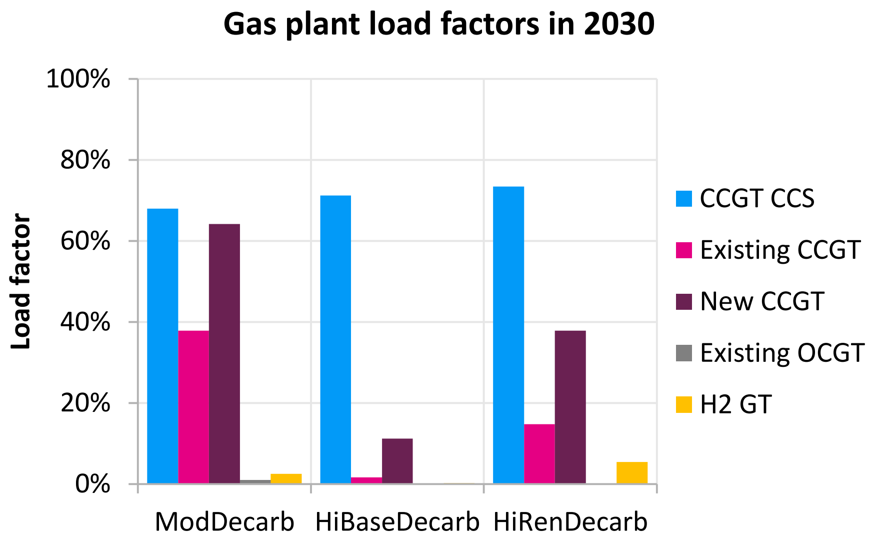


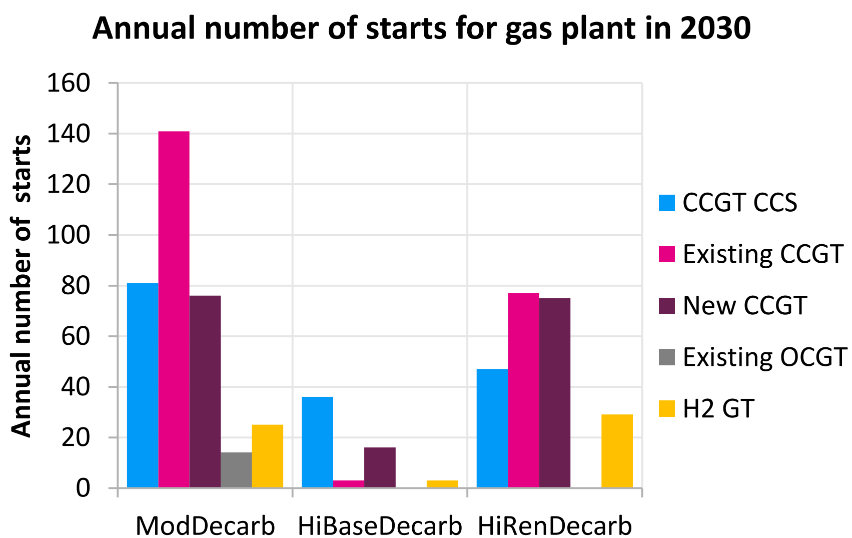
New CCGT load factor increases slightly cf. 2030 with slightly more concentrated cycling driven by increasing exports

Contents

Load factor and number of starts in 2030

Carbon price is a key factor for H2 GT operation and profitability

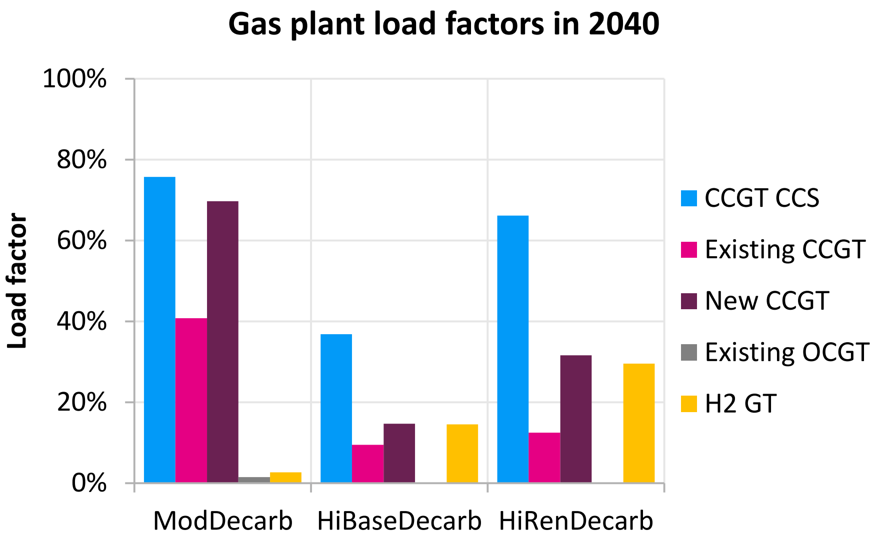


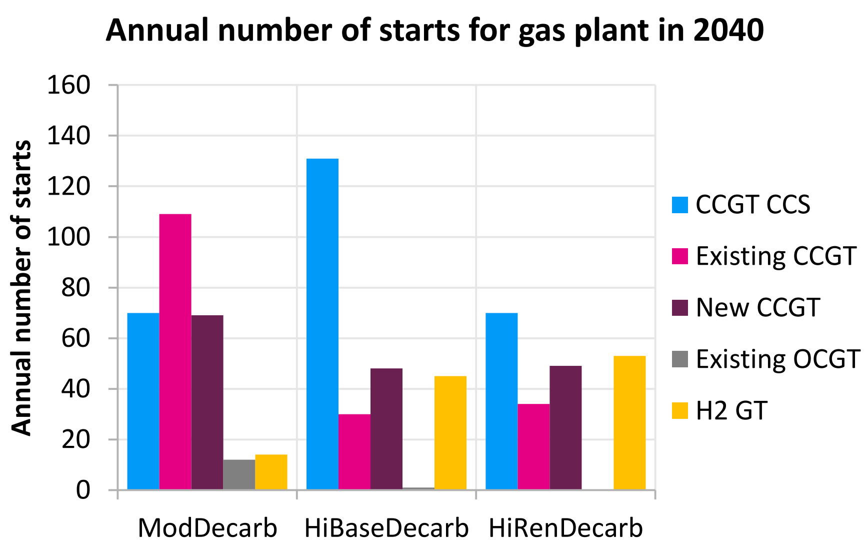


- Note that for the asset valuation analysis (assuming dispatch of the individual asset as a profit maximising price taker – see Appendix B for further details of the approach) we have not included a CfD for CCS or H2 GTs as the primary purpose is first to understand how these assets would operate in each scenario in the *absence* of policy support
- The analysis therefore provides insight into the more detailed operation and profitability of individual gas assets on a merchant basis in each of the market modelling scenarios
- With the lowest power price in 2030, load factors for CCGT/OCGTs are also lowest in HiBaseDecarb as shown on the left and below the new CCGT load factor seen in the market run. Note that a profit maximising asset may run differently due to maintenance schedules and to capture potential price spikes
- CCGT load factors are the highest in the ModDecarb case due to higher power and less penetration of low carbon generation.
- CCS load factors are around 70% across the three cases. H2 GT profitability is driven by carbon price and share of intermittent generation. With the lowest prices in HiBaseDecarb, H2 GTs almost never run (annual load factor 0.2%)
- Load factors for existing OCGT is negligible in all cases in 2030

Load factor and number of starts in 2040

Carbon price is a key factor for H2 GT operation and profitability

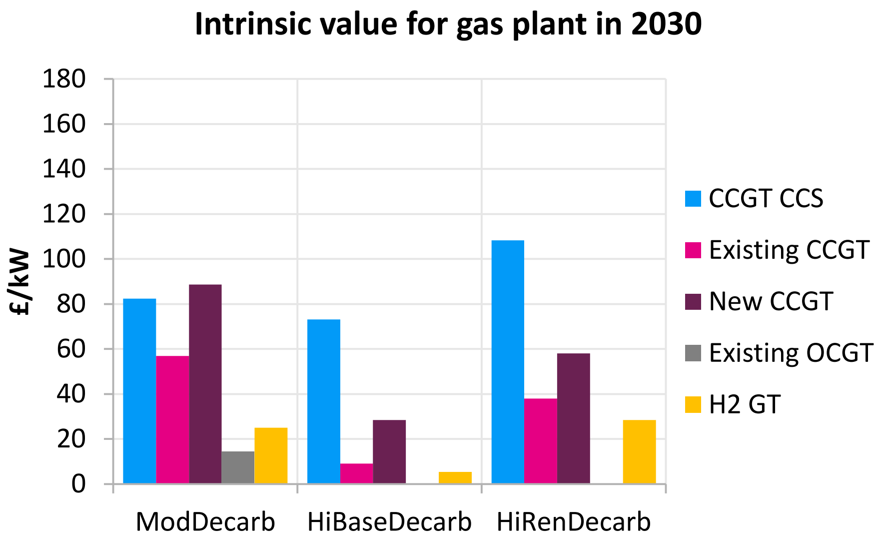


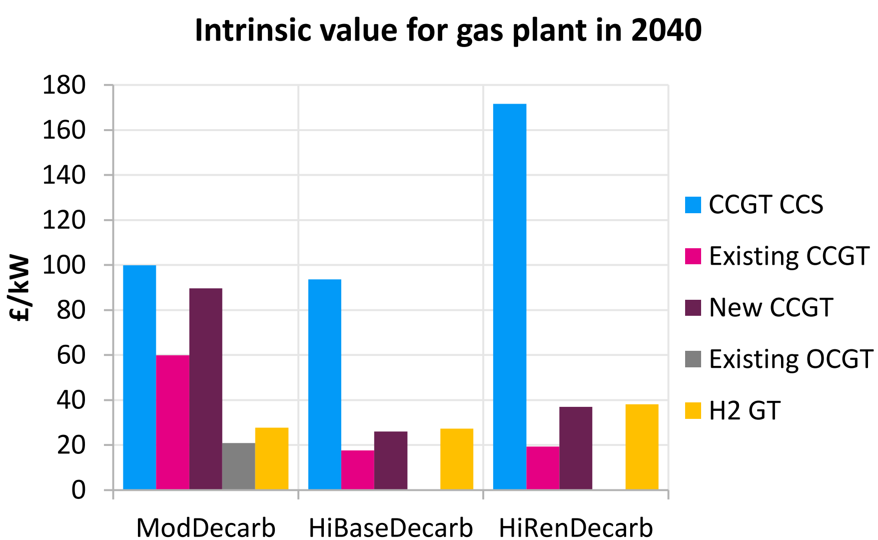


- With the highest increase in power price from 2030 to 2040 and lowest growth of low carbon generation, CCGT load factors remain most favourable in the ModDecarb scenario.
- CCS load factors decrease significantly in HiBaseDecarb from 2030 to 2040 due to higher number of hours with negative prices and lower annual price overall, due to significant further expansion of nuclear. This is effect is less material in HiRenDecarb, but there is still a modest decline in load factor moving from 2030 to 2040
- H2 GT load factors increase from 0.2% to 15% in HiBaseDecarb due to the more than doubling of carbon price from 2030 to 2040 (from 44 £/t in 2030 to 119 £/t in 2040) and around 30% in HiRenDecarb
- New CCGT load factors are slightly lower in HiRenDecarb compared to 2040 as higher carbon prices increase operating costs.

Intrinsic Value

Carbon price drives significant value for mid-merit and baseload low carbon plant

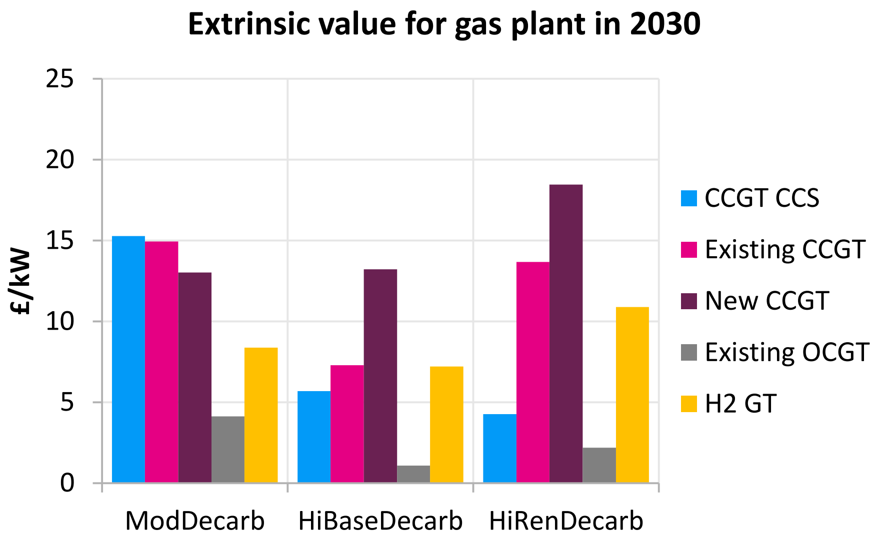


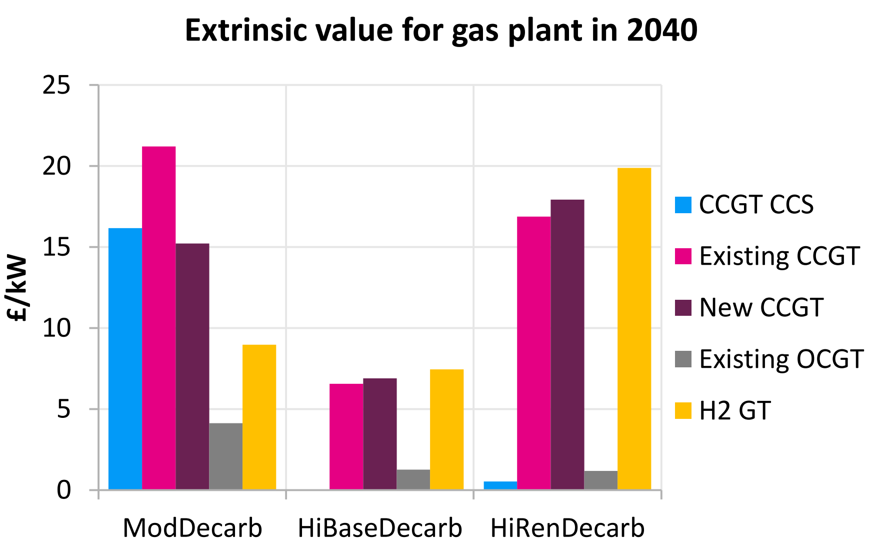


- Intrinsic value for CCGTs is lowest in HiBaseDecarb in both years, due to lower annual power price overall and lower number of hours with high prices
- H2 GT profitability remains at similar levels from 2030 to 2040 in the ModDecarb and HiRenDecarb scenarios driven by the strong increase in power prices, however, low load overall factors limit revenues
- H2 GT profitability increases somewhat in HiBaseDecarb from 2030 to 2040, as the increase in carbon price raises the power price for a portion of the year, leading to higher load factors and profitability for H2GTs (even if on average prices have declined due to the strong expansion of subsidized low carbon plant)
- Intrinsic value is highest for CCS in almost all cases, which run at higher load factors compared to other gas plants, and is the highest in HiRenDecarb in 2040 given the highest average power prices in this scenario

Extrinsic Value

Short-term electricity price volatility could add a modest amount to the plant revenues

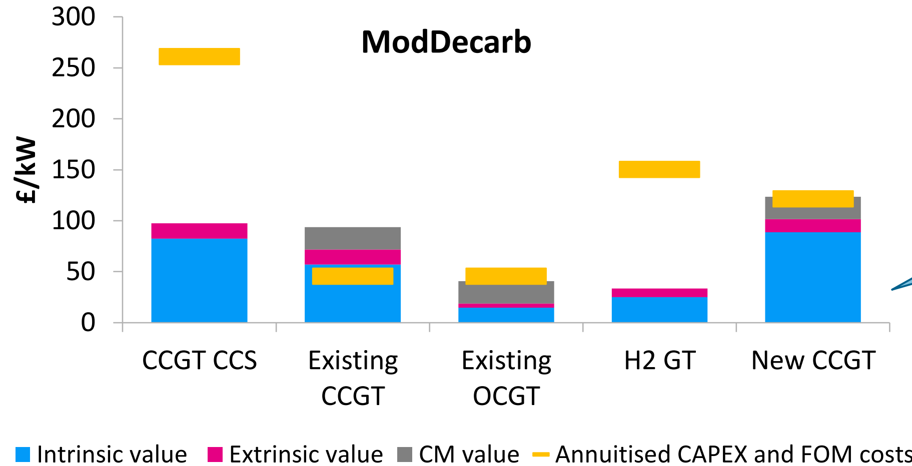




- The values on the left are likely to represent an upper bound on the extrinsic value and a hair-cut is likely to be required in reality to reflect lack of perfect foresight and cost of adjusting trading strategy (e.g. day-ahead and intraday)
- As an example from real world operators a CCGT is able to capture 30% of the potential value of extrinsic margin indicated by our stochastic modelling (which is a value we commonly use for CCGT valuation purposes)
- In addition, if the asset is often at the margin setting the price, then there will be less potential for extrinsic margin

Gross Margin (wholesale + CM) in 2030

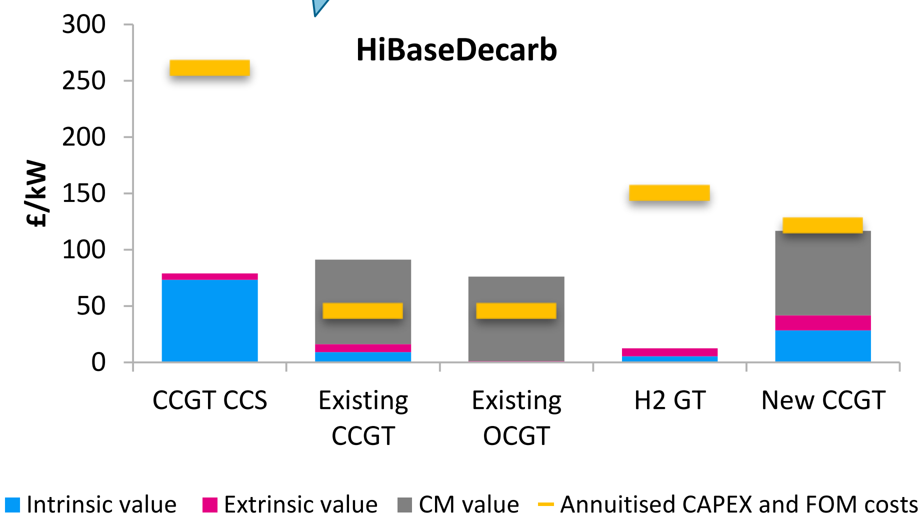
The total revenue for an asset is a result of the combined wholesale and capacity market revenues (breakeven cost assuming WACC=10/15% for existing/new and economic life = 20 yrs)*

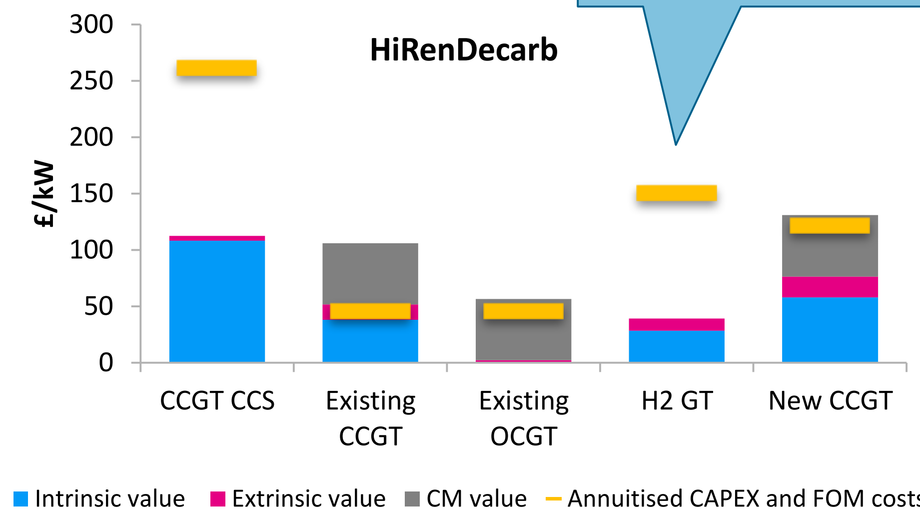


Existing CCGT well in the money and close to the money for new CCGT (note that missing BM/other revenues could be ~£5-15/kW for new CCGT)

Significant support needed for new low carbon CCGT CCS and H2 GTs in both HiBaseDecarb and HiRenDecarb (as noted potential CM revenues can be quite volatile year to year)

Both CCS and H2GT assumed to be ineligible for CM due to CfD (or comparable) support





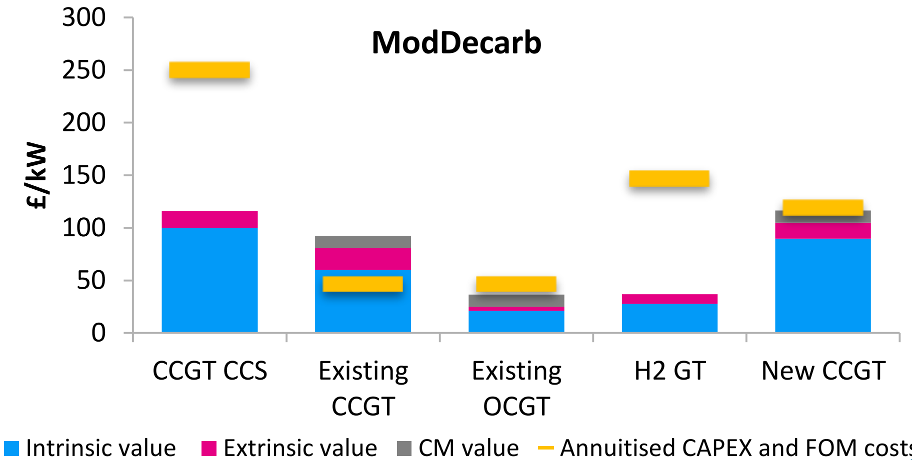
Simple illustration of annualised CAPEX (including IDC), FOM and UoS charges, note that these will be refined through in-house ETI financial modelling

Gross Margin (wholesale + CM) in 2040

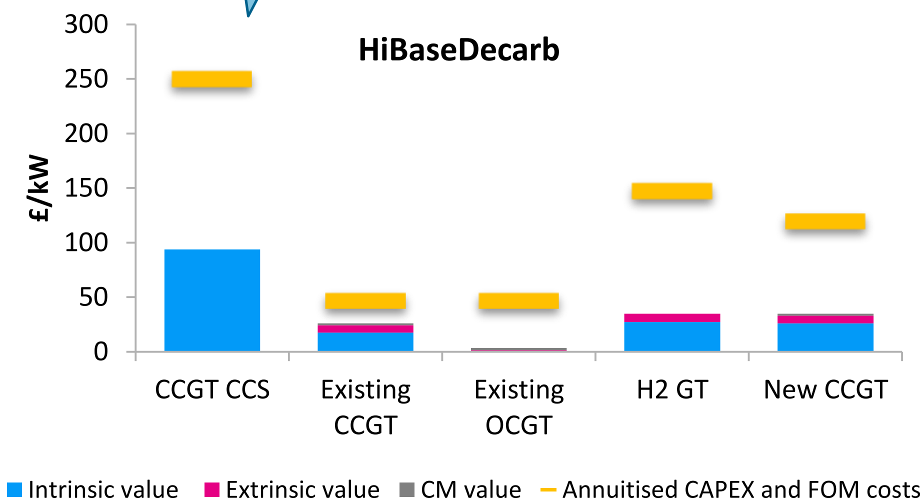
Baringa

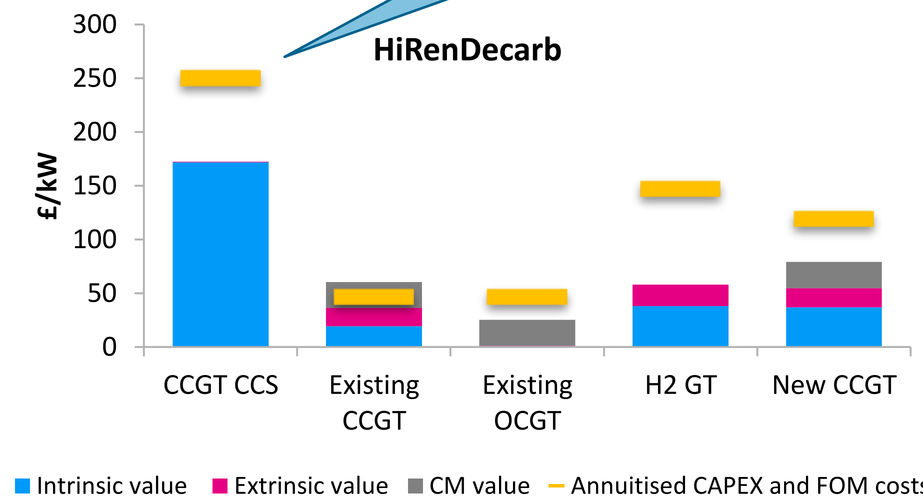
The total revenue for an asset is a result of the combined wholesale and capacity market revenues (breakeven cost assuming WACC=10/15% for existing/new and economic life = 20 yrs)*

Gap increases in HiBaseDecarb cf. 2030 as large expansion of subsidised nuclear lowers prices



Highest average prices across all scenarios (due to carbon price) and fewer low/negative price periods cf. HiBaseDecarb lead to highest intrinsic value for CCS / H2)



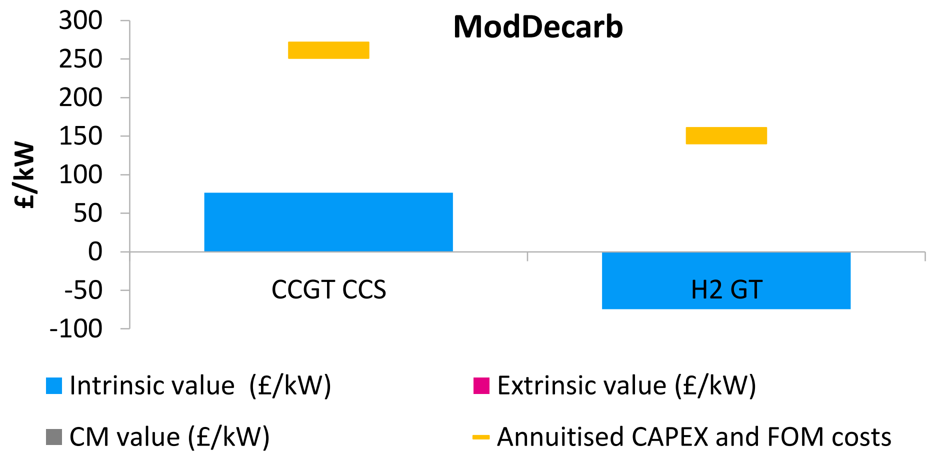


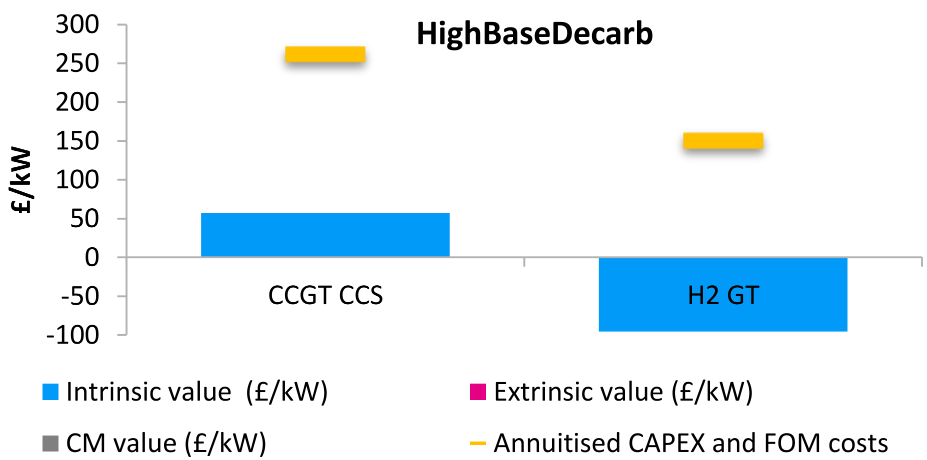
Simple illustration of annualised CAPEX (including IDC), FOM and UoS charges, note that these will be refined through in-house ETI financial modelling

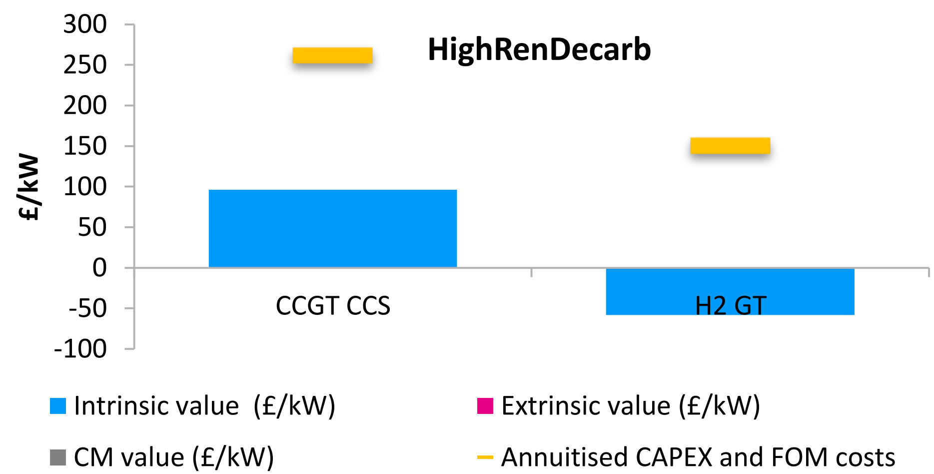
Gross Margin (wholesale + CM) in 2030 - sensitivity

Baringa

The GM analysis on slide 30 has been repeated, but forcing the CCGT with CCS and H2 GTs to run at the higher load factors seen in the wholesale market analysis from slide 11 – due to the implied CfD support in place (n.b. HighBaseDecarb scenario load factors were used when the technology was not present in the original wholesale market run). This forces the plant to run in hours where the power price is less than the plants' short-run operating costs, reducing the overall gross margins.



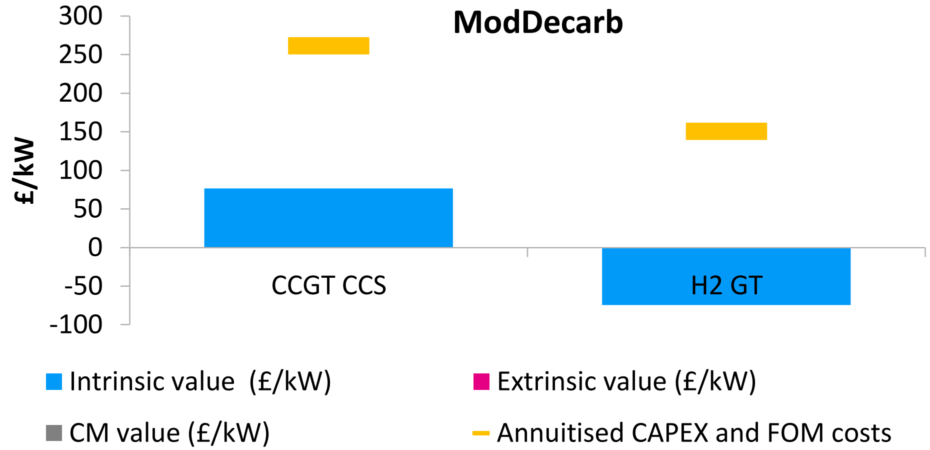


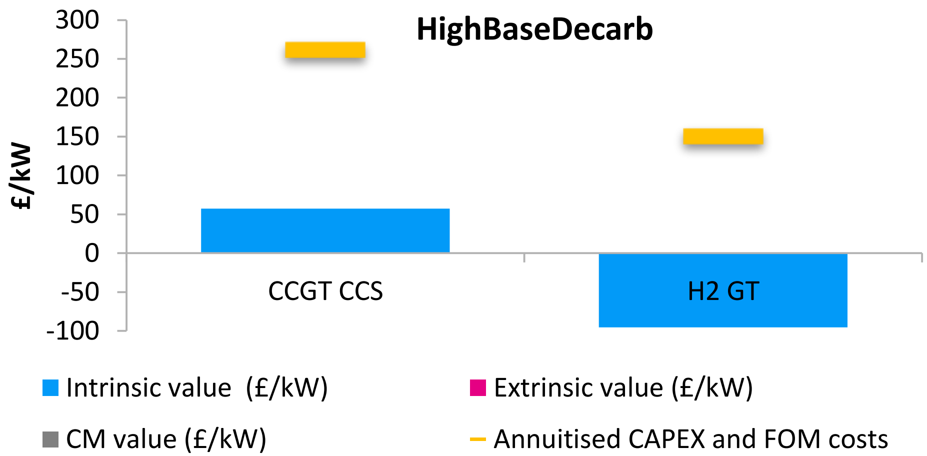


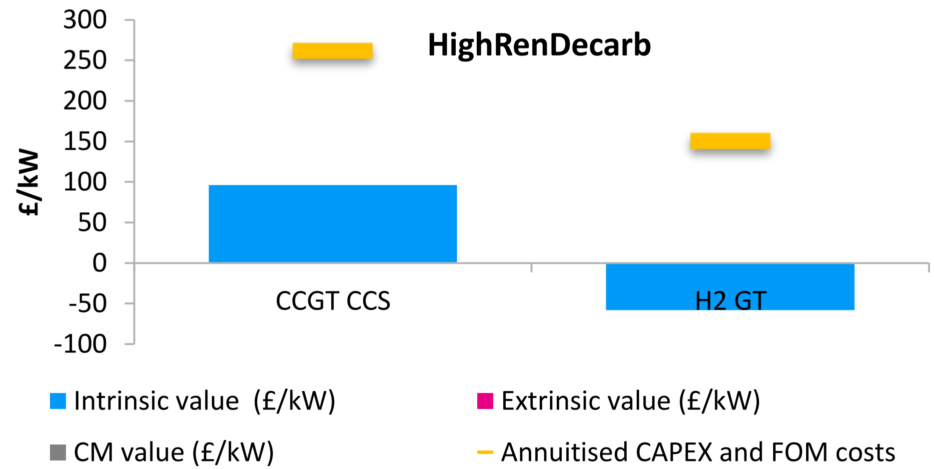
Simple illustration of annualised CAPEX (including IDC), FOM and UoS charges, note that these will be refined through in-house ETI financial modelling

Gross Margin (wholesale + CM) in 2040 - sensitivity

The GM analysis on slide 31 has been repeated, but forcing the CCGT with CCS and H2 GTs to run at the higher load factors seen in the wholesale market analysis from slide 12 – due to the implied CfD support in place (n.b. HighBaseDecarb scenario load factors were used when the technology was not present in the original wholesale market run). This forces the plant to run in hours where the power price is less than the plants' short-run operating costs, reducing the overall gross margins.







Simple illustration of annualised CAPEX (including IDC), FOM and UoS charges, note that these will be refined through in-house ETI financial modelling

Contents

Conclusions (1)

Significant support is needed for new low carbon CCS and H2 turbines across all scenarios, but conditions are more challenging where substantial subsidised nuclear is being deployed

- We have modelled 3 distinct scenarios: ModDecarb (with only modest decarbonisation) and two alternative pathways to more significant decarbonisation with higher carbon prices and different capacity mixes: HiBaseDecarb is baseload focused and HiRenDecarb wind/solar focused
  - Within these we have modelled gross margin returns for existing OCGT, existing/new CCGT, CCGT CCS and H2GT assets

- For existing and new unabated fossil plant conditions becoming more challenging (in terms of wholesale market revenues) as you move from 2030 to 2040 and from ModDecarb ➔ HiRenDecarb ➔ HiBaseDecarb
  - This is due to a combination of increasing carbon price (which directly affects short run operating costs) compounded in the case of HiBaseDecarb by significant expansion of subsidised low carbon baseload plant which helps to depress average wholesale prices
  - In ModDecarb new CCGT is close to the money with limited need for CM revenues, whereas by 2040 in scenarios HiBaseDecarb/b it requires CM support at near to or above the £75/kW limit, but this appears highly unlikely given expected CM clearing prices

- A final scenario 6 (in approximately late July) will be undertaken to explore the value of new ETI GT assets with revised cost and technical parameters (from a separate ETI work stream) within the ModDecarb and HiBaseDecarb/b scenarios.

Conclusions (2)

Significant support is needed for new low carbon CCS and H2 turbines across all scenarios, but conditions are more challenging where substantial subsidised nuclear is being deployed

- For CCS and H2GT wholesale revenues broadly improve over time, but from a low base for H2GT due to the limited number of operating hours in 2030. Wholesale revenues for CCS plant in 2040 are materially higher in HiRenDecarb compared to ModDecarb and HiBaseDecarb.
  - This is due to the higher carbon price pushing up wholesale prices more generally, but without the significant impact of subsidised low carbon baseload depressing the prices for part of the year, as seen in HiBaseDecarb.
  - However significant support for both CCS and H2GT would still be needed in the 2040s in HiBaseDecarb

- H2GTs appear more valuable as a low carbon mid-merit plant than a baseload or pure peaking unit. Supporting these via a CfD would tend to over-incentivise running hours whilst the current CM does not adequately reflect the value of low carbon capacity. A higher carbon (>£119/tCO2 in 2040) would be one option, but otherwise alternative forms of policy support (e.g. adapting the CfD/CM scheme) would need to be explored for this particular asset type

- A final scenario 6 (in approximately late July) will be undertaken to explore the value of new ETI GT assets with revised cost and technical parameters (from a separate ETI work stream) within the ModDecarb and HiBaseDecarb/b scenarios.

Contents

Day-ahead wholesale power prices

We project spot wholesale electricity prices using our industry-leading pan-European hourly dispatch model, based on economic fundamentals

What questions does it answer?

- What will be the level and volatility of future day-ahead and intra-day power prices, and their sensitivity to different scenarios and outcomes?
- How will assets be dispatched in these timeframes on an hourly basis?
- What energy gross margins will be earned by different assets?
- What will the level of 'uplift' be, above short-run marginal costs?
- How will hourly price 'shape' change over time?

Key inputs

- Scenario inputs: fuel and carbon prices, demand (growth and shape), plant build, plant retirement
- Detailed pan-EU plant level database: installed capacity, efficiencies, operating costs, operating constraints
- Cross-border interconnector capacity
- Detailed hourly wind and solar profiles

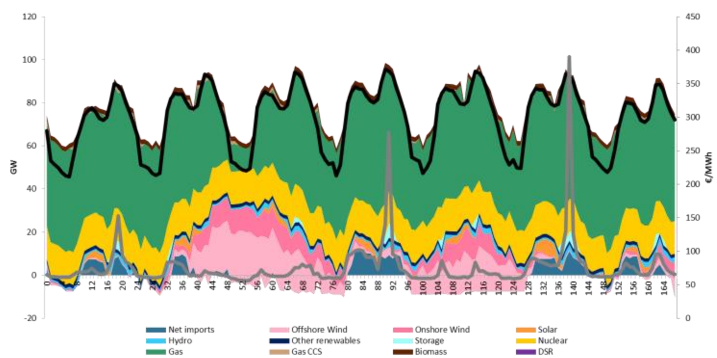
Model engine

- Hourly dispatch, least-cost optimisation framework using the PLEXOS platform
- Optimisation of operational constraints including start costs, ramp rates, heat rates
- Maintenance scheduling and unplanned outages

Key outputs

- Wholesale electricity prices
- Generation schedules
- Asset energy revenues and gross margins
- Emissions
- Dispatch costs
- Cross-border flows (imports / exports)

Illustrative schematic



Capacity market

We model the dynamics of capacity market auctions to project revenues, contracted volumes and the new build timing, using an integrated and internally consistent approach

What questions does it answer?

- What capacity market revenue will specific assets or technology types earn, and how will this be influenced by earnings across other markets?
- When will new build be required, and how much?
- Who will be the winners / losers in each capacity auction?
- What will be the split of contracted / merchant earnings for specific assets?

Key inputs

- Security standard / capacity requirement
- Volume of eligible existing capacity
- De-rating factors
- Auction / market rules
- Penalty regime
- Modelled balancing services and energy market revenues

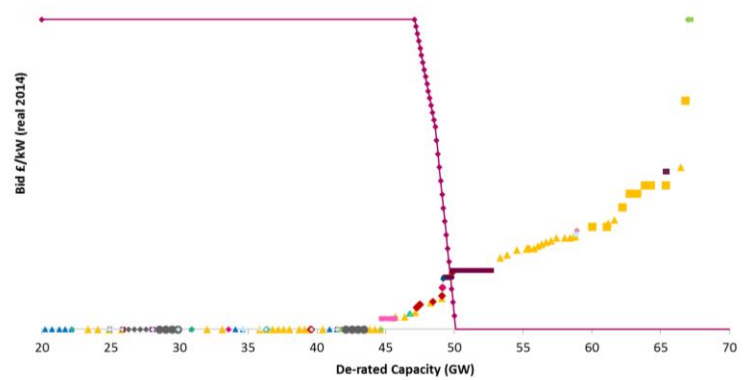
Model engine

- Fundamental supply / demand capacity auction clearing model
- Fully integrated with energy / balancing services models with operation in an iterative process
- Ability to model alternative bidding / strategies, as well as 'economically rational' missing money bidding

Key outputs

- Annual capacity market clearing prices
- New capacity build
- Cleared and non-cleared capacity

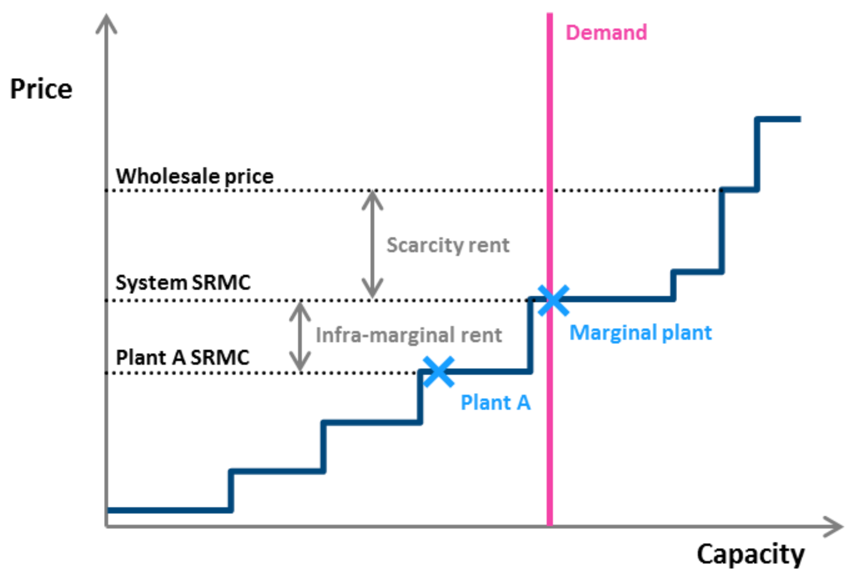
Illustrative modelled auction supply stack



Introduction

Wholesale price formation

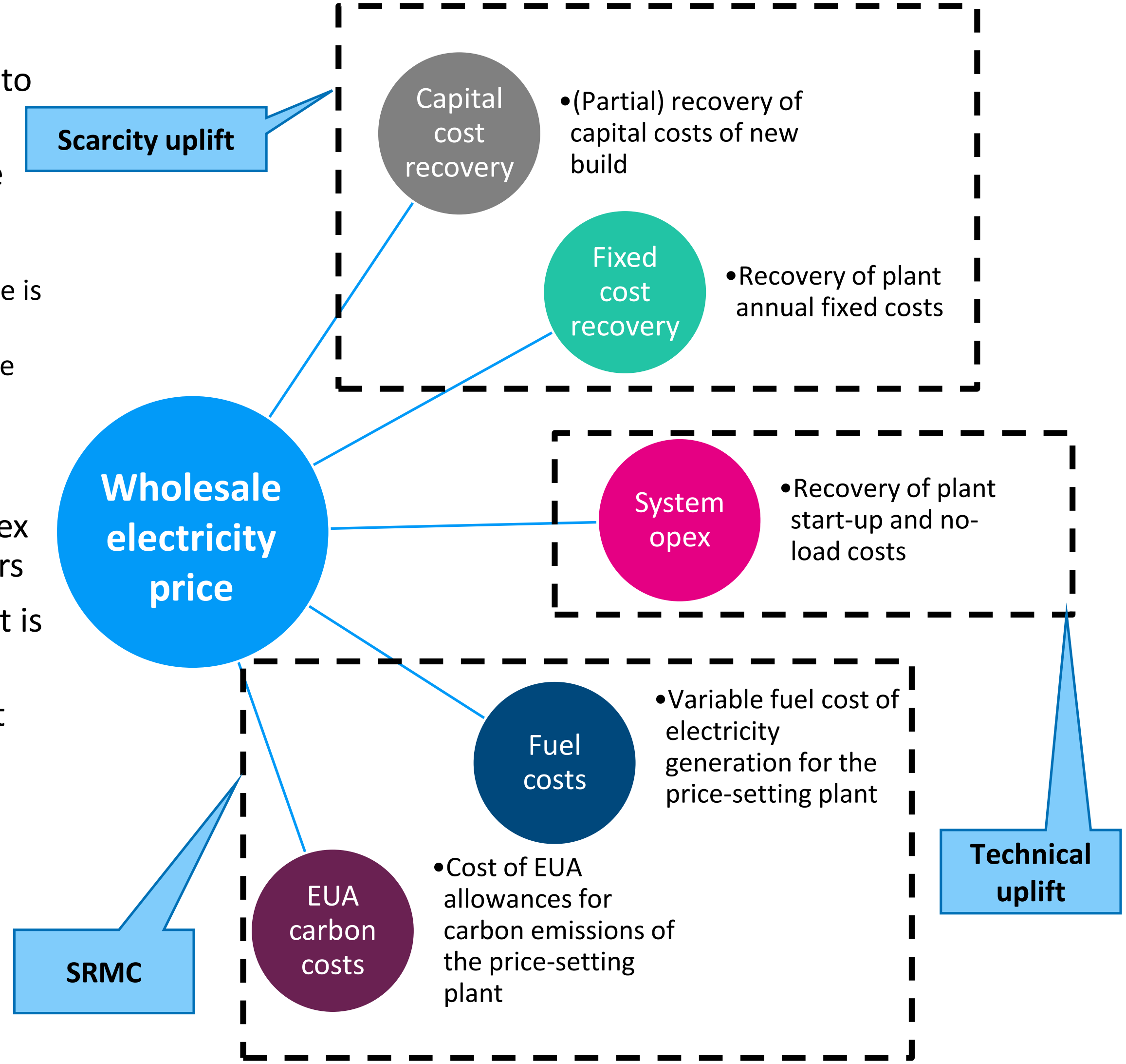
- The system short run marginal cost (SRMC) is the marginal cost of the marginal generation unit in each hour
- Plant with lower SRMCs than the marginal generation unit will earn profit termed ‘infra-marginal rent’ which is the difference between their SRMC and system SRMC
- ‘Scarcity rent’ is added to the system SRMC to calculate final hourly wholesale prices
- We treat scarcity rent as a function of hourly capacity margin – the tighter the capacity margin, the higher the scarcity rent
- This reflects the scarcity value of power on an hourly basis, and is important in delivering a return on capital
- We correlate scarcity rent to the capacity margin, but in reality it is the result of many inter-related factors



GB wholesale electricity price components

There are five components likely to comprise a sustainable wholesale electricity price level

- Wholesale electricity prices can be broken down into five basic components
- These components are likely to be present at some level in a sustainable GB wholesale price
  - It is important to note that the wholesale electricity price is subject to year-to-year variation
  - Short-term events may mean that in isolated years, some components (such as scarcity rent) may not emerge
  - However, such a situation is unlikely to be sustainable in the long term
- Interactions between price components are complex with some having a greater price impact than others
- We assume that behaviour in the wholesale market is unaffected by the capacity market
- Generators still price in a 'scarcity rent' component which is based on the capacity margin



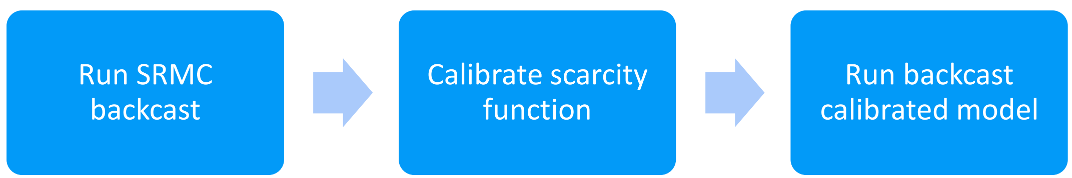
Model backcast and calibration

Model Calibration 2009-2015

Methodology

- We regularly backcast our market model against historic prices to validate input parameters and to calibrate the uplift function. The model calibration consists of three steps:

  1. Running a backcast simulation to estimate the system hourly SRMC. The backcast simulation uses outturn wind, demand, commodity prices and plant availability as inputs to be as accurate as possible
  2. Calibrate the scarcity function by regressing estimated scarcity value against estimated capacity margins
  3. Running the backcast model with the calibrated scarcity function to verify that there is no systematic bias between projected and outturn prices

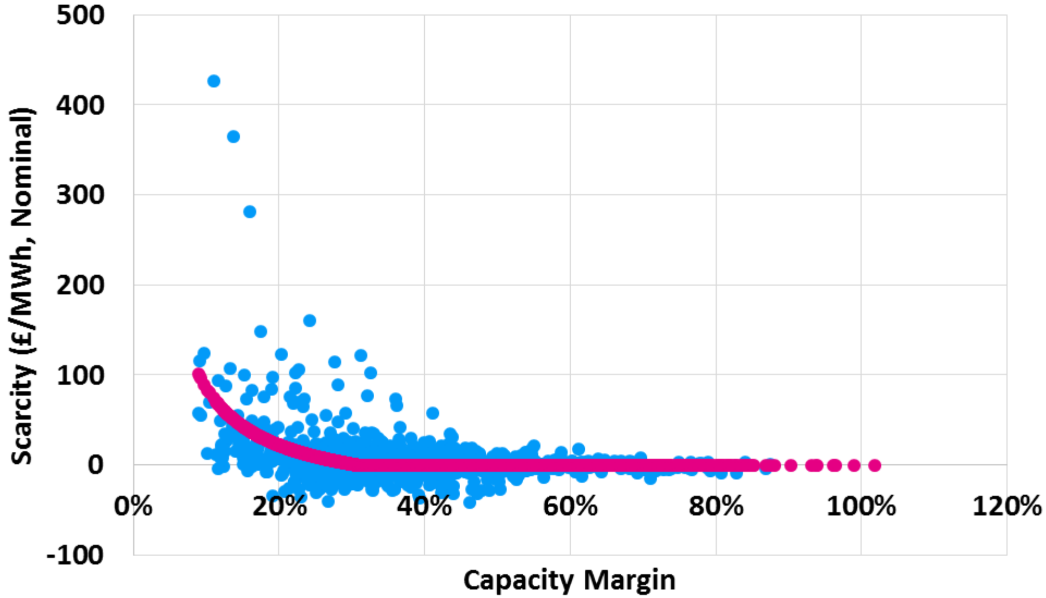


- At the beginning of 2016, we re-calibrated our scarcity function based on historical data covering the period January 2009 – December 2015. Some results of this calibration are presented in the following slides

Model backcast and calibration

Step 2 - Scarcity Calibration

Estimated Scarcity and calibrated scarcity function (Winter afternoon peak)



Methodology

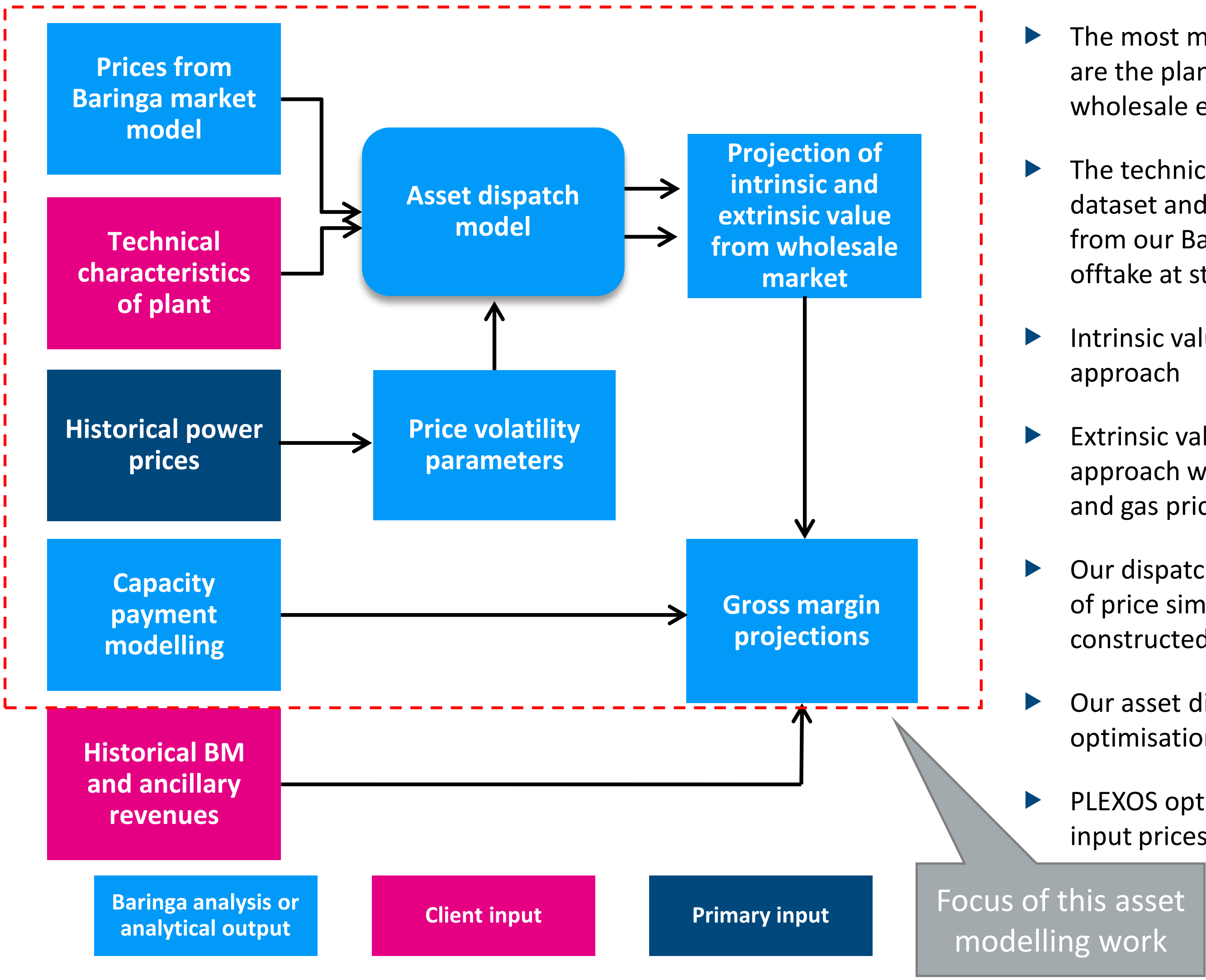
- The scarcity function is calibrated on the basis of historically observed capacity margins and uplift above SRMC, based on backcast modelling of historic system SRMC and actual outturn spot prices
- Outturn scarcity is regressed against observed capacity margins to estimate a relationship between these two variables. We assume this relationship will hold in the future
- Separate regressions are run for winter and summer days differentiating between day, night, and peak hours
- Finally, we implement the updated scarcity function into the model and re-run the backcast analysis to verify that there is no significant bias between outturn and projected prices

Contents

Overview of methodology for asset valuation

Baringa

Final gross margin accounts for energy market income and additional revenues streams like capacity payments

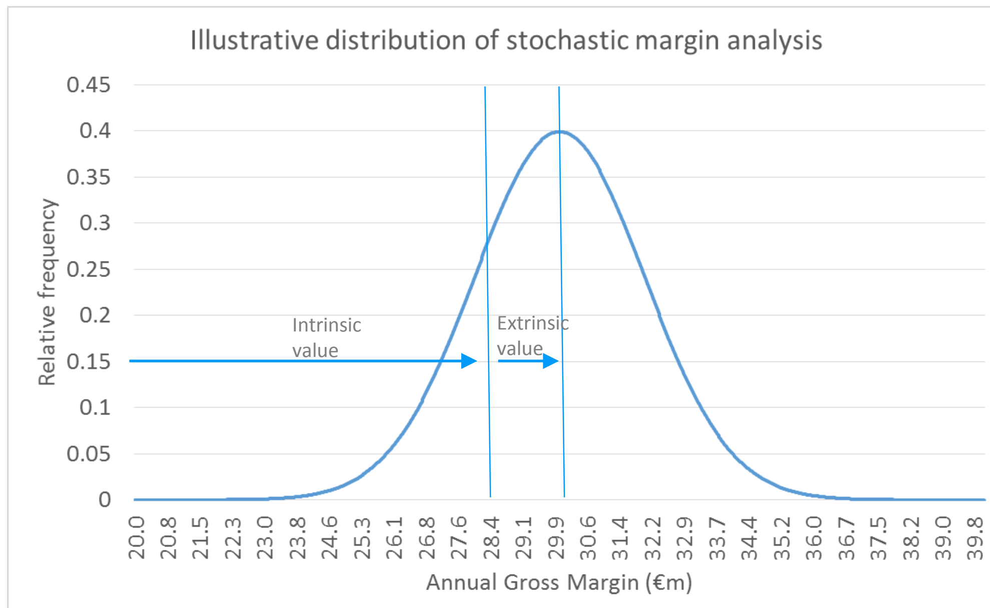


- The most material inputs to our gross margin modelling are the plant technical parameters, and our projected wholesale electricity prices
- The technical plant parameters are based on ESME dataset and we have layered in additional assumptions from our Baringa Reference Case where required (fuel offtake at start and VOM for CCGT/OCGT)
- Intrinsic value has been projected using a deterministic approach
- Extrinsic value has been projected using a stochastic approach with calculated price volatility, mean reversion and gas price correlation based upon historical price data
- Our dispatch model has been run against a large number of price simulations (Monte-Carlo simulation), constructed using these calibrated parameters
- Our asset dispatch model utilises PLEXOS power system optimisation software
- PLEXOS optimises the dispatch of the plant against the input prices, taking account of technical constraints

Extrinsic gross margin (Option value)

Baringa asset modelling with stochastic treatment of commodities determines option value

- Intrinsic value captures all of the value inherent in liquid and granular traded markets. Our hourly PLEXOS scenario projections represent the full intrinsic value of the asset, capturing hour-by-hour variations in demand, intermittent generation and the availability of plant capacity in the market
- However, there is extra *time value* available to flexible assets which are able to respond to random fluctuations in conditions over time: although these fluctuations might be positive or negative, the asset can respond selectively so that the value of positive fluctuations is captured but negative fluctuations are avoided
- Baringa's Price Simulation Engine is used to generate a statistically consistent set of spot time series for power and fuel prices, calibrated to historic price dynamics. This will include parameters representing the volatility, mean reversion and correlation for and between the price series
- The mean of the simulated price series is set to match the deterministic prices used in the intrinsic scenario analysis
- For each of the simulated price series, the PLEXOS model determines how the plant would dispatch to maximize gross margin; a probability distribution of gross margin outcomes is then produced for the complete set of simulations
- Some of these outcomes will display lower gross margins than the deterministic outcome, but most of the outcomes will display higher gross margins; the asymmetry reflects the flexibility/controllability of the asset
- The mean (expected) value of the distribution is the expected total (intrinsic + extrinsic) value of the asset
- Extrinsic value is then determined as the difference between this expected value and the deterministic (intrinsic) outcome
- This is likely to represent an upper bound on the extrinsic value and a hair-cut is likely to be required in reality to reflect lack of perfect foresight and cost of adjusting trading strategy (e.g. day-ahead and intraday)
- In addition, if the asset is often at the margin setting the price, then there will be less potential for extrinsic margin



Gross margin drivers

CCGT in the GB market can expect to receive a diverse range of earnings streams, depending on flexibility, plant operation and contracting strategy

Driver	Indicative contribution to the plant gross margin (£m, real 2017) 2017	2020	2030	Description of GM driver	Relevance to CCGTs
Intrinsic Value	16	21	25	Intrinsic value is the gross margin associated with 'expected' hourly price shape. It comprises two main components: infra-marginal rent (IMR) and scarcity rent. IMR is the margin between the generation costs of the price-setting power plant and those of the asset in question. Scarcity rent is additional value which emerges in periods of tight capacity margin.	IMR increases as the merit order position of a CCGT improves and more expensive plants operate at the margin. IMR may increase as coal plants retire and as carbon prices rise, increasing the competitiveness of gas versus coal-fired generation. New plants commissioning with lower generation costs will reduce IMR. A tightening capacity margin in coming years is forecast to put upward pressure on scarcity rent.
Extrinsic value	4	4	3	The extrinsic value of the power plant is the option value that can be realised when that plant is able to run to capture upward movements in spark spread away from the average. It is the additional option value associated with hourly price volatility at the day-ahead and within-day stage.	The ability to realise extrinsic value is dependent on plant flexibility. Flexible CCGTs are well-placed to capture the option value associated with price volatility. The level of extrinsic value captured by a plant will also depend on efficiency, and the risk-appetite of owners.
Capacity payments	1	16	25	The first auction for capacity under the Capacity Mechanism (CM) was held in December 2014, with the first payments under the CM being made during winter 2017/18.	Existing plants will be subject to rolling one year contract whereas this is fifteen years for a new plant. The level of capacity payment in any one year will depend on the capacity auction clearing price.
Ancillary services & Balancing Mechanism	7	7	7	Revenues from providing ancillary services and the plant operation in the Balancing Mechanism.	Some CCGTs can get these extra revenues if they are eligible to provide these services.

Contents

Introduction

Requirements and objectives of the initial analysis

Overview

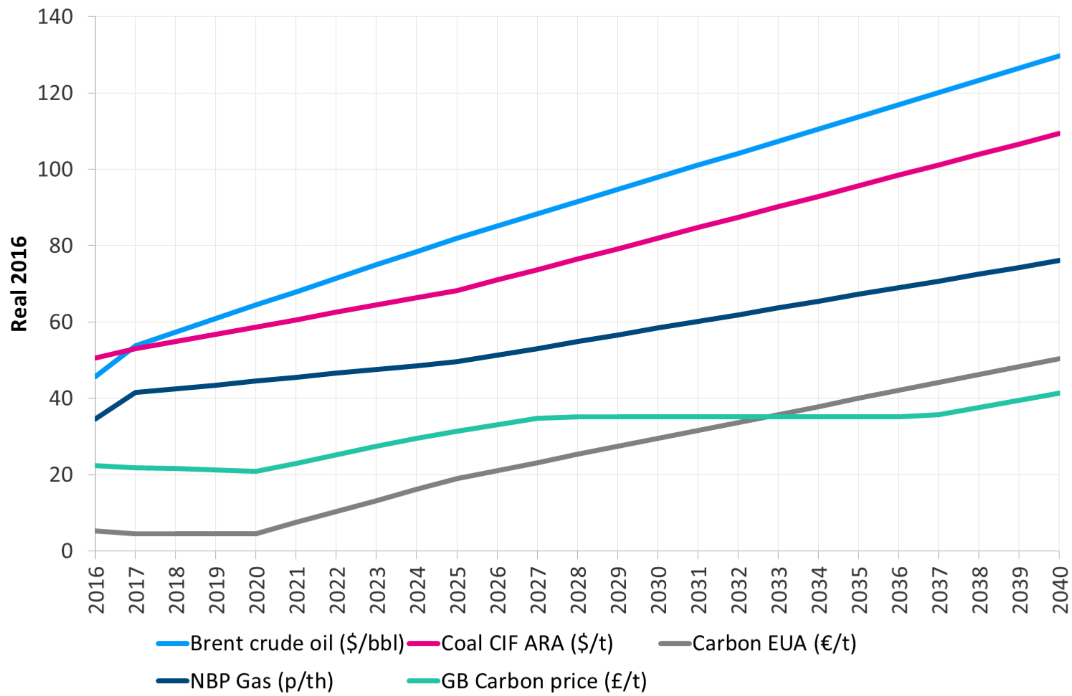
- ETI would like to characterise better the fundamental dispatch of different types of gas and H2 electricity plant in future GB electricity systems (from ~2020-2030/40 (the later date sufficient to enable meaningful consideration of the role of CCS).
  - This would provide an understanding of e.g. load 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)
  - 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

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

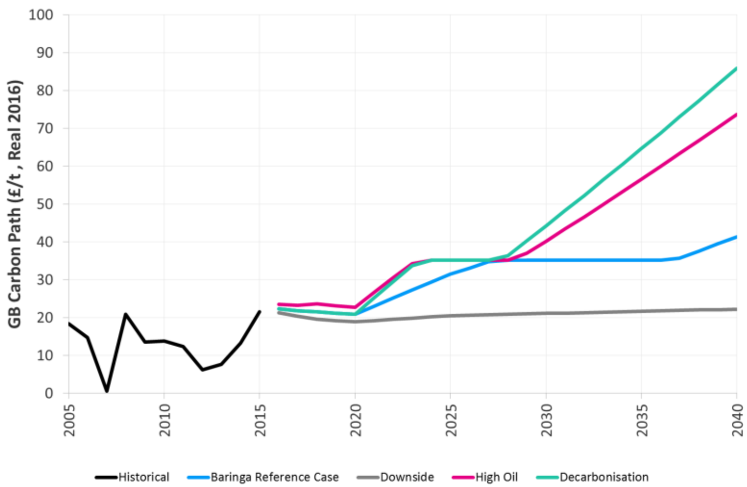
Baringa Reference Case

- 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

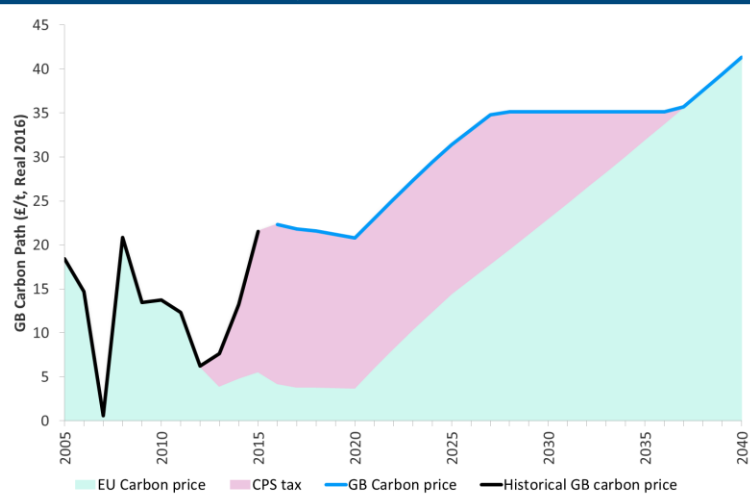
GB carbon price

Baringa Reference Case assumptions

GB Carbon price (£/tCO2, Real 2016)



GB Carbon price (£/tCO2, Real 2016)



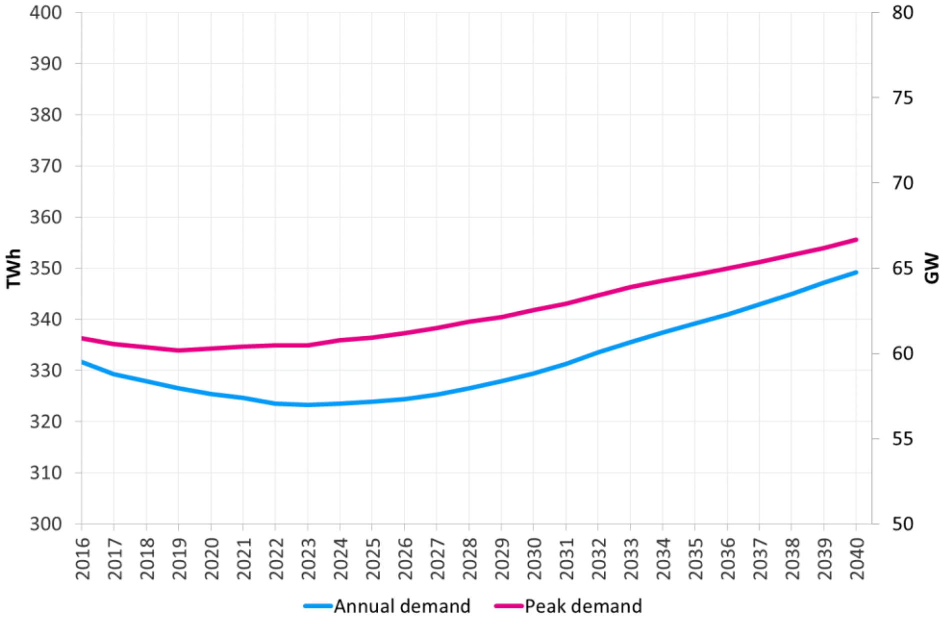
GB Carbon price

- 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

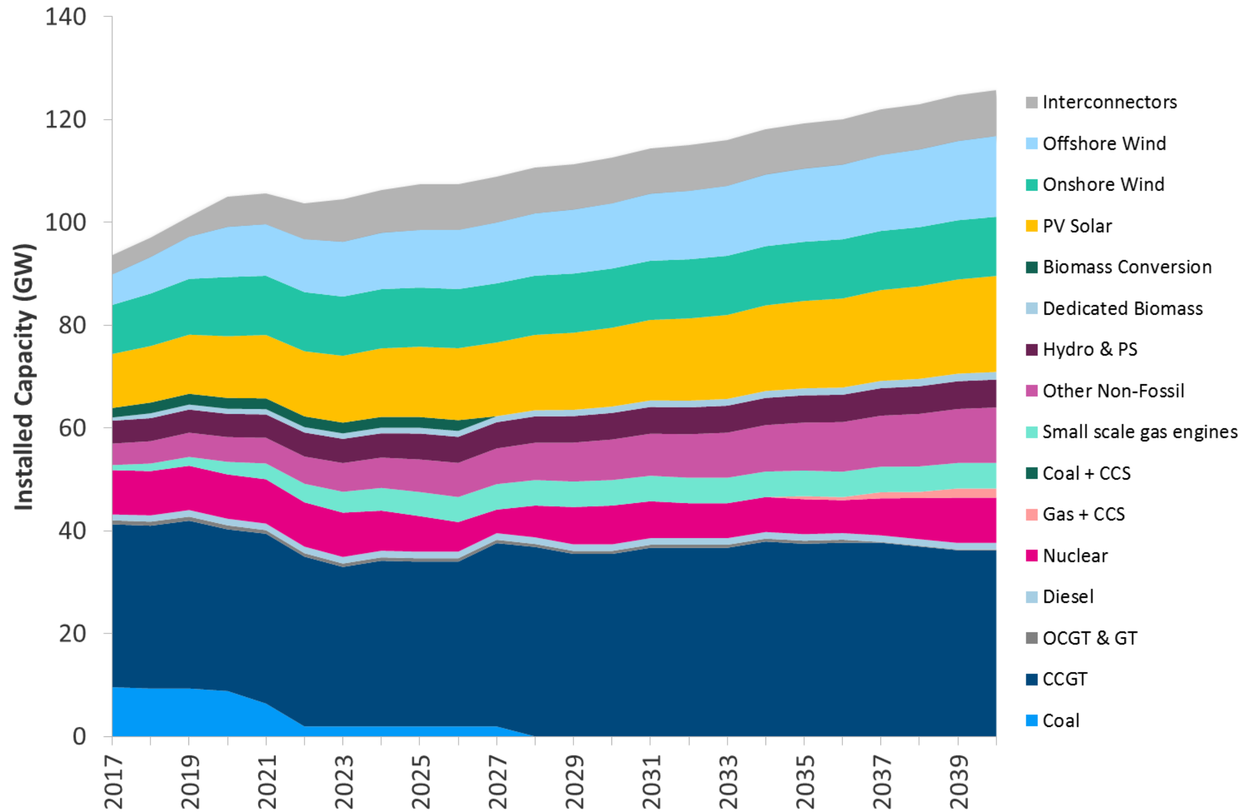
- Peak electricity demand is assumed to grow at the same rate as in the corresponding FES scenarios. Peak demand grows at approximately the same rate as energy demand growth in the Reference Case

Capacity mix

Baringa Reference Case assumptions

Installed Capacity (GW) (Baringa Reference case)

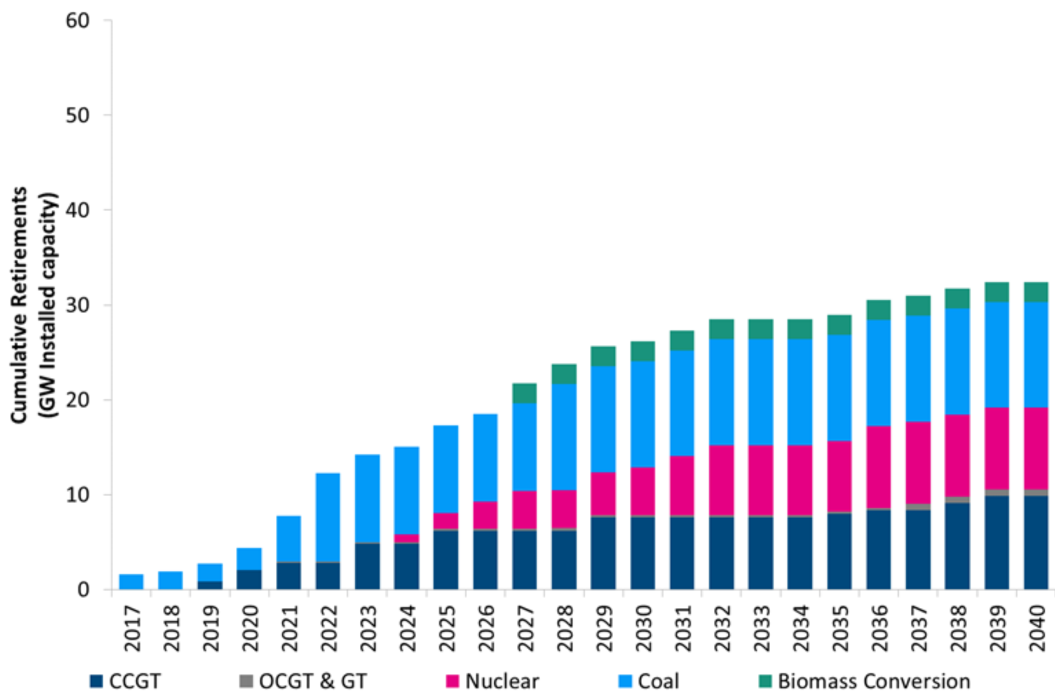
- The GB capacity mix in the Reference Case is shown below. The capacity build out represents the current market policy and regulatory environment and considers the economic viability of both new and existing generation plants from the operators' perspective. This is a different perspective to ESME,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



Capacity assumptions

Cumulative plant retirements

Cumulative Plant Retirements (GW) (Baringa Reference Case)



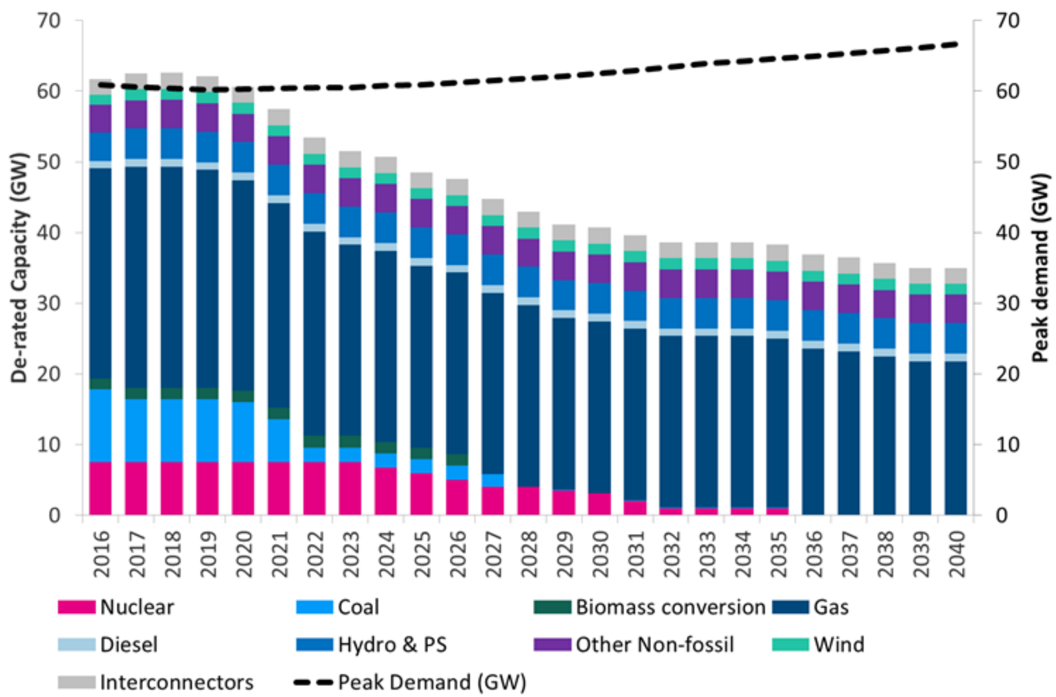
Cumulative Plant Retirements

- 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)



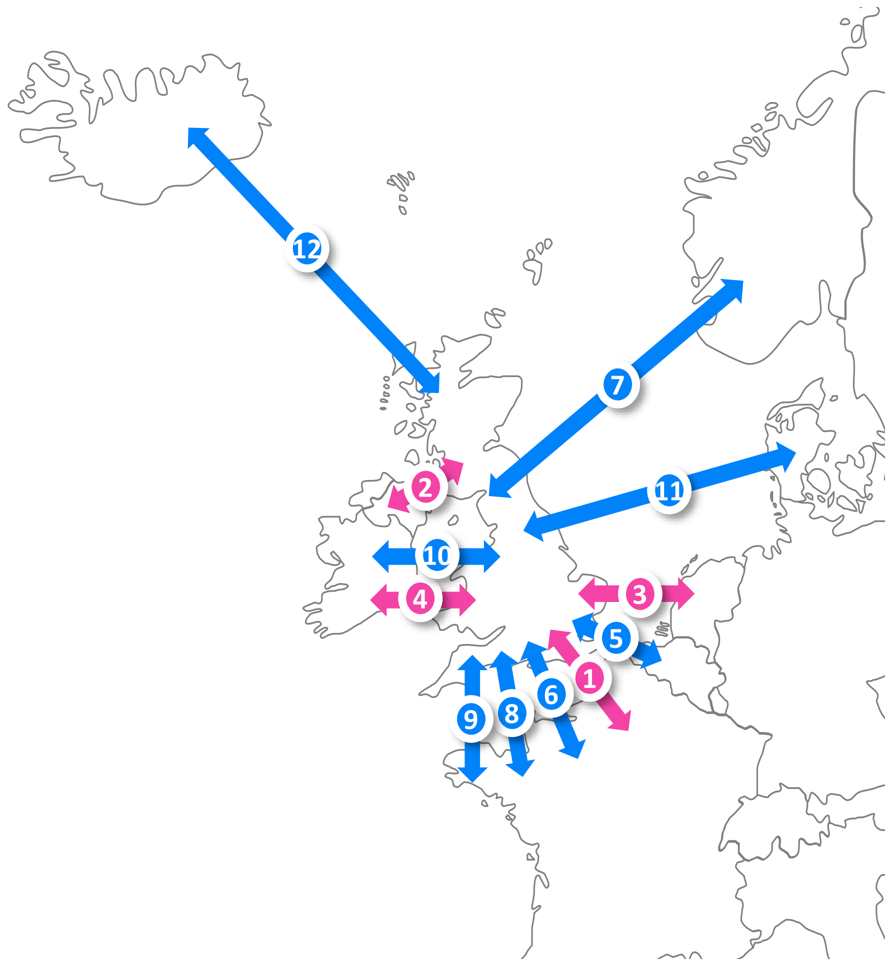
Evolution of existing plant de-rated capacity

- 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

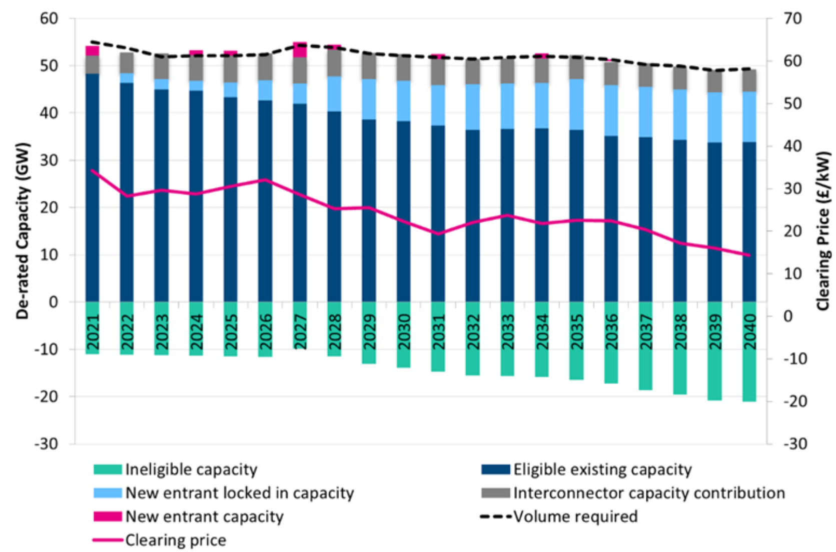
New plant build

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

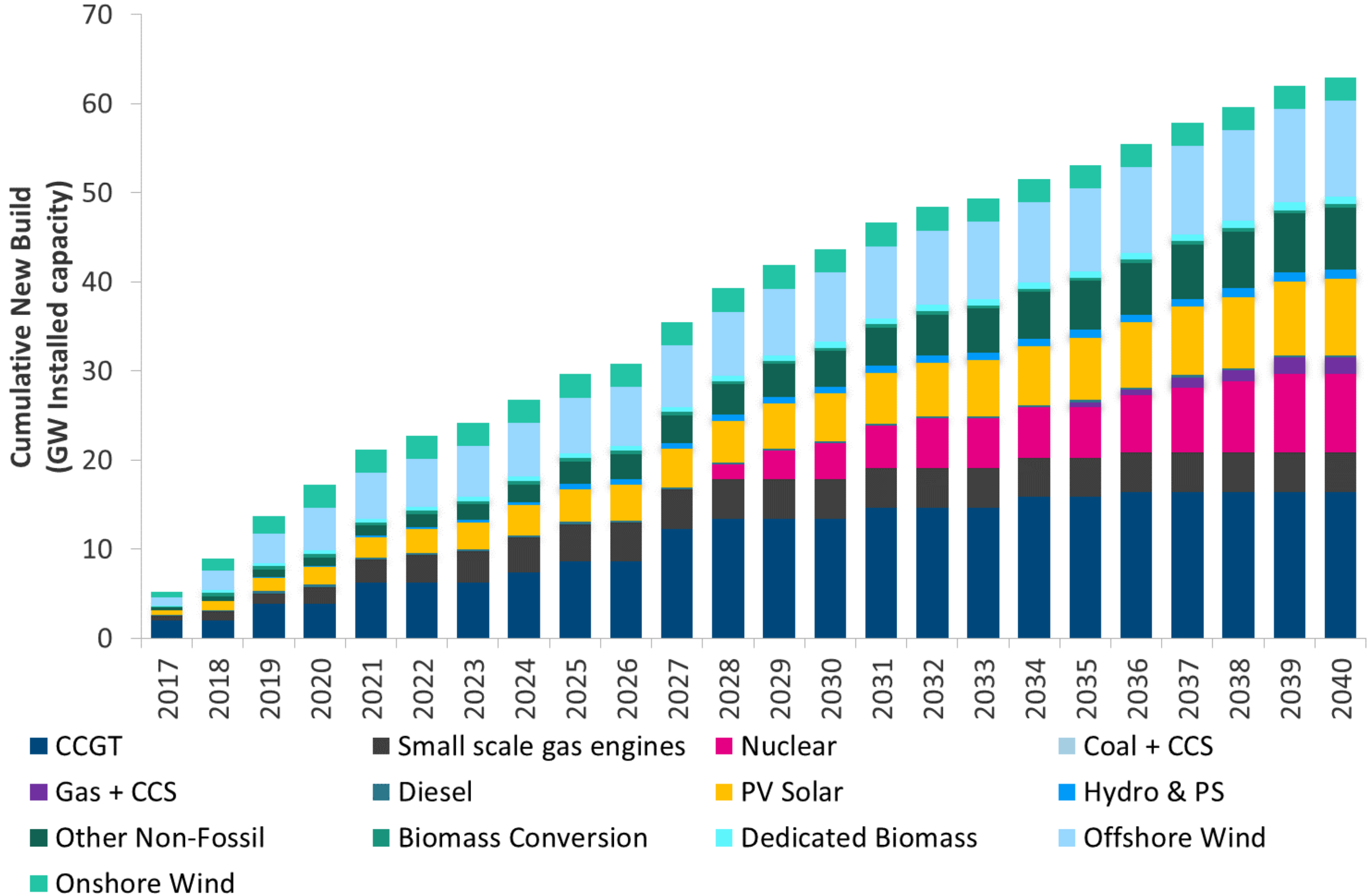
- With the exception of nuclear capacity, in the near term new build thermal capacity is only commissioned if it is in receipt of a 15 year Capacity Market (CM) contract
- As such new build capacity that clears in our CM auction modelling is commissioned in the market models of the respective scenarios
- 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)



Role of Gas in the GB Power Sector

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

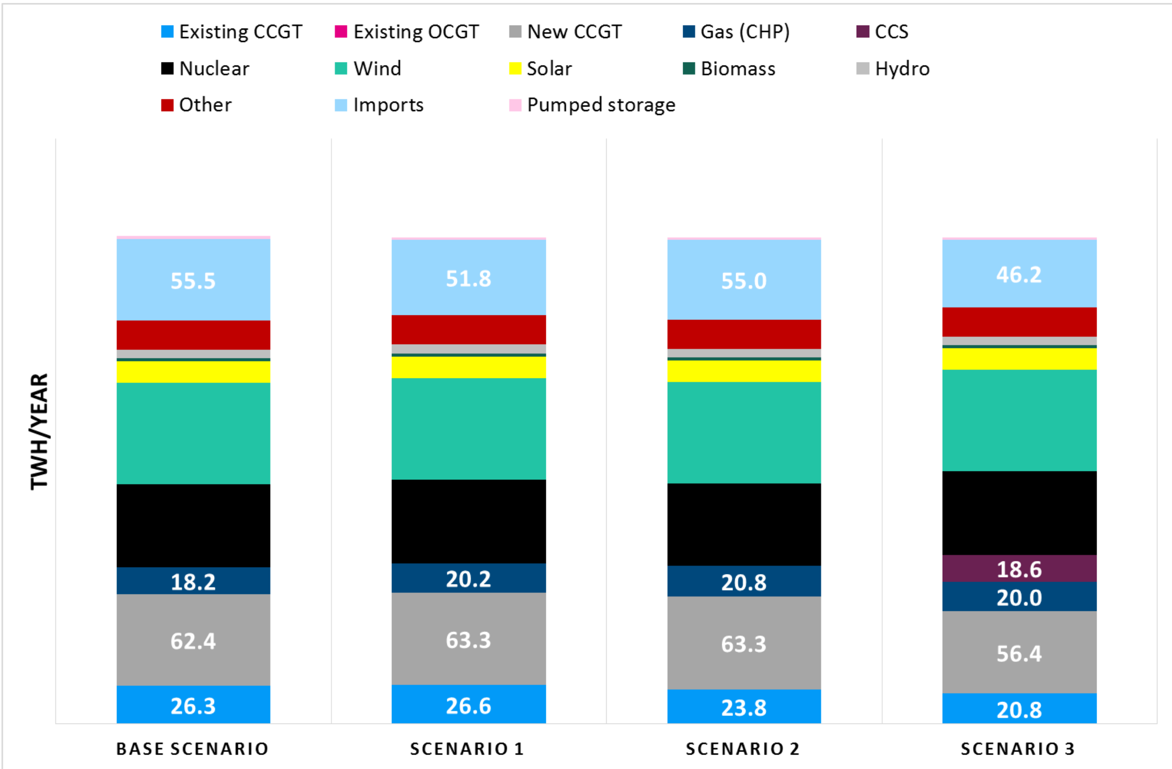
Overview of scenarios	Description
Base scenario	Baringa Reference Case (half hourly input data and dispatch profiles, daily optimisation step with 12 hour look-ahead period)
Scenario 1	More detailed operational parameters for thermal capacity, including hot/warm/cold start costs, start times, run up 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

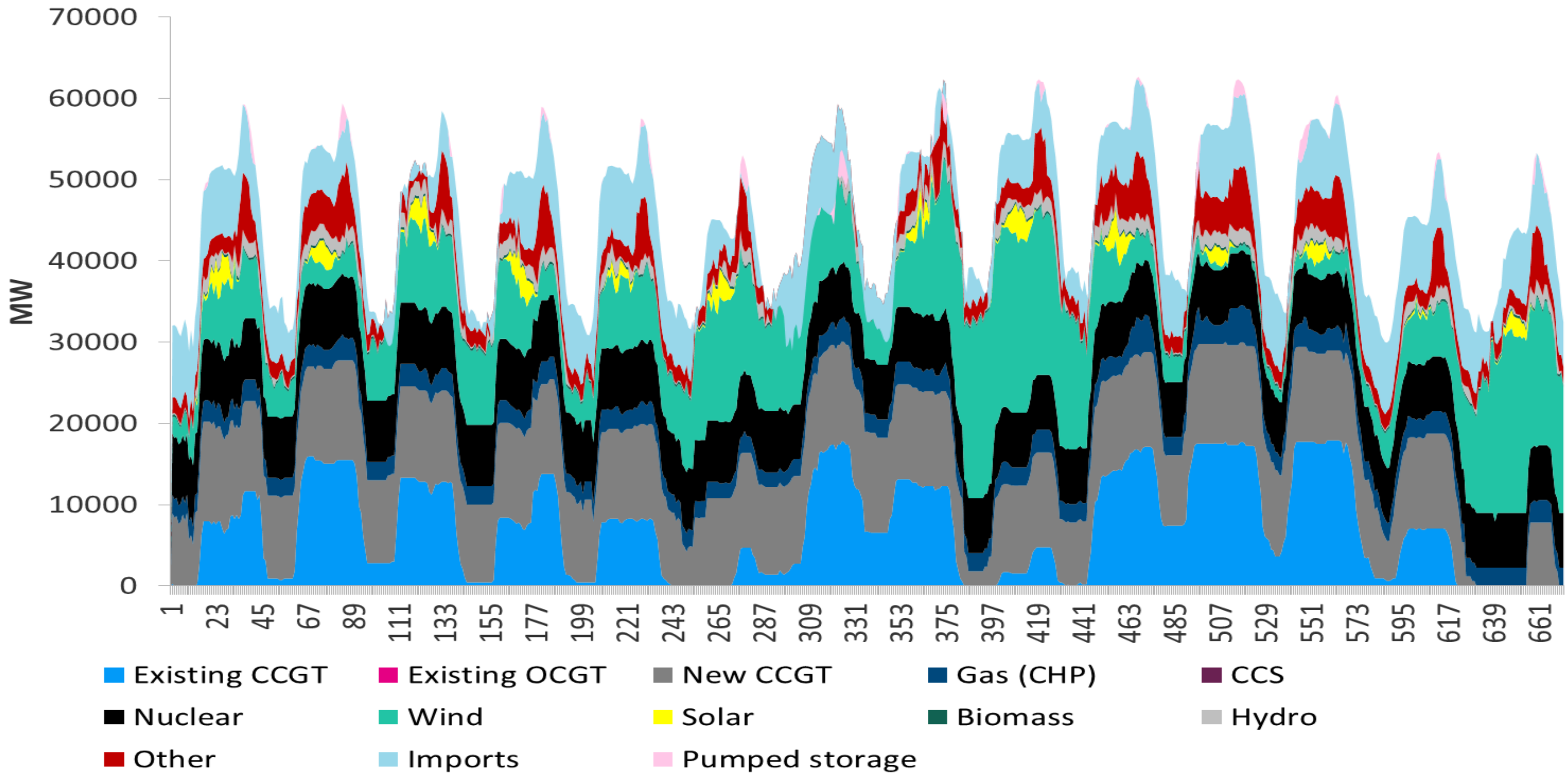
- Below is the generation by type under the four scenarios in 2030. Overall generation levels are similar in the base scenario, scenario 1 and scenario 2, however, in scenario 2 the need for additional flexibility means that some of the existing gas CCGT output is displaced to a combination of new CCGT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

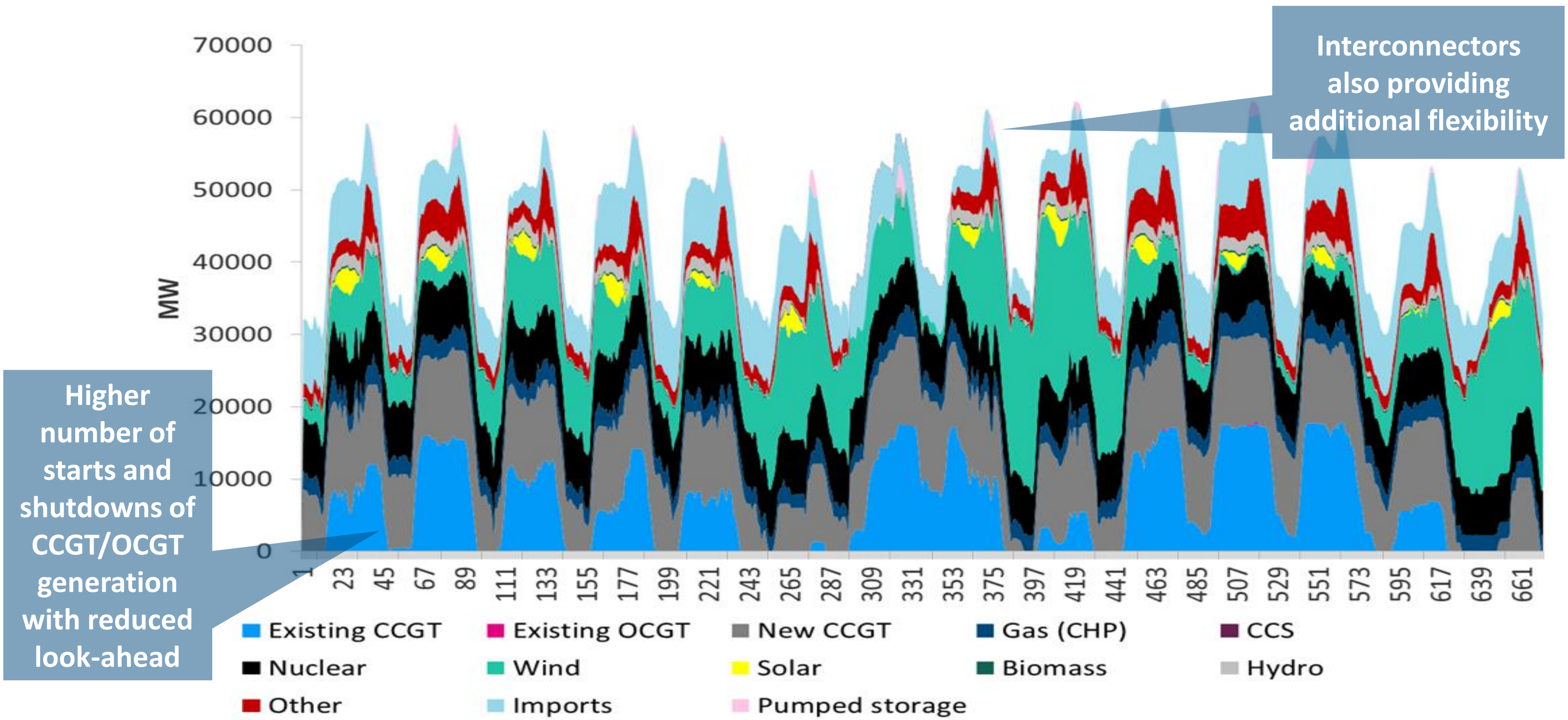
- Below is a typical generation profile in Scenario 1 over a winter fortnightly period. Nuclear provides baseload power for most of the time, wind and solar provide intermittent generation with gas generation excluding Gas CHP and pumped storage increasing generation over high price periods



Generation dispatch profile in a winter fortnightly period

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

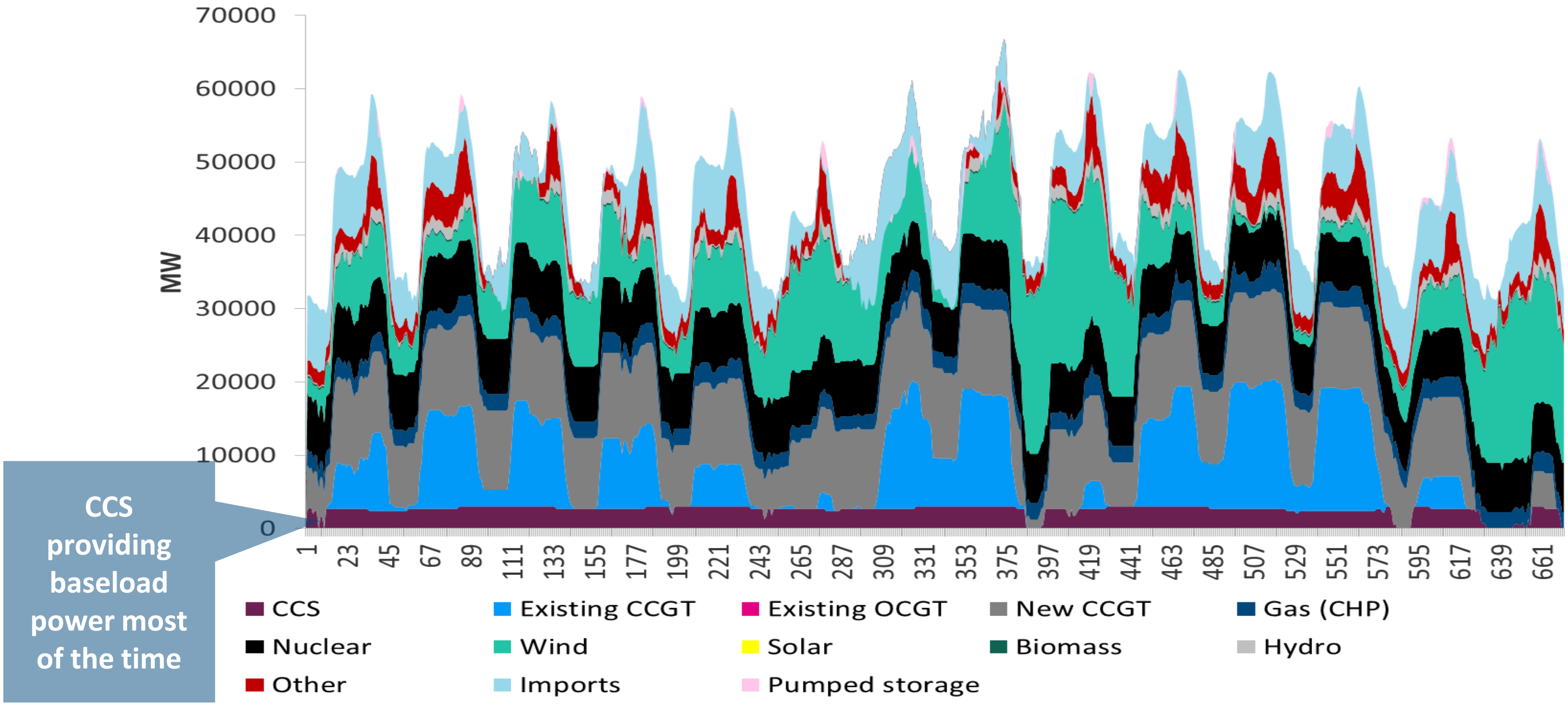
- We see a greater 'cycling' effect in the CCGT/OCGT generation with the reduced perfect foresight in Scenario 2 as below . The total generation from new CCGTs remain at a similar level to scenario 1 but they provide higher flexibility. Imports also provide higher flexibility to compensate for the reduced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

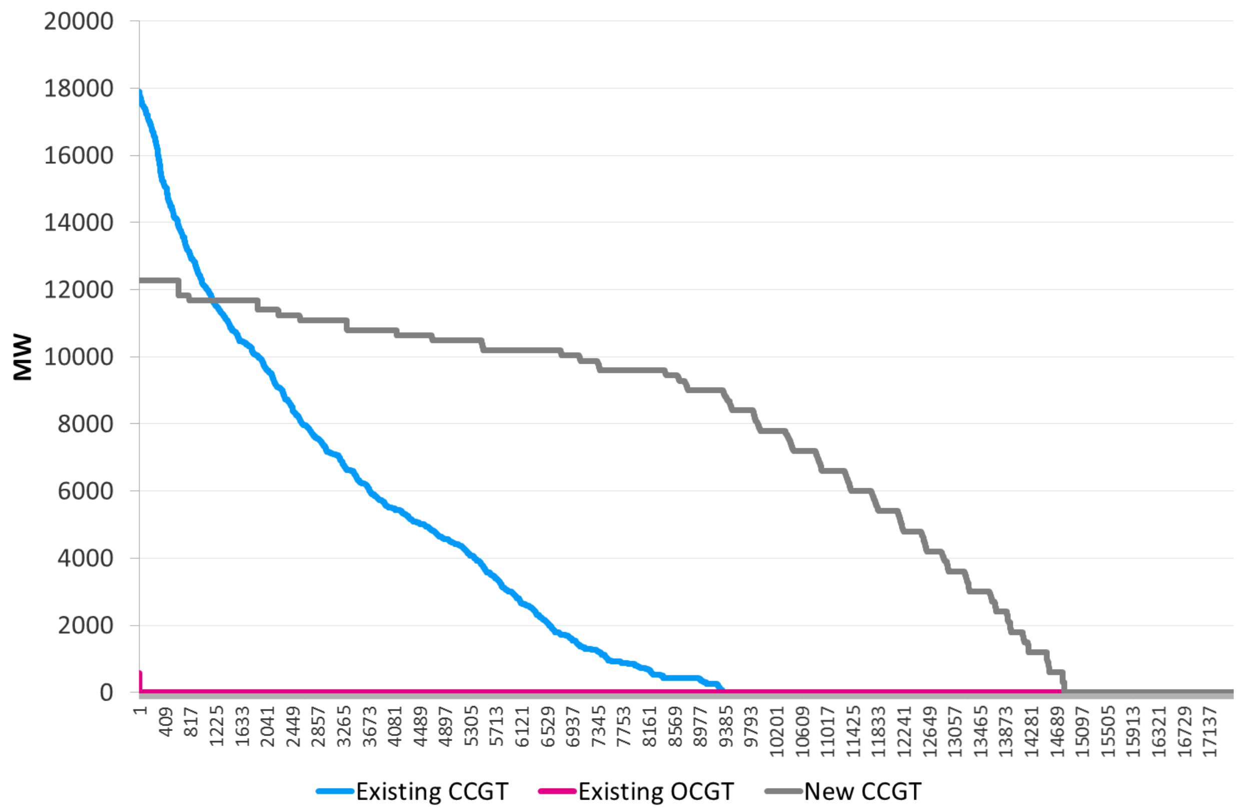
- In scenario 3, the new Gas CCS capacity provides baseload power for most of the time, resulting in reduced generation from CCGTs/OCGTs as well as reduced imports



Duration curves for flexible gas generation

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

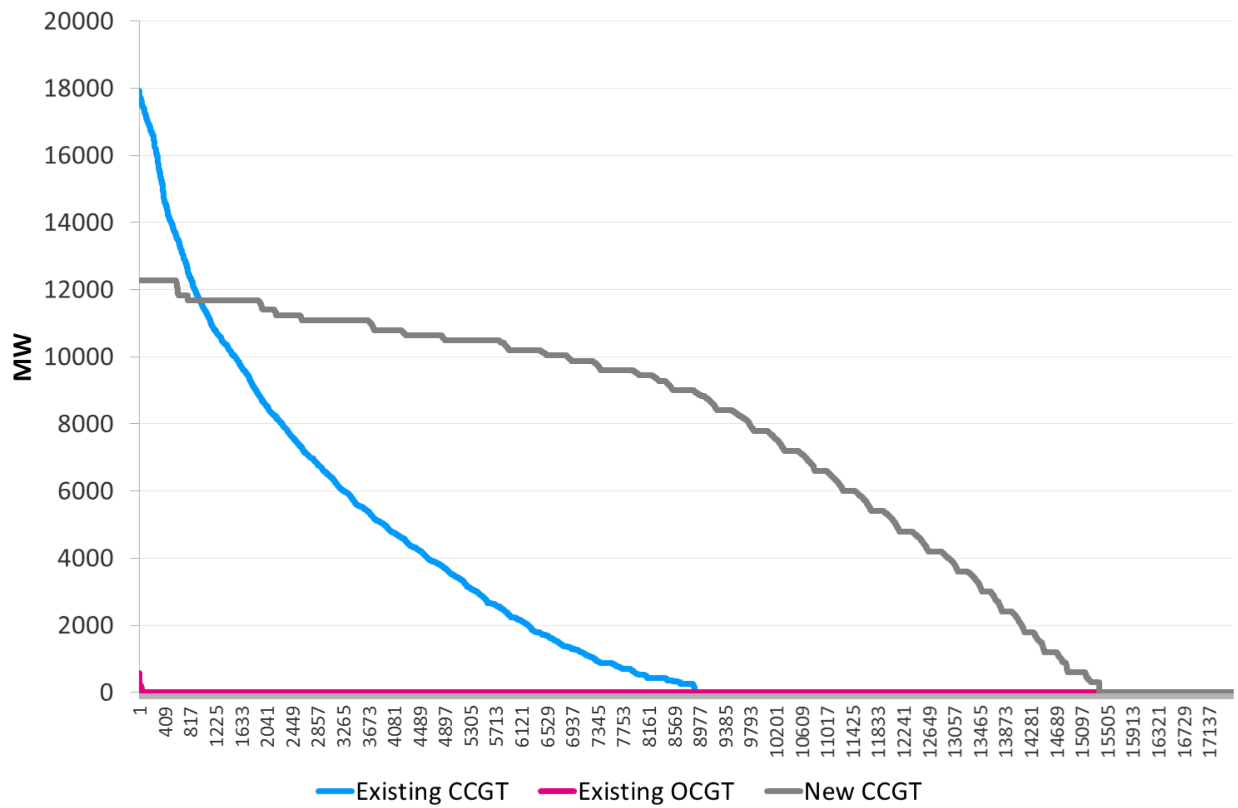
- Below is the half-hourly generation duration curves for existing and new CCGTs and existing OCGTs in scenario 1 in 2030. Existing and new CCGTs provide most of the flexibility on the gas side with generation from OCGTs being limited to a very small number of running hours.



Duration curves for flexible gas generation

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

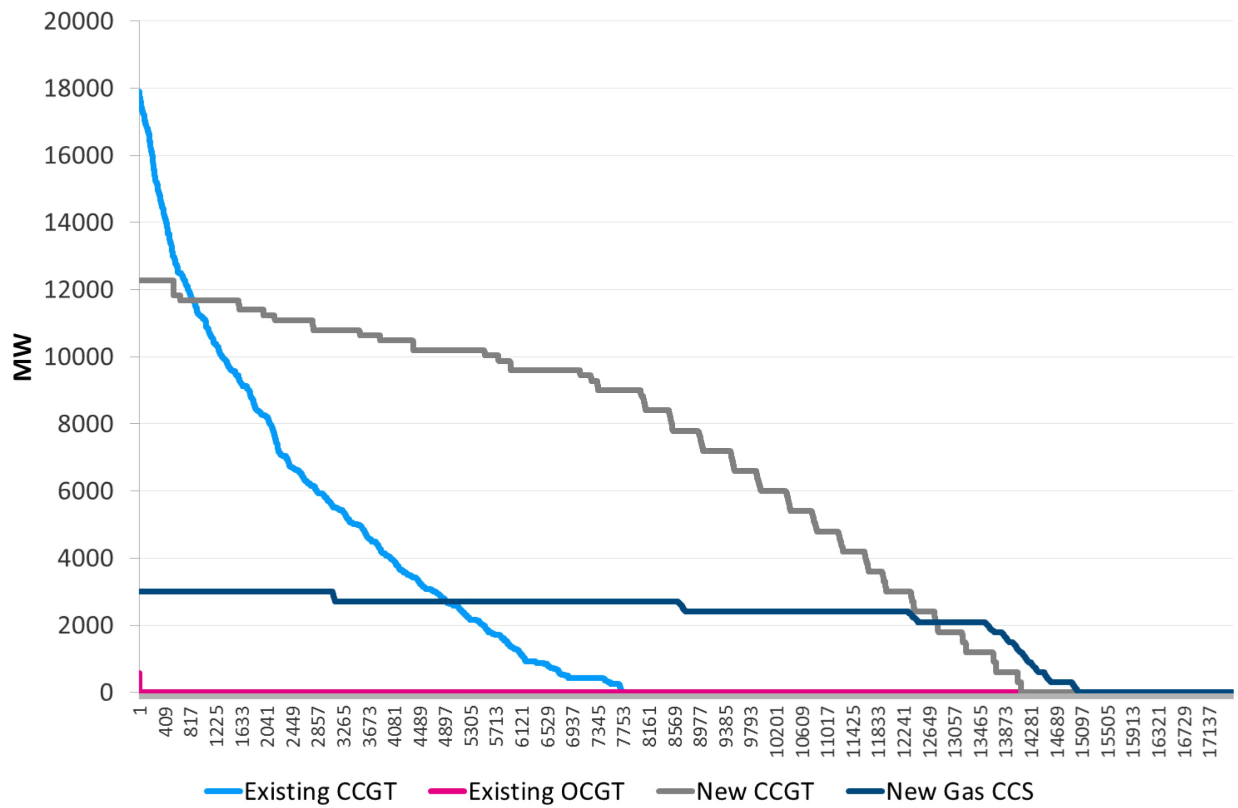
- The greater ‘cycling’ of the new CCGT/OCGT generation is visible in scenario 2 with the reduced perfect foresight, however some of the additional flexibility is also being provided by interconnectors.



Duration curves for flexible gas generation

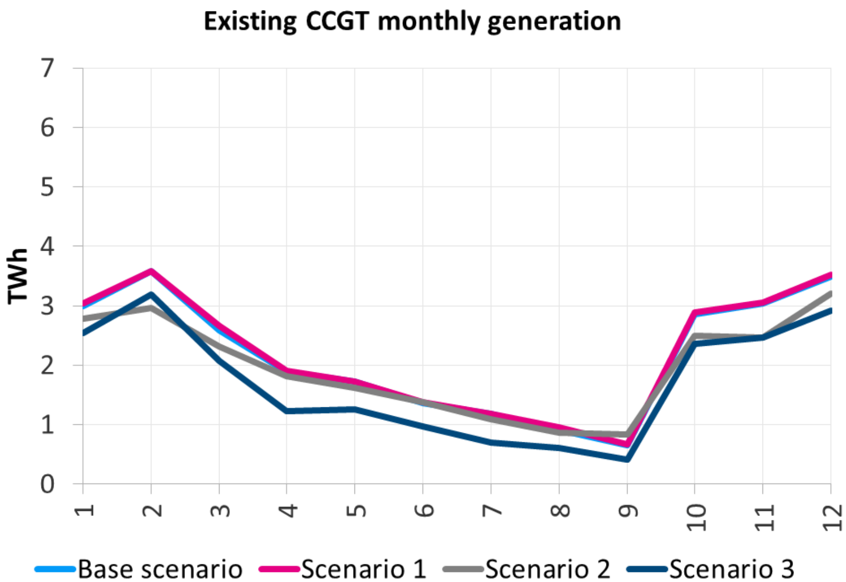
Generation duration curve of flexible gas generation in Scenario 3 in 2030

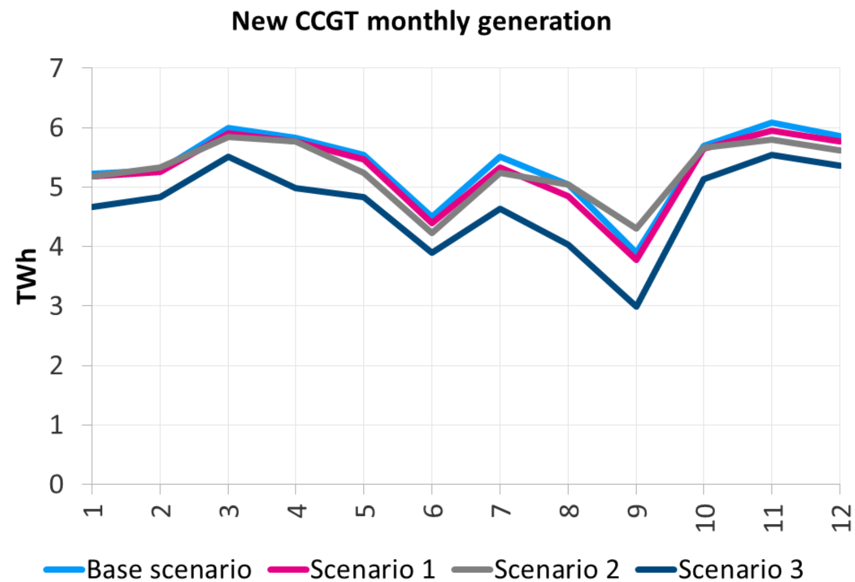
- CCS provides baseload power in most of the high demand periods reducing the required generation from CCGTs/OCGTs



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

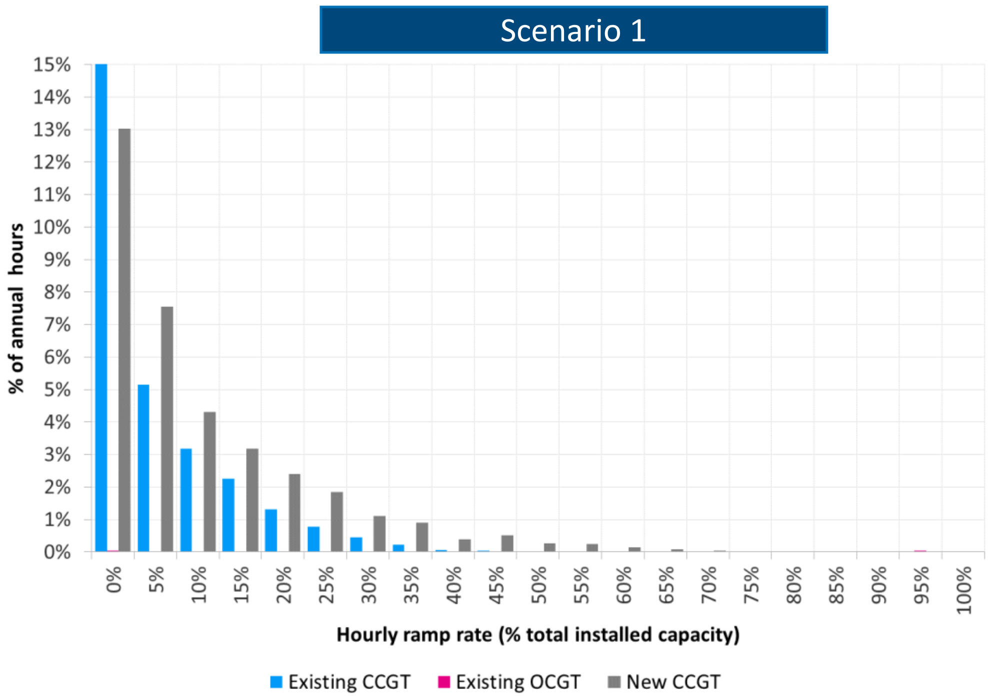
Average number of annual starts per unit	Existing CCGTs	Existing OCGTs	New CCGTs
Base scenario	85	3	143
Scenario 1	93	3	167
Scenario 2	114	9	231
Scenario 3	75	2	161

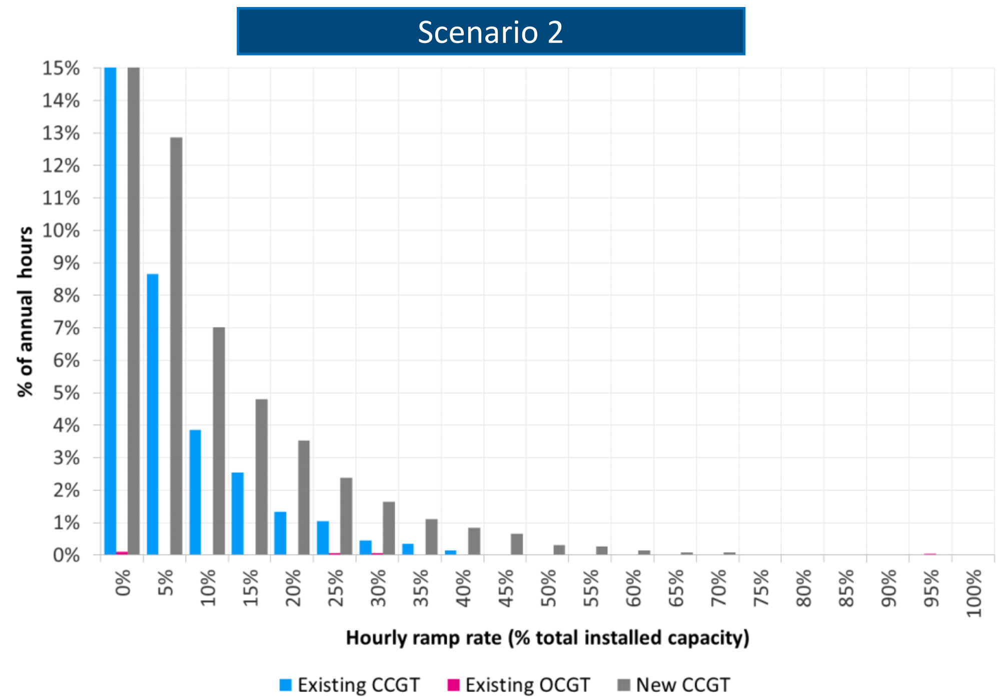
Total number of starts per unit for Existing CCGT/New CCGT	Hot	Warm	Cold
Scenario 1	23/68	45/85	25/14
Scenario 2	30/136	58/88	26/7
Scenario 3	15/59	36/82	24/20

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

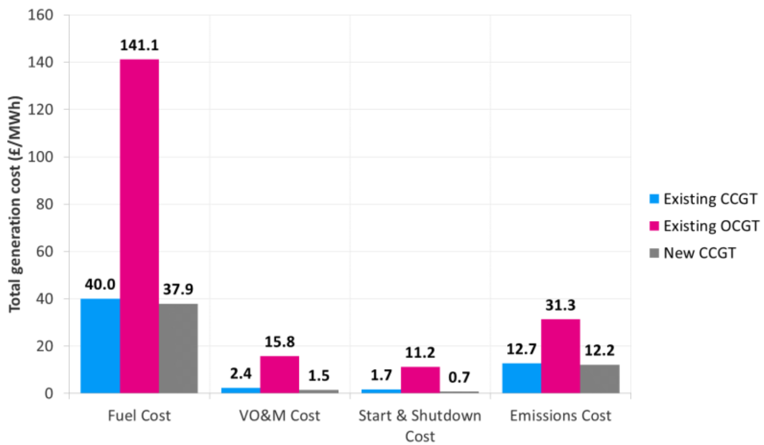
Total fuel consumption (TWh / year)	Existing CCGTs	Existing OCGTs	New CCGTs
Base scenario	47.6	0.0	117.7
Scenario 1	52.2	0.0	119.1
Scenario 2	47.1	0.0	119.4
Scenario 3	40.7	0.0	106.1

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

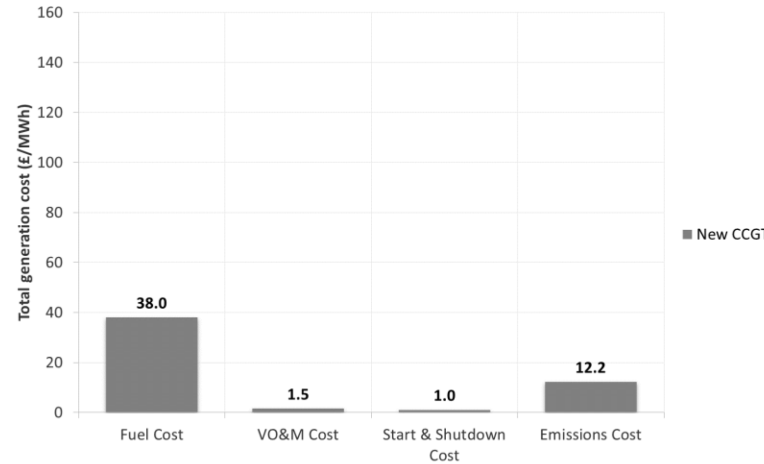
Total generation cost breakdown for gas plant types

Breakdown of average generation cost per MWh of output in 2030

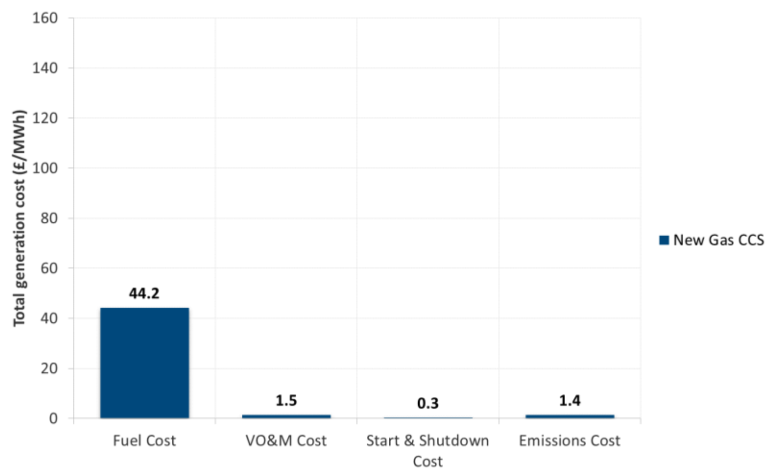
Total generation cost breakdown for Existing CCGT, New CCGT and Existing OCGT (Scenario 1)



Total generation cost breakdown for New CCGT (Scenario 2)



Total generation cost breakdown for New Gas CCS (Scenario 3)

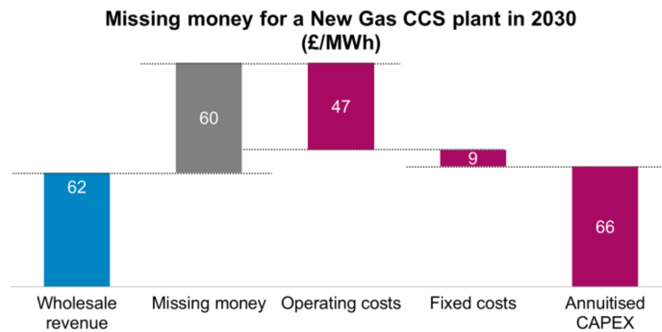


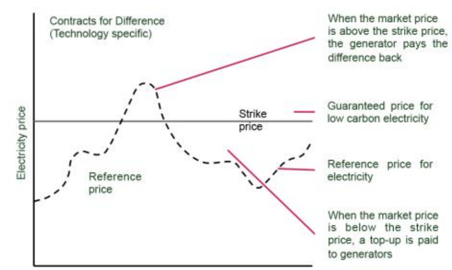
We have excluded an estimate of CCS transport and storage costs in this initial analysis to avoid unduly distorting dispatch, but can consider in more detail in subsequent work

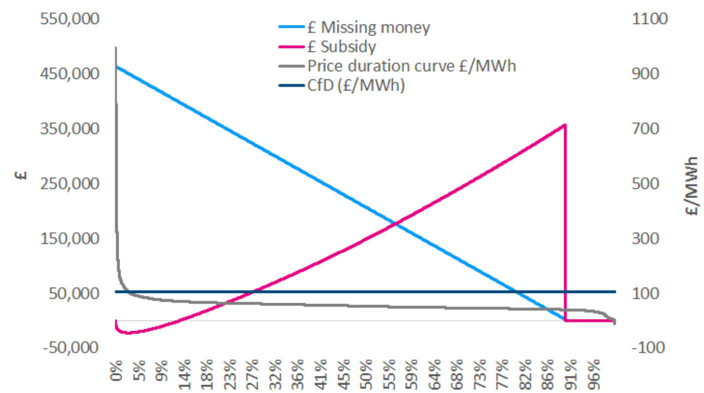
Missing money for CCS plant

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.
- 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







Contents

Introduction

Requirements and objectives of the analysis

Overview

- The purpose of this analysis is to present:
  - the market modelling results for Scenario 3 and Baringa Reference Case in 2030 and 2040
  - the asset modeling results based on the inputs from the wholesale market modeling scenarios above and considering four different asset types: existing OCGT, new CCGT, H2 GT and CCGT CCS
- Scenario 3 considers ESME capacity/demand with Baringa adjustments (same as Scenario 2c*), Baringa commodity prices for coal, gas and oil (same as Scenario 2c*)and ESME CO2 shadow price (different to Scenario 2c*)
- Baringa Reference Case is considered as the second market modelling scenario with higher share of intermittent renewables in 2040
- Scenario 4 focusses asset evaluation taking scenario 3 and Baringa Reference Case results as inputs (e.g. power and commodity prices)
- The asset parameters for the four asset types mentioned above are based on ESME and additional assumptions have been layered in from Baringa Reference Case where needed

	Scenario 4	Scenario 5	Scenario 6
Title	Selected Asset Evaluation.	Evaluation of 'Thermal Power' Asset.	Evaluation of 'ETI GT'.
Objective/Scope	To explore the financial performance of specified individual plant operating in the market. Scope to cover three assets (e.g. specific GT, CCGT, Hydrogen GT).	To explore the financial performance of a '3GW CCGT with CCS' plant operating in the market. Scope to include sensitivity studies on the impact of CfD (CCGT with CCS) vs CM (unabated CCGT) contracts.	To explore the financial performance of an 'ETI GT' operating in the market. Assumed scope to include two off 'ETI GT' configurations, each operating in two fleet/market Scenarios.
Prime Contractor Inputs	Input data/results from agreed Scenario(s).	Input data/results from agreed Scenario(s).	Input data/results from agreed Scenario(s).
ETI Inputs	Review/update of all plant parameters.	Detailed cost and performance data of '3GW CCGT with CCS' plant. Revised fleet incorporating the plant.	Detailed cost and performance date for 'ETI GT'. Revised fleet including the GT.
Specific Results	Estimated gross margin from the 3 assets, capturing value from short term volatility.	Sensitivity study will report back gross margin to inform selection of agreed cases (two off). For the two agreed cases only, detailed financial and performance data for the '3GW CCGT with CCS' plant in the market (including load factors, gross margin, profitability etc.).	Detailed financial and performance data for the 'ETI GT' plant in the market (including load factors, gross margin, profitability etc.).

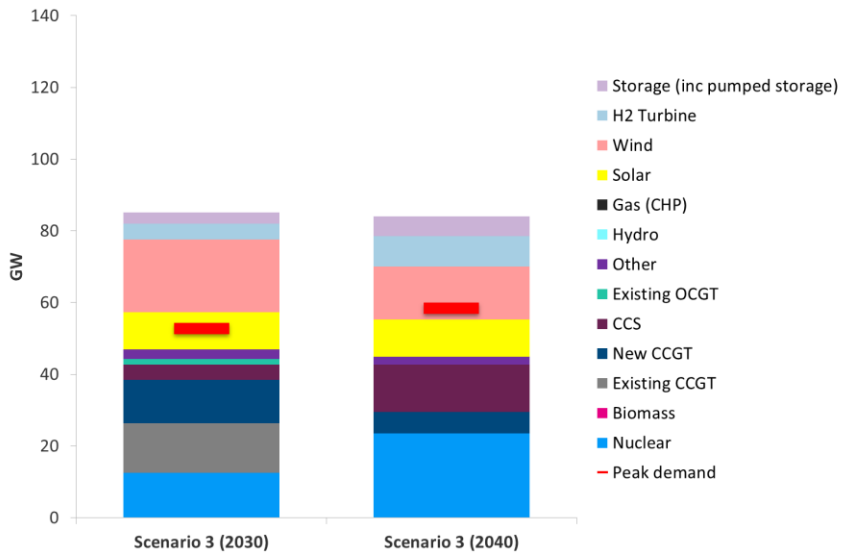
Capacity mix and demand

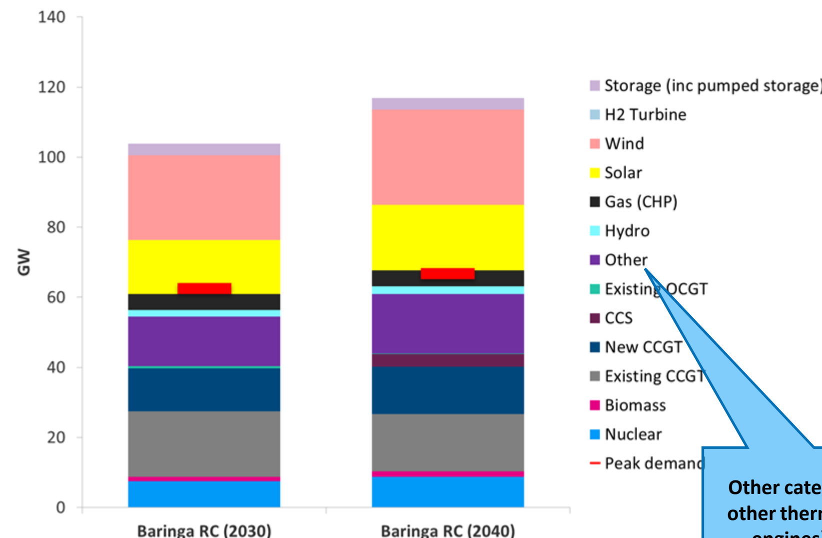
Baringa

Comparison of Scenario 3 supply and demand in 2030 and 2040 with Baringa Reference Case

Installed Capacity (GW) (Baringa Reference case and ESME)

- The comparison of GB supply and demand in scenario 3 in 2030 and 2040 is shown in the charts below compared to Baringa Reference Case
- The capacity is generally less tighter in the Baringa Reference Case, implying a higher capacity margin and therefore lower scarcity uplift on its own
- The penetration of renewables including hydro, solar and wind is higher in both years in the Reference Case, with the difference being larger in 2040





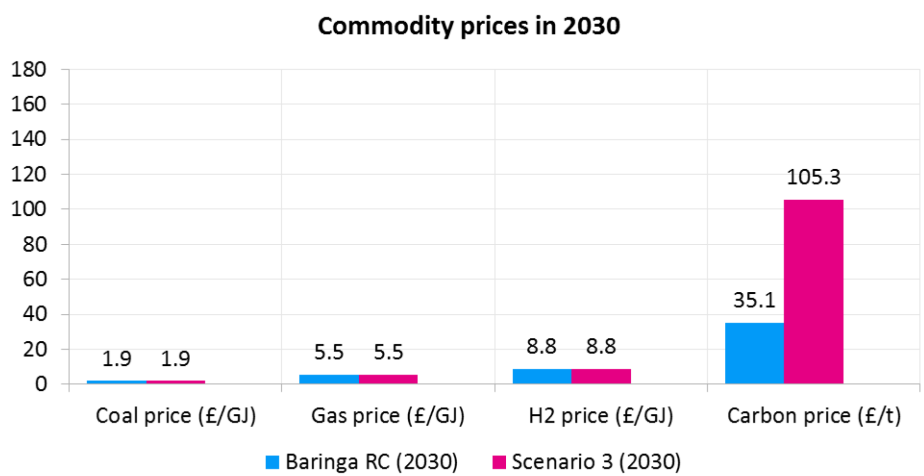
Other category includes: other thermal (e.g. diesel engines): 22%/18% , small gas:41%/34% , other generation for DSR and balancing services: 25%/28% , and other renewables (e.g. tidal, wave):12%/20% in 2030/2040

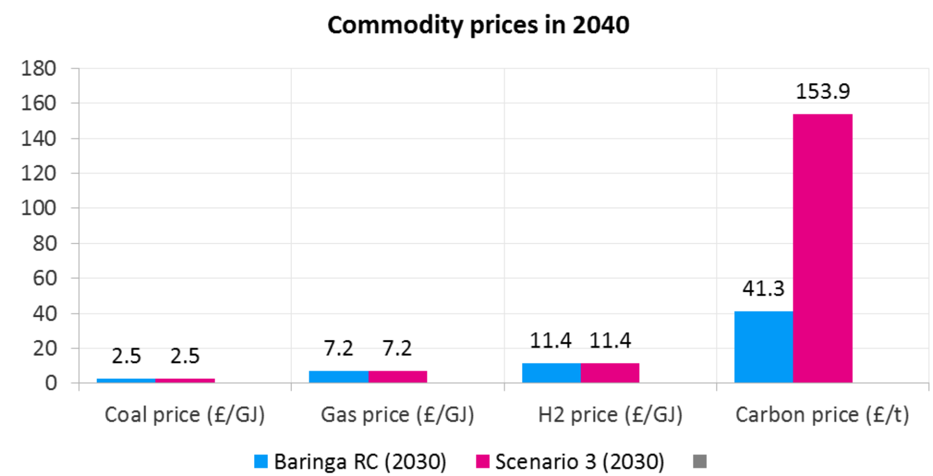
GB power demand	Scenario 3 (2030)	Scenario 3 (2040)	Baringa RC (2030)	Baringa RC (2040)
Annual demand (TWh)	334	373.5	329.4	349.2
Peak demand (GW)	52.7	58.3	62.5	66.7

Commodity prices (real 2016)

Comparison of Baringa Reference Case and Scenario 3 assumptions

- Scenario 3 assumes the same commodity prices for coal, oil and gas as the Baringa Reference Case as shown below. The hydrogen price is calculated using the conversion efficiency from natural gas assumed in ESME and the Reference Case gas price
- The main difference between the two scenarios is the carbon price which is significantly higher under ESME (scenario 3) case, as it is based on an electricity system solution with an explicit 100gCO2/kWh target in 2030, alongside the standard system wide CO2 constraints
- The Baringa Reference Case reflects a world in which carbon abatement is achieved largely in the power sector through coal-to-gas switching, therefore the long term carbon price in 2040 is determined on that switching principle. We have assumed the same carbon price in the interconnected markets as in GB

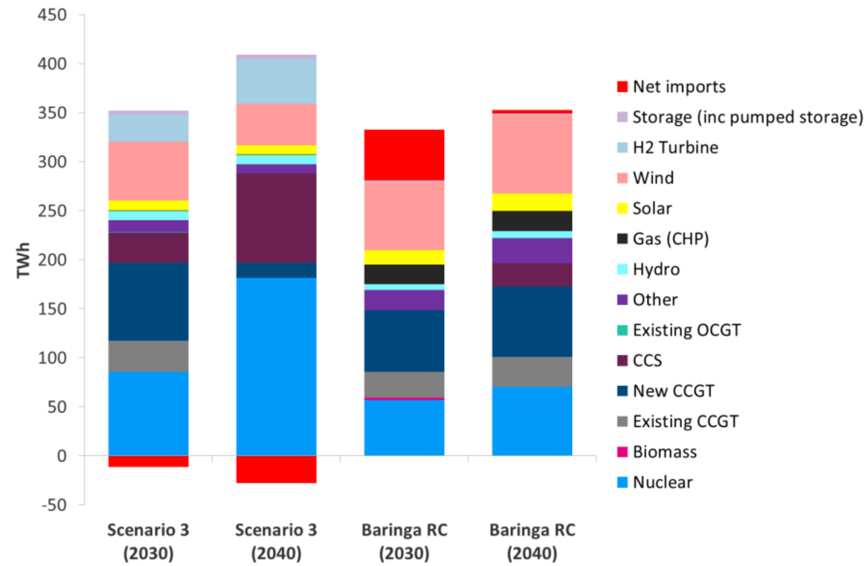




Gas generation in the power mix

2030 and 2040 Generation mix overview across scenarios

- Overall generation level in 2030 in both scenarios is similar, with higher generation in 2040 in Scenario 3 due to higher annual demand
- Existing and new CCGTs have a significant share in generation in 2030 in both cases. This is displaced to an extent by H2 GT and CCGT CCS generation in scenario 3 in 2040 as more capacity is built. In the Baringa RC where there is much less CCGT CCS capacity and no H2 GT is assumed, CCGTs still remain to be an important source of generation in 2040
- CCGT CCS provide baseload power in all cases and years. H2 GTs also run at significant load factors (>60%), driven by the high carbon price in scenario 3
- Both existing and new CCGTs run at a lower load factor in 2030 in the Baringa RC, mainly driven by the lower efficiency of the fleet assumed. In 2040, new CCGTs run at a much higher load factor in this scenario as CCGT CCS and H2 GTs displace some of their generation in scenario 3
- GB is a net exporter in scenario 3 in both years, whereas it is a net importer in the Baringa RC. This can be attributed to the fact that the higher carbon price in scenario 3 results in gas (main price setter in GB) being more competitive against coal which sets the price at times in the interconnected markets to GB



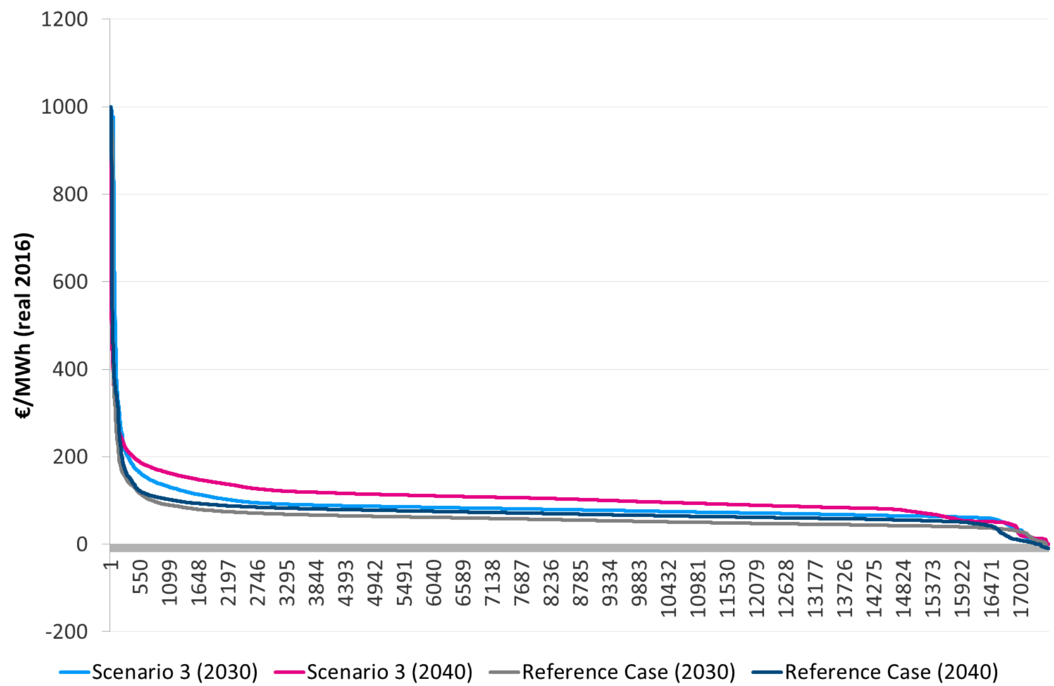
	Scenario 3 (2030)	**Scenario 3 (2040)**	Baringa RC (2030)	**Baringa RC (2040)**
Generation (TWh)				
CCS	31.0	91.4	0.0	23.5
H2 Turbine	27.7	44.8	0.0	0.0
Existing CCGT	31.8	0.0	26.6	30.7
New CCGT	79.0	15.4	63.3	71.8
Existing OCGT	0.1	0.0	0.0	0.0
Load factor (%)				
CCGT CCS	82%	79%	0% *	74%
H2 Turbine	72%	61%	0%*	0%*
Existing CCGT	26%	0%*	16%	21%
New CCGT	75%	29%	59%	61%
Existing OCGT	1%	0%	0%	0%

**The installed capacity is 0, so the load factor is 0%*

Comparison of GB price duration curves

GB (day-ahead wholesale station gate basis) power price in 2030 and 2040 (real 2016 basis)

- The comparison of the price duration curves for GB in 2030 and 2040 is shown below. Higher carbon price and tighter margin in scenario 3 lead to higher prices than the Baringa RC
- The much higher carbon price in scenario 3 leads to significant decarbonisation by 2040, whereas it remains at a similar level in the Baringa RC from 2030 to 2040

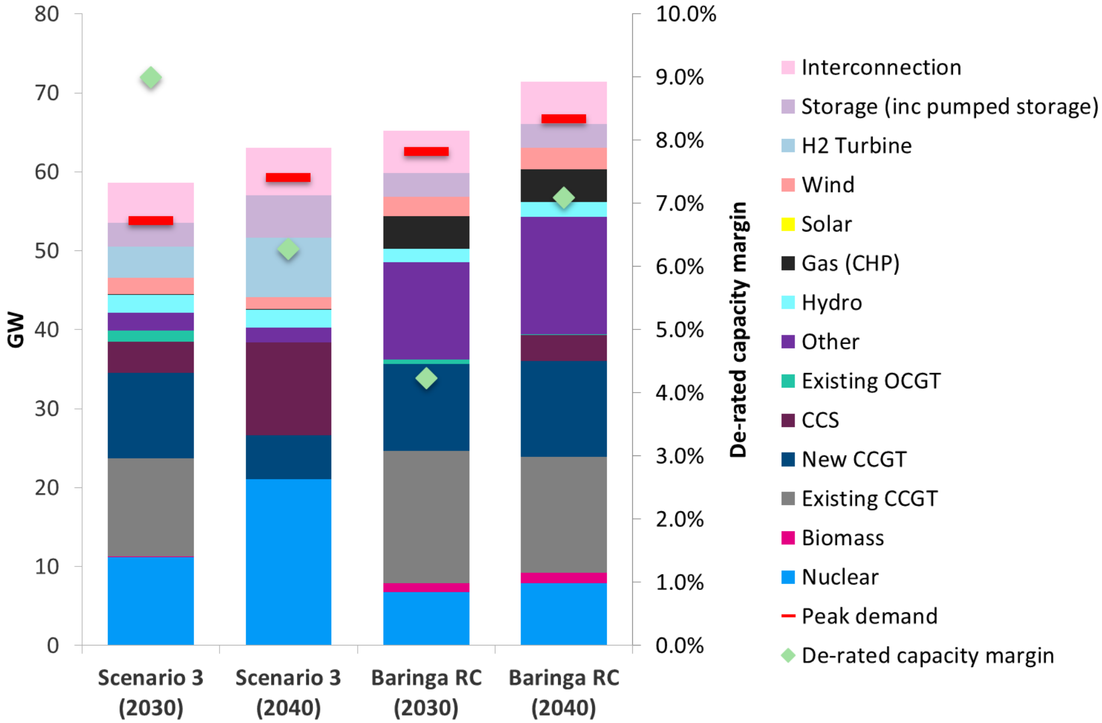


Scenarios	GB time weighted price (£/MWh)	Carbon intensity of power generation (g CO2/kWh)
Scenario 3 (2030)	87.7	105.8
Scenario 3 (2040)	104.8	20.1
Baringa RC (2030)	61.9	147.9
Baringa RC (2040)	73.4	143.3

Capacity market analysis – Scenario 3

The capacity margin is less tighter in scenario 3 compared to Baringa RC in both years

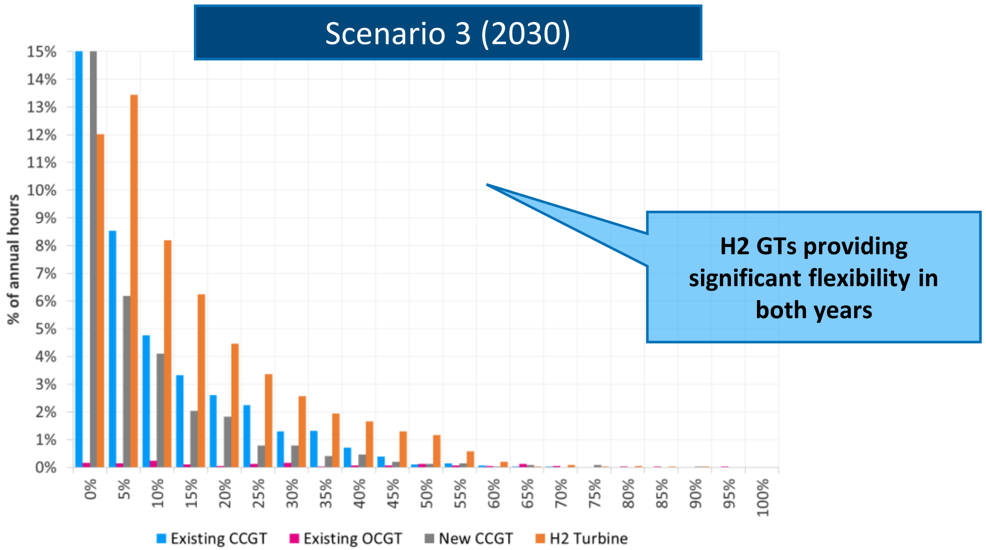
- The capacity margin is higher in scenario 3 compared to Baringa RC as shown below for 2030 and 2040
- Based on a targeted level of 3.4% domestic margin (excluding interconnectors), we have done capacity market simulation for scenario 3, which resulted in a clearing price of **23.6 £/kW** (de-rated) in 2030 and **13.1 £/kW** (de-rated) in 2040
- The simulated clearing prices for years 2030 and 2040 in the Baringa Reference Case are **19.4 £/kW** (de-rated) and **14.3 £/kW** (de-rated), respectively. The plant costs and technical assumptions are different between Baringa RC and Scenario 3 along with the auction prices and clearing plant (new/existing CCGT in the Baringa RC, OCGT/storage in scenario 3)

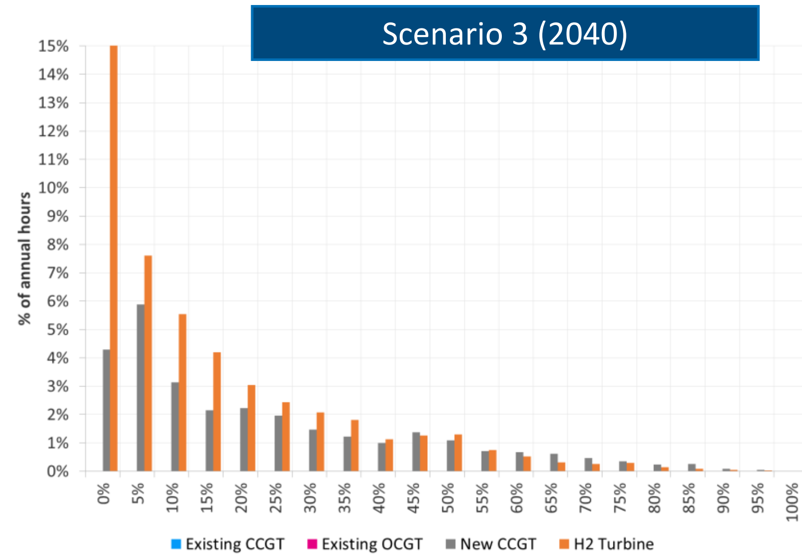


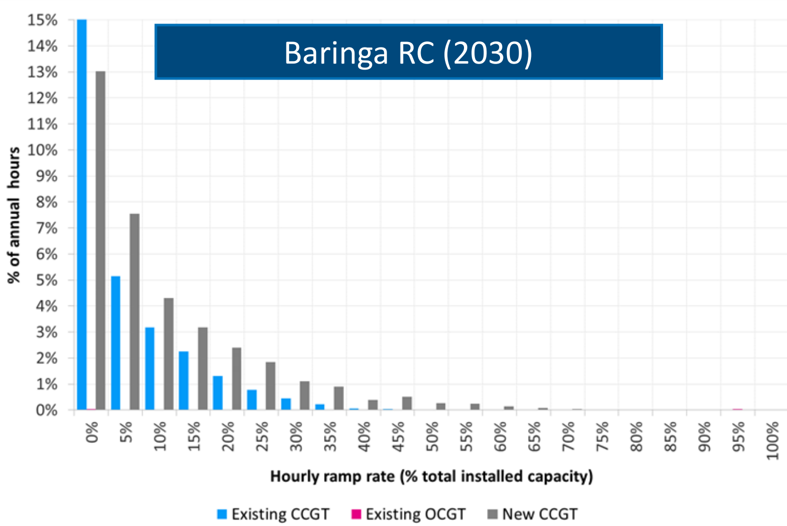
Technology	GB CM de-rating factors
Nuclear	90.0%
Biomass	86.9%
Existing CCGT	90.0%
CCS	90.0%
Existing OCGT	94.2%
Other	86.9%
Hydro	86.2%
Gas (CHP)	90.0%
Solar	0.0%
Wind	10.0%
Pumped storage	96.6%
Interconnection	60%

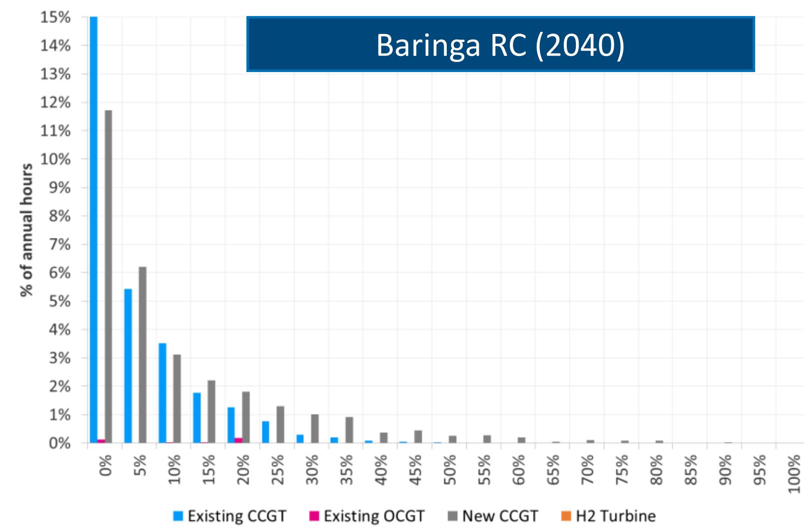
Ramping of flexible gas generation

Ramping as a percentage of installed capacity for flexible generation



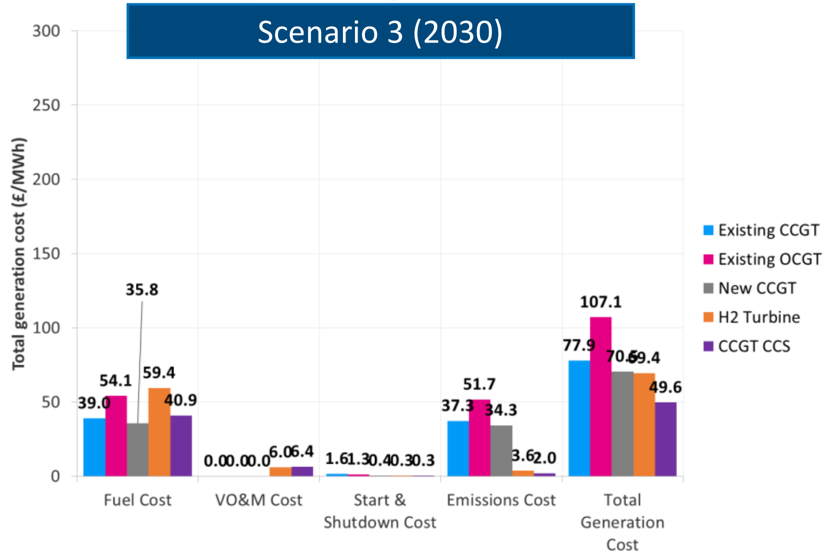


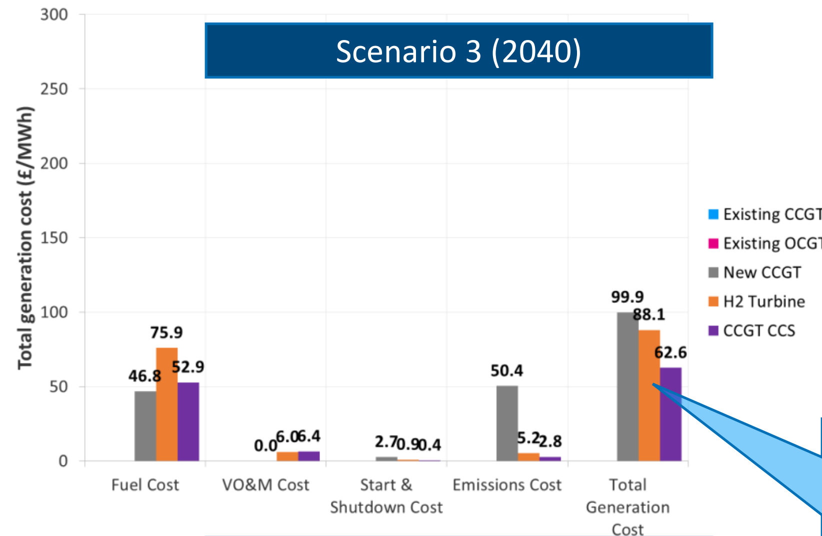




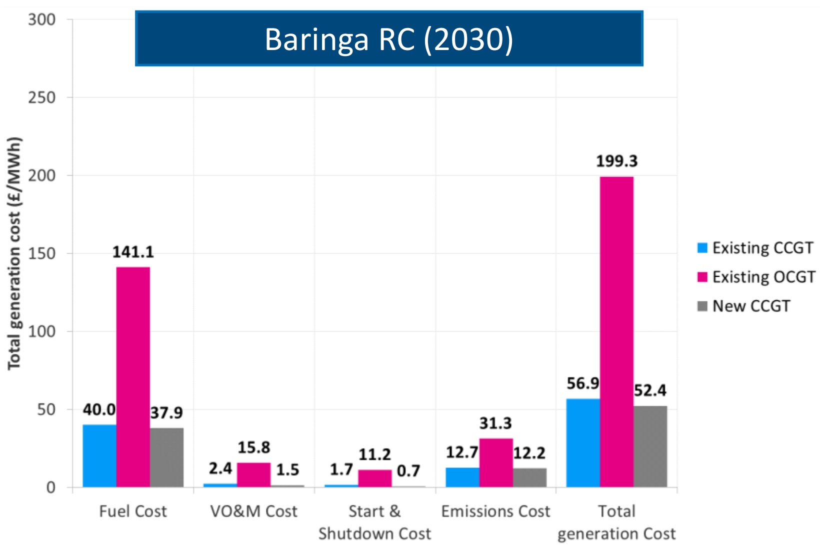
Plant operating costs

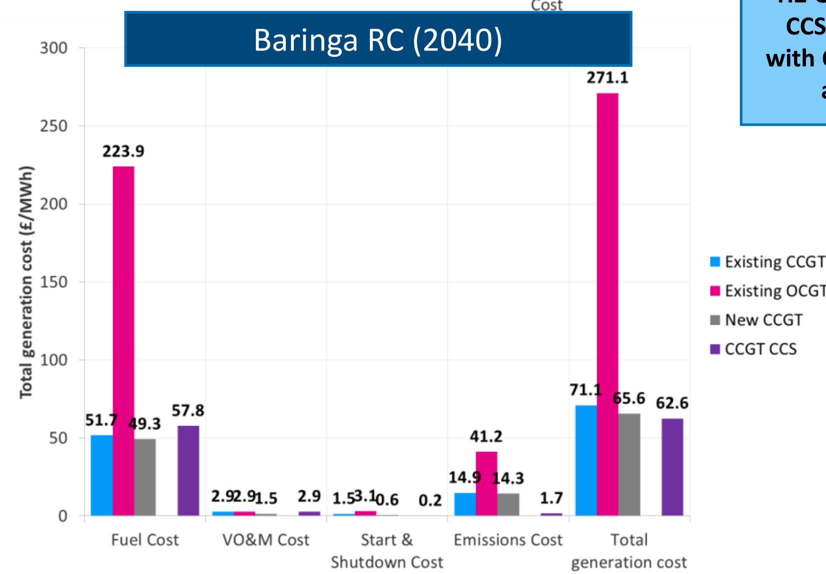
Breakdown of operating costs





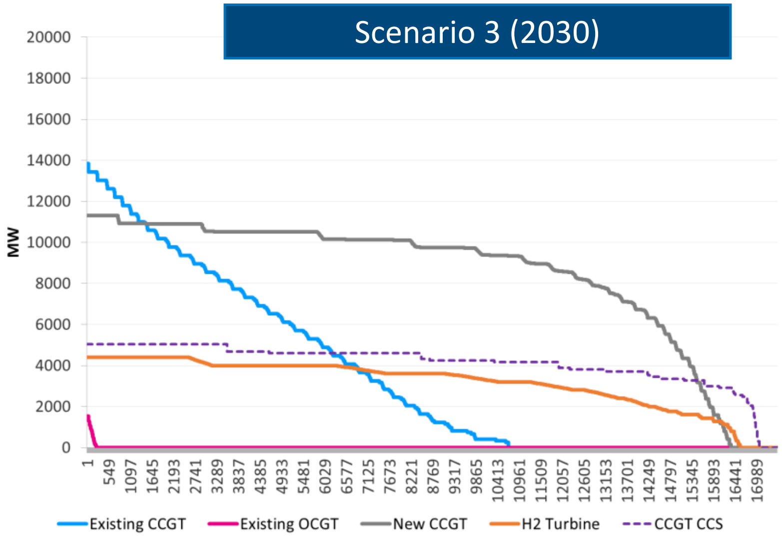
High carbon costs in scenario 3 makes H2 GTs and CCGT CCS compatible with CCGTs in 2030 and 2040

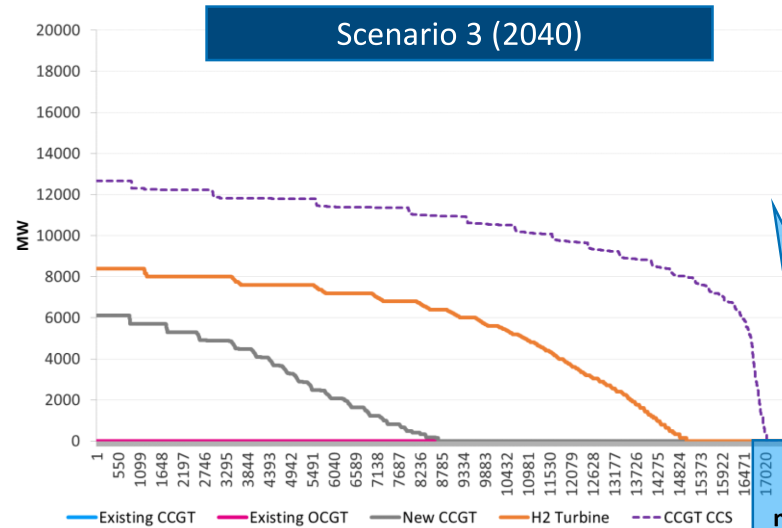




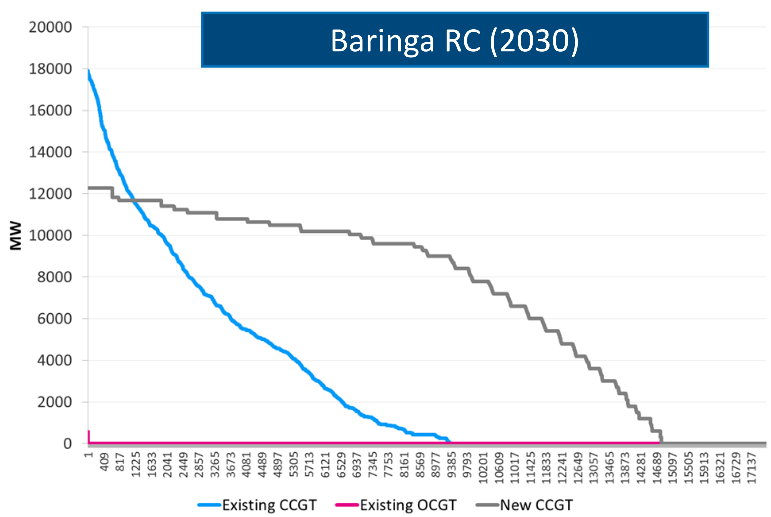
Duration curves for flexible gas generation

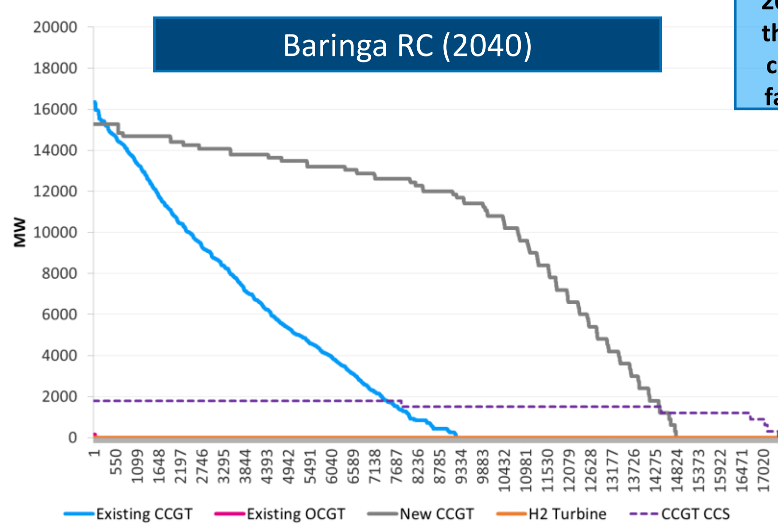
Generation duration curve of flexible gas generation in 2030





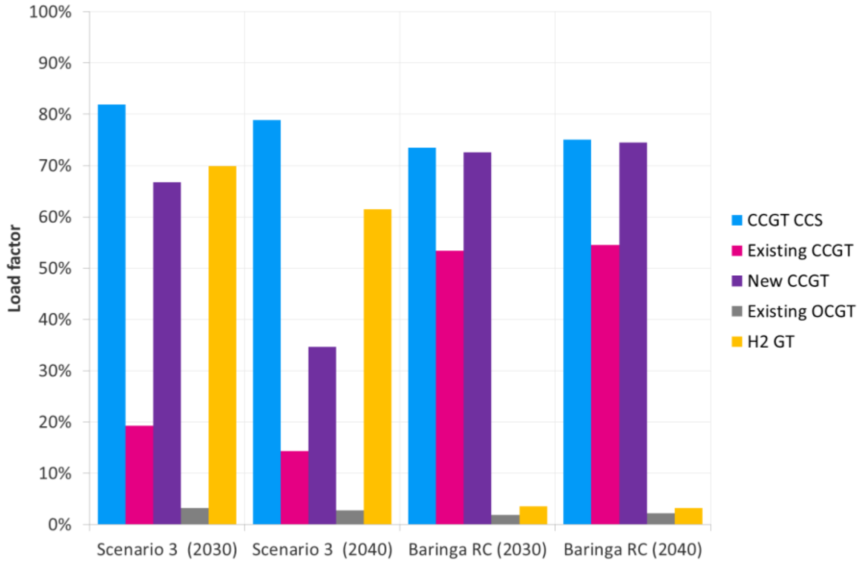
H2 GTs and CCGT CCS generating significantly more in 2040 compared to 2030 mainly as a result of the significant increase in carbon price (H2 GT load factor decreases in 2040)

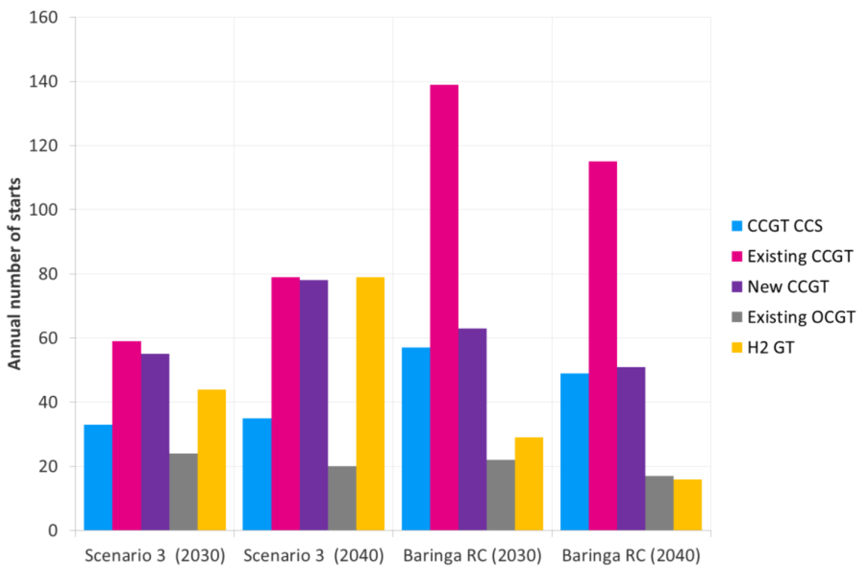




Load factor and number of starts

Plant load factor decreases overtime in scenario 3

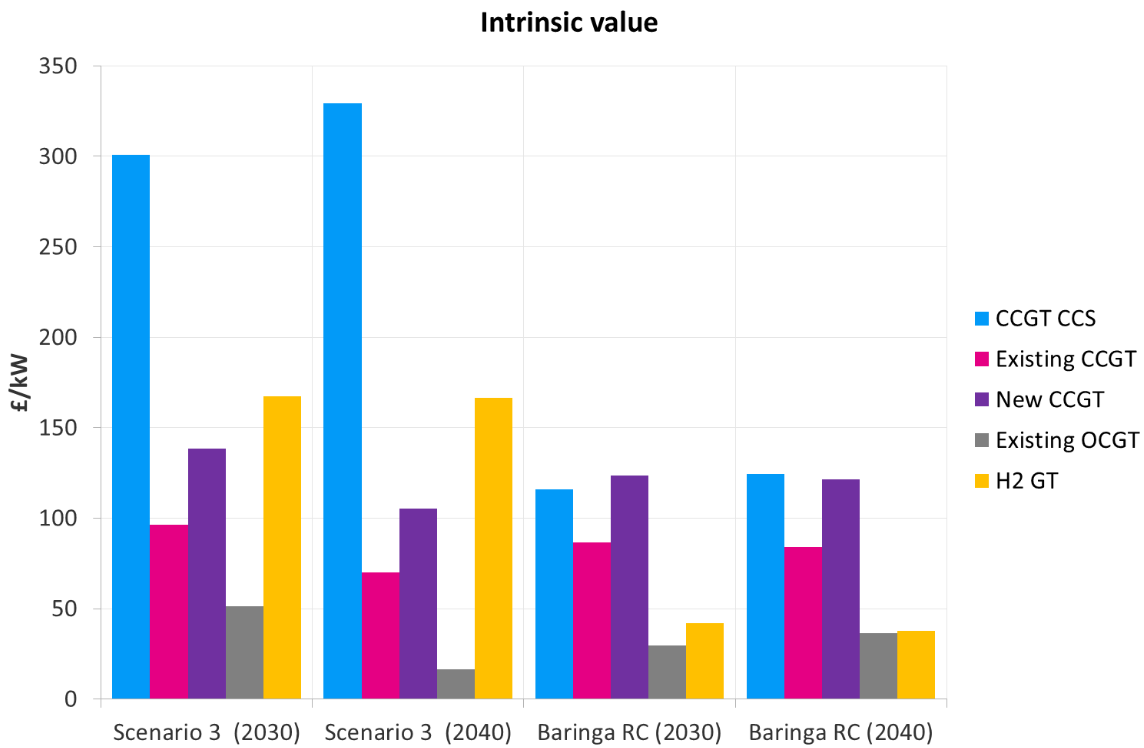




- The load factor for unabated plant decreases sharply in scenario 3 form 2030 to 2040 due to significantly increasing carbon price
- For low carbon generation, the load factor decreases slightly due to significant expansion of nuclear
- Much lower carbon price in the Baringa RC mean that H2 GTs hardly ever dispatch

Intrinsic Value

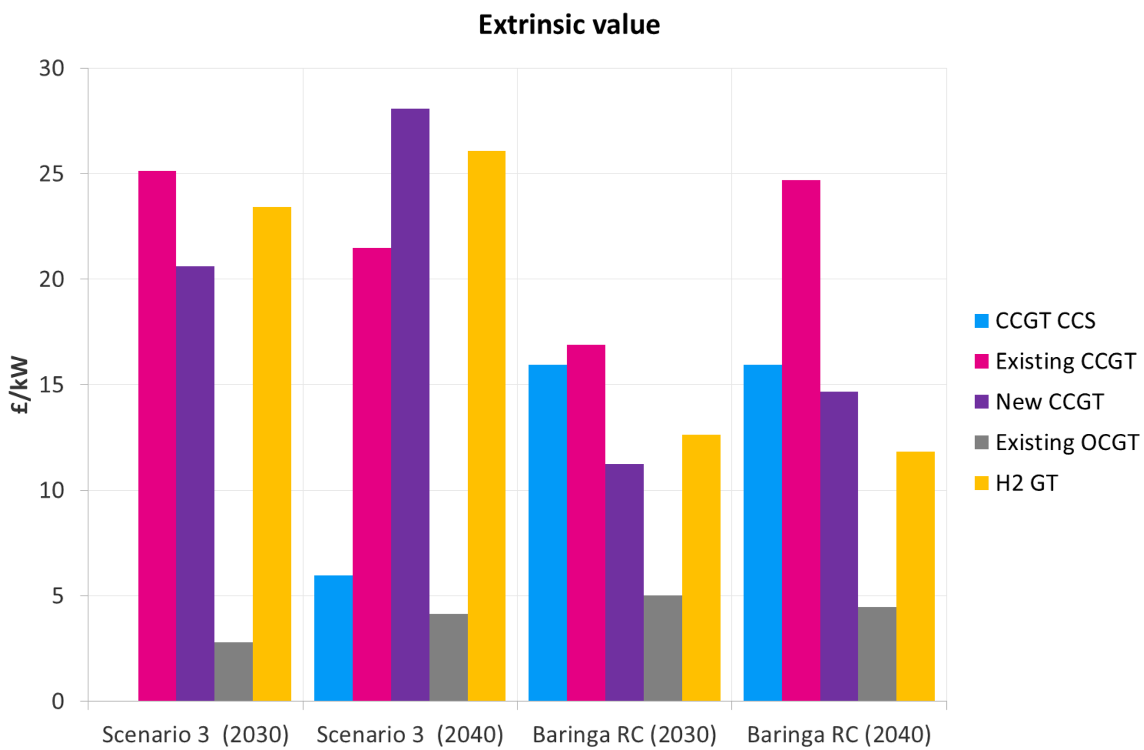
Carbon price drives significant value for mid-merit and baseload low carbon plant



- High carbon price in scenario 3 is the main contributor to the higher value for H2 GTs and CCGT CCS.
- This drives significantly higher price of largely unabated plant at the margin and allows low carbon baseload plant to capture high infra-marginal rent

Extrinsic Value

Short-term electricity price volatility could add a modest amount to the plant revenues



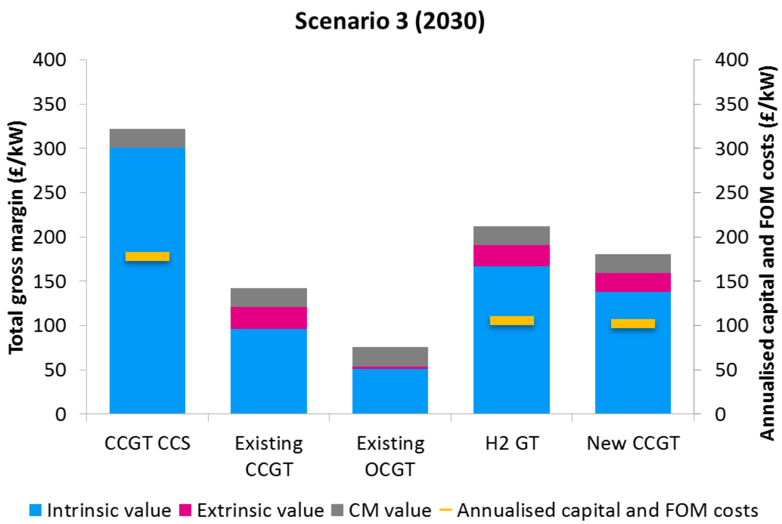
- The values on the left are likely to represent an upper bound on the extrinsic value and a hair-cut is likely to be required in reality to reflect lack of perfect foresight and cost of adjusting trading strategy (e.g. day-ahead and intraday)

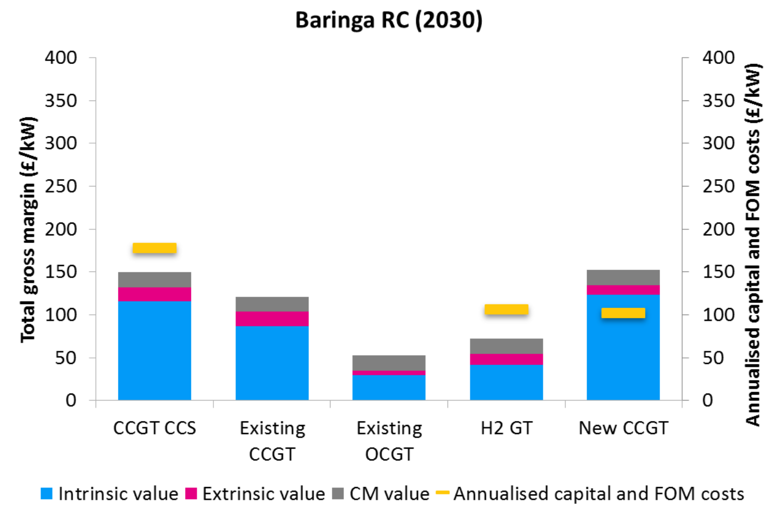
- As an example from real world operators a CCGT is able to capture 30% of the potential value of extrinsic margin indicated by our stochastic modelling (which is a value we commonly use for CCGT valuation purposes)

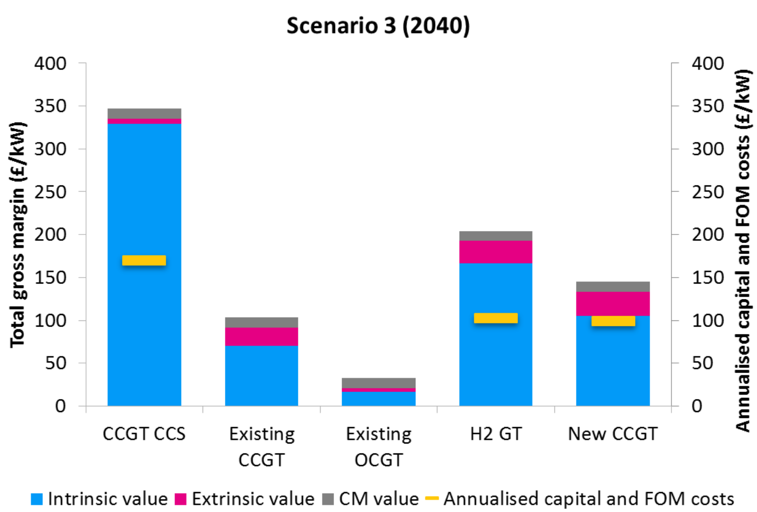
- In addition, if the asset is often at the margin setting the price, then there will be less potential for extrinsic margin

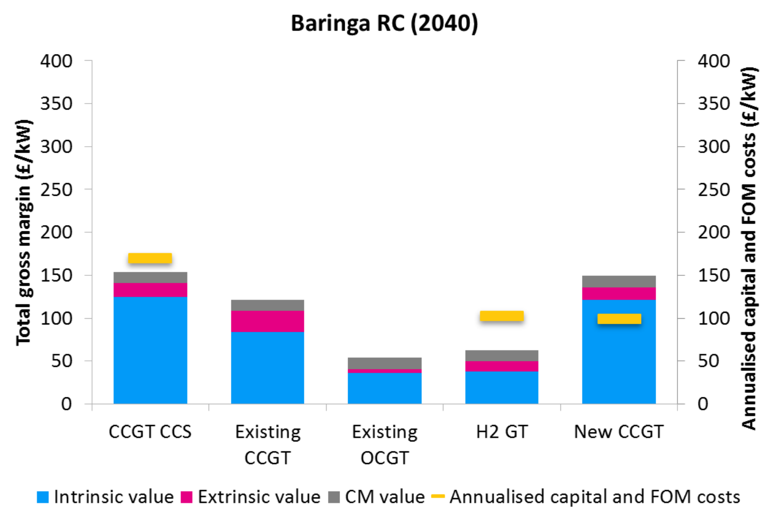
Total wholesale Value

The total revenue for an asset is a result of the combined wholesale and capacity market revenues (breakeven cost assuming WACC=12% and economic life=20 yrs)*









The Capex and FOM costs are just for illustration, in practice there will likely be additional costs that need to be reflected such as connection, insurance, use of system charges, etc

Key conclusions

Baringa

CCS and H2 assets appear profitable in high CO2 price world (particularly CCS), but would need significant support under a more "central market" scenario

- Recap of scenarios
  - Baringa RC is central market view of the world with increasing levels of wind/solar/CCGT and modestly rising carbon price, but which leads to limited further decarbonisation post 2030
  - Scenario 3 shows significant ongoing decarbonisation due to a far higher CO2 price (x3-4) and expansion of baseload CCS/Nuclear and H2 turbine as a low carbon replacement for CCGT (but with limited wind/solar)
- High carbon price in 2030 and 2040 is key value driver of CCS and H2 turbine in 2030 / 2040
  - In scenario 3 this pushes up price of marginal plant (primarily remaining unabated CCGT) and allows H2 turbines and CCGT with CCS to capture significant infra-marginal rent
  - CM and extrinsic value a relatively modest component of future value
- Significant nuclear expansion (to ~24GW from 2030-2040) impacts CCS / H2 load factors
  - 2-3 percentage point drop for CCS and ~10 for H2 turbine, but increasing prices mean GMs are maintained