Programme Area: Carbon Capture and Storage

Project: Hydrogen Turbines Follow On

Title: Scenarios 1 & 2 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.

CCS and H2 Dispatch modelling

Results for Scenarios 1 and 2

Client: ETI
Date: 3 March 2017
Version: V4_0

Reputation built on results

Contents

Introduction

Requirements and objectives of the initial analysis

Overview

- The purpose of this analysis is to present the modelling results for Scenarios 1 and 2 as previously agreed with ETI and summarised on the right. Scenario 1 is based on an ESME 2030 electricity system solution with an explicit 100gCO2/kWh target in 2030, alongside the standard system wide CO2 constraints.
- Scenario 2 considers the following three sensitivities based on the same GB capacity mix and demand from scenario 1:
  - Scenario 2a: ESME fleet 2030 + Baringa Reference Case gas price (including the implied H2 price)
  - Scenario 2b: ESME fleet 2030 + Baringa Reference Case carbon price + output-based subsidy (RO/CfD) for eligible low carbon generation
  - Scenario 2c: ESME fleet 2030 + all Baringa Reference Case commodity prices (including the implied H2 price)

	Scenario 1	Scenario 2	Scenario 3
Title	ESME Fleet 2030	Policy Interventions	Modifications
Objective/Scope	Provide a 2030 baseline based on the ESME fleet and identify the proximity of adoption of hydrogen turbines.	Determine how policy interventions change fleet load factors.	Test modified assumptions (e.g. target year 2025, 2030, 2040). 3 model runs.
Prime Contractor Inputs	Results from the 'Dispatch Modelling of 2030 Baringa Fleet to Understand Role of gas/H2 in the GB Power Sector'. Cost and performance data for 'standard' assets.	Input data/results from Scenario 1.	Input data/results from Scenario 1 and/or 2.
ETI Inputs	ESME fleet for 2030. ESME demand profile. Cost and performance data for 'non-standard' assets (e.g. hydrogen storage and turbines).	Policy interventions to be incorporated into the model, e.g. CM, CfD, cost of carbon, gas price.	Additional input data required for runs, e.g. revised fleet; demand profile.
Specific Results	• GT load duration curves by scale. • Load factors by type. • Number of starts - hot/cold. • System costs, by type and total – incl capital. • Gas used 2015 and 2030. • Demand ramp rates.		

Additional assumptions

- We have also layered in the more detailed (hot/warm/cold) start costs and times, ramp rates, run up rates from the phase 1 work for the flexible gas generation

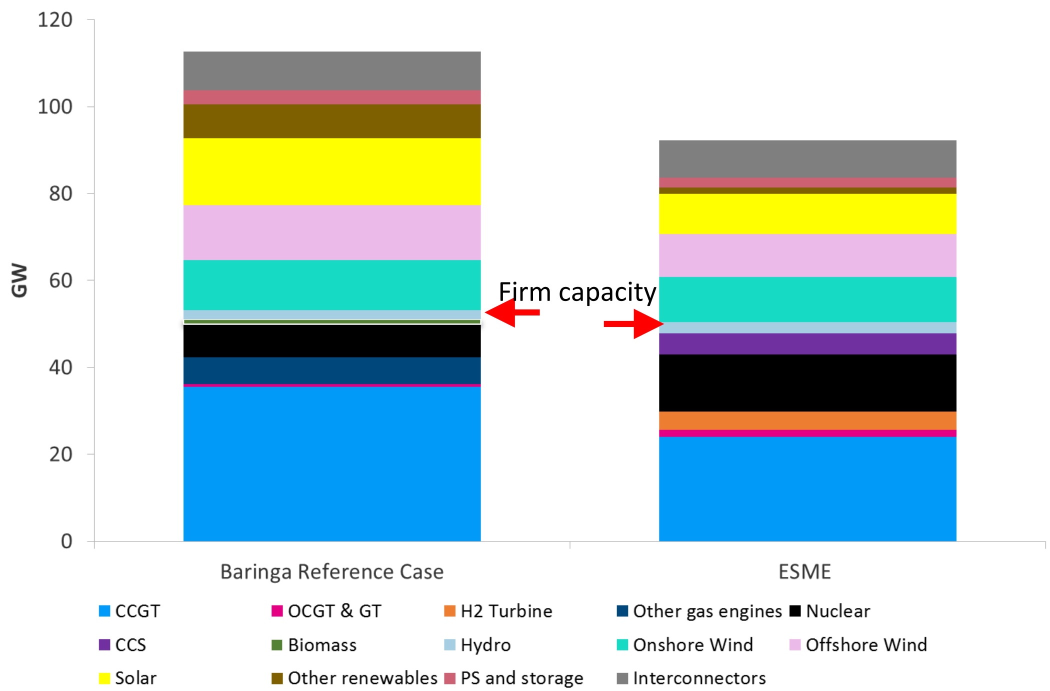
- For H2 turbines, upon ETI's input, we have assumed:
  - H2 GTs are of the large "frame" type
  - Fuel consumption: converting natural gas to power with HHV efficiency 34% by 2030, with 90% of carbon captured (we calculate the implied H2 price from the conversion efficiency from natural gas to hydrogen and natural gas price)
  - Flexibility parameters are the same as for the large frame CCGT (same dataset for a modern CCGT for unit size, ramp-rates, MSG, start costs , on/off times etc)
  - Transport and storage of CO2 Tariff for all gas fired CCS power production - £6 /MWhe (2015 Real)

Capacity mix

Comparison of Baringa Reference Case and ESME assumptions (Scenario 1)

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

- The comparison of capacity GB capacity mix and electricity demand in 2030 is shown below based on the Baringa Reference Case and ESME assumptions.
- The total ESME installed capacity is lower than the Baringa Reference Case, due to lower intermittent generation, but firm capacity is similar and the difference broadly mirrors the delta in peak demand. Annual demand is very close in both scenarios
- On its own, this would imply a higher power price in GB under the ESME assumptions due to tighter capacity margin in 2030, but the scenarios also contain material differences in commodity prices (see next slide)

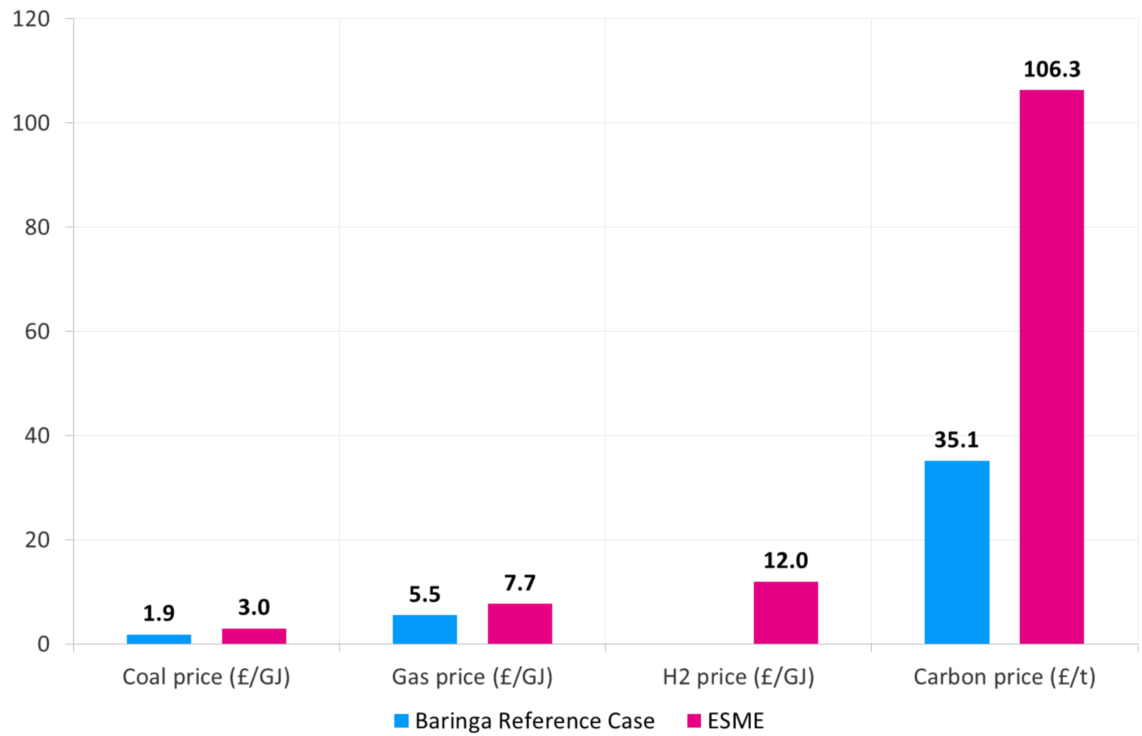


GB 2030 power demand	Baringa Reference Case	ESME
Annual demand (TWh)	329,392	333,661
Peak demand (GW)	62.5	59.3

Commodity prices (real 2016)

Comparison of Baringa Reference Case and ESME assumptions (Scenario 1)

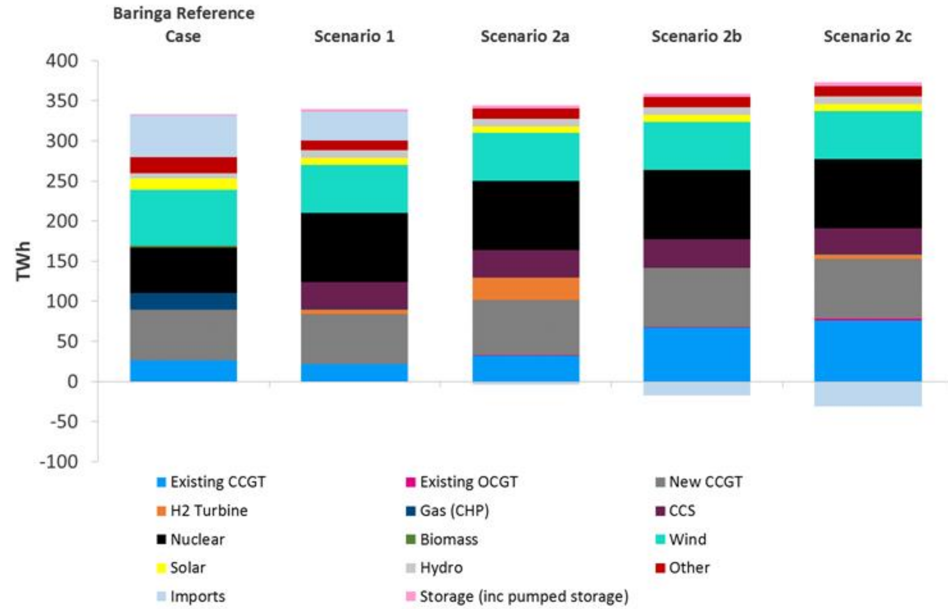
- The comparison of 2030 commodity prices is shown below based on the Baringa Reference Case and ESME assumptions. ESME commodity prices, mainly the carbon price are higher than the Baringa Reference Case, which would lead to higher GB power price on its own
- The H2 price shown below is the implied price calculated from the natural gas price and conversion efficiency of natural gas to H2 based on ESME assumptions. For comparison the ESME H2 system shadow price is £13/GJ, which also includes the impact of the carbon price implicitly



Gas generation in the power mix

2030 Generation mix overview across scenarios

- The increased generation from nuclear and CCS in **Scenario 1** is significant cf. Baringa reference case from Phase 1. The total generation from flexible gas assets (CCGTs, OCGTs and H2 Turbines) are similar, where H2 GTs generate 5.4 TWh at an annual level (a load factor of 14.4%) in the ESME case with £106.3/t CO2 price.
- **Scenario 2a with lower gas price**, incentivises generation from gas plants, particularly H2 turbines. The increased generation from gas displaces net imports to GB significantly cf. to Scenario 1.
- **Scenario 2b with lower carbon price and subsidy for eligible low carbon generation**, leads to a significant reduction in generation from H2 turbines (to < 1 TWh) but increasing generation from other flexible gas. As a result of the offsetting impacts of lower carbon price and subsidy, generation from CCGT CCS increases by only about 1.4 TWh cf. scenario 1.
- **Scenario 2c with all Baringa Reference Case commodity prices**, leads to significant increase in CCGT generation cf. to scenario 1. Generation from H2 turbines increases marginally and CCGT CCGS generation decreases slightly due to the combined effect of lower gas and carbon prices. The increased generation from gas displaces net imports to GB, making it a net exporter as in scenarios 2a and 2b but to a larger extent.

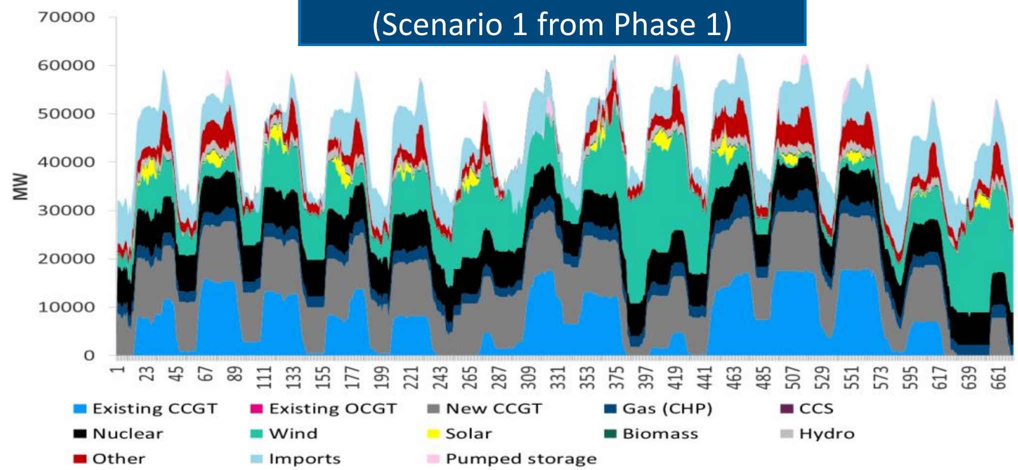


	Scenario 1	Scenario 2a	Scenario 2b	Scenario 2c
Generation (TWh)				
CCS	33.9	34.1	35.3	32.6
H2 Turbine	5.4	28.1	0.9	6.1
Existing CCGT	21.7	32.3	67.5	76.2
New CCGT	62.5	68.8	72.9	74.3
Existing OCGT	0.0	0.1	0.4	1.7
Load factor (%)				
CCGT CCS	79%	80%	83%	76%
H2 Turbine	14%	74%	2%	16%
Existing CCGT	18%	27%	56%	63%
New CCGT	70%	77%	81%	83%
Existing OCGT	0%	1%	3%	13%

Generation dispatch profile in a winter fortnightly period

Winter fortnightly generation profile from 02/12/2030 to 16/12/2030

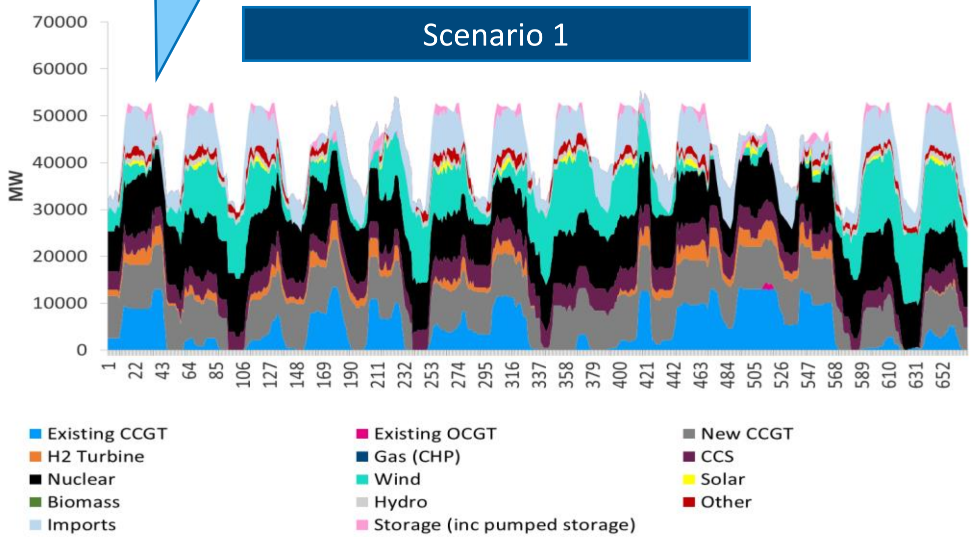
Baringa Reference Case (Scenario 1 from Phase 1)



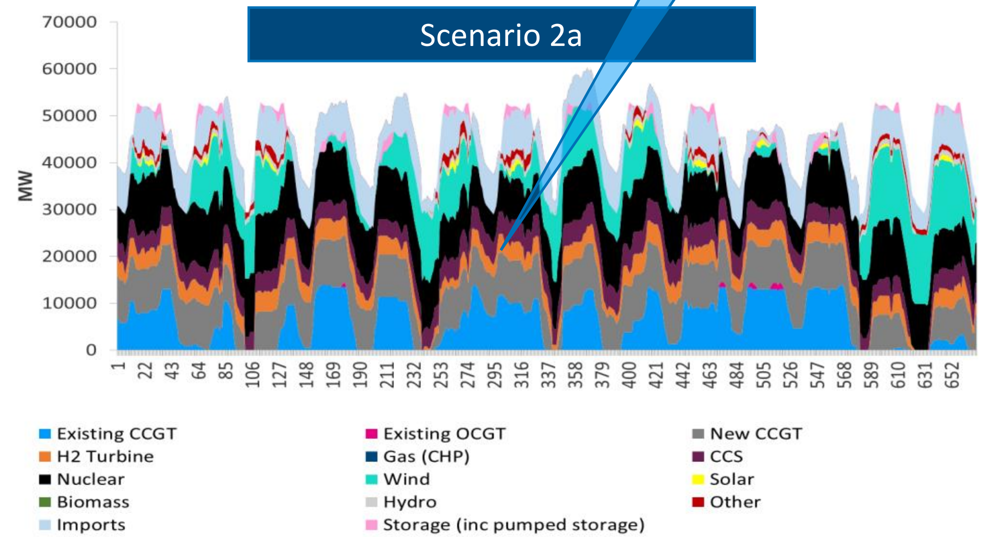
CCGT CCS providing baseload generation most of the time with H2 turbines playing more of a peaking role

Increase in H2 turbine generation with the lower gas price is remarkable in scenario 2a

Scenario 1



Scenario 2a



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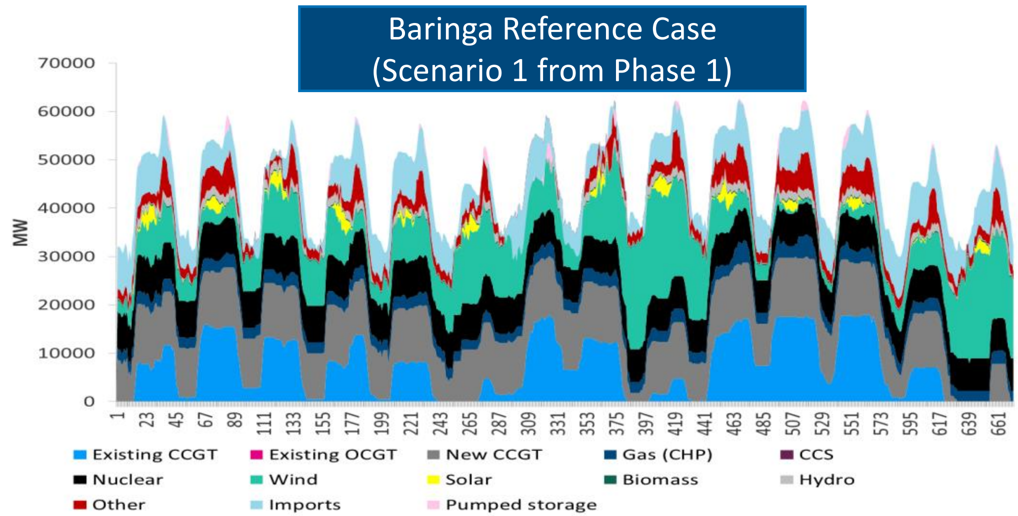
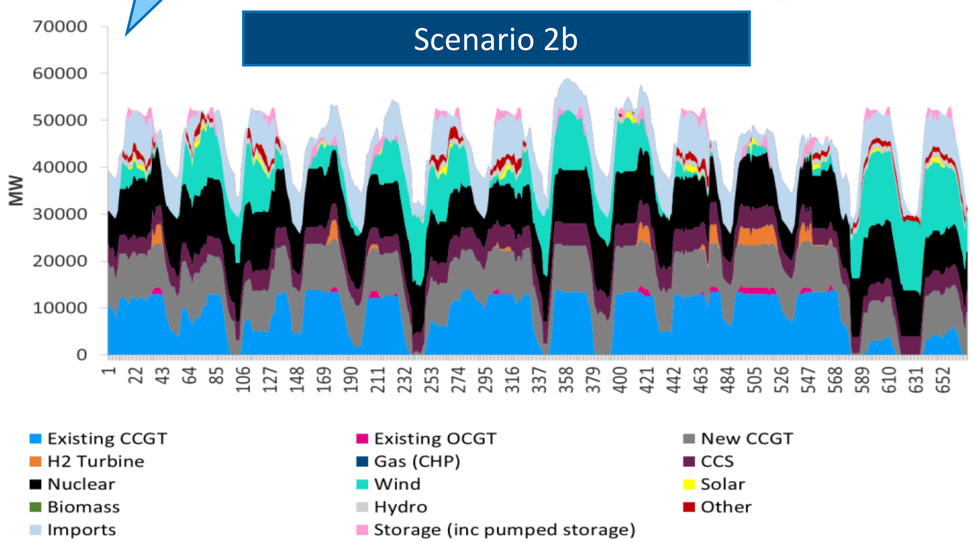
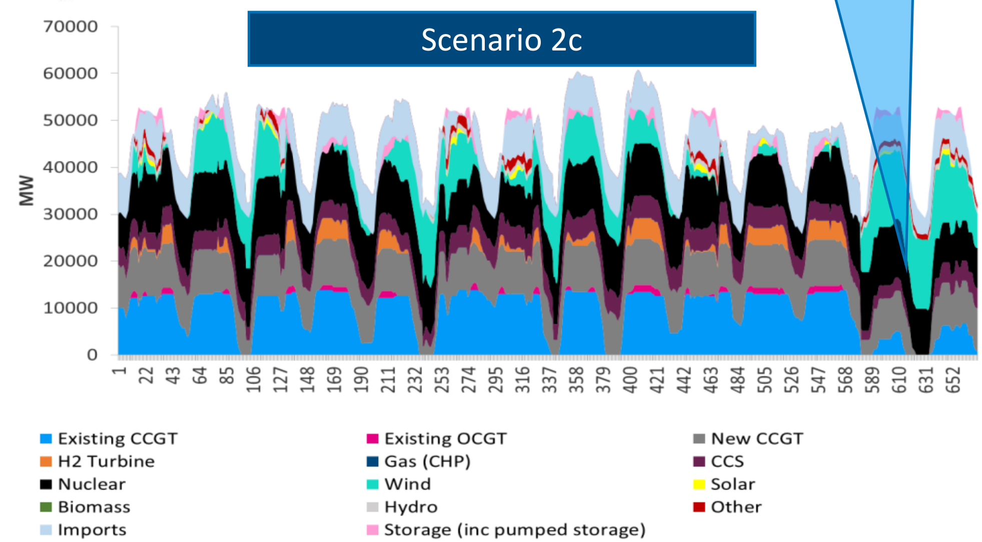


Generation from H2 turbine decreases significantly with a CO2 price of 35 £/t whereas generation from CCGT/OCGT increases

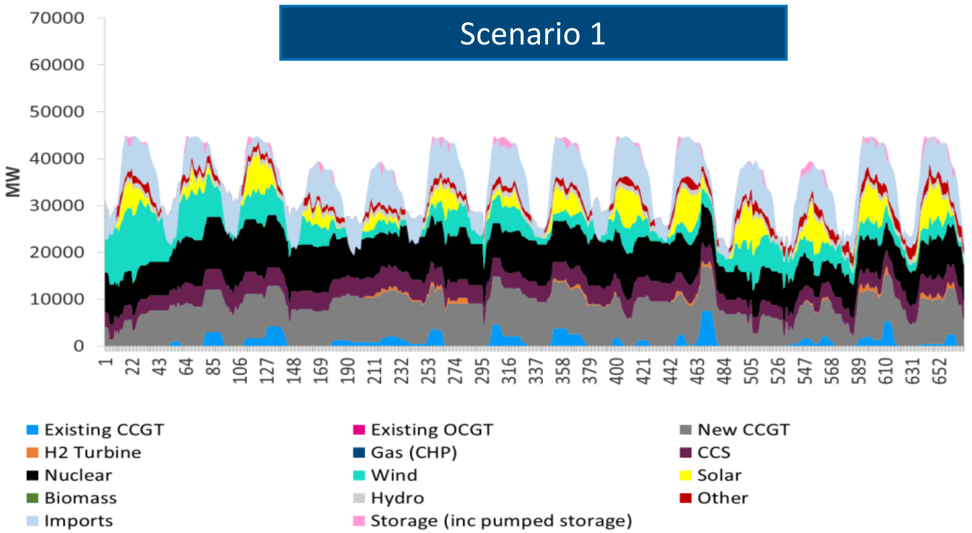
This scenario shows the impact of the two conflicting effects on H2 GT and CCGT CCS generation: lower gas and carbon prices. Overall generation levels are similar to scenario 1

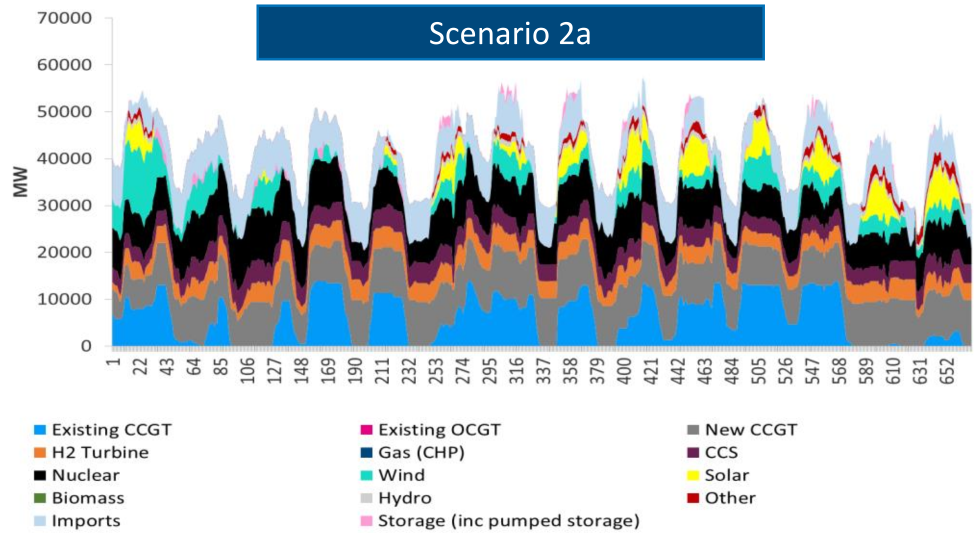


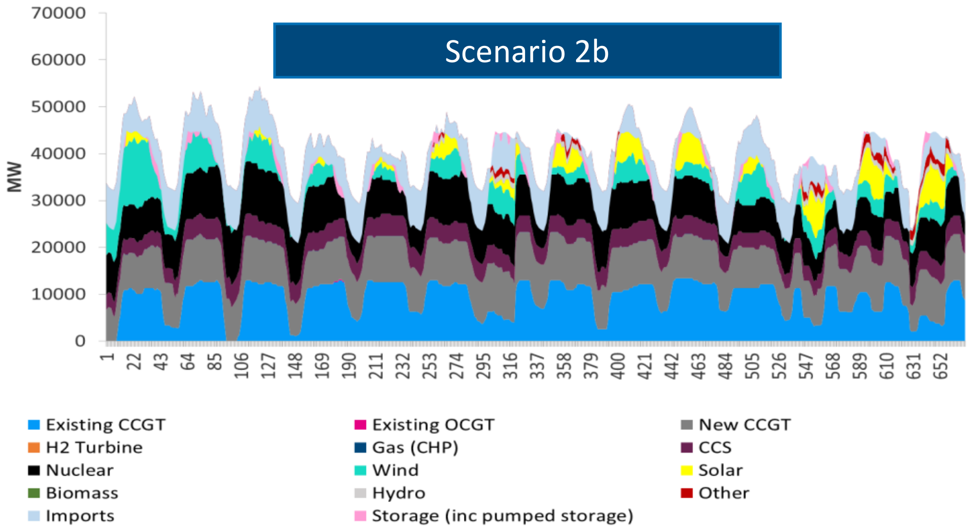


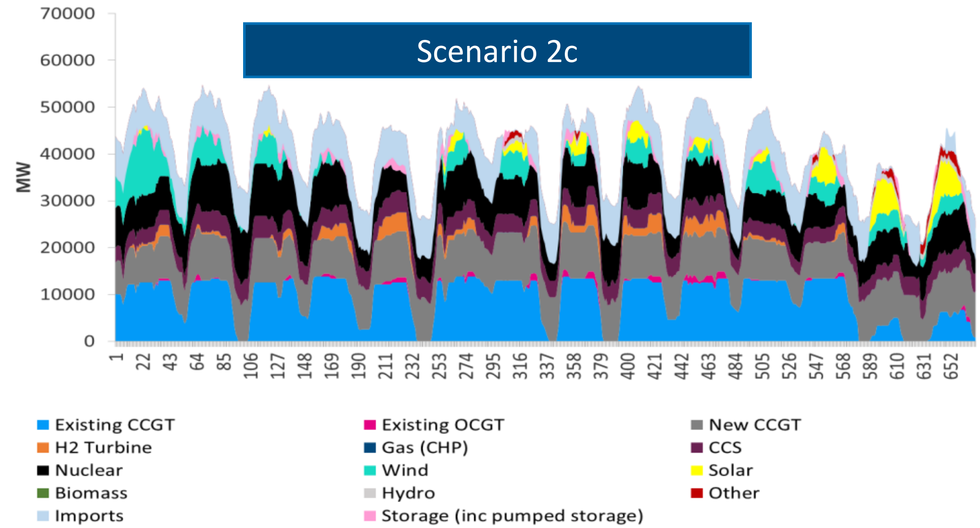
Generation dispatch profile in a summer fortnightly period

Winter fortnightly generation profile from 01/07/2030 to 14/07/2030



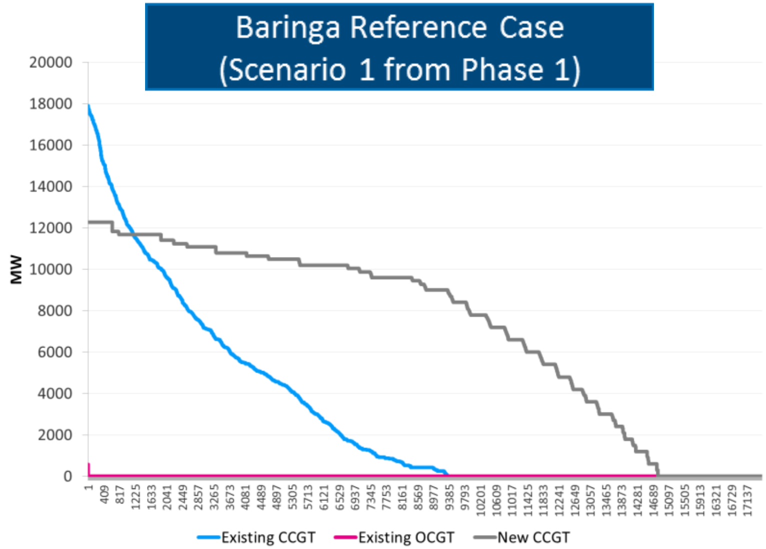


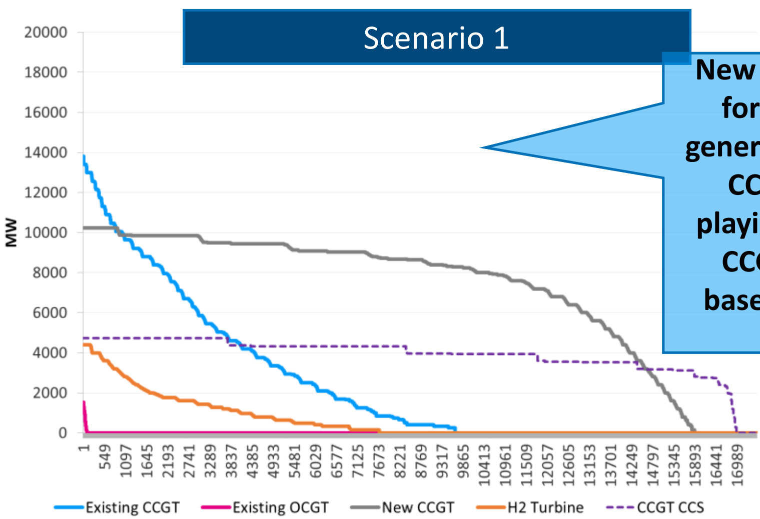




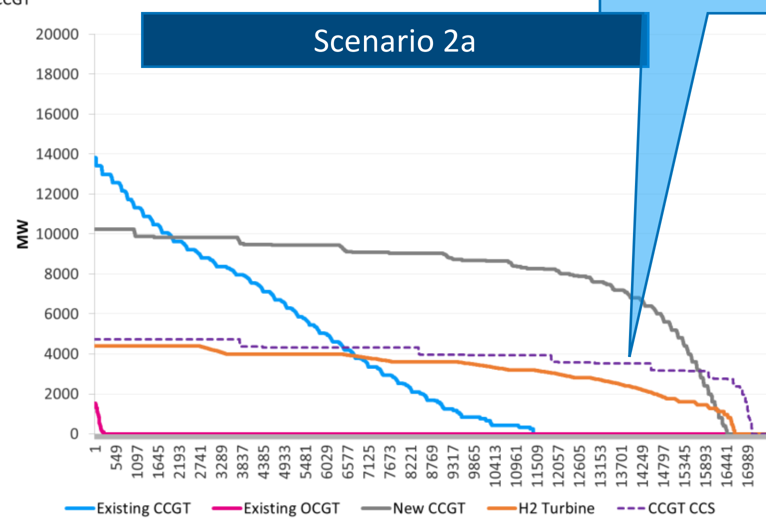
Duration curves for flexible gas generation

Generation duration curve of flexible gas generation in 2030





New CCGTs accounting for most of the gas generation with existing CCGTs and H2 GTs playing a peaking role. CCGT CCS provides baseload power in all cases

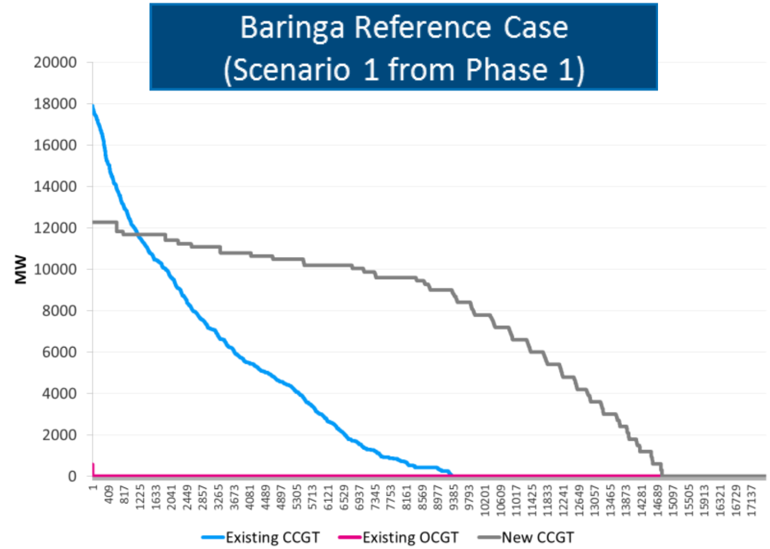


H2 GTs provide almost baseload generation due to the lower gas price

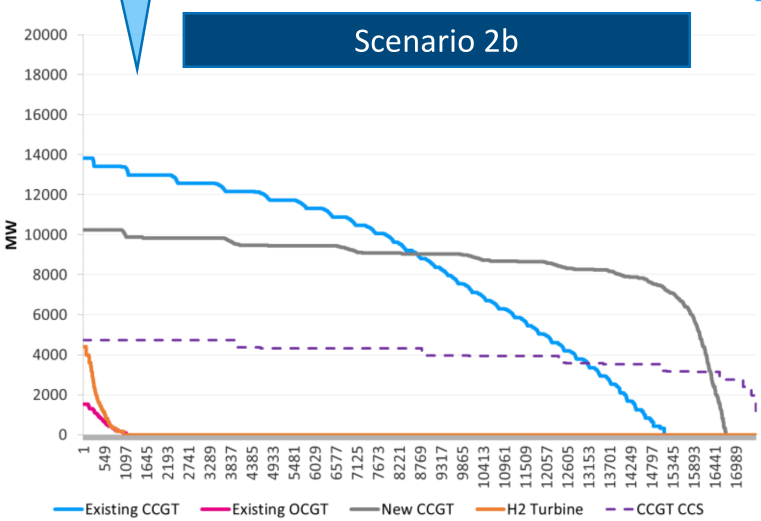
Duration curves for flexible gas generation

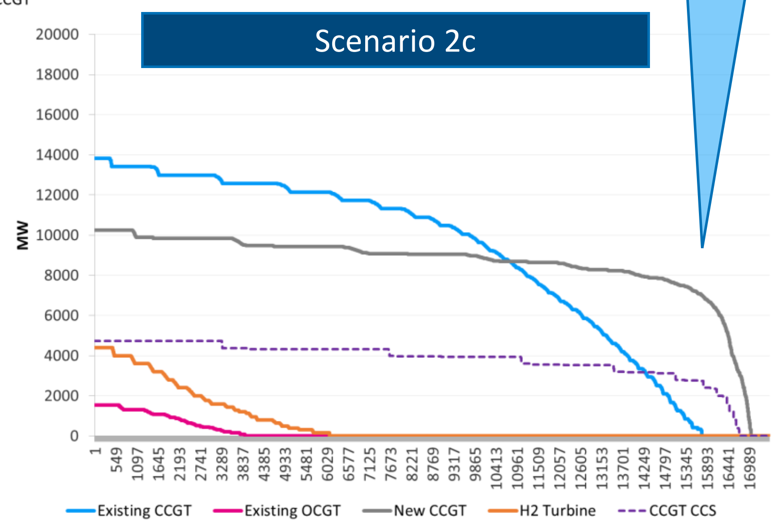
Generation duration curve of flexible gas generation in 2030

Lower carbon price leads to significant increase in CCGT generation, also reducing H2 GT generation significantly



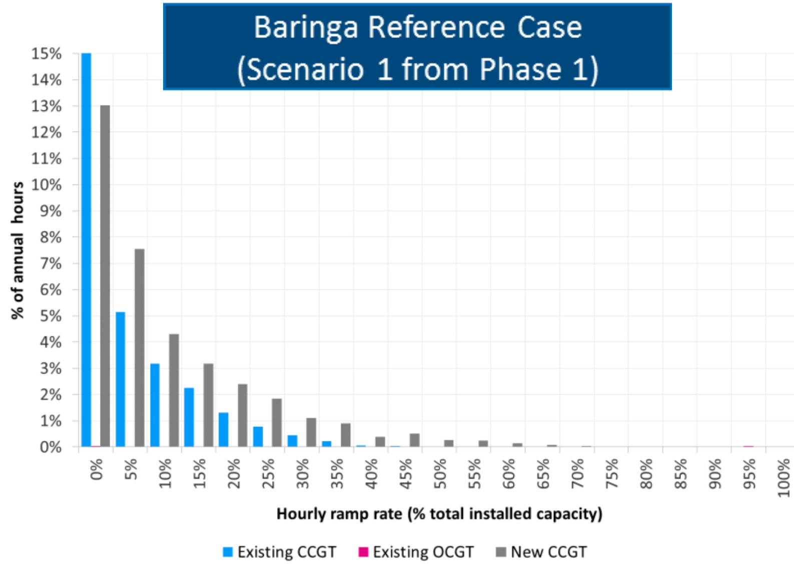
Lower gas and carbon prices increase CCGT/OCGT generation remarkably, with H2 GT and CCGT CCS generation being at similar levels to Scenario 1

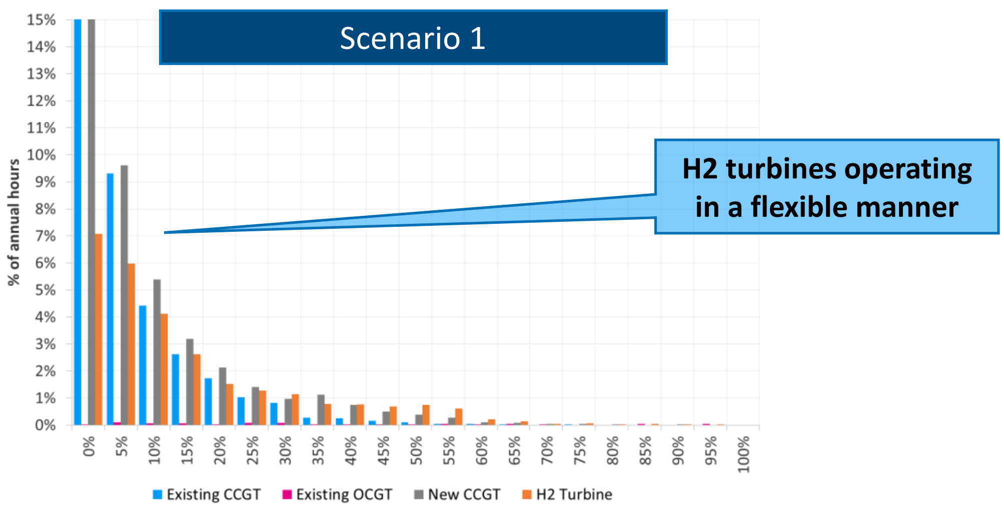


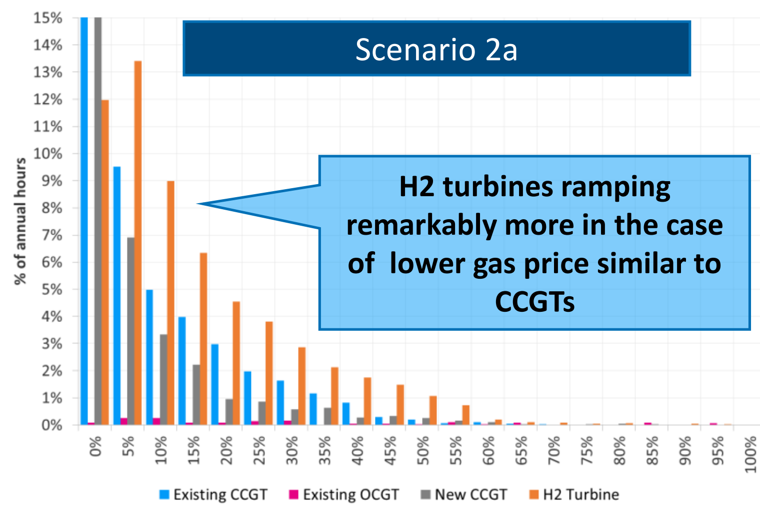


Ramping of flexible gas generation

Ramping as a percentage of installed capacity for flexible generation







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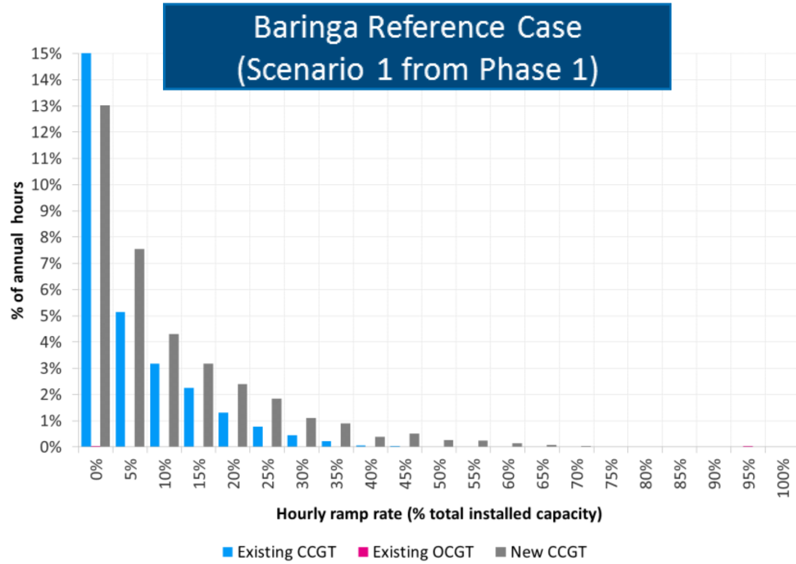
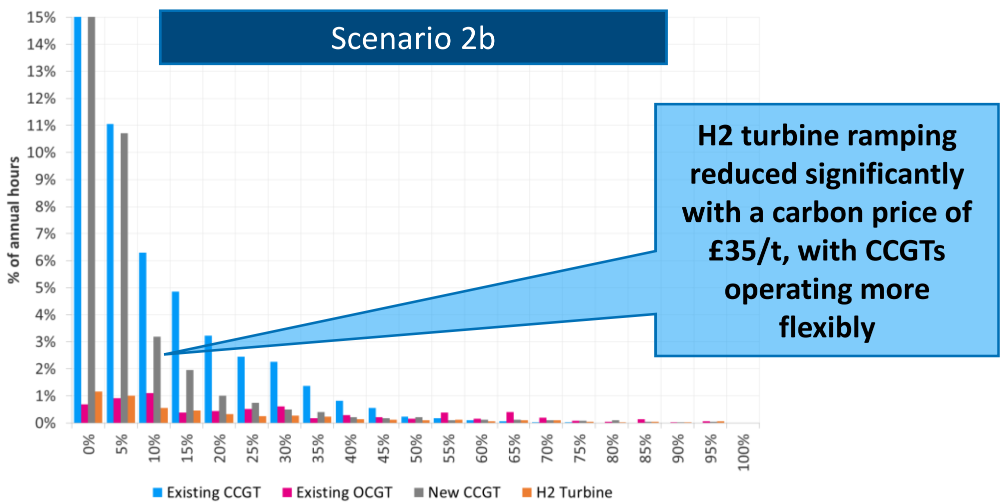
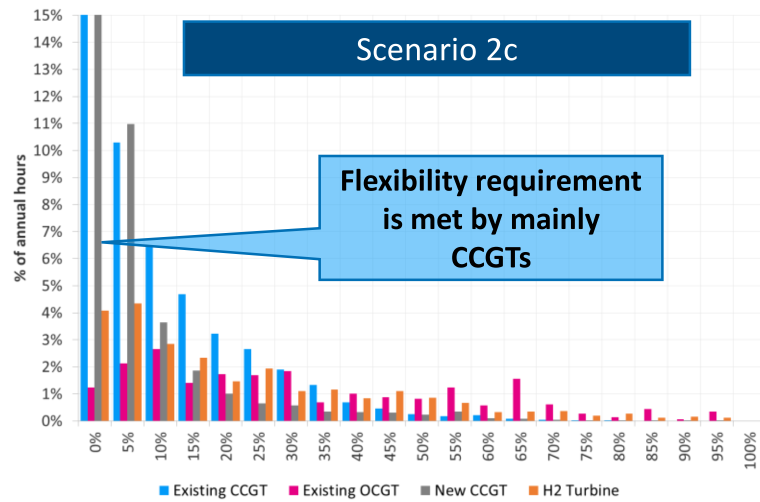


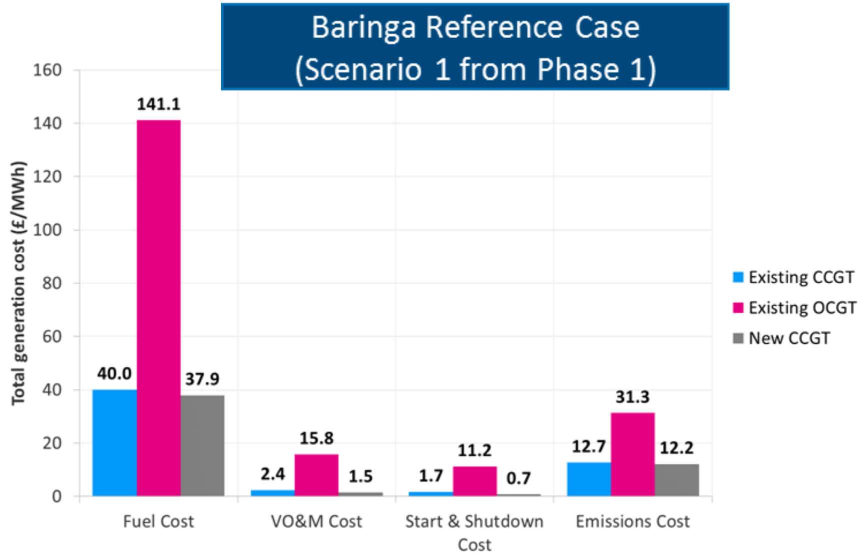




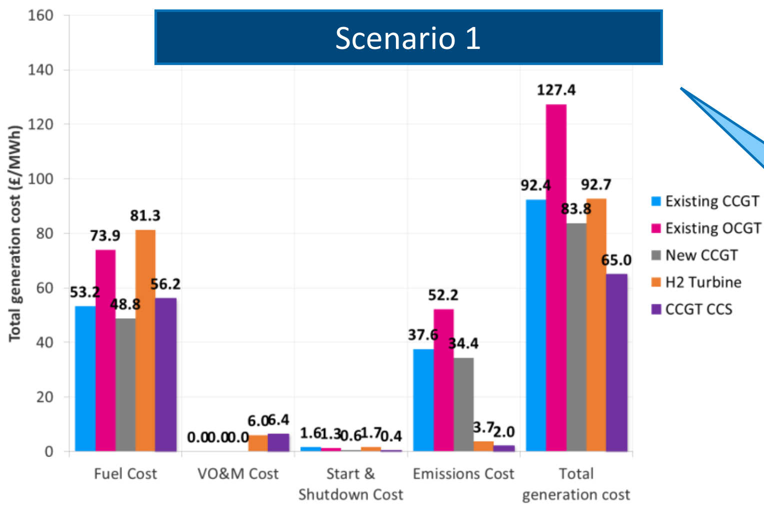
Plant operating costs

Breakdown of operating costs

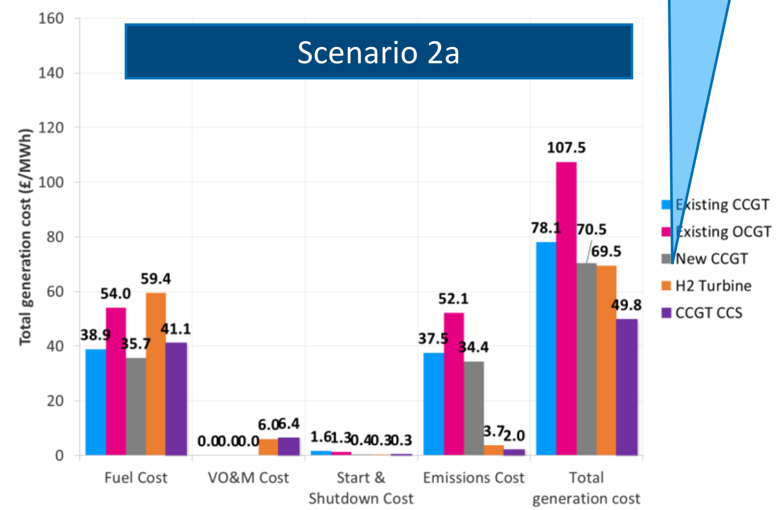
Gas plant type	Baringa Reference Case/ESME efficiency assumptions (HHV)
Existing CCGT	51.5%/52.0%
Existing OCGT	27.0%/37.8%
New CCGT	53.3%/56.5%
H2 Turbine	-/53.1%
CCCGT CCS	45%/48.7%



Fuel costs reduced significantly due to lower gas price, making them similar to emission costs for CCGT/OCGTs. H2 GT turbines are at a similar cost to new CCGTs as a result



H2 GT generation costs at a similar level to existing CCGTs with higher fuel cost and lower emission costs



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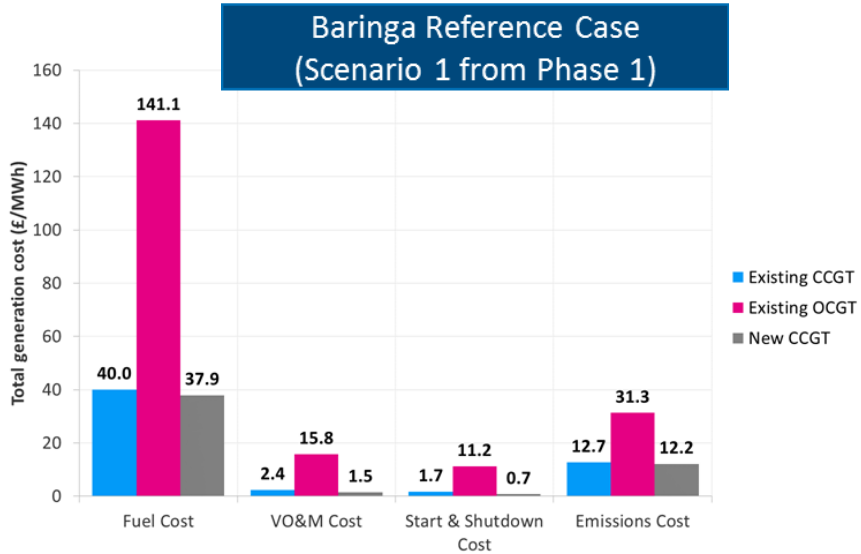
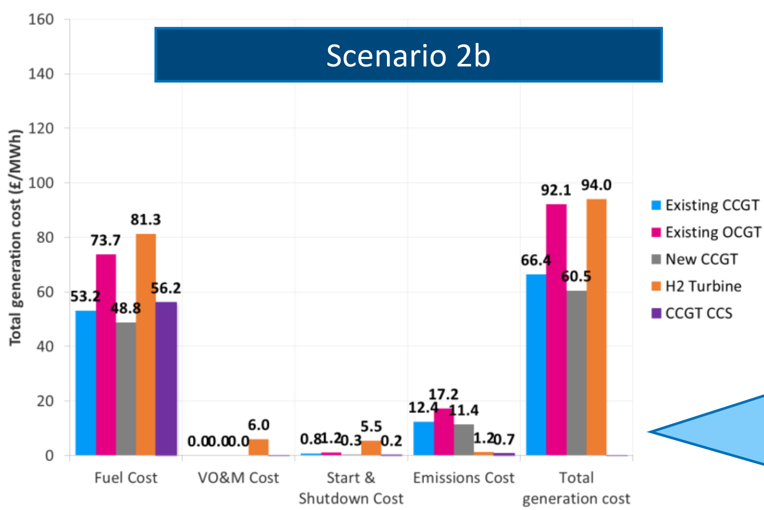
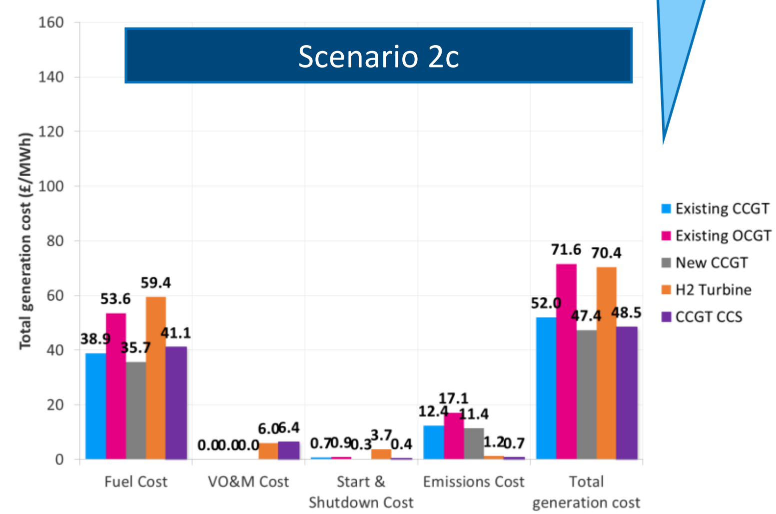


Lower gas and carbon prices make H2 GTs and CCGT CCS less cost competitive compared to CCGT/OCGTs



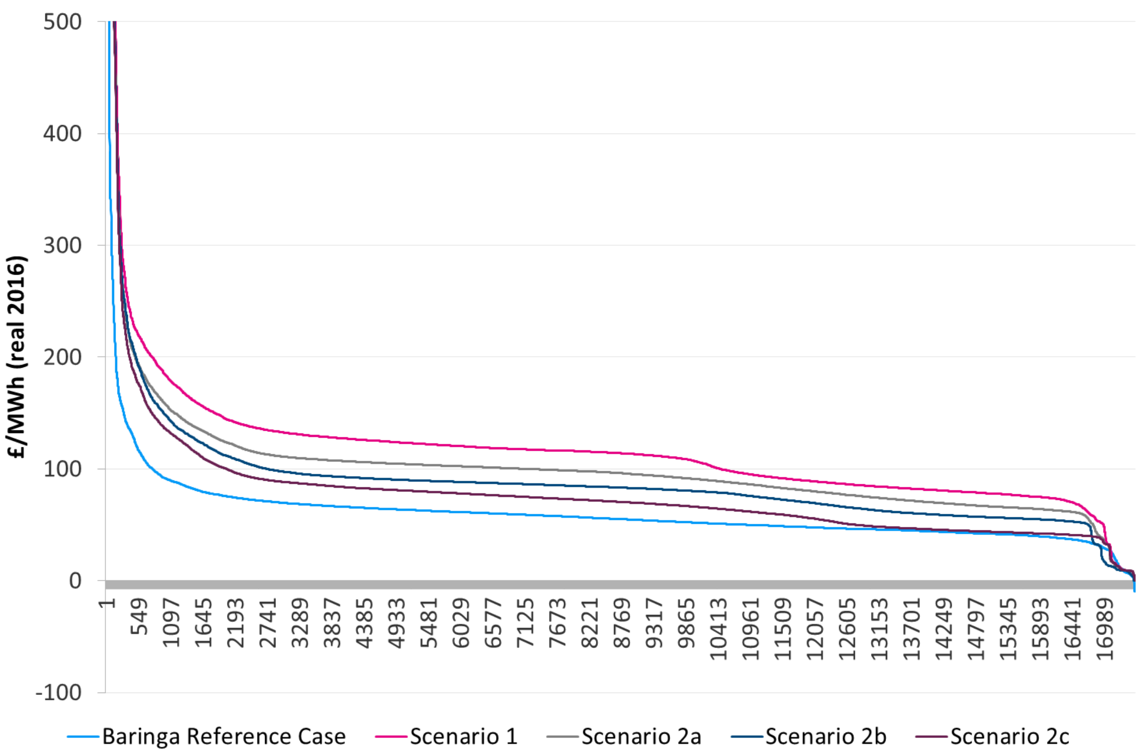
The net generation cost for CCGT CCS is negative due to subsidy level (95 £/MWh) represented as negative VOM



Comparison of GB price duration curves

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

- The comparison of the price duration curves for GB in 2030 is shown below. The higher commodity prices and tighter margin under the ESME assumption lead to significantly higher prices overall compared to Baringa Reference Case (scenario 1 from Phase 1).
- No negative prices are observed (Scenario 2b) or are very limited in any of the cases with output-subsidies (Baringa RC).

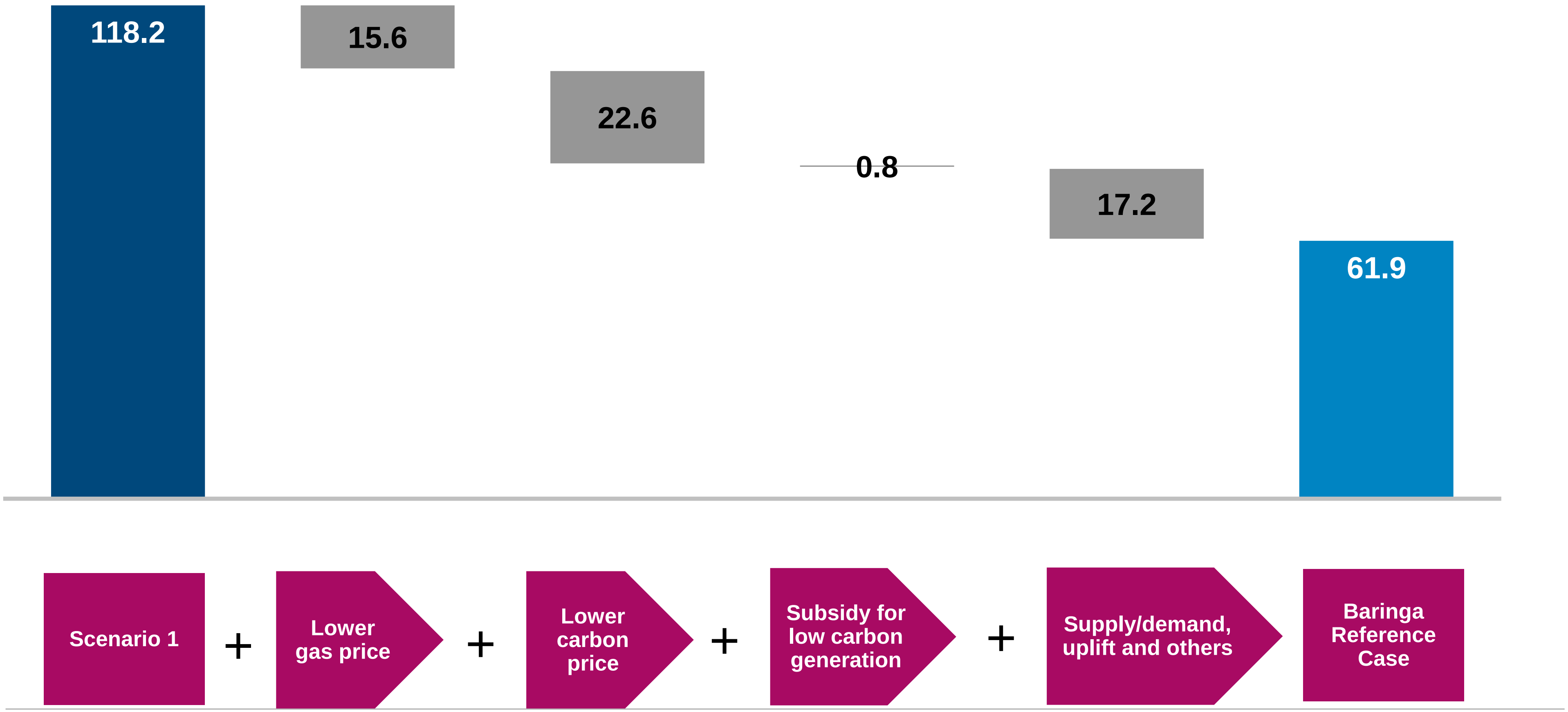


Scenarios	GB time weighted price in 2030 (£/MWh)	Carbon intensity of power generation (g CO2/kWh)
Baringa RC	61.9 (~35-72 range across scenarios)	147.9
Scenario 1	118.2	94.9
Scenario 2a	102.6	103.0
Scenario 2b	91.4	136.3
Scenario 2c	79.9	141.6

Impact of the differences in assumptions on power price

Commodity prices explain ~2/3 of the difference between the Baringa RC and ESME scenarios, however the impact of tighter capacity margin for the ESME fleet is material

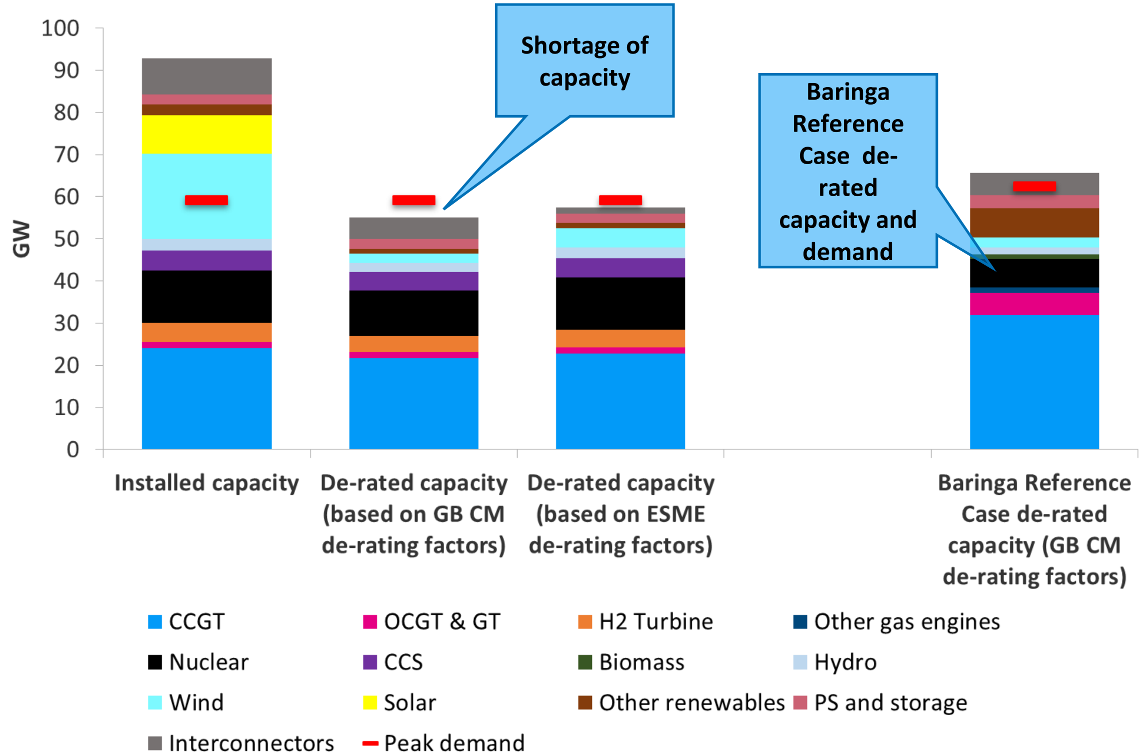
- The tighter average ESME capacity margin drives significantly more periods where uplift/scarcity pricing occurs (given a historically calibrated relationship), this has implications for the choice of market scenario used for subsequent asset valuation analysis
- The impact of subsidy for low carbon generation is insignificant at the market level.



CM analysis

The total de-rated ESME fleet indicates maximum clearing price level due to tight capacity margin

- The ESME fleet result in a de-rated capacity margin of -7% in 2030 including interconnector capacity based on the public GB CM de-rating factors. Based on a targeted level of 3.4% domestic margin, this would indicate lack of capacity in the capacity market and hence the clearing price would be capped at the maximum 75 £/kW
- Some additional thermal capacity including CCGT/OCGT could resolve this issue

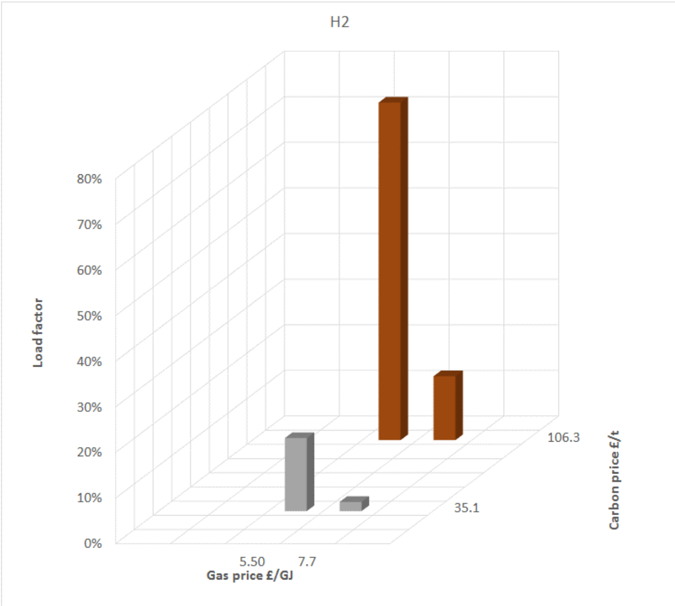


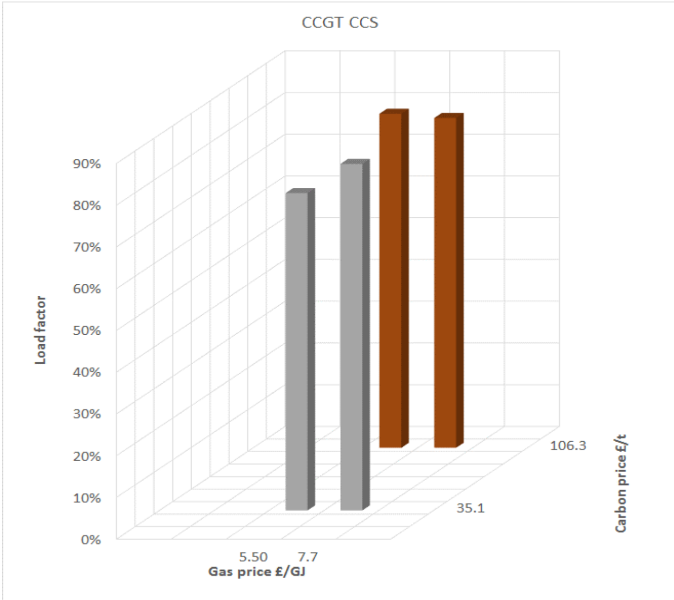
Technology	GB CM de-rating factors	ESME
Nuclear	90.0%	95%
Biomass	86.9%	95%
Existing CCGT	90.0%	95%
CCS	90.0%	95%
Existing OCGT	94.2%	95%
Other	86.9%	95%
Hydro	86.2%	95%
Gas (CHP)	90.0%	95%
Solar	0.0%	0%
Wind	10.0%	22% GW weighted average
Interconnection	60%	17%

Key conclusions and next steps (1)

The results of S1 and S2 will be used to inform the final S3 market runs which will then be the basis of the subsequent asset valuation analysis

- Plant operation
  - H2 turbine is highly sensitive to gas and carbon prices (more so to gas price)
  - CCGT CCS generation is far less sensitive and provides baseload power most of the time across the scenarios tested
    - Note the £35.1/tCO2 and 7.7 £/GJ case has an output subsidy on CCS hence load factor is slightly higher
- Power prices
  - ESME fleet capacity margin is tight – CM clearing price cap hit and significant scarcity/uplift in wholesale prices
  - Subsidies for low carbon generation not having material impact on power prices (limited impact on CCGT CCS LF)





** Scales broadly indicate same relative change in gas vs carbon price*

Key conclusions and next steps (2)

Need to review ESME fleet scenario first before finalising key scenario 3 market run

- Choice of final wholesale market scenario and ESME fleet is important as this will form the basis for asset valuation
  - Drives asset dispatch against market prices
  - Impacts CM clearing price (combination of de-rated capacity and revenues from wholesale market impacting bids)
  - Potential changes to ESME run for scenario 3, before re-running PLEXOS

- Suggest using Baringa commodity prices in ESME (based on recent IEA WEO publication) as more recent than ESME(?)
  - Continue to use ESME output carbon price, but noting that real 2030 policy incentive could be significantly lower
- Initial CM analysis based on ESME fleet suggests capacity is 'too tight' pushing up CM clearing and wholesale prices, need to revisit peak margin constraint in ESME to ensure more capacity is built – two parts to this:
  - De-rating factors in ESME more optimistic compared to GB CM factors (except for interconnectors), but haven't been updated for a while (?), question about whether to use BEIS CM numbers?
  - Reserve margin constraint currently 15% above peak demand, but this needs to covers a range of factors which may not all be included or have different underlying assumptions
    - Current constraint only against end-use demand – needs to include distribution/transmission losses ~6.5%
    - Account for mark-up between ESME timeslice blocks to ½ hour peak (~7 % delta in current scenarios)
    - Actual reserve margin target (3.4% current CM target, although this may change in future)
    - Largest infeed loss (currently ~900MW but expected to increase to e.g. 1600 with new nuclear)

- **Timescales**
  - Need to have fully finalised scenario 3 wholesale market run (potentially different spot years of same mix) by early in w/c 20th to ensure sufficient time for asset analysis, but ideally bring this forward

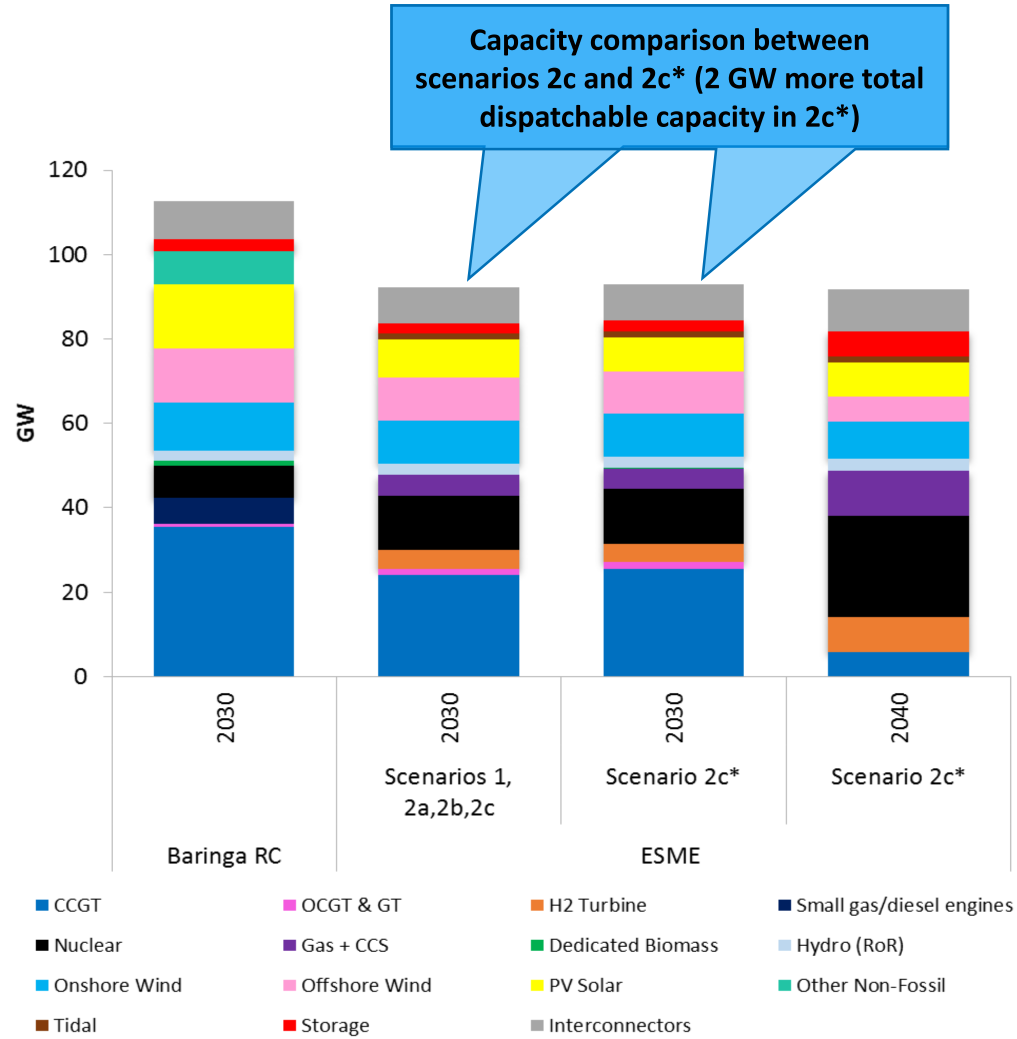
Additional scarcity uplift sensitivities

Scarcity uplift sensitivity

Baringa

Re-running ESME with GB CM de-rating factors (all else being the same as scenario 2c) implies a less tighter capacity margin

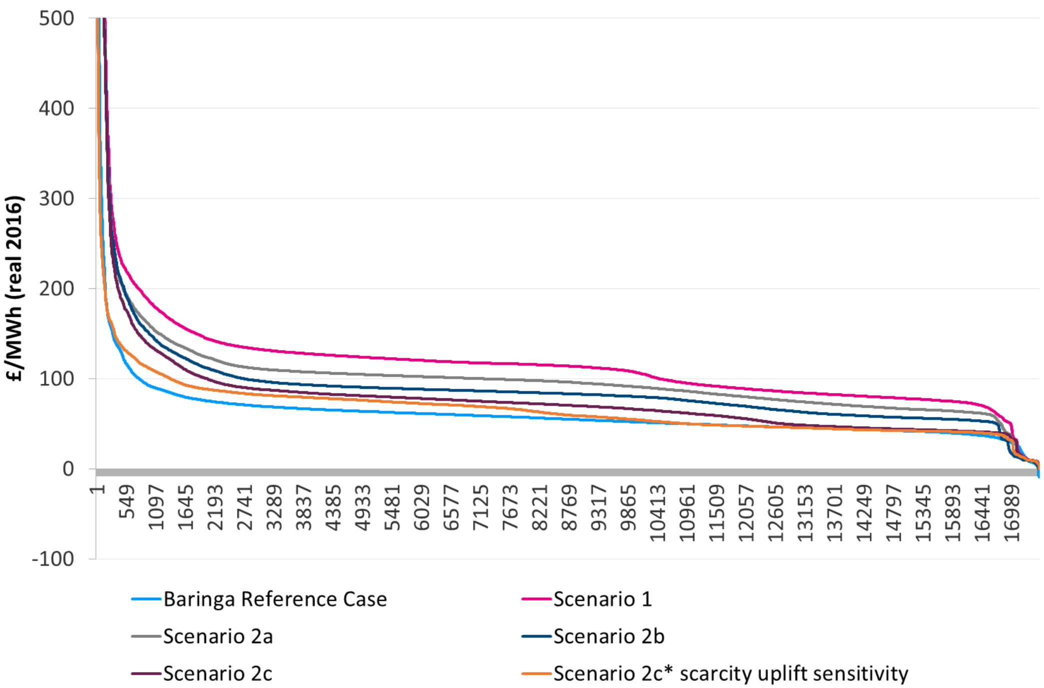
- We have re-run ESME based on the GB CM de-rating factors which are generally lower than the ESME de-rating factors. This also included the following changes in the peak reserve margin constraint:
  - Added losses
  - Added 1.6 GW infeed loss
  - 7% uplift from ESME time slice to 1/2 hour peak
  - 3.4% target margin derated margin
- As a result, the capacity mix for the 2c* scarcity uplift sensitivity (based on scenario 2c commodity prices which come from Baringa Reference Case) is less tight than scenario 2c as shown on the right.
- The new ESME CO_2 shadow price for scenario 2c* is only slightly lower than 2c: 104.6 £/t compared to 106.3 £/t
- We have then run the scarcity uplift sensitivity in Plexos to be able to isolate the impact of scarcity value on GB price and gas plant dispatch further. The following slides show the results from the sensitivity compared to scenario 2c and other cases where necessary
- The new capacity mix and demand in this sensitivity implies a CM clearing price of less than £10/kW



Comparison of GB price duration curves

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

- The uplift sensitivity results in a decrease of 13.2 £/MWh in the GB annual power price compared to scenario 2c. This implies the impact of scarcity value. The remaining 4£/MWh from the 17.2 £/MWh shown on the waterfall chart on slide 18 can be explained by differences in technical uplift (recovery of start and no-load costs) and other assumptions
- There are less high price periods in the sensitivity compared to scenario 2c as can be seen below from the price duration curves

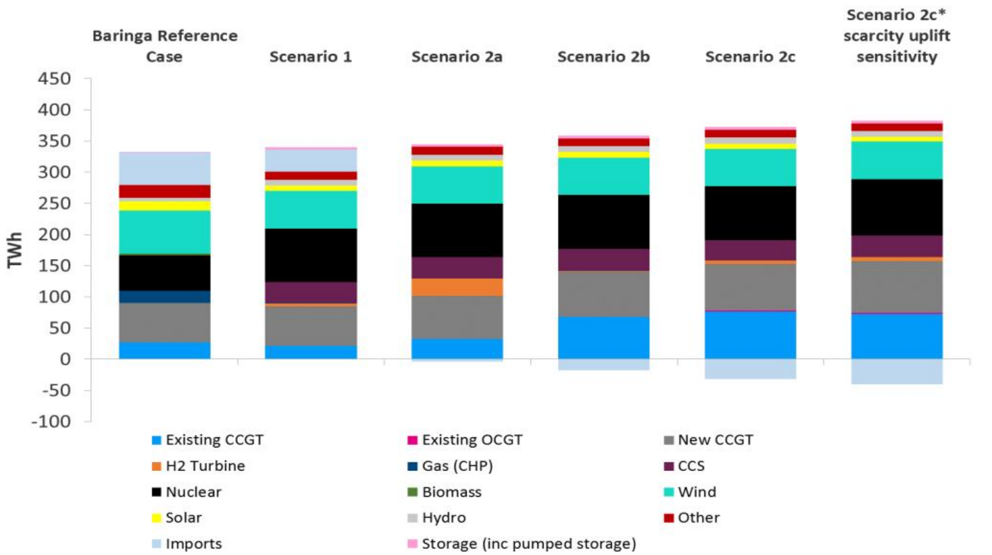


Scenarios	GB time weighted price in 2030 (£/MWh)	Scarcity uplift in 2030 (£/MWh)	Carbon intensity of power generation (g CO2/kWh)
Baringa RC	61.9 (~35-72 range across scenarios)	5.4	147.9
Scenario 1	118.2	13.7	94.9
Scenario 2a	102.6	13.3	103.0
Scenario 2b	91.4	13	136.3
Scenario 2c	79.9	12.5	141.6
Scenario 2c* scarcity uplift sensitivity	66.7	4.4	142.2

Gas generation in the power mix

2030 Generation mix overview across scenario

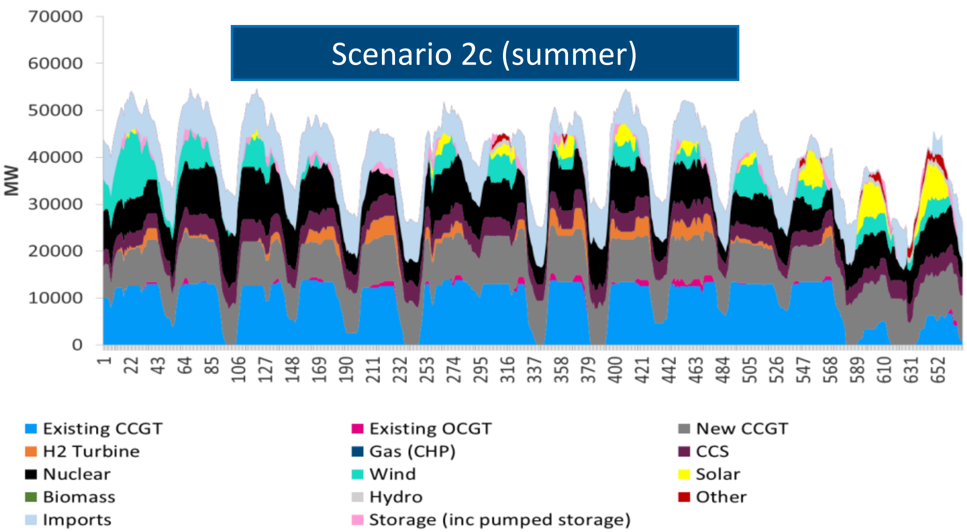
- The generation mix in 2c*uplift sensitivity is similar to scenario 2c with a slight decrease in H2 turbine, existing and new CCGT and existing OCGT load factors
- This decrease in the gas plant load factors is mainly due to the reduced scarcity value as a result of the higher capacity margin in the case of sensitivity
- CCGT CCS provides baseload power as in the case of scenario 2c

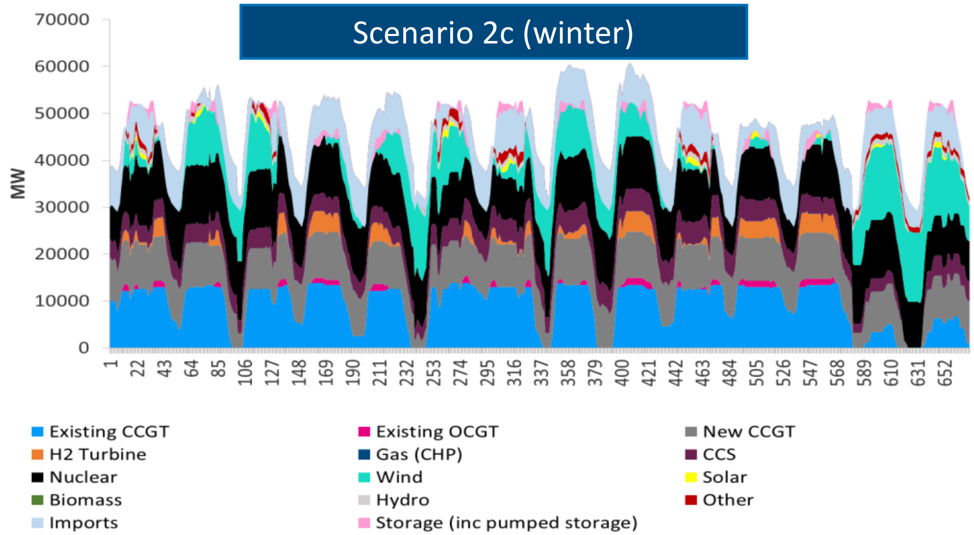


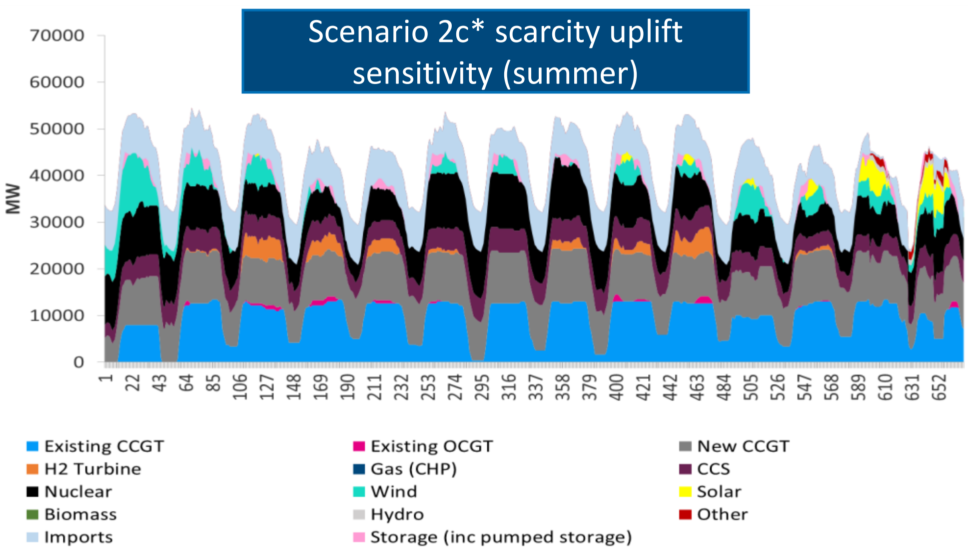
	Scenario 1	Scenario 2a	Scenario 2b	Scenario 2c	Scenario 2c* scarcity uplift sensitivity
Generation (TWh)					
CCS	33.9	34.1	35.3	32.6	34.3
H2 Turbine	5.4	28.1	0.9	6.1	6.8
Existing CCGT	21.7	32.3	67.5	76.2	72.6
New CCGT	62.5	68.8	72.9	74.3	83.0
Existing OCGT	0.0	0.1	0.4	1.7	1.5
Load factor (%)					
CCGT CCS	79%	80%	83%	76%	77%
H2 Turbine	14%	74%	2%	16%	14%
Existing CCGT	18%	27%	56%	63%	60%
New CCGT	70%	77%	81%	83%	81%
Existing OCGT	0%	1%	3%	13%	11%

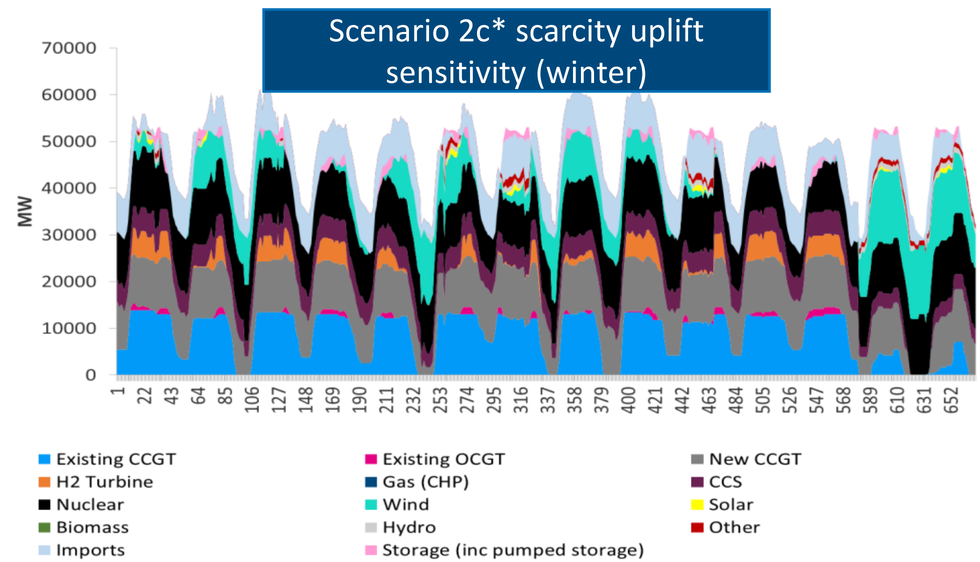
Generation dispatch profile in a fortnightly period

Winter and summer fortnightly generation profile



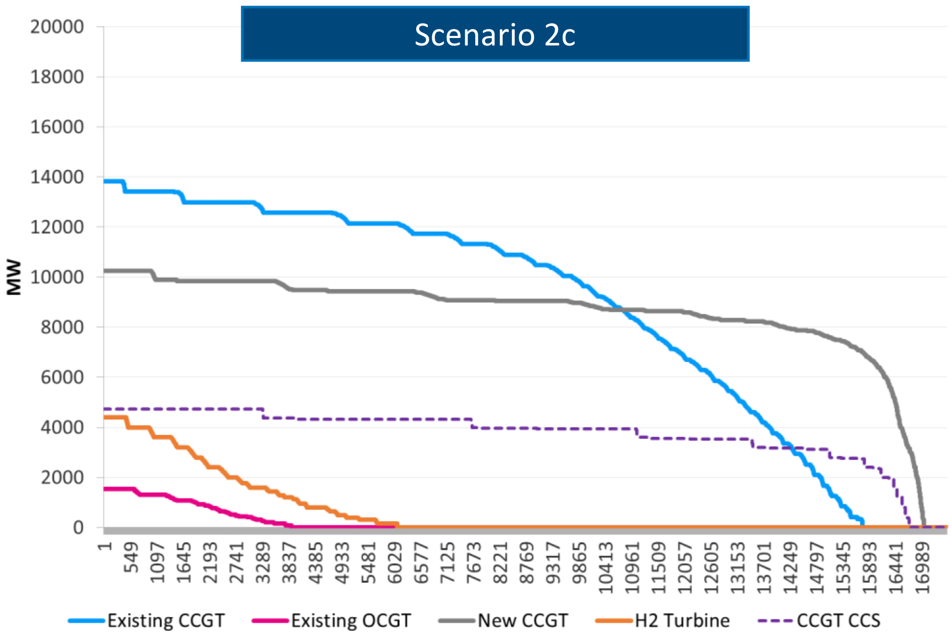


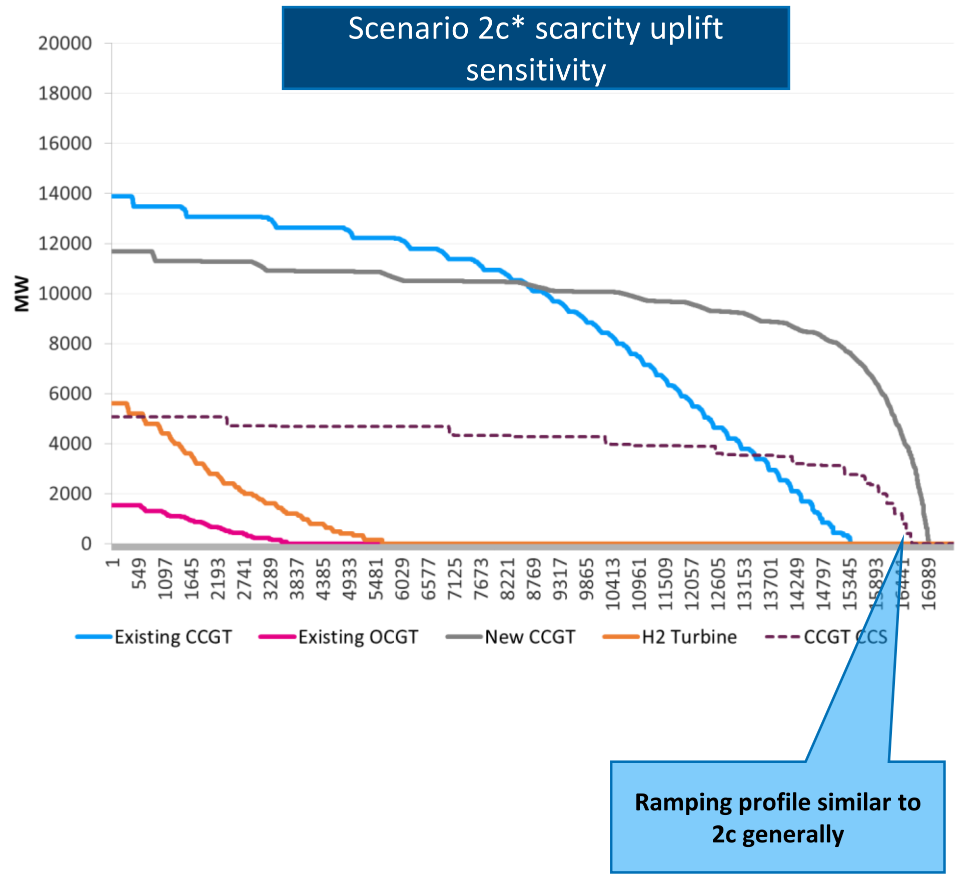




Duration curves for flexible gas generation

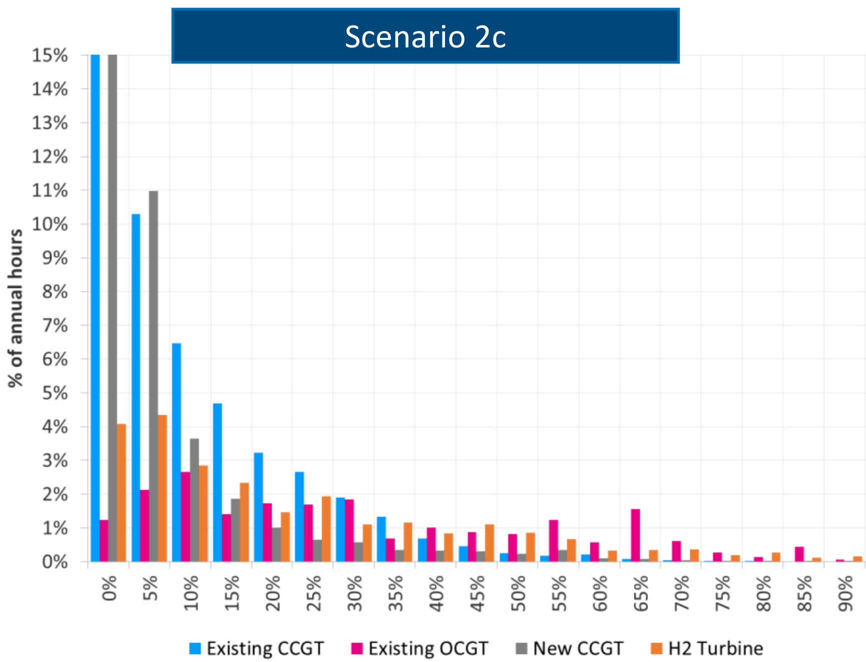
Generation duration curve of flexible gas generation in 2030

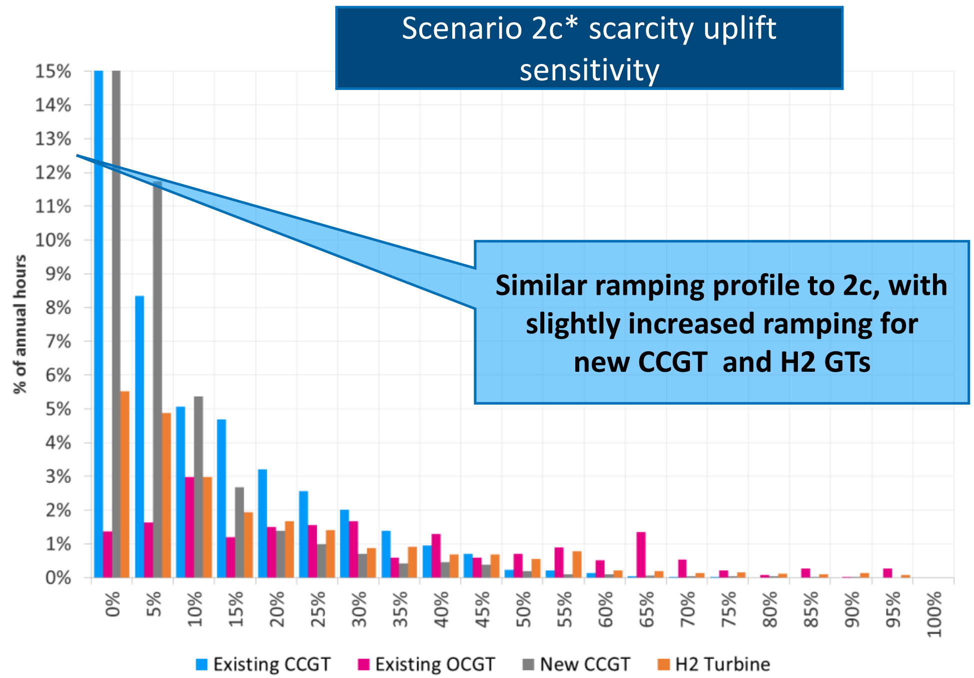




Ramping of flexible gas generation

Ramping as a percentage of installed capacity for flexible generation

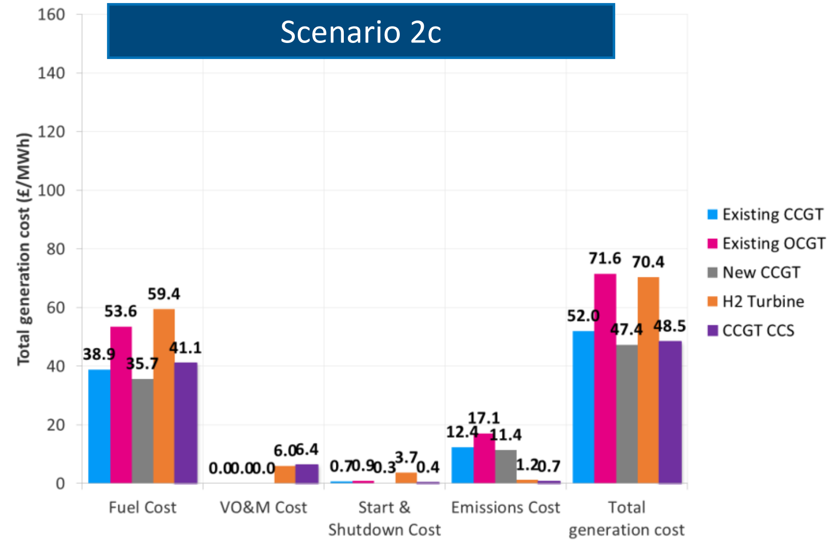


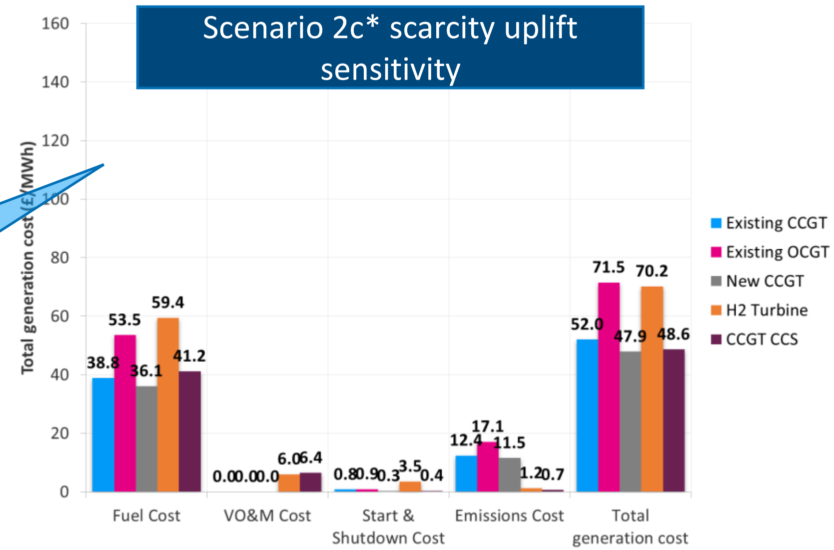


Plant operating costs

Breakdown of operating costs

Gas plant type	Baringa Reference Case/ESME efficiency assumptions (HHV)
Existing CCGT	51.5%/52.0%
Existing OCGT	27.0%/37.8%
New CCGT	53.3%/56.5%
H2 Turbine	-/53.1%
CCCGT CCS	45%/48.7%



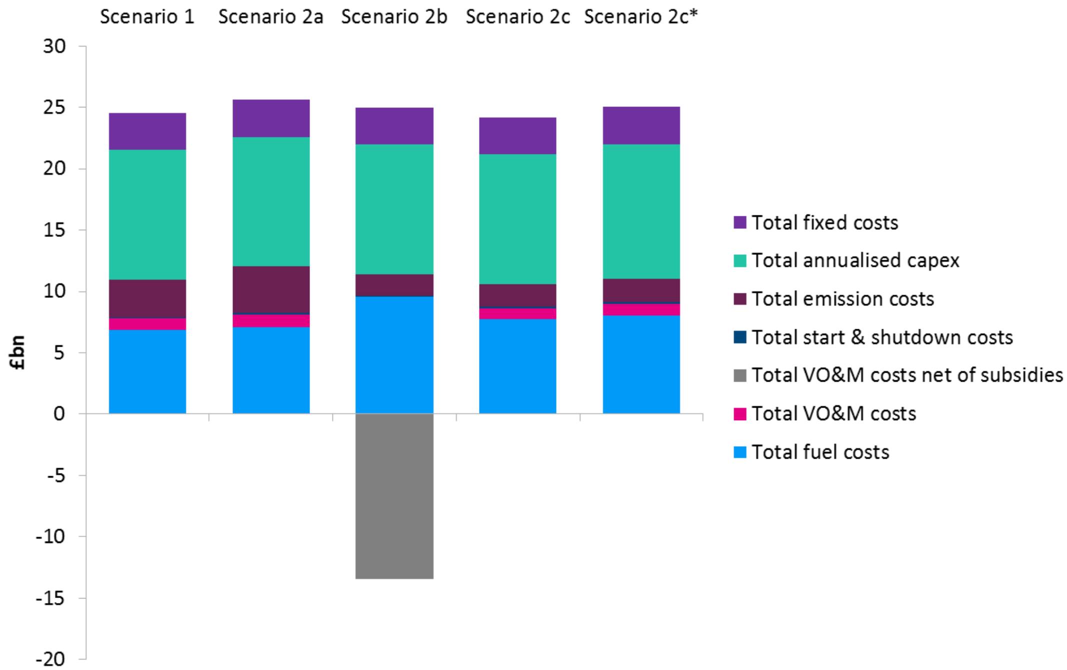


Total generation costs are very similar to scenario 2c due to the same commodity prices in both cases (based on Baringa Reference Case)

Total system costs

Total system costs account for total running costs, annualised capex and fixed costs

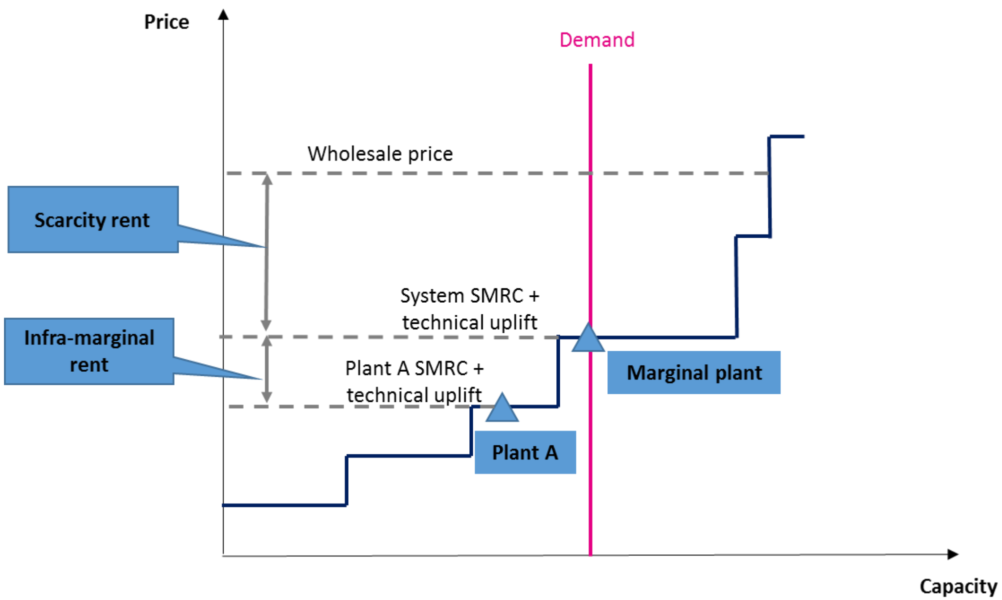
- The chart below shows the total system costs in the five cases in 2030. Total running costs (including fuel, VO&M, emission and start & shutdown costs) are a result of our market modelling and total annualised and fixed costs are taken from ESME
- Total system costs are similar across all cases apart from scenario 2b, where there is a significant reduction in the total running costs due to subsidies for eligible low carbon generation. The effect of the subsidies in this case has been shown as 'VO&M costs net of subsidies' below (grey bar) as these subsidies are modelled as negative VO&M costs in our modelling



APPENDIX

Price setting

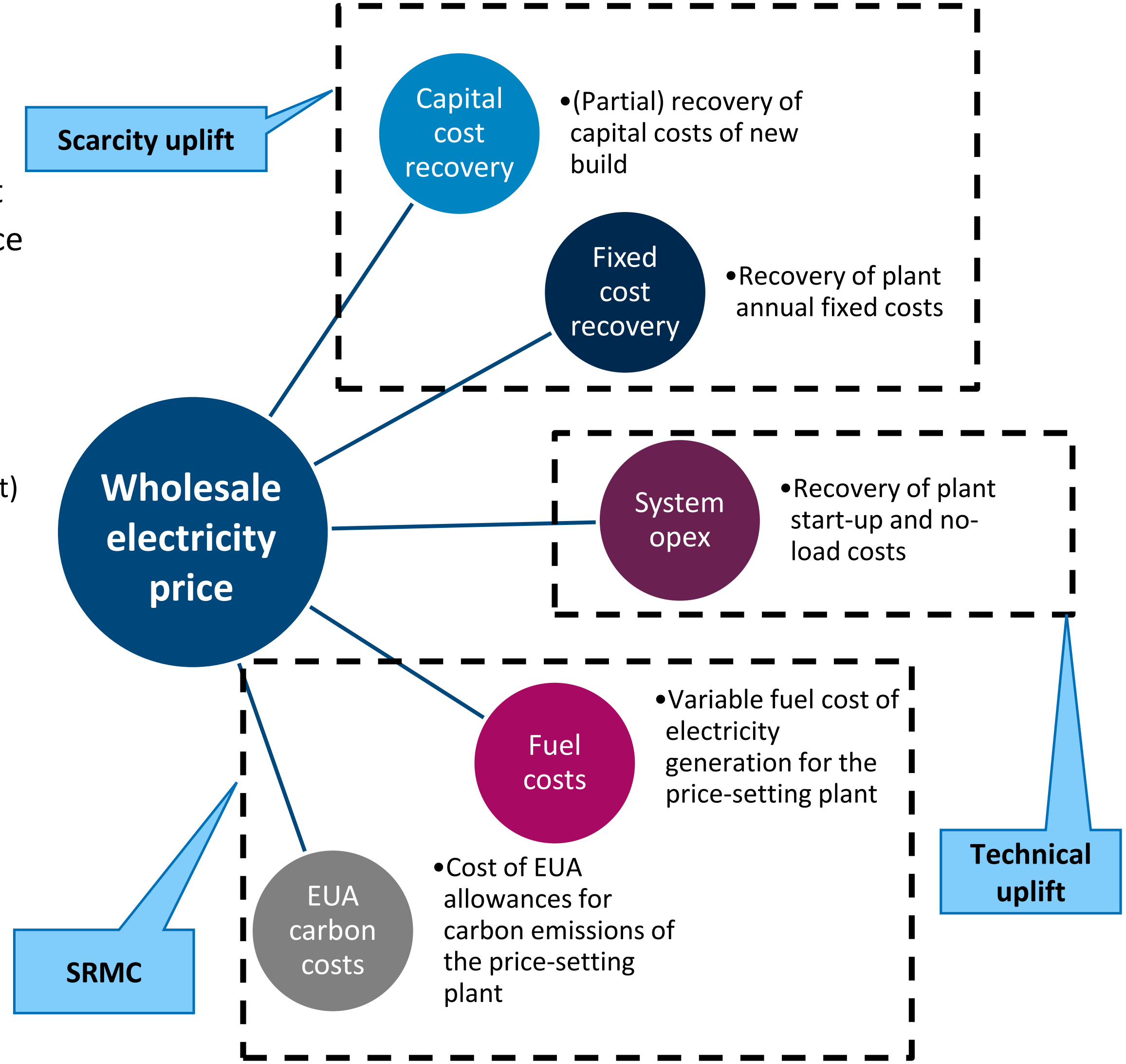
- The system short run marginal cost (SRMC) is the marginal cost of the marginal generation unit in each hour
- Plant with lower SRMC + technical uplift than the marginal generation unit will earn profit termed ‘infra-marginal rent’ which is the difference between their SRMC and technical uplift and system SRMC and technical uplift
- ‘Scarcity rent’ is added to the system SRMC and technical uplift 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



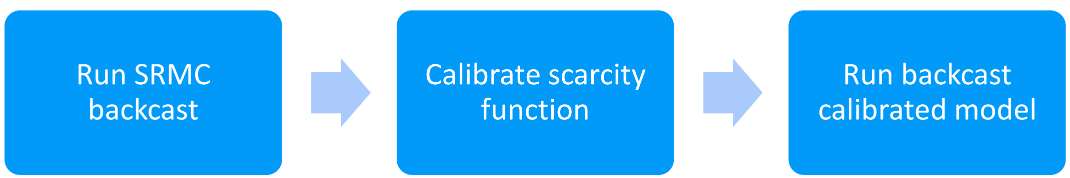
Model backcast and calibration

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

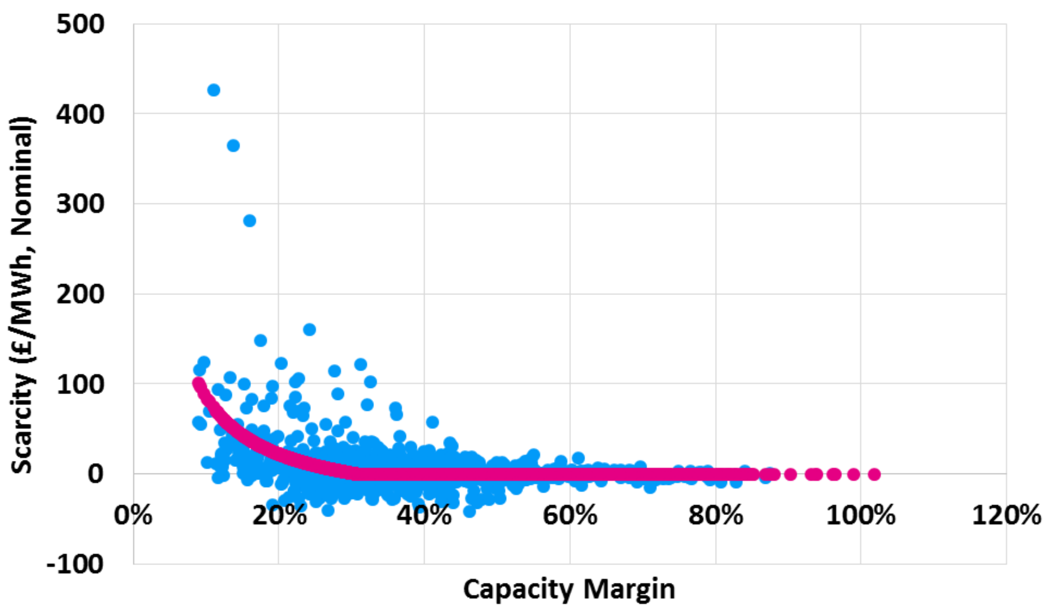


- At the beginning of 2016, we re-calibrated our scarcity function based on historical data covering the period January 2009 – December 2015. Some results of this calibration are presented in the following slides

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

Baringa