

# **Dynamics of GB Generation Investment**

## **Detailed Analysis**

July 2006

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# I. Background

# 1.1 Background – Objectives of Energy Review

## Key questions for the Energy Review:

- What more could Government do in the energy sector to ensure that the long term UK carbon reduction goal is met?
- What are the implications of increasing energy imports?
- Are there particular considerations which affect nuclear?
- Are there particular considerations which affect carbon abatement and other low-carbon technologies?
- What should be done to ensure every home is adequately and affordably heated?

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## 1.2 Background – Objectives of study

1. To analyse expected investment behaviour in the electricity market under different scenarios in the period 2006-2020 assuming 'Status Quo' energy policy
2. To identify alternative policy options which might be applied and assess their effects relative to the Status Quo against the following cost/benefit metrics:
  - Total generation costs
  - Total costs to consumers
  - CO<sub>2</sub> emissions
  - Security of supply
  - Generation diversity
3. To draw conclusions relevant to the Energy Review

## 1.2 Background – Study: Notes

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### Study scope

- In total 4 policy options were analysed in addition to the Status Quo under 5 different scenarios. This gave a total of 25 different policy option/scenario combinations.
- The choice of key metrics for evaluating the policy options relate to the objectives of the Energy Review. Additional indicators surrounding the performance of the different policy options are provided in the analysis.
- The main focus of the analysis was on baseload investment. The issue of investment in peaking plant is addressed on a qualitative basis.

### Document outline

- The remainder of this document is structured as follows:

**Section 2:** outlines issues facing investors in the market

**Section 3:** presents the policy options that were chosen to address potential concerns surrounding security of supply, generation diversity and CO<sub>2</sub> emissions

**Section 4:** describes the modelling methodology, scenarios and key input assumptions

**Section 5:** presents the results of the analysis and the cost/benefits of different policy options

**Section 6:** presents the results of analysis on sensitivities to the policy options

**Section 7:** presents the conclusions of the study

## 2. Issues facing investors

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## 2.1 Issues facing investors - overview

- Uncertain returns
  - No liquid long term market to offset risk
  - No clear winner in fuel pricing (but CCGT can pass on most risk to the market)
  - Load factor risk on new plant
  - Uncertain demand levels
  - Policy risks (CO<sub>2</sub>, planning, Government initiatives)
- Potential for generation capacity shortfall after 2015
  - Closure of plant under Large Combustion Plant Directive (LCPD)
  - Possible nuclear closures
  - Growing proportion of intermittent renewables in the capacity mix

## 2.1 Issues facing investors - overview: Notes

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### Issues facing investors

Investment decisions by market participants depend on an understanding of the expected return and associated risk, and the tools available to manage that risk. It can be argued that there are significant issues around each of these areas, seen through the degree of overall market uncertainty, the changing nature of price behaviour, and concerns around liquidity and market structure.

#### *Market uncertainty*

- The level of carbon allowance allocations (European Union Allowances – EUAs) for Phase II of the EU ETS, for both new and existing plant, remains uncertain, as is the future of emissions trading policy thereafter.
- The planning process is lengthy and unpredictable, particularly for potential nuclear plant.
- Market participants are uncertain as to whether the government will bring in measures to encourage new build.
- The approval of Emission Limit Values (ELV) as an option for coal fired stations and the recent decision of an additional 4 GW of plant to opt in to the Large Combustion Plant Directive (LCPD) and fit flue-gas desulphurisation (FGD) will have reduced the near term demand for other investment.

#### *Price behaviour*

- Structural changes and high volatility in fuel prices, and hence power prices, has made an understanding of price behaviour, and a corresponding assessment of risk, more difficult.
- A changed dynamic between gas and coal prices has removed the clear-cut advantage of new entrant plant once enjoyed by CCGTs, leaving potential projects much more exposed to merit order uncertainty.
- A wide divergence of views as to the likely pattern of expected new build (illustrated, for example, by the disparity between 2010 projections from the DTI and NGC) increases uncertainty as to the level and behaviour of future prices.

#### *Liquidity and market structure*

- Liquidity in the wholesale power market has decreased, reducing price transparency, and decreasing the effectiveness of traded instruments as risk management tools.
- Vertical integration has increased, arguably reinforcing the trends in liquidity as companies look to reduce exposure to the wholesale market through more balanced supply and generation portfolios.
- Even within vertically integrated companies, the broad lack of longer term contractual arrangements with customers reduces the effectiveness of a supply portfolio as a natural hedge to a generation position beyond the short term. This is especially an issue for industrial and commercial customers, which make up the majority of total demand and which are not subject to the inertia observed in the domestic market.
- Lack of longer term fuel forward curves leaves participants without tools to hedge fuel risk beyond one to two years out.

## 2.2 Issues facing investors – scarcity

- Little track record of whether scarcity of capacity will bring forward timely investment
  - First dash for gas was strategic and supported by franchise customers
  - Second dash for gas was driven by historically low gas prices
  - Current “dash for FGD” being driven by high gas prices
- Asymmetric risk for investment, based on scarcity alone, to meet I&C demand
  - Over-investment likely to lead to pricing at short run marginal cost (SRMC) levels leading to losses across portfolio
  - Under-investment has limited consequences (simply offer fewer contracts to the industrial and commercial sector in the following year)

## 2.2 Issues facing investors – scarcity: Notes

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### Further comments

- Since large I&C customers shop around on an annual basis (or more frequently) for their electricity, suppliers seek only short term hedges for this part of their portfolio. (The ‘stickier’ domestic and small commercial customers support longer term hedging strategies.)
- The increasing amount of electricity indexation in supply contracts also precludes the requirement for significant forward hedging.
- Currently the large players are able to buy significant quantities of baseload electricity from the likes of British Energy or Drax to service their I&C customers as they secure them.
- As the volume of British Energy’s output decreases with nuclear closures, it is not clear that the vertically integrated players will be willing to replace the baseload capacity through their own investment, given the inherent risk.

## 2.3 Issues facing investors – peak

- Difficult to invest for peaks
  - Dedicated peaking capacity difficult to finance
    - Few (and uncertain) hours where demand peaks – hard to recover capital
    - Plant likely to be out of the money at other times
  - Quantified view would require further analysis
- Traditional process is to invest for baseload
  - Existing written down but older plant is forced to margin because of higher operating costs
  - Process needs new entrant plant to have fuel cost advantage
  - Depends on fuel price scenario; risk to new entrant load factors

## 2.3 Issues facing investors – peak capacity: Notes

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### Further comments

- There are few examples of investment in peaking capacity in the GB market since liberalisation.
- The expected return on investment is based on the expectation of very high prices for a small numbers of hours when the capacity margin is tight. There is no guarantee when, or if, these hours will occur.
- The only open cycle gas turbine (OCGT) constructed in recent years was the Indian Queens plant. A significant proportion of the investment case for that project was associated with locational transmission benefits and the provision of Ancillary Services.
- It is possible that other projects will be financed based on ancillary revenue streams which may provide side benefits for the peak capacity margin.
- The risk for an investor building a peaking plant from purely a merchant perspective is that it is very difficult to manage the risk associated with the asset. Since most of the vertically integrated players have their peak domestic load covered, there may be few takers for buying high priced call options out beyond one or two years.
- In other markets, such as Australia, where vertically integrated suppliers to the domestic market have been short peak cover there have been greater levels of investment in new peaking capacity.
- With high gas prices, the low efficiency of OCGT plant makes them very uneconomic relative to higher efficiency CCGTs. Oil based peaking technologies are similarly disadvantaged in the current world of high oil prices.
- Traditionally, peak cover has been achieved by an influx of new plant built for baseload, driven by fuel price advantages, which has pushed other plant to the margin. The case for keeping open an existing plant is generally easier than that for building new and is currently bolstered by the free carbon allocations.

### 3. Policy options considered

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## 3.1 Policy option overview

- The following policy options in addition to the Status Quo (i.e. no measures) were considered in the analysis:

**Capacity obligation certificates (COCs):** A mechanism similar to the existing Renewables Obligation (RO), designed to accelerate investment in new capacity

**Diversity obligation certificates (DOCs):** A mechanism designed to bring on stream new capacity other than CCGT or renewables

**Nuclear obligation certificates (NOCs):** A mechanism designed to bring on new nuclear plant

**Tendering:** Government or Transmission System Operator tenders for construction of specified quantities of new plant and auctions tolling rights into the market on an annual basis

## 3.1 Policy option overview: Notes

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### Choice of policy options

- The following criteria were used in deciding upon the four policy options to model:
  - The anticipated effectiveness of the policy in delivering the required result
  - The practicality of implementing the policy option
  - The cost of implementing the policy option
  - Minimising the amount of Government intervention required (with the exception of Tendering)
  - Minimising the ability of market participants to game
  - The likelihood of the policy option being raised by stakeholders in the Energy Review
- It was recognised that there are a large number of permutations in the parameters of the selected policy options. It is not within the scope of the study to do detailed analysis on all of these. However, in some cases a qualitative assessment of the probable impact of certain permutations is provided in the Analysis Results section.

## 3.2 Capacity Obligation Certificates (COCs)

- Stimulate investment in new capacity by placing obligations on suppliers to buy capacity rights pro-rata to actual energy sales
- Similar mechanism to Renewables Obligation:
  - COC target set to achieve a specific energy margin (annual available TWhs over annual demand quoted as a percentage)
  - Buy-out price set to provide sufficient incentive to stimulate new build
  - Only new capacity qualifies (including renewables)
  - Plant are rewarded based on proven annual availability
  - The mechanism rolls forward and there is a cut-off period for each plant to prevent the mechanism becoming ‘silted up’ i.e. to prevent further subsidies to plant that have already earned a sufficient return on investment

## 3.2 Capacity Obligation Certificates: Notes

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### Implementation

- It is assumed that generators would qualify for COCs if they could demonstrate a certain level of availability during the year. The exact mechanism for how this would be done is not within the scope of this study.
- This is preferable to awarding COCs to new plant by MWh generated because that approach would mean that new plant could run ahead of old even where fuel and carbon prices would dictate otherwise.
- Focusing COCs on new build has the following considerations:
  - The policy is likely to be cheaper (because eligibility for COCs is much reduced)
  - It would specifically support new investment
  - It could hasten the closure of older existing plant because the earlier build of new plant will reduce returns generally in the generation sector.

### Alternative implementation

- The alternative policy would be to allow COCs for all plant. This has a similar effect to free carbon allocations (with an equal New Entrant Reserve) under EU ETS.
  - COCs for all plant would be likely to create windfall gains for existing generators
  - To the extent that windfall gains were competed away through lower commodity prices, COCs applicable to all plant would be ineffective in promoting investment. This may occur if the required volume of COCs is less than the amount of new build the market would have delivered anyway, or if incumbents used market power deliberately to keep prices below new entry levels.
  - COCs applicable to all plant would however be likely to promote the continued availability of older plant which might otherwise be uneconomic to keep open for the peaks. Quantitative review of this issue is outside the scope of this study. However under the policy option sensitivities we examine the impact of free carbon allocations (which have similar effects to COCs) in subsidising existing plant.

### Parameters used

- Target: 35% energy margin (equivalent to current levels).
- Buy-out price: £12/hr for every MW of installed capacity (calculated per annum assuming baseload operation).
- Cut-off period per plant: 10 years.

### 3.3 Diversity Obligation Certificates (DOCs)

- Designed to stimulate non-CCGT investment
- Similar to COCs mechanism but targeted at specific volume of non-CCGT generation investment
- DOC features:
  - All new plant other than gas-fired and renewables (already rewarded under ROCs) qualify
  - Buy-out price set to make non gas technologies economic
  - Plant are rewarded based on proven annual availability
  - The mechanism rolls forward and there is a cut-off period for each plant to prevent the mechanism becoming ‘silted up’

### 3.3 Diversity Obligation Certificates: Notes

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#### Implementation

- It is assumed that generators would qualify for DOCs if they could demonstrate a certain level of availability during the year. The exact mechanism for how this would be done is not within the scope of this study.
- This is preferable to awarding DOCs to new plant by MWh generated because that approach would mean that new plant could run ahead of old even where fuel and carbon prices would dictate otherwise.
- The idea of DOCs is to promote diversity because, under the status quo, CCGTs are favoured even when the economics look marginal. This is because it is a proven technology in the GB market and there is currently a high degree of correlation between electricity and gas prices offering a natural hedge not enjoyed by other technologies. Even if this correlation were to break down because coal became the main price setting technology (i.e. had higher short run marginal costs than gas), the result would be that CCGTs would be able to extract a rent in addition to the spark spread.
- The policy is designed to allow the market to determine the most economic technology away from gas.
- However, the type of station promoted by DOCs is likely to be sensitive to the evolving price profile of the obligation because of the differing lead times of the differing technologies. DOCs with a high level of obligation in the early years will bring forward coal; where the obligation rises at a later date, nuclear and/or sequestration may be more favoured.
- Fine tuning the design of DOCs against specific policy objectives is outside the scope of this study.

#### Parameters used

- Target: 10% of annual demand to be met from new non-gas fired technology by 2009, rising to 25% by 2020.
- Buy-out price: £15/hr for every MW of installed capacity (calculated per annum assuming baseload operation).
- Cut-off period set at 13 years for coal plant, 20 years for nuclear plant (to reflect the different typical economic lifetimes of the different technologies).

## 3.4 Nuclear Obligation Certificates (NOCs)

- Similar to DOCs, but only new nuclear plant is eligible:
  - Target set for an increasing proportion of annual demand to be met by new nuclear plant
  - Buy-out price set to make nuclear economic
  - Plant are rewarded based on proven annual availability
  - Other measures implemented to speed the planning and application process for new nuclear plant

## 3.4 Nuclear Obligation Certificates: Notes

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### Implementation

- It is assumed that generators would qualify for NOCs if they could demonstrate a certain level of availability during the year. The exact mechanism for how this would be done is not within the scope of this study.
- The policy has been implemented in the same way as DOCs with generators only receiving credit for their DOCs once they become operational. There would be no NOCs in the market in the initial years, and hence suppliers could not be expected to yield NOCs until the first new nuclear plant became operational. A transitional scheme may be required to fund nuclear development during the construction phase and lessen the risk of a policy change before the plant becomes operational.
- For simplicity, the same targets have been used as for DOCs although due to the long lead times of new nuclear plant it would take a considerable number of years before the target could be met.

### Parameters used

- Target: 10% of annual demand to be met from new nuclear capacity by 2009, rising to 25% by 2020.
- Buy-out price: £15/hr for every MW of installed capacity (calculated per annum assuming baseload operation).
- Cut-off period per plant set at 20 years.

## 3.5 Tendering

- Government or TSO intervenes in the market by tendering for construction of specified new capacity and auctioning tolling rights to the market on an annual basis
- Tendering is used to promote greater supply security and generation diversity
- The main analysis centred around tendering for baseload capacity, although the option of tendering for peak capacity only was also considered as a sensitivity

## 3.5 Tendering: Notes

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### Implementation

- Government or TSO invites tenders on a per kW price, delivery date basis for construction of new capacity including operations and maintenance cover but not including fuel or CO<sub>2</sub> allowances.
- Tendered plant initially allocated zero CO<sub>2</sub> allowances.
- Government or TSO pays for plant according to tendered price.
- Periodically the Government or TSO auctions tolling rights on an annual or multi-annual basis, either with appropriate CO<sub>2</sub> held back from allocation (if other plant has free allocations) or without CO<sub>2</sub> on the basis that the successful bidder can buy CO<sub>2</sub> in the next Government auction or the open market.
- Net cost of scheme charged or (if negative) rebated to Government expenditure or (if TSO does tendering) to suppliers and hence consumers through a transmission charge adjustment.
- This approach limits the intervention implicit in tendering to an intervention in the capacity market; the Government or TSO does not take a position in commodity markets.

### Parameters

- In the analysis the following plant is tendered:
  - 2 GW of advanced super-critical (ASC) coal to start construction in each of 2007, 2008, 2009
  - 2 GW of integrated gas combined cycle (IGCC) coal plus sequestration to start construction in each of 2008, 2012
  - 1.2 GW of nuclear tendered to start construction in each of 2012, 2013, 2018 and 2019
  - Total of 14.8 GW over 15 year period
- It is assumed in the analysis that the TSO is the tendering party and that profits or losses are smeared back to consumers through transmission charges.
- In the peak capacity sensitivity, which was analysed only against the DTI Base Case, 4 GW of OCGT capacity was assumed, to become operational in 2016.

## 3.6 Other policy considerations

The following policies and actions are also relevant:

- Carbon market policy
  - Free allocations to new entrants significantly improve the economics of new plant; the New Entrant Reserve has similar effects to COCs
- Information
  - Visibility of CO<sub>2</sub> policy going forward and a consensus on demand projections would reduce perceived risk but may be difficult to achieve
- Market structure
  - Market fragmentation might promote liquidity and attract investment; conversely, further market consolidation could reduce risks for incumbents also leading to greater levels of investment
- Generator or buyer consortia
- Faster planning
  - Has little impact on CCGTs because of existing consents pipeline
  - Probably a necessary condition for nuclear

## 3.6 Other Policy Considerations: Notes

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### Carbon allocation

- To separate the impact of carbon allowance allocation policy from other policy options, the analysis assumes that all allowances are auctioned, starting from Phase II. We have shown some illustrative effects of maintaining the current policy of free allocations plus New Entrant Reserve in the Analysis Results section. We have also analysed the impact of implementing a mechanism that effectively places a floor on the carbon price.
- In broad terms, free carbon allocations for new plant act like COCs. However, the free allocations for existing plant, withdrawn on closure, also have the effect of prolonging the lives of otherwise uneconomic plant, improving peak capacity margins (which is not always the case for COCs). The effectiveness of the free carbon allocation policy in incentivising new plant build will depend on the carbon price and the forward visibility of the arrangements, and is dependent on how the Directive evolves which is outside of the Government's direct control. Hence, relying on free allocation of carbon allowances as a mechanism for promoting new build is risky.

### Information

- Better information would reduce risks.
- Information on future carbon policy and pricing is difficult to obtain because it depends on international negotiations.
- A greater consensus on demand views might be achievable, at least in respect of the medium term, though this is inhibited by differing views of the impact of current energy saving and renewables programmes.

### Market Structure

- The current market structure removes the need for liquid long term markets (because integrated players have self-hedging capability) but has insufficient oligopolistic power for significant pricing risks to be passed on to consumers, except where these reflect general market position.
- A more fragmented market is unlikely to be better for investment – the experience of the 2002 price crash and associated insolvencies showed the fragility of an apparently liquid forward market. A more oligopolised market could increase the appetite for risk of the remaining players, at the expense of higher margins.

### Generator or Buyer Consortia

- If all the generators club together to make an investment, it transfers the risk to consumers. However, the effect is not much different to that of capacity or diversity obligation certificates, which also serve to transfer risk from market participants to consumers.
- If consumers club together to buy output from a new plant, this can remove market risk for the generator to the extent that the consumers' long term credit is good. The problem is whether consumers will want to take the risk of their energy costs being different to those of competitors 'not in the club', and whether they feel comfortable with collective buying on competition grounds.

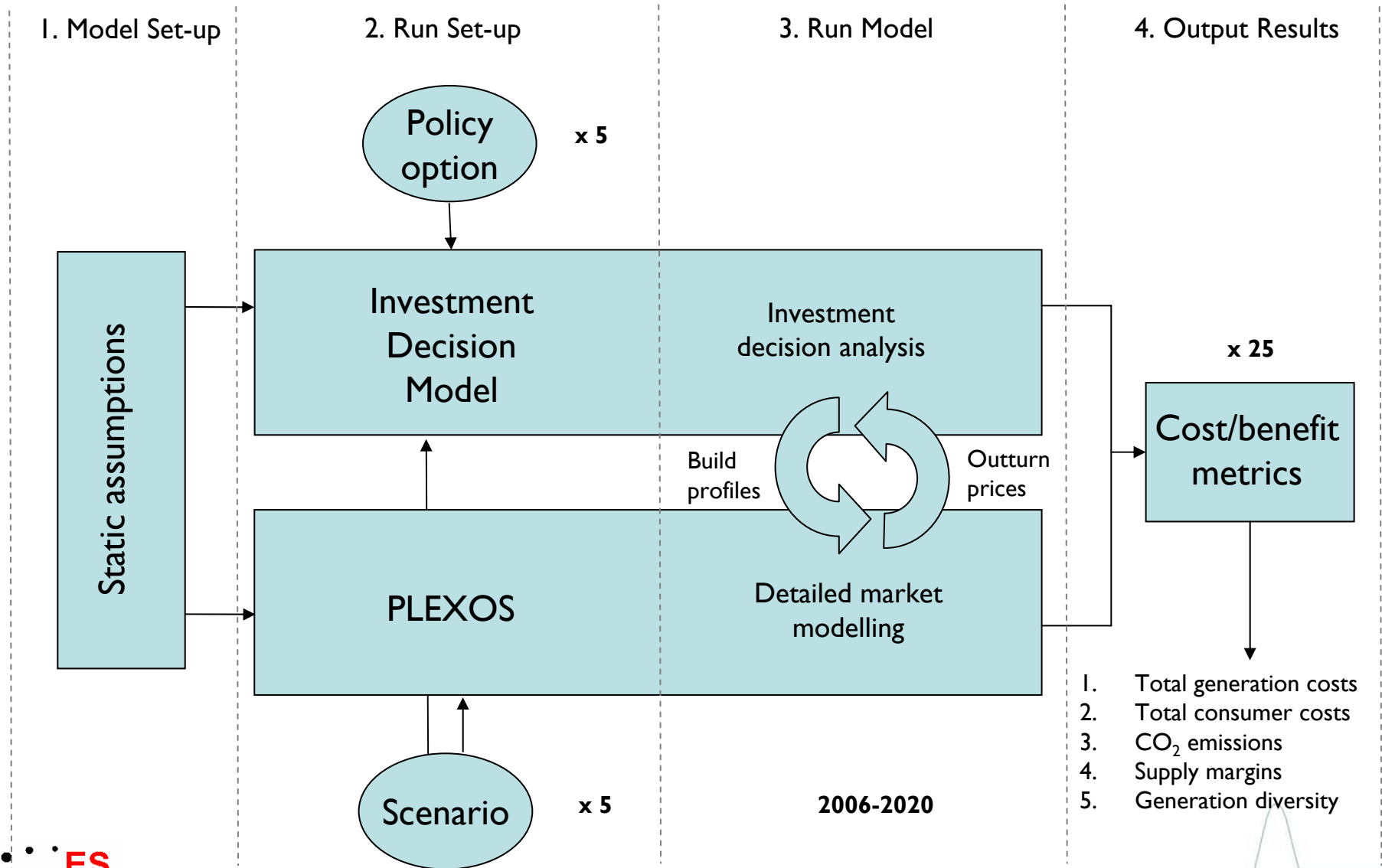
### Planning

- Streamlined planning procedures could reduce plant build lead times but may be politically challenging to achieve. Where planning costs are reasonable, market participants can build up a bank of reserve permissions which await the right financial conditions. This has happened in recent years with CCGTs.

## 4. Cost/benefit analysis framework

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# 4.1.1 Modelling Approach - Overview



## 4.1.1 Modelling Approach - Overview: Notes

### Models deployed

- The following models are used in the modelling process:
  - Investment Decision Model (IDM)
  - PLEXOS
  - Stochastic IDM
  - Loss of Load Probability (LOLP) model
- The IDM models the investment decisions of market participants under different scenarios and policy options. It produces a profile of new build capacity that is uploaded into PLEXOS.
- PLEXOS is used for detailed annual modelling of the electricity market taking into account short run marginal costs, demand, generation constraints and the competitive market dynamics.
- Based on the results of the PLEXOS modelling, reiteration takes place with the IDM to update expected prices and to retire existing plant that have become uneconomic in the scenario/policy option combination. The IDM and PLEXOS are subsequently re-run.
- A stochastic version of the IDM is used to calculate the risk premia of different generation technologies for different investors under each scenario.
- A stand-alone loss of load probability (LOLP) model is used to estimate the unserved energy and probability of the need for load curtailment in each scenario/policy option combination.

### Scenarios/policy options

- 5 different policy options (including the 'business as usual' case termed Status Quo) are modelled under 5 different scenarios.
- This gives a total of 25 different results.
- Additional sensitivities are also modelled.

### Modelling time horizon

- The modelling time horizon is 2006-2020.
- In addition, the IDM is run out to 2025 to show the impact of build decisions late in the modelling time horizon post-2020.

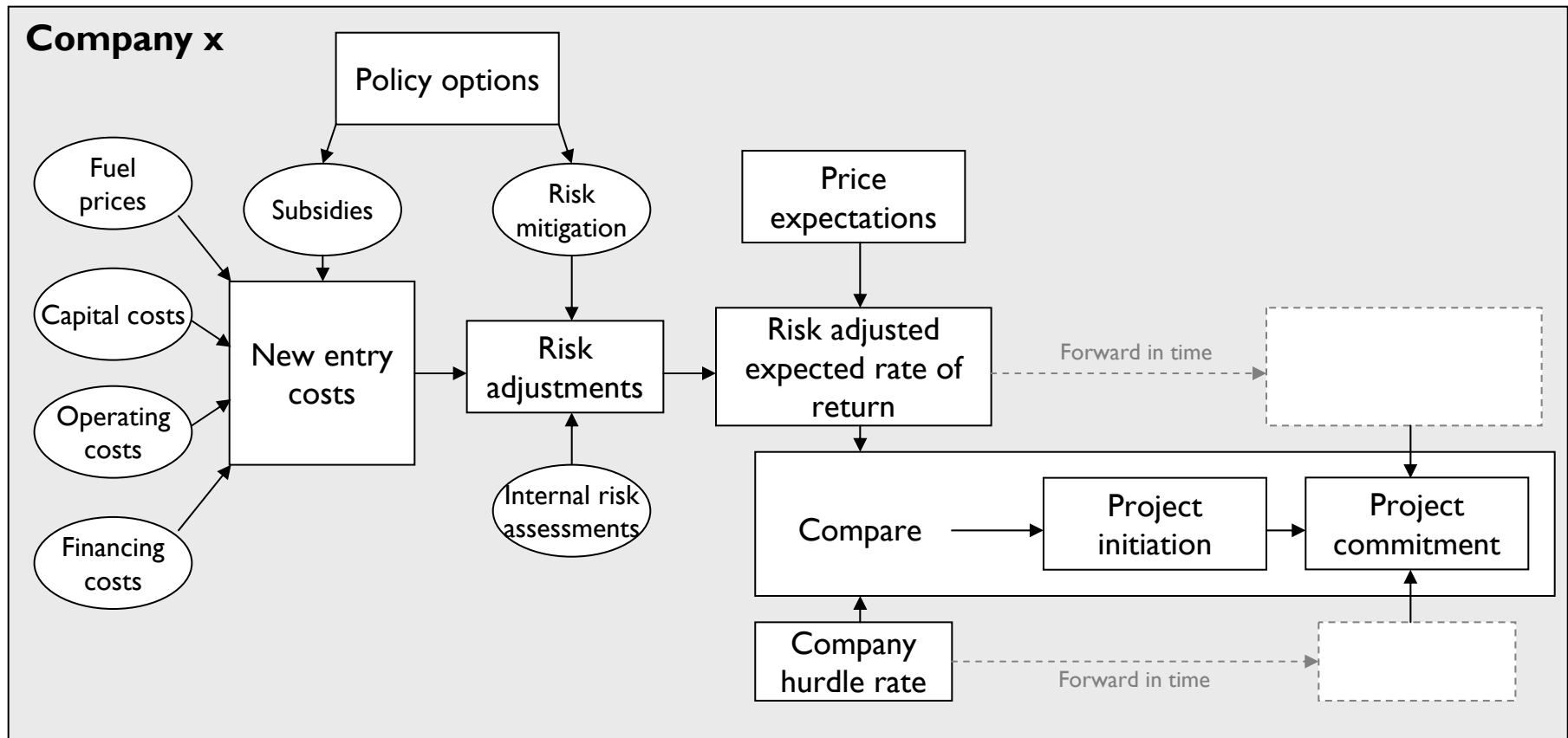
### Generation technologies

- CCGT category is assumed to include investments in large scale CHPs.
- New nuclear plant have a theoretical unit size of 1200MW, with costs based on Framatome's European Pressurised Reactor (EPR) and the Westinghouse AP1000.

New generation technologies modelled
CCGT
Advanced supercritical (ASC) coal
Integrated gas combined cycle (IGCC) coal
ASC Coal with sequestration
IGCC Coal with sequestration
Nuclear
Onshore wind
Offshore wind
Biomass (energy crops)

Investors modelled
Nuclear generator
Vertically integrated companies
Independent generators
Oil Major
Developer
Niche renewable
TSO/Government (Tendering only)

## 4.1.2 Modelling Approach – Investment Decision Model



## 4.1.2 Modelling Approach – Investment Decision Model: Notes

### IDM methodology

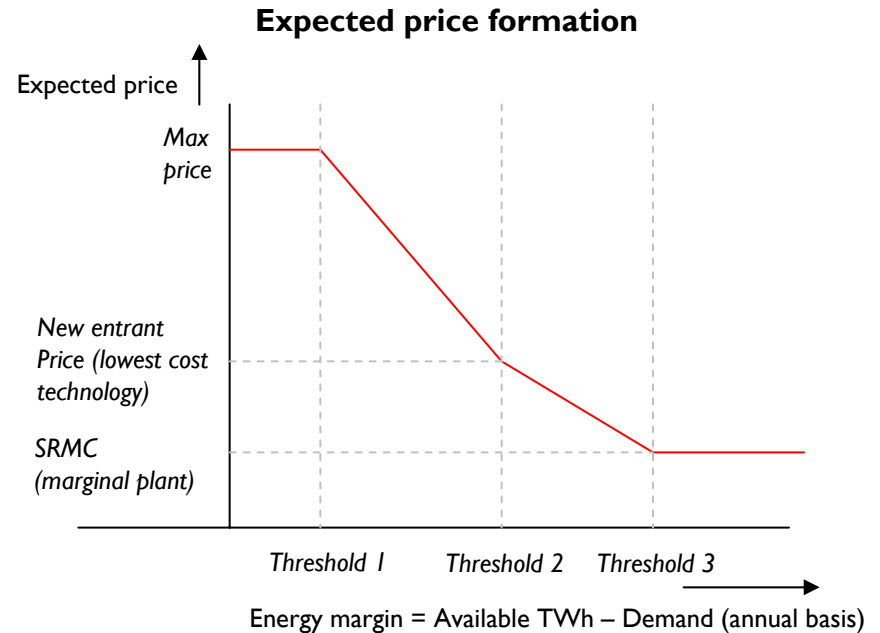
- The IDM models the investment decisions of different companies by comparing their risk adjusted long run marginal costs to an expected price level.
- The expected price is based on a combination of the previous year's outturn price and the 5 year forward projection of price related to the anticipated energy margin (taking into account consented plant). This is shown schematically in the diagram to the right. The expected price is evolved as the model runs forward.
- The fuel element of the long run marginal cost calculation assumes a price based on the average of the forward 5 year prices.

### Building plant

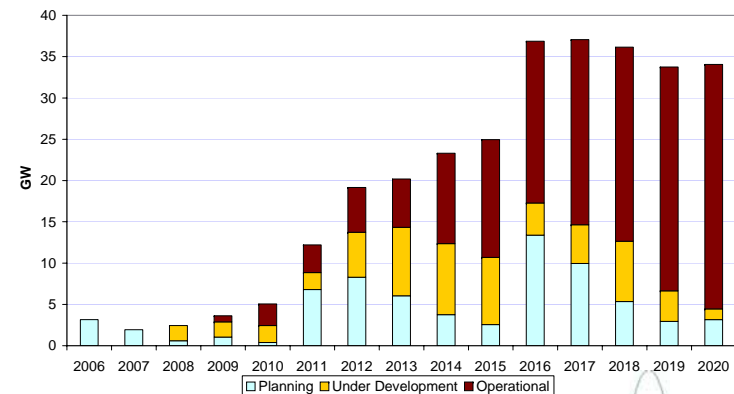
- Planning/decision and construction times for each technology are included in the model.
- If the technology is economic for an investor it will move into the planning phase. If it remains economic throughout the planning/decision timeframe it will be committed and become operational at the end of the construction period. If it becomes uneconomic during the planning/decision phase the planning process restarts.
- Limits are placed on the amount of capacity each company can have under construction by technology type and in total.

### Other parameters

- The IDM includes a model of the Renewables Obligation Certificate (ROCs) market.
- It also includes models of the different markets surrounding the policy options.

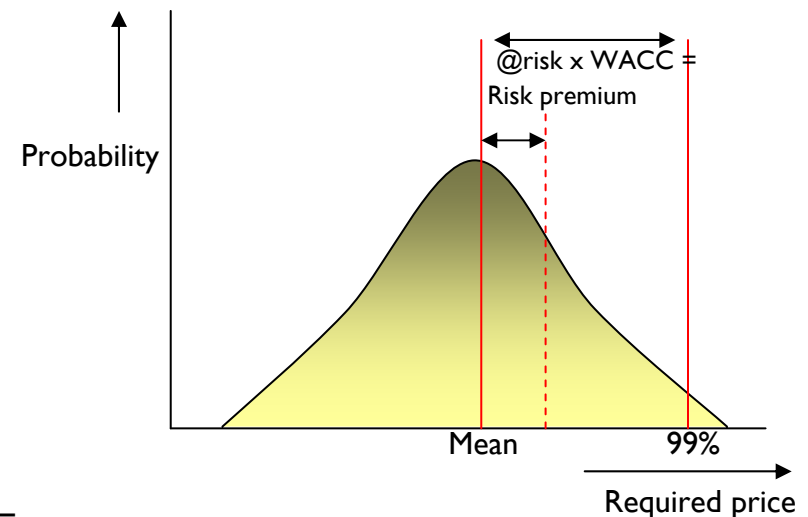


### Example plant build profile



## 4.1.3 Modelling approach – Calculating hurdle rates

- Risk premium added to required price (LRMC) to reflect uncertainty of input variables
- Key uncertainties
  - Fuel prices
  - Electricity prices
  - Carbon allocations/prices
  - Construction costs/times
  - Annual fixed operating costs
  - Subsidy prices
  - Decommissioning costs
- Risk premium (£/MWh) =  
Company WACC \* (Required Price at 99% percentile – mean)
- Hurdle rate (%) =  
Internal rate of return based on risk adjusted required price



## 4.1.3 Modelling approach – Calculating hurdle rates: Notes

### Stochastic variables

- Distributions vary between scenarios and over time. Tables on the right show assumptions for Restrained Demand in 2006.
- Standard deviations surrounding fuel prices greater in Volatile World. Carbon (EUA) price volatility greater in DTI Base Case.
- Construction risks surrounding nuclear, sequestration and offshore wind decrease significantly by 2020 in all scenarios.
- The impact of uncertain revenues is accounted for by adding the variation of electricity prices around a mean level to the required price.
- Vertically integrated companies with a short position (relative to their domestic load) are assumed to be exposed to the less volatile retail electricity price thus lowering their hurdle rate relative to independents who are fully exposed to the wholesale price.
- Retail market shares are based on Ofgem's Domestic Retail Market Report, September 2005.
- Correlations between gas and electricity vary between scenarios:
  - Lower in Steady Growth and Volatile World by 2020 as the proportion of gas fired generation decreases

### Restrained Demand 2006 assumptions

#### Triangular

Capital costs	Min	Median	Max
CCGT	0.9	1	1.1
Coal (ASC)	0.9	1	1.2
Coal (IGCC)	0.9	1	1.3
Coal (ASC) + Seq	0.9	1	2
Coal (IGCC) + Seq	0.9	1	2
Nuclear	0.9	1	2.5
Onshore wind	0.9	1	1.1
Offshore wind	0.9	1	1.6
Biomass	0.9	1	1.3

#### Normal

Variable Operating Costs	SD
CCGT	5%
Coal (ASC)	20%
Coal (IGCC)	20%
Coal (ASC) + Seq	30%
Coal (IGCC) + Seq	30%
Nuclear	35%
Onshore wind	5%
Offshore wind	5%
Biomass	20%

#### Triangular

Decommissioning risk	Min	Median	Max
Nuclear	0.9	1	5

#### Normal

Subsidies	SD
ROCs	30%
COCs	30%
DOCs	30%

#### Lognormal

Fuel prices	SD
Gas	30%
Coal	15%
Biomass	5%
Nuclear	10%
Carbon	20%

#### Lognormal

Electricity prices	SD
Wholesale	30%
Retail	20%

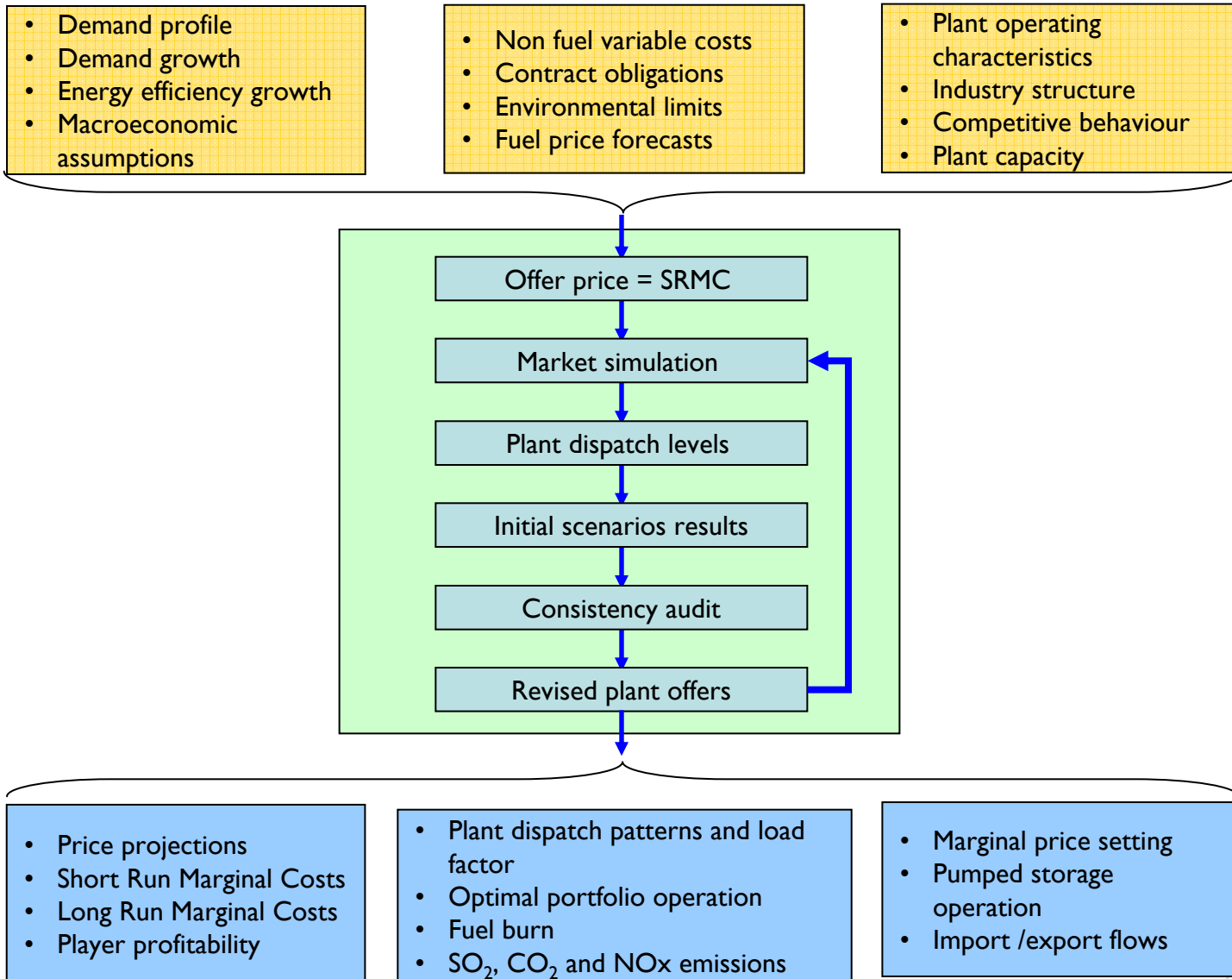
#### Normal

Carbon allocation	Mean	SD
All	50%	30%

#### Correlation matrix

	Gas	Coal	Carbon	Wholesale elec	Retail elec
Gas	100%				
Coal	30%	100%			
Carbon	30%	-30%	100%		
Wholesale elec	80%	40%	50%	100%	
Retail elec	80%	40%	50%	100%	100%

# 4.1.4 Modelling Approach - PLEXOS



## 4.1.4 Modelling Approach - PLEXOS: Notes

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### About PLEXOS

- PLEXOS for Power Systems is an advanced power market modelling tool, incorporating a number of alternative pricing algorithms ranging from marginal cost pricing through to game-theoretic approaches.
- At the heart of PLEXOS lies a dispatch 'engine' based on a detailed representation of the supply and demand fundamentals and the market constraints which combine with the price setting algorithms.
- The methodology underlying PLEXOS is that dispatch is determined on a bid-price basis, rather than a marginal cost basis. Hence the PLEXOS pricing algorithms interact with the dispatch engine by adjusting generator bid prices in an iterative manner.

### Calculation of SRMC

- The SRMC for each plant is calculated from heat rates, fuel costs, transportation costs, non-fuel variable operating costs and carbon costs. The SRMC forms the starting point for a generator's offers into the market.
- The model also incorporates a number of specific constraints which must be met. These include:
  - Min and max annual generation limits for CHP plant
  - Biomass burning limits for co-firing coal plant
  - SO<sub>2</sub> constraints (both pre-2008 and in accordance with the LCPD from 2008)
  - Take-or-pay must run constraints on some gas-fired CCGTs
- Since plants are scheduled to meet these constraints, the 'perfectly economic' merit order will be somewhat distorted, hence raising the overall system marginal generation costs.

### Competitive behaviour

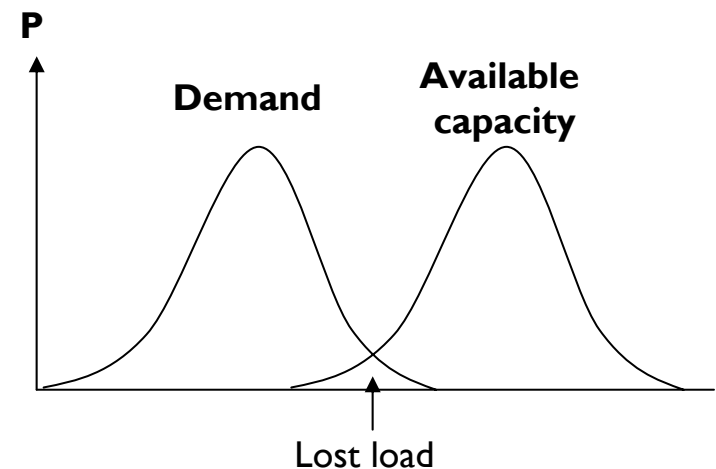
- The calculation of each plant's SRMC is the first step in determining prices. Key inputs to PLEXOS are a metric to assess the 'competitiveness' of the market, together with target equity returns for each generator. A complex heuristic algorithm will then revise the SRMC offer levels in order to try and increase the profitability of each company's portfolio. It is important to note that equity recovery takes place at the portfolio level, and hence some plant may see a reduction in load factor if the net result is to increase overall profits. There are a series of iterations between generator offers and plant load factors, before the final solution is derived.

### Outputs

- The key outputs that PLEXOS produces used in this analysis are: time and demand weighted electricity prices, generation costs, output by plant type and company, CO<sub>2</sub> emissions, and plant and company level profitability.

## 4.1.5 Modelling Approach – LOLP Model

- Stochastic simulation of peak plant availability and demand
- Model calculates:
  - Expected unserved load
  - Probability of a need for load curtailment (probability of loss of load in at least 1 hour of the year)
  - Maximum individual loss in any hour
- Can be run with independent plant outages or with correlated plant outages to test the value of diversity



## 4.1.5 Modelling Approach – LOLP Model: Notes

### Modelling details

- For all non-wind plant, discrete distributions are used to model the plant being fully available or incurring an outage.
- For wind plant, triangular distributions are used, giving an average wind availability of 33%.
- A temperature adjustment is made to thermal plant since higher output levels are normally achieved in colder weather at times when demand is high.
- Interconnectors are assumed to have a 99% availability.
- For testing the value of diversity:
  - It is assumed that output from wind plant are all 100% correlated.
  - For gas plant an additional simplified fuel constraint is modelled to capture the possibility of a gas supply problem:
    - 1% probability of 20% reduction in available gas supply to the generation sector in each hour
    - 0.5% probability of 40% reduction in available gas supply to the generation sector in each hour
    - No correlation between hours
    - The possibility of running on back-up fuel (gas oil/distillate) is not included in this simple analysis
  - This has greater impact in the scenarios with low generation diversity and high reliance on gas

### Plant peak availability distributions

	Distribution	Max avail	Temp effect	Min	Adj max	Prob Min	Prob Max
CCGT	Discrete	100%	3%	0%	103%	5.00%	95.00%
Coal	Discrete	100%	3%	0%	103%	5.00%	95.00%
Gas turbines	Discrete	100%	3%	0%	103%	5.00%	95.00%
Pumped storage	Discrete	100%	0%	0%	100%	1.00%	99.00%
Onshore wind	Triangle	100%	0%	0%	100%		
Offshore wind	Triangle	100%	0%	0%	100%		
Oil	Discrete	100%	3%	0%	103%	5.00%	95.00%
Nuclear	Discrete	100%	0%	0%	100%	10.00%	90.00%
Biomass	Discrete	100%	3%	0%	103%	5.00%	95.00%
CHP	Discrete	100%	3%	0%	103%	5.00%	95.00%
Interconnector	Discrete	100%	0%	0%	100%	1.00%	99.00%

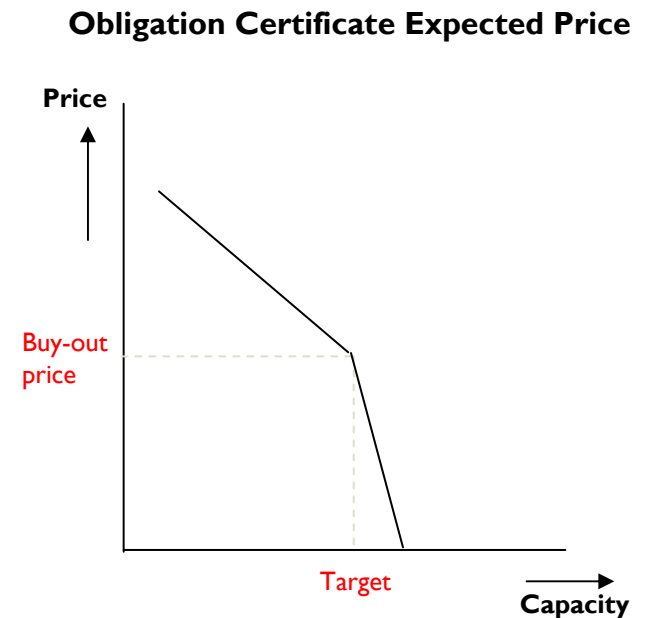
### Standard deviation of demand (business days)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	2.96%	3.47%	3.91%	4.49%	5.08%	6.72%	11.86%	16.82%	13.23%	10.36%	8.53%	7.43%	7.22%	7.75%	8.04%	8.10%	7.68%	5.92%	5.83%	5.79%	5.67%	5.00%	3.78%	3.24%
Feb	3.04%	3.48%	4.11%	4.82%	5.30%	6.37%	10.65%	14.47%	11.28%	9.20%	7.74%	7.28%	7.11%	7.62%	7.96%	8.24%	8.40%	6.12%	5.14%	5.24%	5.32%	4.85%	3.69%	3.19%
Mar	7.39%	8.00%	9.43%	9.67%	9.34%	9.81%	13.53%	14.86%	11.76%	10.31%	9.61%	9.71%	10.38%	11.12%	11.62%	11.83%	10.90%	9.59%	8.33%	8.44%	8.23%	8.20%	8.45%	8.45%
Apr	3.50%	4.34%	4.74%	4.96%	6.40%	11.15%	14.49%	12.48%	10.22%	8.94%	8.60%	8.73%	9.83%	10.51%	10.81%	10.64%	8.91%	7.81%	7.07%	6.58%	5.60%	4.89%	4.30%	11.14%
May	4.90%	5.70%	5.84%	6.64%	8.15%	12.94%	16.02%	13.34%	10.88%	9.53%	9.16%	9.04%	10.04%	10.66%	11.02%	11.17%	9.68%	8.46%	7.98%	8.21%	6.88%	5.05%	4.04%	4.28%
Jun	2.96%	3.49%	3.89%	4.70%	6.67%	11.60%	14.60%	12.41%	10.09%	8.71%	8.48%	8.54%	9.50%	10.11%	10.43%	10.25%	8.51%	7.22%	6.41%	5.97%	5.31%	4.44%	3.83%	3.54%
Jul	3.58%	3.97%	4.60%	5.42%	7.47%	12.54%	15.64%	13.41%	11.19%	9.59%	9.24%	9.32%	10.24%	11.03%	11.28%	11.24%	9.62%	8.37%	7.40%	6.86%	6.10%	4.90%	4.25%	3.68%
Aug	3.17%	3.44%	3.92%	4.39%	5.03%	7.19%	11.23%	13.77%	12.70%	10.68%	9.37%	9.03%	9.10%	10.06%	10.91%	11.06%	11.24%	9.54%	8.73%	8.21%	8.26%	5.98%	4.97%	4.28%
Sept	2.02%	3.14%	3.57%	3.81%	4.24%	6.26%	12.39%	15.60%	12.12%	9.68%	8.46%	8.24%	8.33%	9.24%	9.92%	10.37%	10.43%	8.68%	8.31%	7.84%	5.99%	5.11%	3.85%	3.10%
Oct	20.27%	3.60%	4.39%	4.66%	5.32%	7.25%	13.14%	17.47%	14.41%	11.15%	9.17%	8.56%	8.21%	8.99%	9.74%	9.93%	10.05%	8.53%	7.34%	6.17%	5.99%	5.27%	4.34%	4.04%
Nov	7.39%	8.67%	9.99%	11.20%	11.61%	11.18%	10.77%	12.97%	16.23%	12.73%	10.41%	9.09%	8.59%	8.52%	9.15%	9.63%	10.12%	8.72%	7.10%	7.43%	7.86%	7.76%	7.37%	6.94%
Dec	4.34%	3.47%	4.59%	5.06%	5.40%	5.88%	7.19%	11.75%	16.38%	12.83%	9.99%	8.65%	8.27%	7.87%	8.52%	9.40%	10.23%	10.37%	10.09%	9.79%	9.21%	8.71%	7.46%	5.42%

Based on 2005 outturn demand

## 4.1.6 Modelling Approach – Policy options

- Each policy option is designed to address an issue in a specific scenario
- The qualification rules and market for obligation certificates are modelled in the IDM
- The expected market price is modelled using the simple function illustrated on the right:
  - Below target: linear relationship between % shortfall and premium above buy-out price
  - Above target: price collapses to zero at a specified % above target



## 4.1.6 Modelling Approach – Policy options: Notes

### Design of policy options

- There are a large number of permutations of how each policy option can be defined in terms of buy-out prices, target levels, qualification and roll-off rules. The parameters used in this analysis are described in Section 5.
- The table on the right illustrates which scenarios were used to design each policy option.
- By then keeping the parameters the same when applying the policy option to the different scenarios, the impact of implementing a policy option without knowledge of how the market will develop in future can be analysed.

### Modelling considerations

- The expected price of obligation certificates is evolved in the model in exactly the same way as the expected commodity price using a combination of outturn prices and forward five year expectations. The amount of qualifying plant being planned influences investors' expectations of future prices.
- The price of obligation certificates is expected to collapse to zero at the following percentages above target:
  - DOCs: 30%
  - COCs: 10%
  - NOCs: 30%

Scenario designed against

Policy option	Scenario
Capacity Obligation Certificates	Volatile World
Diversity Obligation Certificates	Third Dash for Gas
Nuclear Obligation Certificates	Restrained Demand
Tendering	Volatile World

## 4.2 Cost/benefit analysis - metrics

	<b>Metric</b>	<b>Definition</b>
1	Total generation costs (2006-2020)	The net present value of the total costs of generation including variable generation costs, annual fixed costs and annualised capital costs, over the modelling horizon.
2	Total consumer costs (2006-2020)	The net present value of total costs to consumers including the cost of different policy options.
3	CO <sub>2</sub> emissions (2006-2020)	Annual average emissions of CO <sub>2</sub> from the power sector over the study period.
4	Supply margins (2006-2020)	The minimum energy margin (annual plant availability less annual demand quoted as a percentage of annual demand), and the minimum peak capacity margin (peak plant availability less peak demand quoted as a percentage of peak demand).
5	Generation diversity (2020)	The percentage capacity of the most dominant fuel/technology, and the two most dominant.

## 4.2 Cost/benefits analysis - metrics

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### Total generation costs

- The variable generation costs are comprised of fuel costs, fuel transportation costs, non-fuel variable costs, and carbon (assuming carbon is priced at its full opportunity cost). It also includes the cost of exported power (i.e. power generated in GB) but does not include the cost of purchasing imported power. Losses are excluded from the variable costs.
- Annual fixed costs include operations and maintenance, rates, salaries, network connection charges and insurance. These costs are incurred by all plant on the system irrespective of whether they generate or not.
- The annualised capital costs are only included for new plant from the year they are commissioned until the end of the study period. The generation costs do not include the capital cost assumptions for plant already operating.
- An allowance for decommissioning is included in the annualised capital costs of nuclear plant.
- A discount rate of 3.5% is used to calculate the NPV of generation costs.
- Generation costs include the costs of subsidies where they make up part of the investment costs, and are equivalent to resource costs as defined in the Energy Review Guidance document.

### Total consumer costs

- The total annual consumer costs are calculated from the demand-weighted electricity price in each year, multiplied by total demand. In addition the cost incurred by consumers (expressed in £/MWh) to fund each of the policy options (including the cost of the existing Renewables Obligations Certificate scheme) is included.

### CO<sub>2</sub> emissions

- The CO<sub>2</sub> emissions are from plant defined as power stations under the EU ETS sector definition. This definition excludes the CO<sub>2</sub> emissions from Lynemouth and some other smaller CHP plant.

### Supply margins

- In calculating the annual energy margin, account is taken of the availability of plant. The most significant limits are:
  - LCPD opt out plant limited to a 28.5% annual load factor (proportionally higher for plant that shut earlier than 2015)
  - Onshore wind and offshore wind assumed to have 30% annual availability.
  - Thermal and nuclear plant annual availabilities in the range 80-87% reflecting annual maintenance and unplanned outage.
  - Interconnectors are excluded from this metric
- Different peak availabilities are applied to calculate the peak capacity margin. The following assumptions are made:
  - A 5% derating from the installed capacity of thermal plant
  - The French and future Norwegian interconnectors are included with a 5% derating
  - Wind plant are assumed to be 30% available at peak

## 4.2 Cost/benefit analysis - net cost/benefit

- In order to compute a unified financial measure to compare the net cost/benefit of each policy option relative to the Status Quo the following methodology is used:
  - Defining the underlying costs (the ‘resource’ costs) as the total generation costs (rather than the consumer costs)
  - Replacing the costs of the EUAs in the generation costs with a social cost for the carbon dioxide emissions
  - Adding the cost of unserved load by estimating the volumes of unserved load at different levels of supply margins and applying a value of lost load (£15,000/MWh)
  - Adding in the increased risk of unserved load due to correlated gas plant outages and wind plant availabilities

## 4.2 Cost/benefit analysis - net cost/benefit

### Net cost/benefit calculation

- The net cost/benefit is the net present value (2006) of the total benefits less the total costs across the study period (2006-2020) using a discount rate of 3.5%
- The three components of the net cost/benefit calculation are:
  - Generation costs (higher –ve, lower +ve): including SRMC costs (including the cost of carbon allowances - EUAs), annual fixed costs and investments costs for new plant
  - Carbon emissions (higher – ve, lower +ve): cost/benefit of higher/lower carbon emissions monetised at the difference between the social cost of carbon and the EUA cost already captured in the generation costs.
  - Improved security of supply (higher cost of lost load –ve, lower cost of lost load +ve). This includes the quantification of the value of security and the value of diversity.

### Social cost of carbon

- The DTI's central view is used for the social cost of carbon shown in the graph on the right.

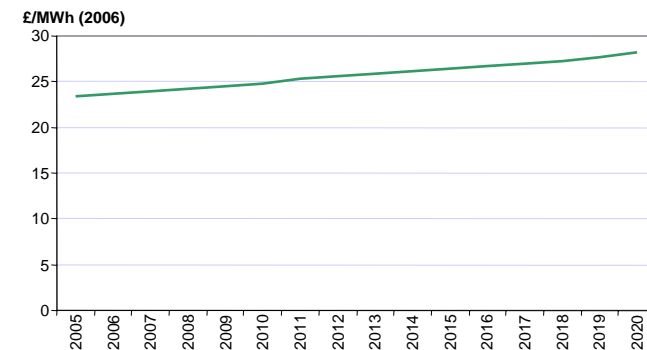
### Quantification of value of security

- A value of lost load of £15,000/MWh (real 2006) was used.

### Quantification of value of diversity

- In the quantification of value of security analysis it is assumed that plant availability is uncorrelated. Hence from a security of supply perspective it does not matter which technology type is built.
- In order to quantify the cost of low diversity, the analysis is rerun with the following assumptions:
  - 100% correlation in wind output
  - 1% probability of 20% reduction in available gas supply to the generation sector in each hour
  - 0.5% probability of 40% reduction in available gas supply to the generation sector in each hour
  - No correlation between hours
  - The possibility of running on back-up fuel (gas oil/distillate) is not considered

Social cost of carbon (central case)



## 4.3 Scenarios

**Restrained Demand:** A world where demand served from the transmission grid is steady or falls through a combination of effective energy efficiency measures and growth in embedded generation. Lifetimes of nuclear plant (other than Magnox) are extended and availability increases from current levels. Based on the revised DTI's UK Energy and Emissions Projections (UEP) case.

**Steady Growth:** A world of relatively high gas prices, improving clean coal economics, loose post-2012 carbon emissions constraints and continuing electricity demand growth. Further consolidation amongst energy companies.

**Third Dash for Gas:** Falling gas prices leading to competition to build next generation of CCGTs to replace anticipated plant retirements.

**Volatile World:** A world characterised by high and volatile fuel prices, especially gas, coupled with strong environmental concerns and hence tight post-2012 carbon emissions constraints. Further market consolidation as some players exit the market.

**DTI Base Case:** An update to Restrained Demand using some DTI modelling assumptions on fuel prices (which are higher), and electricity demand (which is higher long-term). This scenario is labelled the DTI Base Case because it uses DTI central modelling assumptions on future fuel price and electricity demand. It does not necessarily represent the DTI's view of the most likely scenario outcome.

## 4.3 Scenarios: Notes

### Scenario characteristics

	<b>Restrained Demand</b>	<b>Steady Growth</b>	<b>Third Dash for Gas</b>	<b>Volatile World</b>	<b>DTI Base Case</b>
<b>Fuel prices</b>	Significant falls from current levels.	Falls from current levels.	Significant falls from current levels.	Remaining high and volatile. Very high carbon prices.	Falls from current levels.
<b>Technology costs</b>	Falls in nuclear and offshore wind costs. Significant falls in sequestration costs.	Falls in nuclear and offshore wind costs. Significant falls in costs of new coal technologies Significant falls in sequestration costs.	Falls in nuclear and offshore wind costs. Significant falls in sequestration costs.	Falls in nuclear and offshore wind costs. Significant falls in sequestration costs.	Falls in nuclear and offshore wind costs. Significant falls in sequestration costs.
<b>Demand</b>	Initial falls from current levels before growing again post 2010.	Growth at historical trend levels.	Growth at historical trend levels.	Continued growth but some demand side response to high price levels.	Initial falls from current levels before growing again post 2010. Stronger growth than Restrained Demand.
<b>Plant retirements</b>	Determined by economics of scenario.	Determined by economics of scenario. Kingsnorth and Tilbury assumed to be retrofitted and extended beyond 2015.	Determined by economics of scenario.	Extensions of Hartlepool and Heysham 1 to 2019.	Determined by economics of scenario.
<b>Market structure</b>	No significant further consolidation.	Further consolidation of the market.	No significant further consolidation.	Further consolidation of the market.	Further consolidation of the market.

Note: This assumption was made in order to isolate the impact of carbon allowance allocation policy from other policy options and does not represent Government intentions. The Directive provides for a maximum of 10% auctioning in Phase II. Alternative allocation policies are examined in the policy option sensitivity section.

# 4.4.1 Input assumptions – fuel prices

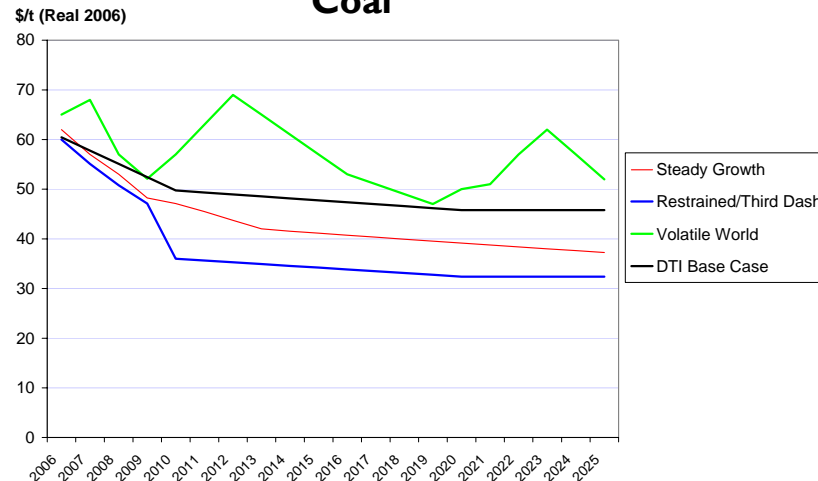
## Gas



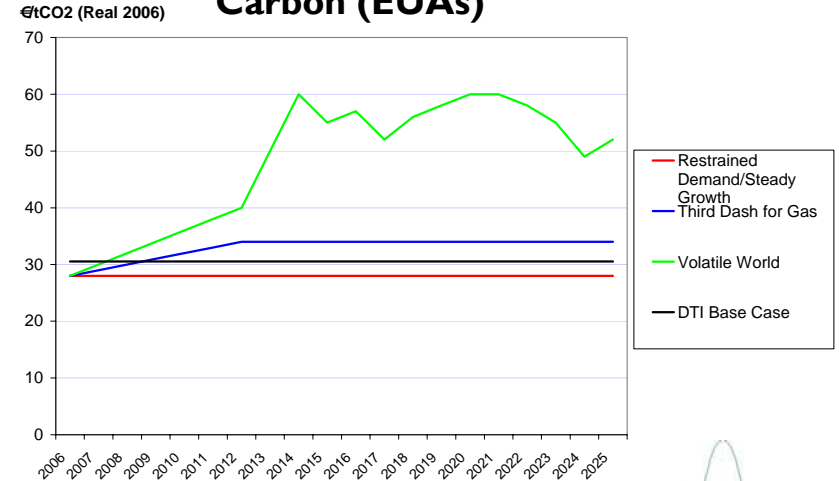
## Crude



## Coal



## Carbon (EUAs)



## 4.4.1 Input assumptions – fuel prices: Notes

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### Basis for fuel price assumptions

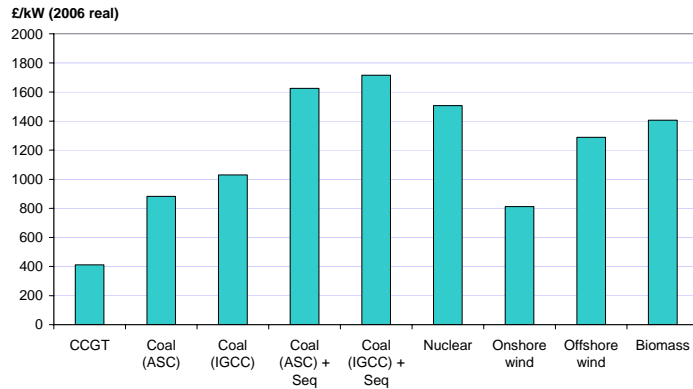
- Restrained Demand and Third Dash Gas fuel price assumptions based on DTI's low case – February 2006. (Note different EUA price assumptions between the two scenarios.)
- Steady Growth assumptions based on DTI's central case – February 2006.
- DTI Base Case based on DTI's central views – April 2006.
- Volatile World assumptions created as a specific scenario for this study to test the impact of high and volatile fuel and EUA prices.
- Prices are real in 2006 money.

### Other fuel price input assumptions

- Foreign exchange rates the same in all scenarios and flat throughout study period:
  - \$:£ - 1.7
  - €:£ - 1.4
- Biomass costs: 2.0 £/GJ in all scenarios constant across study period. Based on energy crops – averaged across several sources.

## 4.4.2 Input assumptions – technology costs

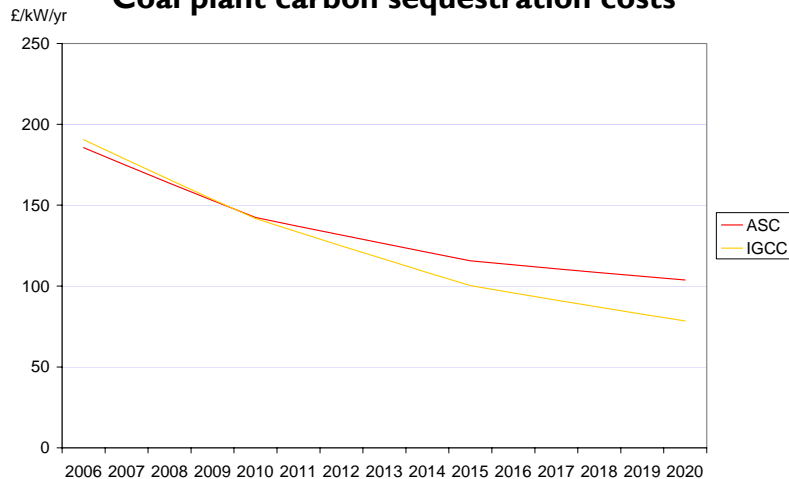
Investment costs (2006)



Investment cost reductions by 2020

Technology	Restrained Demand	Steady Growth	Third Dash for Gas	Volatile World	DTI Base Case
CCGT	5%	10%	15%	5%	10%
Coal (ASC)	10%	15%	10%	10%	15%
Coal (IGCC)	15%	30%	10%	20%	30%
Coal (ASC) + Seq	10%	15%	10%	10%	15%
Coal (IGCC) + Seq	15%	30%	10%	20%	30%
Nuclear	20%	20%	20%	20%	20%
Onshore wind	5%	5%	5%	5%	5%
Offshore wind	10%	10%	10%	10%	10%
Biomass	10%	20%	10%	10%	20%

Coal plant carbon sequestration costs



Sequestration cost reductions

	ASC	IGCC
By 2010	24%	25%
By 2020	27%	50%

## 4.4.2 Input assumptions – technology costs: Notes

### 2006 technology assumptions

#### Technology assumptions

- Plant cost assumptions mainly based on “Costs of Generation Electricity” by the Royal Academy of Engineering (2004) with the following exceptions:
  - Nuclear and offshore wind based on DTI’s own estimates
  - Sequestration costs (and reductions in sequestration costs) based on IEA World Energy Outlook, 2005 update
- Investment costs exclude interest during construction
- Fixed annual costs and variable operating costs are the same in all scenarios. They are constant throughout the study period in real terms with the exception of sequestration costs which fall in line with reduction in plant costs.
- Biomass costs based on energy crop combustion.
- Nuclear decommissioning costs assumed to be £250/kW (DTI assumption).

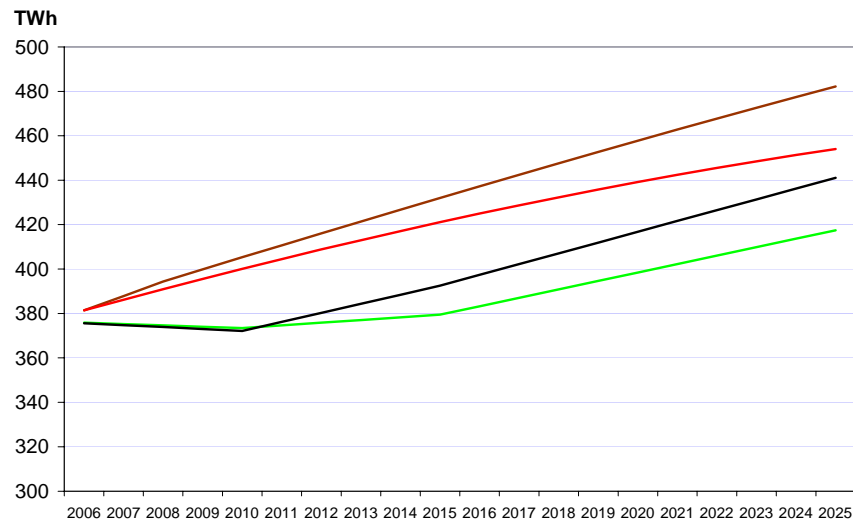
Technology	Unit sizes	Plant costs	Investment costs	Fixed annual costs	Variable operating costs
	MW	£/kW	£/kW	£/kW	£/MWh
CCGT	400	280	411	23.0	1.00
Coal (ASC)	500	720	882	31.3	2.00
Coal (IGCC)	500	850	1030	50.1	2.00
Coal (ASC) + Seq	500	720	1625	81.3	5.00
Coal (IGCC) + Seq	500	850	1715	100.1	4.00
Nuclear	1200	900	1507	42.8	0.05
Onshore wind	25	600	812	25.1	0.05
Offshore wind	100	1000	1288	59.5	0.05
Biomass	120	1000	1407	235.0	2.00

#### Efficiency assumptions (HHV)

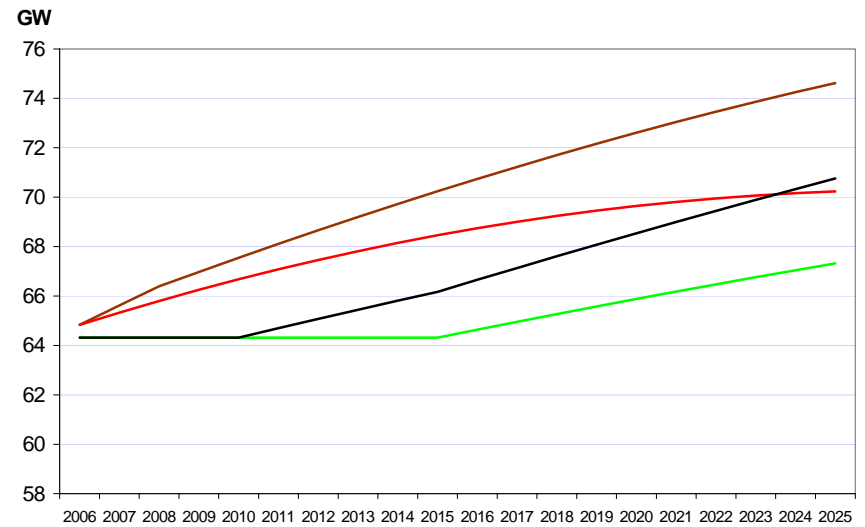
Technology	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CCGT	51.8%	52.0%	52.2%	52.4%	52.6%	52.8%	53.0%	53.2%	53.4%	53.6%	53.8%	54.0%	54.2%	54.4%	54.5%
Coal (ASC)	42.0%	42.4%	42.9%	43.3%	43.7%	44.1%	44.6%	45.0%	45.4%	45.9%	46.3%	46.7%	47.1%	47.6%	48.0%
Coal (IGCC)	46.0%	46.4%	46.9%	47.3%	47.7%	48.1%	48.6%	49.0%	49.4%	49.9%	50.3%	50.7%	51.1%	51.6%	52.0%
Coal (ASC) + Seq	30.0%	30.4%	30.9%	31.3%	31.7%	32.5%	33.4%	34.2%	35.0%	35.9%	36.7%	37.5%	38.3%	39.2%	40.0%
Coal (IGCC) + Seq	38.0%	38.4%	38.9%	39.3%	39.7%	40.3%	41.0%	41.6%	42.2%	42.9%	43.5%	44.1%	44.7%	45.4%	46.0%
Nuclear	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Onshore wind	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Offshore wind	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Biomass	24.0%	24.3%	24.6%	24.9%	25.1%	25.4%	25.7%	26.0%	26.3%	26.6%	26.9%	27.1%	27.4%	27.7%	28.0%

# 4.4.3 Input assumptions - demand

Annual demand



Peak demand



Restrained Demand Steady Growth/Third Dash for Gas Volatile World DTI Base Case

## 4.4.3 Input assumptions - demand: Notes

### Basis for demand assumptions

- The measure of demand used is total system demand including embedded and combined heat and power (CHP) served demand but excluding power stations' own consumption. Network losses are included within the demand projections and hence demand is modelled at the station-gate.
- The hourly profile used as the starting point is derived from 2005 actual demand, adjusted to be consistent with the above definition. This hourly profile is scaled in each year according to the peak and energy demand projected in each year.
- The key driver of electricity demand growth has traditionally been GDP growth. The historic ratio of demand growth to GDP growth for GB is approximately 0.58:1. In other words, for every percentage point rise in GDP, electricity demand would rise by 0.58%. We assume this ratio falls linearly to 0.4 by 2025 in the Steady Growth and Third Dash for Gas scenarios, and to 0.3 in the high commodity priced Volatile World scenario.
- The GDP projections are a long term rate of 2.5% in Steady Growth and Third Dash for Gas, and falling from 2.5% to 2% in Volatile World. These projections are combined with the above ratios to derive the demand projections below.
- The Restrained Demand projections are based on interpolation of data published in the DTI's UEP.
- The DTI Base Case demand projections are based on DTI's forecasts – April 2006.
- In all scenarios peak demand is assumed to grow more slowly than the energy demand, reflecting a steady flattening of the demand profile.

### Annual demand projections

Total - TWh	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Restrained Demand	375.87	375.27	374.67	374.07	373.47	374.67	375.87	377.07	378.27	379.47	383.27	387.07	390.87	394.67	398.47	402.27
Steady Growth	381.38	387.91	394.44	399.87	405.29	410.69	416.06	421.41	426.72	432.00	437.24	442.44	447.59	452.71	457.77	462.78
Third Dash for Gas	381.38	387.91	394.44	399.87	405.29	410.69	416.06	421.41	426.72	432.00	437.24	442.44	447.59	452.71	457.77	462.78
Volatile World	381.38	386.20	390.93	395.56	400.09	404.51	408.83	413.04	417.13	421.11	424.97	428.71	432.32	435.81	439.18	442.41
DTI Base Case	375.61	374.75	373.89	373.03	372.17	376.24	380.31	384.38	388.45	392.52	397.38	402.23	407.09	411.94	416.80	421.65

### Year-on-year changes

Year % change	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Restrained Demand	2.25%	-0.16%	-0.16%	-0.16%	-0.16%	0.32%	0.32%	0.32%	0.32%	0.32%	1.00%	0.99%	0.98%	0.97%	0.96%	0.95%
Steady Growth	3.75%	1.71%	1.68%	1.38%	1.36%	1.33%	1.31%	1.28%	1.26%	1.24%	1.21%	1.19%	1.17%	1.14%	1.12%	1.09%
Third Dash for Gas	3.75%	1.71%	1.68%	1.38%	1.36%	1.33%	1.31%	1.28%	1.26%	1.24%	1.21%	1.19%	1.17%	1.14%	1.12%	1.09%
Volatile World	3.75%	1.26%	1.22%	1.18%	1.14%	1.11%	1.07%	1.03%	0.99%	0.95%	0.92%	0.88%	0.84%	0.81%	0.77%	0.74%
DTI Base Case	2.18%	-0.23%	-0.23%	-0.23%	-0.23%	1.09%	1.08%	1.07%	1.06%	1.05%	1.24%	1.22%	1.21%	1.19%	1.18%	1.16%

### Peak demand projections

Peak	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Restrained Demand	64.31	64.31	64.31	64.31	64.31	64.31	64.31	64.31	64.31	64.31	64.64	64.95	65.27	65.57	65.88	66.18
Steady Growth	64.83	65.62	66.39	66.98	67.55	68.11	68.66	69.20	69.73	70.24	70.74	71.23	71.70	72.16	72.61	73.04
Third Dash for Gas	64.83	65.62	66.39	66.98	67.55	68.11	68.66	69.20	69.73	70.24	70.74	71.23	71.70	72.16	72.61	73.04
Volatile World	64.83	65.33	65.80	66.25	66.68	67.08	67.46	67.82	68.15	68.46	68.75	69.01	69.24	69.46	69.65	69.81
DTI Base Case	64.31	64.31	64.31	64.31	64.31	64.69	65.07	65.44	65.81	66.17	66.66	67.14	67.61	68.08	68.54	69.00

## 4.4.4 Input assumptions – plant retirements/availabilities

- Further extensions of Hartlepool and Heysham I under Volatile World
- LCPD opt-out plant assumed to spread 20,000 running hours equally over years that they remain open between 2008 and 2015.
- Tilbury and Kingsnorth (opted-out) assumed to be retrofitted with flue-gas desulphurisation (FGD) and selective catalytic reduction (SCR) and extended beyond 2015 under Steady Growth
- All other LCPD opted-out plant assumed to close between 2012 and 2015
- Other retirements based on economics result from modelling

**Nuclear closures**

Station	Restrained Demand	Steady Growth	Third Dash for Gas	Volatile World	DTI Base Case
Dungeness A	2006	2006	2006	2006	2006
Dungeness B	2018	2018	2018	2018	2018
Hartlepool	2014	2014	2014	2019	2014
Heysham 1	2014	2014	2014	2019	2014
Heysham 2	2023	2025	2025	2025	2023
Hinkley Point	2011	2011	2011	2011	2011
Hunterston	2011	2011	2011	2011	2011
Oldbury	2008	2008	2008	2008	2008
Sizewell A	2006	2006	2006	2006	2006
Sizewell B	Post 2025	Post 2025	Post 2025	Post 2025	Post 2025
Torness	2023	2025	2025	2025	2023
Wylfa	2010	2010	2010	2010	2010

**LCPD plant opted-out**

Plant	Capacity MW
Cockenzie	1200
Didcot A	1984
Fawley	484
Ferrybridge (1 stack)	980
Grain	1355
Ironbridge	964
Kingsnorth	1966
Littlebrook	1370
Tilbury	1041
<b>Total</b>	<b>11344</b>

Note: capacities exclude units which are expected to remain mothballed between 2008 and 2015.

## 4.4.4 Input assumptions – plant retirements/availabilities: Notes

### Nuclear closure assumptions

- Quoted closure dates are based on 31/12 for that year.
- Closure assumptions taken from latest data published by the Nuclear Industry Association.

### LCPD assumptions

- LCPD opted-out plant run according to the economics of the scenario.
- Some will remain open until 2015 and assumed to spread the available 20,000 running hours equally between 2008-2015.
- Others will close by 2012 and have correspondingly higher availabilities whilst they remain in operation.
- The costs of fitting FGD and SCR on Tilbury and Kingsnorth are assumed to be £120/kW. This is only economic in the Steady Growth scenario. All coal plant that have opted-in to LCPD assumed to fit SCR by 2016.

### New build assumptions

- The IDM begins the planning process from the beginning of 2006 and hence does not capture plant that are already under construction or in advanced stages of planning
- Assumptions for new ROC build for 2006, 2007, 2008 are made based on current construction plans
- The Langage (850 MW) and Marchwood (935 MW) CCGTs are assumed to be built under Third Dash for Gas and become operational by 2009. Under all other scenarios it is assumed that these CCGTs (and the Pembroke CCGT) would not become operational before 2009 and hence the decision is left to the IDM.

### Interconnector capacity

- All interconnectors can import and export, depending on the price differentials.
- The existing Moyle and French interconnectors remain in place for the duration of the scenario.
- The same assumptions for new interconnection capacity were made for all scenarios
  - 2010: 500 MW link to Republic of Ireland
  - 2011: 800 MW link to Norway
- There is the possibility of other interconnectors, most notably with the Netherlands, however this was not included in the scenarios.

### Assumed availabilities for new plant

Technology	%
CCGT	87%
Coal (ASC)	87%
Coal (IGCC)	87%
Coal (ASC) + Seq	87%
Coal (IGCC) + Seq	87%
Nuclear	87%
Onshore wind	32%
Offshore wind	36%
Biomass	87%

## 4.4.5 Input assumptions – market structure

- Market consolidation assumed under Steady Growth, Volatile World and DTI Base Case:
  - Three of the large energy companies are acquired
- Market remains more competitive under Restrained Demand and Third Dash for Gas
  - Greater wholesale market liquidity
  - New entry from independents encouraged

## 4.4.5 Input assumptions – market structure: Notes

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### Market structure assumptions

- Under Steady Growth, Volatile World and the DTI Base Case three of the large energy companies are assumed to be acquired separately by three of the remaining vertically integrated companies.
- For modelling simplicity and to isolate market structure changes from other factors that will drive prices under the policy options, all these transactions are assumed to occur from the beginning of the study period.

### Modelling implications of market structure assumptions

- Lower hurdle rates for independents (oil majors, developers) in Restrained Demand and Third Dash for Gas encourage more build compared to the other two scenarios.
- In PLEXOS, the state of competition is reflected by the number of companies competing in the market, and by the flexibility of plant in the portfolio to alter its price and volume offers.
- There are very limited opportunities for any form of competitive bidding by wind, nuclear, biomass and CHP plant. These plant do not have the ability to change their offer prices and adjust volumes accordingly. Price-setting and therefore profitability is largely determined by gas and coal plant, and how each portfolio generator is able to offer these plant into the market to maximise its overall profitability.
- In Volatile World, Steady Growth and the DTI Base Case the market consolidation drives up electricity prices in PLEXOS as fewer companies mean the market is less competitive.

## 4.4.6 Investor hurdle rates – company WACCs

	Debt gearing	Debt prem	Market prem	Risk free rate	Equity beta	Tax rate	Post tax nom WACC
Vertically integrated companies	12.8% - 39.1%	1.5% - 2.0%	4.0% - 4.5%	3.6% - 4.3%	0.65-0.84	30.0%	5.85-6.8%
Nuclear generator	16.2%	2.5%	4.0%	4.3%	1.54	30.0%	9.5%
Independent generator	40.1%	2.5%	4.0%	4.3%	1.01	30.0%	6.9%
Oil Major	25.0%	1.5%	4.0%	4.3%	1.15	30.0%	7.7%
Developer	50.0%	4.5%	6.5%	4.3%	1.00	30.0%	8.5%
Niche Renewable	60.0%	4.5%	6.5%	4.3%	1.20	30.0%	8.5%
TSO (Government financed)	100.0%	0.0%	0.0%	4.3%	0.00	30.0%	3.0%

## 4.4.6 Investor hurdle rates – company WACCs: Notes

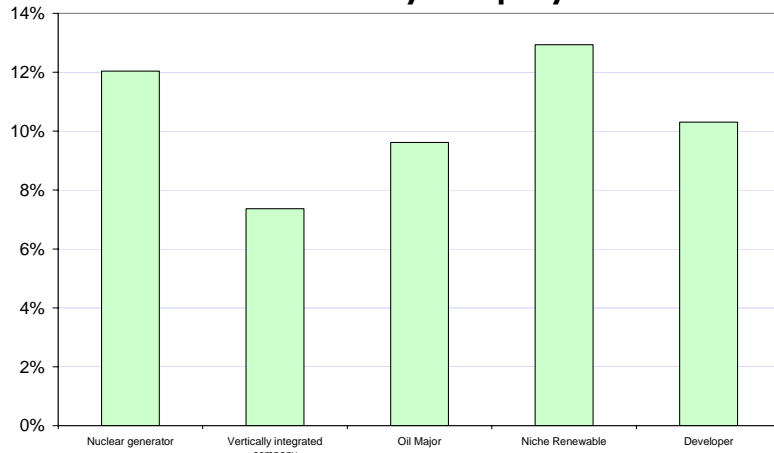
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### Calculation of weighted average cost of capital

- The WACCs shown above are post tax nominal.
- The calculation is  $WACC = \text{Debt gearing} * (\text{Risk free rate} + \text{debt premium}) * (1 - \text{corporation tax rate}) + (1 - \text{Debt gearing}) * (\text{Risk free rate} + \text{Equity premium} * \text{Equity beta})$ .
- Debt gearings are calculated from company annual accounts.
- Debt premia are based on banking reports.
- The market risk premia are calculated from historic stock market performance.
- Equity betas calculated from company's stock performance and calibrated against banking reports.

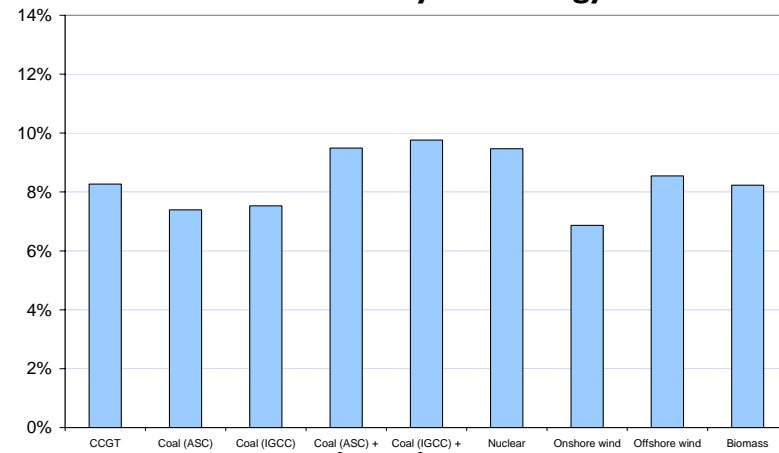
# 4.4.7 Investor hurdle rates – results

Variation by company



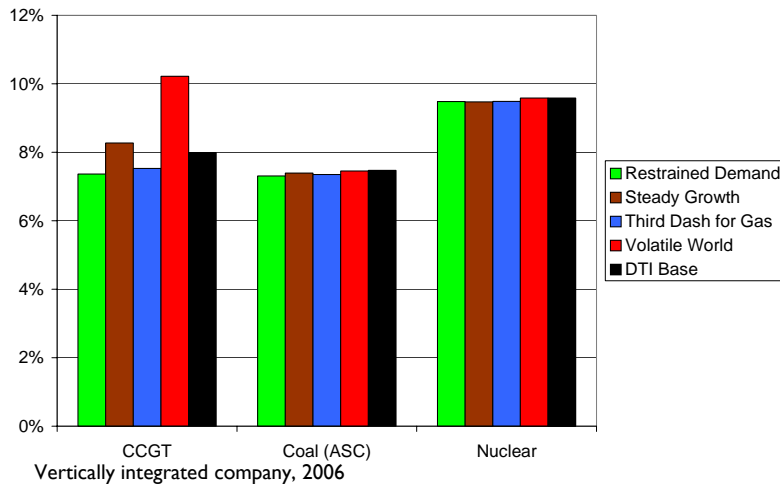
Restrained Demand, CCGT, 2006

Variation by technology



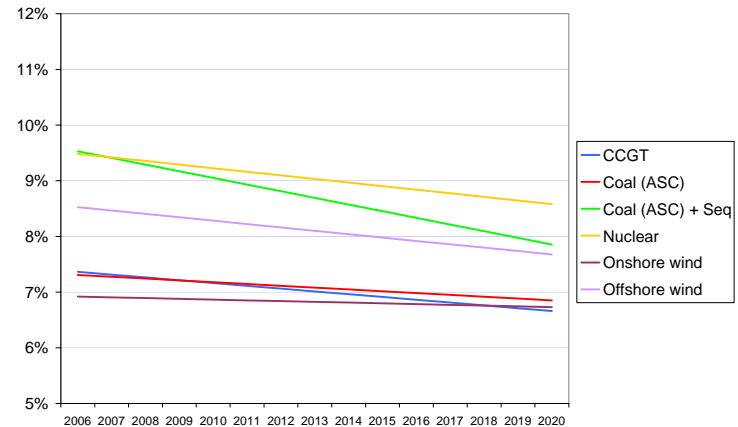
Restrained Demand, Vertically integrated company, 2006

Variation by scenario



Vertically integrated company, 2006

Variation over time



Restrained Demand, Vertically integrated company

## 4.4.7 Investor hurdle rates - results: Notes

### Post-tax nominal hurdle rates

Restrained Demand						2020					
2006						2020					
	Nuclear generator	Vertically integrated company	Oil Major	Niche Renewable	Developer		Nuclear generator	Vertically integrated company	Oil Major	Niche Renewable	Developer
CCGT	12.04%	7.36%	9.62%	12.93%	10.30%	CCGT	11.20%	6.66%	8.69%	11.81%	9.42%
Coal (ASC)	12.01%	7.31%	9.24%	12.58%	9.96%	Coal (ASC)	11.53%	6.85%	8.76%	11.95%	9.50%
Coal (IGCC)	12.54%	7.52%	9.43%	12.83%	10.17%	Coal (IGCC)	12.27%	7.23%	9.11%	12.39%	9.84%
Coal (ASC) + Seq	16.89%	9.53%	11.96%	15.79%	12.52%	Coal (ASC) + Seq	13.58%	7.85%	9.86%	13.26%	10.53%
Coal (IGCC) + Seq	17.05%	9.64%	11.78%	15.72%	12.38%	Coal (IGCC) + Seq	13.62%	7.89%	9.82%	13.27%	10.52%
Nuclear	16.79%	9.48%	11.94%	15.69%	12.50%	Nuclear	14.98%	8.58%	10.56%	14.14%	11.20%
Onshore wind	11.45%	6.92%	8.97%	12.11%	9.67%	Onshore wind	11.32%	6.73%	8.74%	11.84%	9.46%
Offshore wind	14.89%	8.53%	10.68%	14.15%	11.26%	Offshore wind	13.25%	7.68%	9.72%	13.03%	10.38%
Biomass	14.17%	8.28%	10.21%	13.75%	10.86%	Biomass	14.47%	8.28%	10.18%	13.71%	10.83%
Steady Growth						2020					
2006						2020					
CCGT	14.44%	8.27%	10.56%	14.10%	11.19%	CCGT	13.52%	7.81%	10.06%	13.48%	10.72%
Coal (ASC)	12.25%	7.39%	9.32%	12.66%	10.04%	Coal (ASC)	11.53%	6.85%	8.76%	11.95%	9.51%
Coal (IGCC)	12.62%	7.53%	9.39%	12.79%	10.12%	Coal (IGCC)	12.48%	7.33%	9.18%	12.51%	9.91%
Coal (ASC) + Seq	16.82%	9.49%	11.87%	15.67%	12.44%	Coal (ASC) + Seq	13.61%	7.87%	9.88%	13.28%	10.55%
Coal (IGCC) + Seq	17.30%	9.76%	11.94%	15.91%	12.54%	Coal (IGCC) + Seq	13.72%	7.94%	9.85%	13.31%	10.54%
Nuclear	16.77%	9.47%	11.91%	15.67%	12.49%	Nuclear	14.86%	8.53%	10.44%	14.02%	11.10%
Onshore wind	11.34%	6.87%	8.89%	12.02%	9.60%	Onshore wind	11.26%	6.70%	8.72%	11.80%	9.43%
Offshore wind	14.90%	8.54%	10.70%	14.20%	11.29%	Offshore wind	13.19%	7.64%	9.69%	12.99%	10.35%
Biomass	14.09%	8.23%	10.12%	13.64%	10.77%	Biomass	14.47%	8.28%	10.18%	13.71%	10.83%
Third Dash for Gas						2020					
2006						2020					
CCGT	12.02%	7.53%	9.76%	13.09%	10.43%	CCGT	11.32%	6.74%	8.80%	11.94%	9.53%
Coal (ASC)	12.30%	7.35%	9.26%	12.63%	10.01%	Coal (ASC)	11.44%	6.81%	8.71%	11.87%	9.44%
Coal (IGCC)	12.69%	7.54%	9.41%	12.83%	10.14%	Coal (IGCC)	12.13%	7.15%	9.04%	12.30%	9.77%
Coal (ASC) + Seq	16.71%	9.41%	11.77%	15.57%	12.35%	Coal (ASC) + Seq	13.57%	7.85%	9.86%	13.26%	10.54%
Coal (IGCC) + Seq	17.15%	9.69%	11.86%	15.79%	12.46%	Coal (IGCC) + Seq	13.49%	7.82%	9.75%	13.18%	10.45%
Nuclear	16.78%	9.49%	11.90%	15.66%	12.46%	Nuclear	14.91%	8.55%	10.46%	14.08%	11.13%
Onshore wind	11.29%	6.80%	8.83%	11.94%	9.54%	Onshore wind	11.30%	6.72%	8.75%	11.83%	9.46%
Offshore wind	14.91%	8.54%	10.69%	14.19%	11.28%	Offshore wind	13.24%	7.67%	9.72%	13.03%	10.38%
Biomass	14.24%	8.30%	10.26%	13.79%	10.88%	Biomass	14.29%	8.20%	10.10%	13.60%	10.75%
Volatile World						2020					
2006						2020					
CCGT	18.44%	10.22%	12.90%	16.97%	13.40%	CCGT	16.92%	9.49%	12.04%	15.92%	12.59%
Coal (ASC)	12.46%	7.45%	9.40%	12.78%	10.12%	Coal (ASC)	12.86%	7.49%	9.46%	12.84%	10.17%
Coal (IGCC)	12.75%	7.58%	9.47%	12.87%	10.19%	Coal (IGCC)	13.33%	7.76%	9.63%	13.11%	10.35%
Coal (ASC) + Seq	16.82%	9.48%	11.90%	15.70%	12.45%	Coal (ASC) + Seq	14.21%	8.19%	10.19%	13.70%	10.86%
Coal (IGCC) + Seq	17.21%	9.71%	11.86%	15.86%	12.47%	Coal (IGCC) + Seq	14.39%	8.28%	10.20%	13.81%	10.90%
Nuclear	17.01%	9.59%	11.99%	15.82%	12.54%	Nuclear	14.62%	8.43%	10.19%	13.82%	10.88%
Onshore wind	11.55%	6.95%	9.03%	12.17%	9.73%	Onshore wind	11.72%	7.06%	9.16%	12.32%	9.84%
Offshore wind	15.08%	8.62%	10.82%	14.33%	11.40%	Offshore wind	13.58%	7.88%	9.96%	13.32%	10.61%
Biomass	14.34%	8.35%	10.28%	13.83%	10.92%	Biomass	15.21%	8.68%	10.68%	14.31%	11.30%
DTI Base Case						2020					
2006						2020					
CCGT	13.87%	7.99%	10.14%	10.64%	10.80%	CCGT	11.57%	6.86%	8.96%	9.60%	9.68%
Coal (ASC)	12.79%	7.47%	9.43%	10.05%	10.13%	Coal (ASC)	12.05%	7.10%	9.07%	9.72%	9.79%
Coal (IGCC)	13.40%	7.78%	9.68%	10.31%	10.39%	Coal (IGCC)	12.82%	7.49%	9.42%	10.04%	10.13%
Coal (ASC) + Seq	18.50%	10.30%	12.42%	12.66%	12.98%	Coal (ASC) + Seq	13.57%	7.85%	9.88%	10.40%	10.53%
Coal (IGCC) + Seq	18.06%	10.10%	12.12%	12.48%	12.73%	Coal (IGCC) + Seq	13.39%	7.76%	9.73%	10.31%	10.43%
Nuclear	17.07%	9.59%	11.96%	12.16%	12.53%	Nuclear	14.94%	8.57%	10.51%	10.97%	11.16%
Onshore wind	11.82%	6.97%	9.06%	9.65%	9.75%	Onshore wind	11.55%	6.85%	8.89%	9.51%	9.59%
Offshore wind	15.27%	8.65%	10.82%	11.16%	11.41%	Offshore wind	13.38%	7.74%	9.80%	10.30%	10.45%
Biomass	14.83%	8.47%	10.44%	10.92%	11.07%	Biomass	15.26%	8.68%	10.65%	11.11%	11.28%

## 4.4.8 Input assumptions – others

- Planning/decision times
  - Assumed to be longer under Volatile World
  - Nuclear planning process speeded up under NOCs policy option
- Carbon allowances
  - Assumed to be auctioned in Phase II EU ETS and beyond
  - Sensitivity on this assumption is shown in the results

**Investment Timeframes**

Technology	Economic lifetime	Construction	Planning/ Decision
CCGT	20	2	1
Coal (ASC)	25	3	2
Coal (IGCC)	25	4	2
Coal (ASC) + Seq	25	4	2
Coal (IGCC) + Seq	25	5	2
Nuclear	40	6	7
Onshore wind	20	1	2
Offshore wind	20	2	2
Biomass	20	2	2

Note: applies to Restrained Demand, Steady Growth, Third Dash for Gas

## 4.4.8 Input assumptions – others: Notes

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### Planning/decision times

- Under Volatile World, the planning/decision times for thermal plant are assumed to be 1 year longer.
- Under NOCs policy option, the planning/decision time is assumed to be 1 year shorter for nuclear plant.

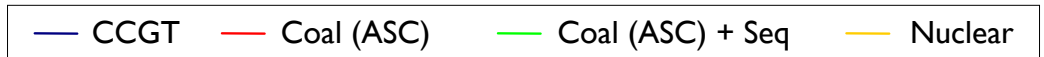
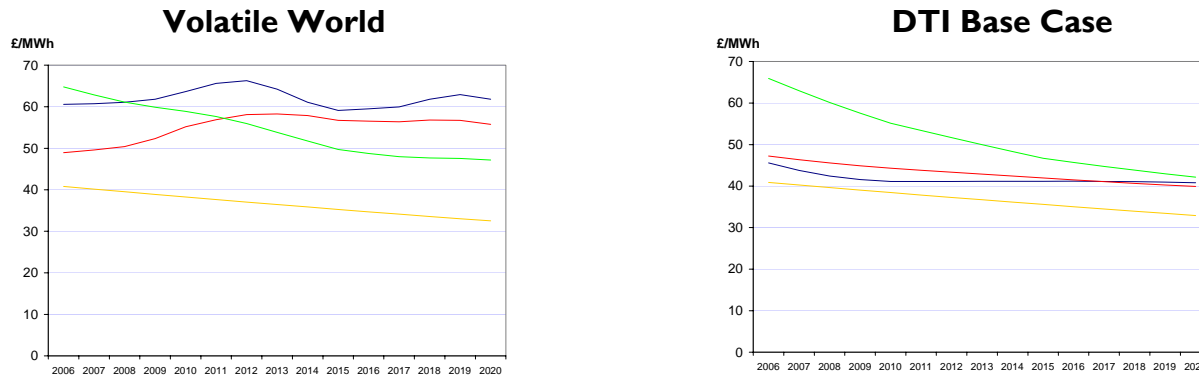
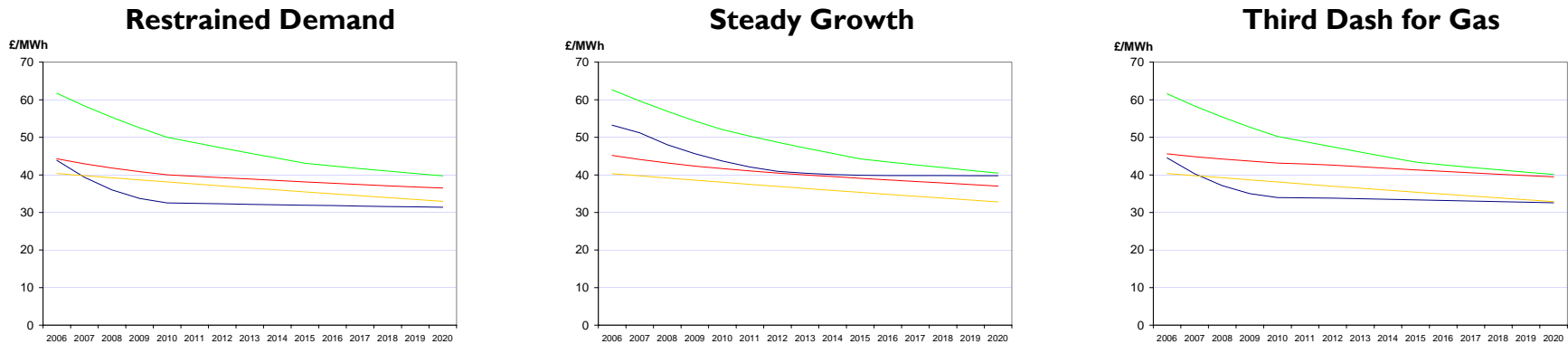
### Build constraints

- Constraints are placed on the amount of capacity (by technology type and in total) that each company can have under construction at any one time.
- The total supply of wind capacity by 2020 is limited due to availability of suitable sites:
  - Onshore: 7.4 GW
  - Offshore: 4.5 GW

### Plant constraints

- There are limits placed on co-fired coal plant for the amount of biomass that qualifies for ROCs. These limits are 10% of the total supplier obligation in each year through to 2011, after which this falls to 5%. No co-firing qualifies for ROCs after 2016.
- CCGTs with fixed destination clauses in their gas contracts are modelled with a must-run obligation that fulfils the minimum take obligation in their contracts. This applies to a few older CCGTs with LTI-style gas contracts.
- Plant with contracts that allow gas to be taken at the NBP are assumed to mark them to market and dispatch the plant according to the spot price of gas rather than the contract gas price.

# 4.4.9 Long run marginal costs (required prices)



## 4.4.9 Long run marginal costs (required prices): Notes

### Restrained Demand

£/MWh	Cap (MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CCGT	400	43.88	39.39	36.01	33.73	32.53	32.41	32.30	32.18	32.06	31.94	31.83	31.71	31.60	31.48	31.37
Coal (ASC)	500	44.31	42.96	41.83	40.86	40.05	39.65	39.27	38.89	38.51	38.14	37.78	37.43	37.10	36.79	36.50
Coal (IGCC)	500	47.39	46.11	45.02	44.09	43.29	42.88	42.47	42.07	41.67	41.28	40.89	40.52	40.16	39.82	39.49
Coal (ASC) + Seq	500	61.73	58.37	55.33	52.55	50.00	48.58	47.17	45.79	44.43	43.10	42.37	41.67	41.01	40.38	39.78
Coal (IGCC) + Seq	500	63.32	60.08	57.12	54.40	51.88	50.24	48.64	47.07	45.53	43.37	42.41	41.49	40.60	39.75	38.92
Nuclear	1200	40.37	39.80	39.24	38.68	38.13	37.59	37.05	36.52	35.99	35.48	34.97	34.46	33.96	33.47	32.99
Onshore wind	25	38.58	38.49	38.39	38.30	38.20	38.11	38.01	37.92	37.83	37.73	37.64	37.54	37.45	37.36	37.26
Offshore wind	100	68.81	68.26	67.70	67.16	66.61	66.07	65.53	65.00	64.47	63.94	63.42	62.90	62.38	61.87	61.36
Biomass	120	85.30	84.84	84.39	83.96	83.52	83.10	82.68	82.27	81.87	81.47	81.08	80.69	80.31	79.93	79.56

### Steady Growth

£/MWh	Cap (MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CCGT	400	53.27	51.19	48.04	45.64	43.68	42.10	40.97	40.46	40.11	39.91	39.85	39.83	39.82	39.80	39.79
Coal (ASC)	500	45.20	44.11	43.17	42.33	41.68	41.06	40.50	40.00	39.55	39.12	38.69	38.26	37.85	37.44	37.03
Coal (IGCC)	500	48.15	47.01	46.01	45.10	44.36	43.65	42.99	42.38	41.82	41.27	40.73	40.19	39.66	39.13	38.61
Coal (ASC) + Seq	500	62.65	59.67	56.93	54.35	52.06	50.32	48.68	47.14	45.70	44.28	43.48	42.69	41.93	41.19	40.47
Coal (IGCC) + Seq	500	64.64	61.50	58.58	55.83	53.33	51.29	49.35	47.51	45.76	43.39	42.24	41.11	40.02	38.95	37.90
Nuclear	1200	40.34	39.75	39.18	38.61	38.05	37.49	36.95	36.40	35.87	35.34	34.83	34.31	33.81	33.31	32.82
Onshore wind	25	38.43	38.34	38.25	38.16	38.07	37.99	37.90	37.81	37.72	37.63	37.54	37.45	37.36	37.27	37.19
Offshore wind	100	68.86	68.29	67.72	67.16	66.60	66.05	65.50	64.95	64.41	63.87	63.33	62.80	62.27	61.75	61.23
Biomass	120	85.22	84.65	84.09	83.53	82.98	82.44	81.90	81.37	80.84	80.32	79.81	79.30	78.80	78.31	77.81

### Third Dash For Gas

£/MWh	Cap (MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CCGT	400	44.52	40.27	37.13	35.03	33.96	33.91	33.81	33.65	33.50	33.34	33.19	33.04	32.88	32.73	32.58
Coal (ASC)	500	45.62	44.82	44.22	43.67	43.14	42.92	42.60	42.17	41.75	41.34	40.93	40.54	40.17	39.82	39.48
Coal (IGCC)	500	48.54	47.81	47.26	46.75	46.26	46.06	45.76	45.36	44.97	44.58	44.20	43.84	43.49	43.16	42.84
Coal (ASC) + Seq	500	61.60	58.34	55.40	52.71	50.23	48.84	47.46	46.09	44.74	43.41	42.68	42.00	41.34	40.72	40.13
Coal (IGCC) + Seq	500	63.65	60.50	57.62	54.97	52.52	50.93	49.36	47.81	46.30	44.16	43.22	42.32	41.46	40.62	39.82
Nuclear	1200	40.39	39.80	39.23	38.66	38.11	37.55	37.01	36.47	35.94	35.41	34.89	34.38	33.88	33.38	32.89
Onshore wind	25	38.37	38.29	38.20	38.12	38.04	37.96	37.88	37.80	37.72	37.64	37.56	37.48	37.40	37.32	37.24
Offshore wind	100	68.88	68.31	67.75	67.20	66.65	66.10	65.55	65.01	64.48	63.94	63.42	62.89	62.37	61.85	61.34
Biomass	120	85.37	84.90	84.43	83.98	83.53	83.09	82.65	82.22	81.80	81.39	80.98	80.58	80.18	79.79	79.40

### Volatile World

£/MWh	Cap (MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CCGT	400	60.57	60.75	61.07	61.82	63.65	65.61	66.26	64.22	61.10	59.10	59.52	59.96	61.82	62.91	61.82
Coal (ASC)	500	48.92	49.61	50.41	52.36	55.19	56.85	58.11	58.28	57.88	56.72	56.56	56.38	56.79	56.73	55.76
Coal (IGCC)	500	51.52	52.08	52.72	54.42	56.94	58.38	59.45	59.53	59.08	57.90	57.44	57.44	57.74	57.60	56.61
Coal (ASC) + Seq	500	64.77	62.85	61.12	59.91	58.87	57.67	55.97	53.83	51.75	49.72	48.74	47.99	47.65	47.53	47.18
Coal (IGCC) + Seq	500	66.13	63.98	62.00	60.47	59.11	57.67	55.84	53.64	51.51	48.75	47.56	46.57	45.93	45.48	44.85
Nuclear	1200	40.82	40.17	39.53	38.89	38.27	37.65	37.04	36.45	35.86	35.28	34.71	34.14	33.59	33.05	32.51
Onshore wind	25	38.71	38.67	38.63	38.59	38.55	38.51	38.47	38.43	38.39	38.35	38.31	38.27	38.23	38.18	38.14
Offshore wind	100	69.28	68.75	68.23	67.71	67.19	66.67	66.16	65.65	65.15	64.65	64.15	63.65	63.16	62.67	62.19
Biomass	120	85.48	85.07	84.66	84.27	83.88	83.50	83.12	82.75	82.39	82.03	81.68	81.33	80.99	80.65	80.32

### DTI Base Case

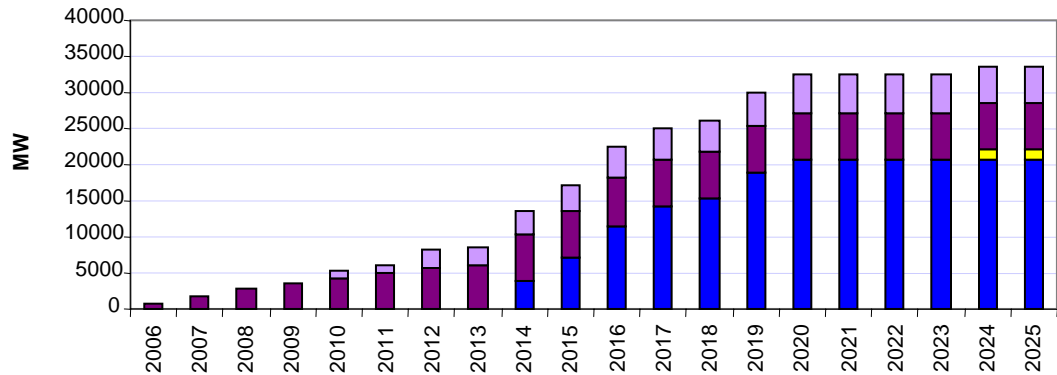
£/MWh	Cap (MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CCGT	400	45.57	43.78	42.44	41.56	41.12	41.13	41.14	41.15	41.16	41.17	41.17	41.14	41.07	40.97	40.82
Coal (ASC)	500	47.24	46.35	45.57	44.89	44.31	43.83	43.35	42.88	42.42	41.96	41.51	41.08	40.67	40.28	39.91
Coal (IGCC)	500	50.35	49.37	48.48	47.68	46.98	46.36	45.75	45.14	44.54	43.95	43.36	42.79	42.24	41.71	41.20
Coal (ASC) + Seq	500	65.92	62.95	60.17	57.57	55.15	53.40	51.68	49.99	48.34	46.72	45.72	44.76	43.85	42.98	42.15
Coal (IGCC) + Seq	500	66.51	63.41	60.49	57.76	55.20	53.73	52.30	50.90	49.52	47.51	46.70	45.93	45.18	44.47	43.78
Nuclear	1200	40.88	40.26	39.65	39.04	38.45	37.86	37.28	36.71	36.15	35.59	35.05	34.51	33.97	33.45	32.93
Onshore wind	25	39.07	38.96	38.86	38.75	38.64	38.53	38.42	38.32	38.21	38.10	37.99	37.89	37.78	37.67	37.57
Offshore wind	100	69.70	69.10	68.49	67.90	67.30	66.71	66.13	65.55	64.97	64.40	63.84	63.27	62.72	62.16	61.61
Biomass	120	85.97	85.40	84.83	84.27	83.71	83.17	82.62	82.09	81.56	81.04	80.52	80.01	79.50	79.00	78.50

# 5. Analysis results

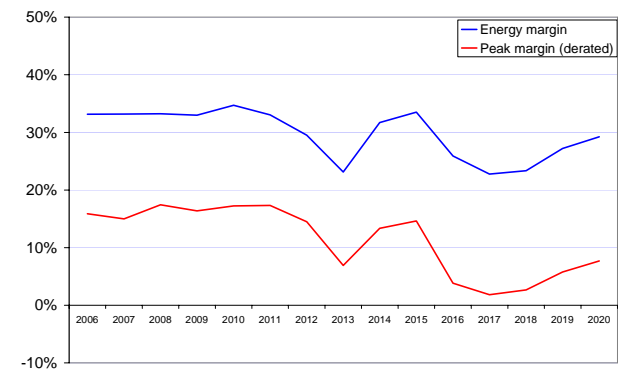
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# 5.1.1 Status Quo - Restrained Demand

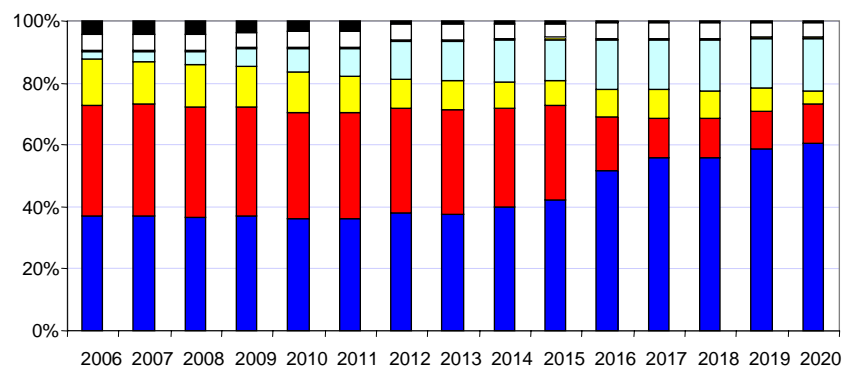
New plant by type



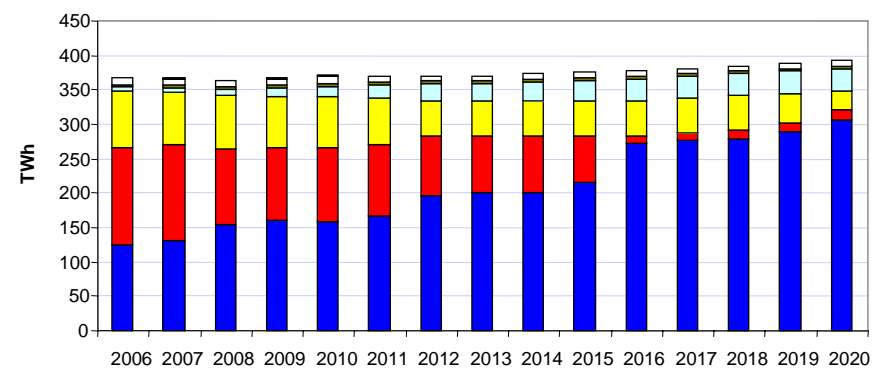
Supply margins



Capacity mix



Output



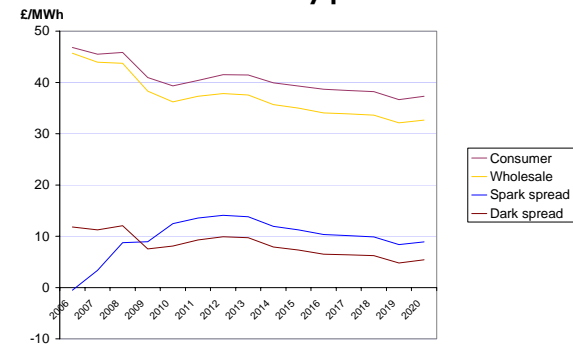
■ Gas 
 ■ Coal 
 ■ Nuclear 
 ■ Wind 
 ■ Biomass 
 ■ Hydro 
 ■ Other

## 5.1.1 Status Quo – Restrained Demand: Notes

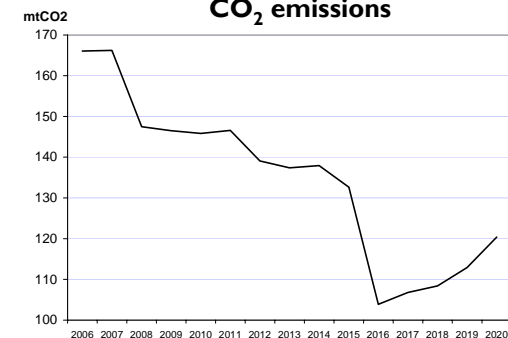
### Comments

- This scenario is characterised by strong CCGT build reflecting the low cost of gas.
- One new nuclear plant becomes operational in 2024.
- Electricity prices generally decline reflecting the reductions in underlying generation costs, although an increase occurs around 2012 associated with tightening of the energy margin when some LCPD opted-out plant close.
- A further tightening of the energy margin occurs after 2015 when additional coal plant closures take place. The impact on time-weighted annual average prices is less pronounced due to a more competitive mid-merit section of the market as CCGTs owned by independents play a greater role in price setting.
- The tightening of the peak capacity margin at this time is likely to lead to higher and more volatile peak prices.
- The reason that the peak capacity margin is more adversely affected than the energy margin by the closure of LCPD opt out plant is that due to the limitation on running hours their contribution to the annual energy margin is significantly lower than their contribution to peak plant availability.
- The displacement of coal generation for gas helps to reduce carbon emissions with a particularly pronounced drop after 2015 as the coal plant close.
- Coal output levels after 2015 are very low. Those coal plant that remain open are largely running at peak.
- Despite maintaining a relatively competitive market structure, most new plant build is undertaken by the vertically integrated players who can take advantage of their relatively low cost of capital and the lower risks associated with their portfolio positions.
- The growth in market share of the vertically integrated players is at the expense of nuclear generators and independents.
- Oil majors re-enter the market seeking to monetise gas positions.

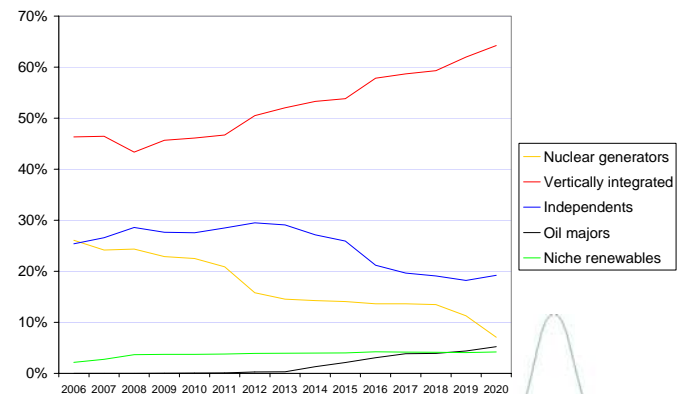
### Electricity prices



### CO<sub>2</sub> emissions

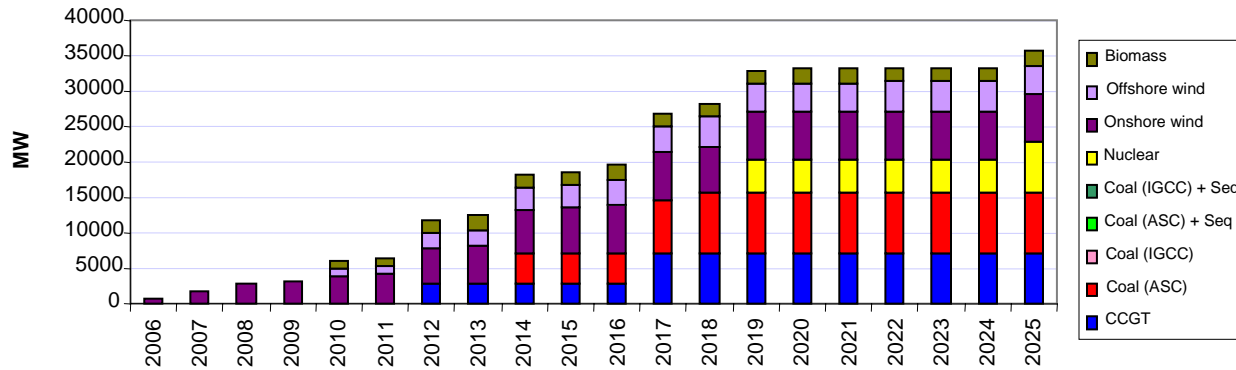


### Generation market shares

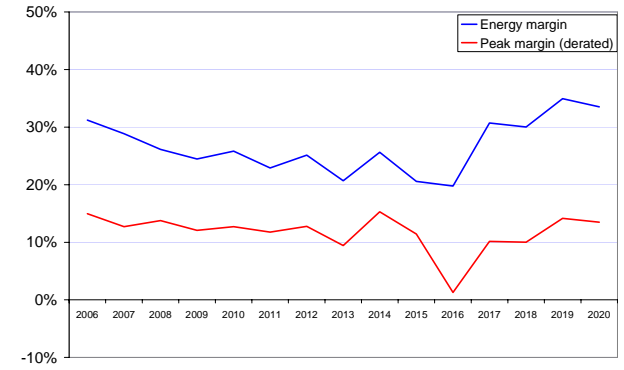


# 5.1.2 Status Quo – Steady Growth

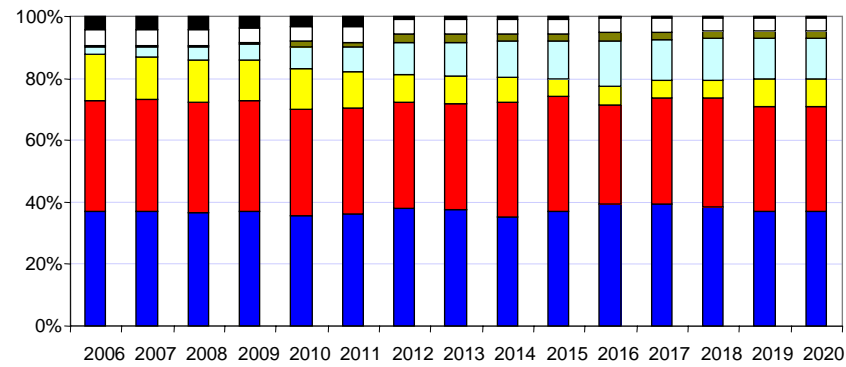
New plant by type



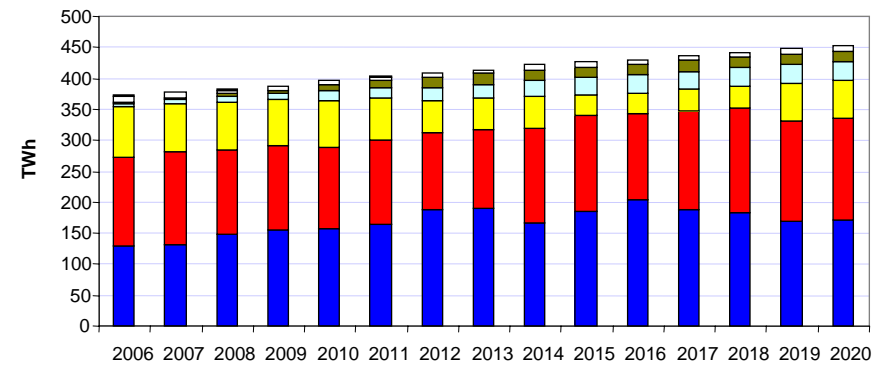
Supply margins



Capacity mix



Output



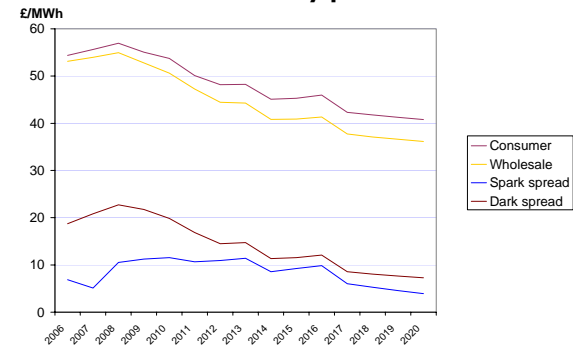
■ Gas ■ Coal ■ Nuclear ■ Wind ■ Biomass ■ Hydro ■ Other

## 5.1.2 Status Quo – Steady Growth: Notes

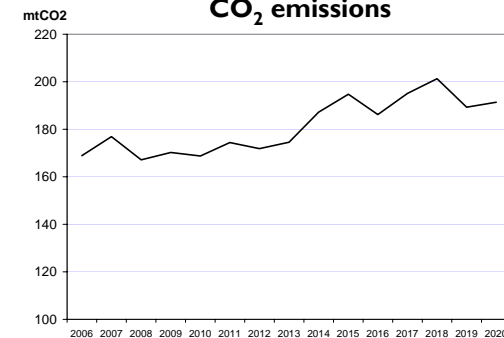
### Comments

- In this scenario, the new plant build is relatively diverse with a combination of CCGT and ASC coal in the early years and new nuclear becoming operational from 2019. New build biomass plant also features.
- In general, electricity prices decline to reflect the underlying reductions in generation costs. However, a general tightening of the energy margin leads to an initial increase in the dark and spark spreads.
- A significant dip in the peak capacity margin in 2016 could lead to high and volatile prices and the possibility of lost load.
- In this scenario, it is economic for Tilbury and Kingsnorth to fit FGD and SCR equipment and it is assumed that they meet the “new-new” standard and remain open throughout the study period.
- Increasing carbon emissions reflect the increasing demand and the fact that it is coal generation that is increasingly meeting the new demand.
- In this scenario, it is assumed that 3 of the large players are acquired by other incumbents (from the start of the study period). Hence, the market share of the vertically integrated players starts high at approximately 67% and increases to almost 80% by 2020.

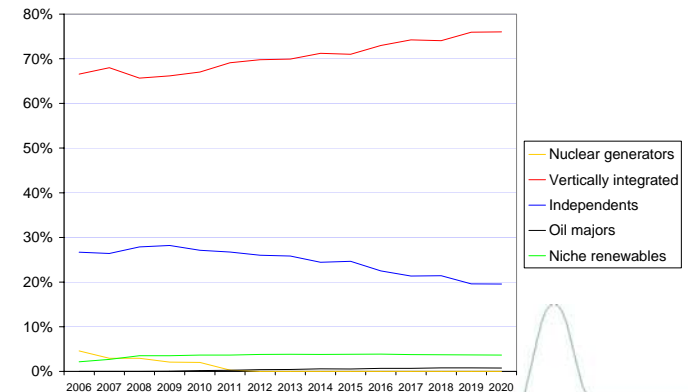
### Electricity prices



### CO<sub>2</sub> emissions

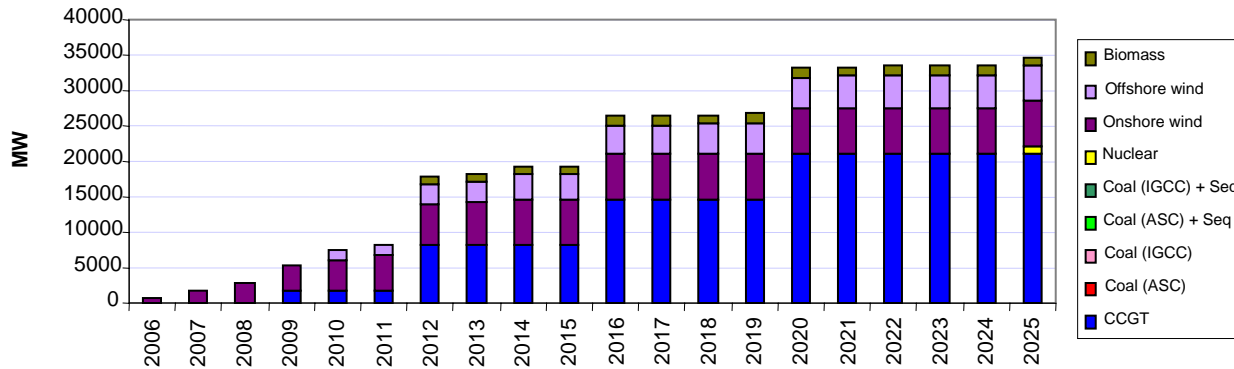


### Generation market shares

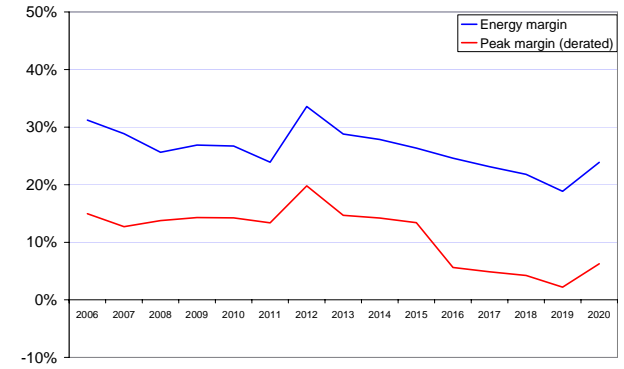


# 5.1.3 Status Quo – Third Dash for Gas

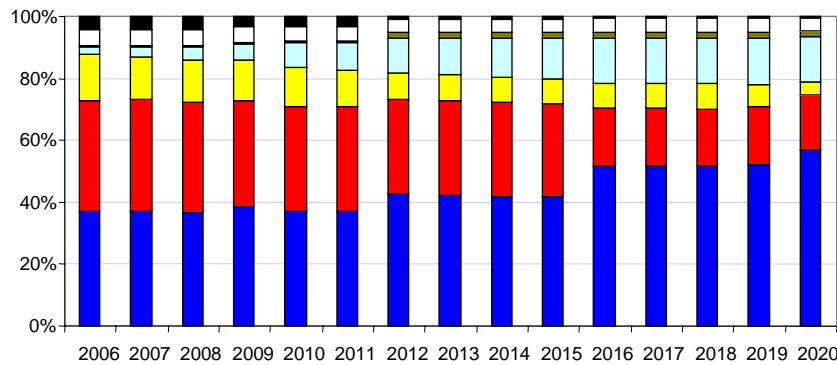
New plant by type



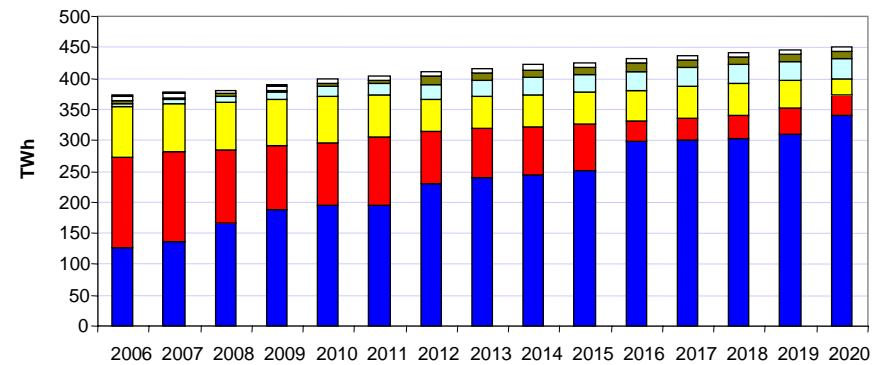
Supply margins



Capacity mix



Output



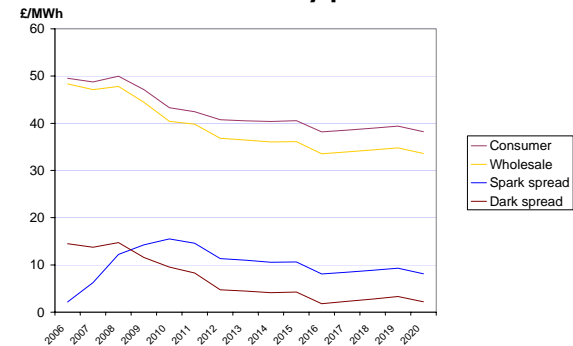
■ Gas ■ Coal ■ Nuclear □ Wind ■ Biomass □ Hydro ■ Other

## 5.1.3 Status Quo – Third Dash for Gas: Notes

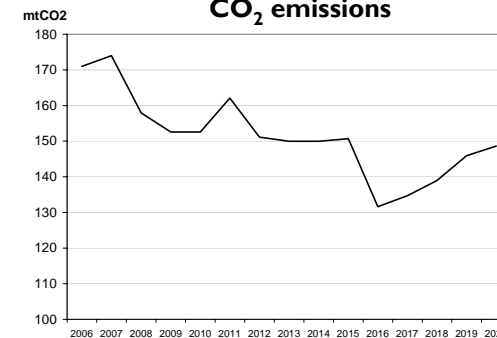
### Comments

- In this scenario, there is significant investment in new CCGTs concentrated into 4 tranches:
  - Tranche 1: Langage and Marchwood become operational in 2009
  - Tranche 2: 2012
  - Tranche 3: 2016
  - Tranche 4: 2020
- Although gas prices start to fall significantly in the early years, electricity prices initially remain high opening up a spark spread that encourages the first wave of investment.
- Thereafter there is a steady decrease in price reflecting the lower gas prices, although this starts to level off during the hiatus in new build between 2016 and 2020.
- The third tranche of new build, becoming operational in 2016, coincides with the closures of many coal plant in 2015 thus mitigating the fall in energy margin seen in other scenarios at this time.
- There is, however, a fairly significant fall in peak capacity margin which would be exacerbated if the new CCGT were non operational or commissioning at the start of 2016 during the peak demand periods.
- As in Restrained Demand, coal output is squeezed although not quite to the same extent since with higher demand there is a bit more room for coal plant to generate.
- The benefits of swapping coal for gas generation in terms of carbon emissions are exhausted by 2016 and thereafter the rising demand leads to increasing carbon emissions.
- A similar pattern to Restrained Demand can be seen in the growing dominance of the vertically integrated players over time.

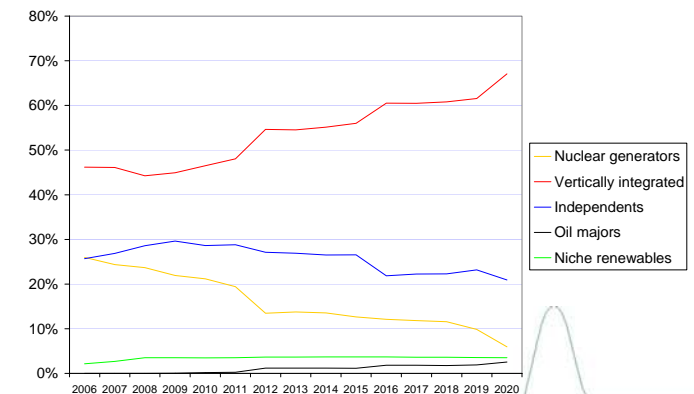
Electricity prices



CO<sub>2</sub> emissions

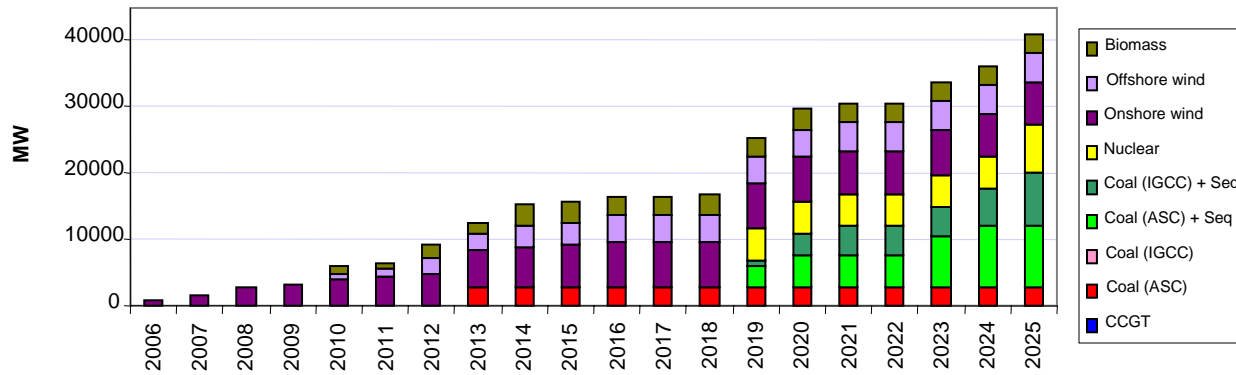


Generation market shares

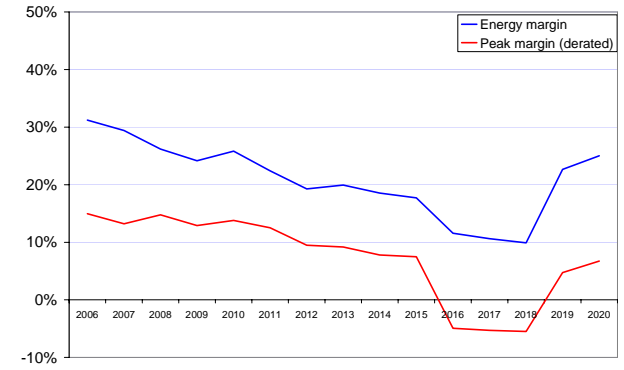


# 5.1.4 Status Quo – Volatile World

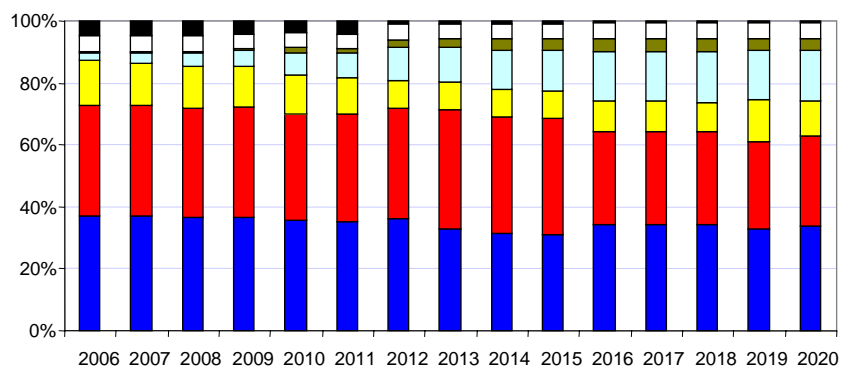
New plant by type



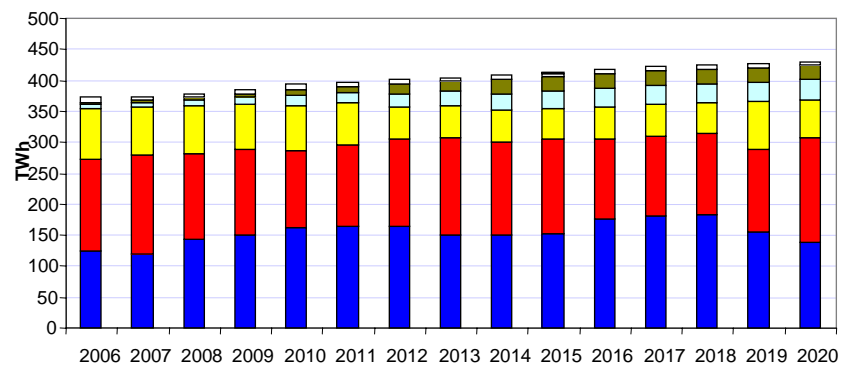
Supply margins



Capacity mix



Output



■ Gas ■ Coal ■ Nuclear □ Wind ■ Biomass □ Hydro ■ Other

## 5.1.4 Status Quo – Volatile World: Notes

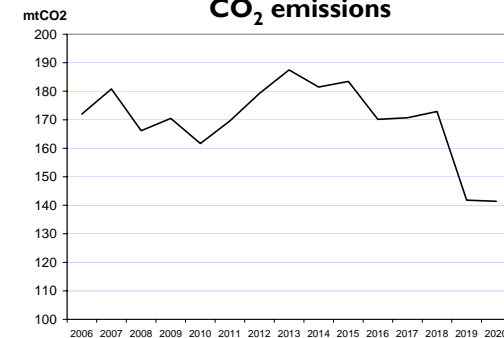
### Comments

- In Volatile World, new investment is deterred for a number of reasons:
  - High gas prices make CCGTs uneconomic
  - High carbon prices makes the economics of new coal build marginal and as an untested technology in the UK leads to a lengthy planning and decision period
  - Whilst economic, the long planning and construction times for new nuclear means that no new plant can become operational in the near term.
- It is only when the economics of carbon sequestration become favourable that significant new build takes place.
- It should be noted that whilst the model predicts 4.8 GW of new nuclear becoming operational in 2019, constraints on the availability of resources to build this plant in GB may mean that there is more of a staggering of this new capacity in reality.
- The high level and volatility of electricity prices is in part a reflection of the underlying fuel costs but also includes significant volatility in dark and spark spreads.
- This is particularly apparent in the period 2016-2018 when there is a very low energy margin (down to 10%) and a negative peak capacity margin.
- These negative peak capacity margins would lead to very high and volatile peak prices and almost certainly to some load curtailment if no other measures were taken to secure peak load.
- Output from existing gas plant fluctuates depending on the relative economics of gas and coal generation.
- The variations in carbon emissions reflect this changing generation pattern. Once the nuclear and sequestration facilities become operational there is a significant reduction in carbon emissions.

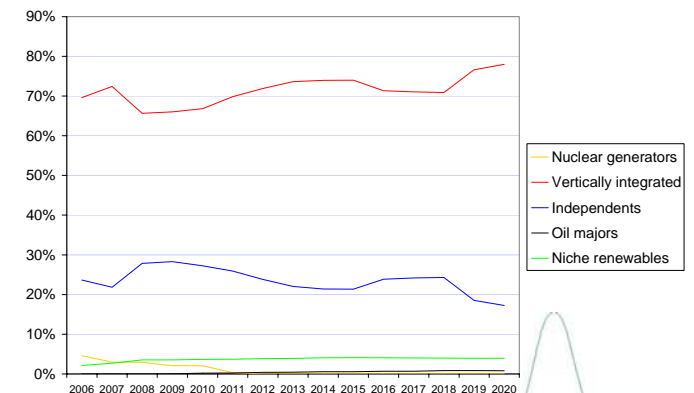
Electricity prices



CO<sub>2</sub> emissions

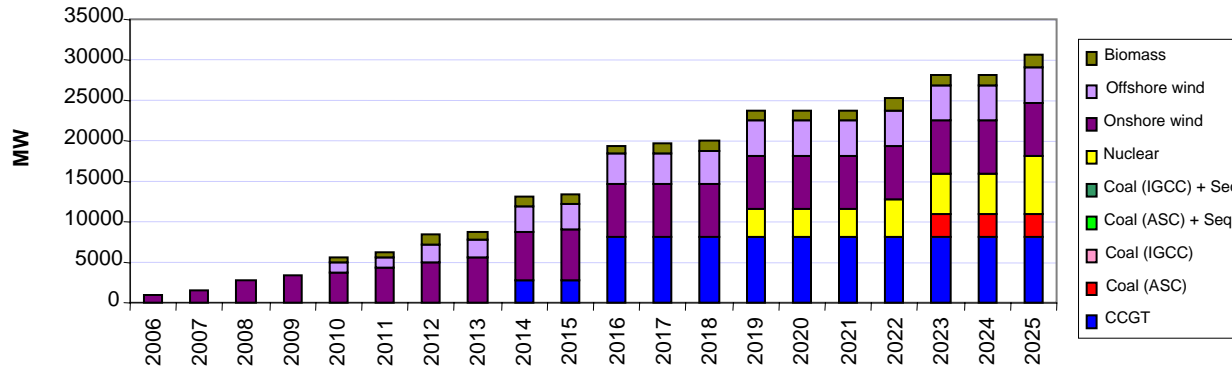


Generation market shares

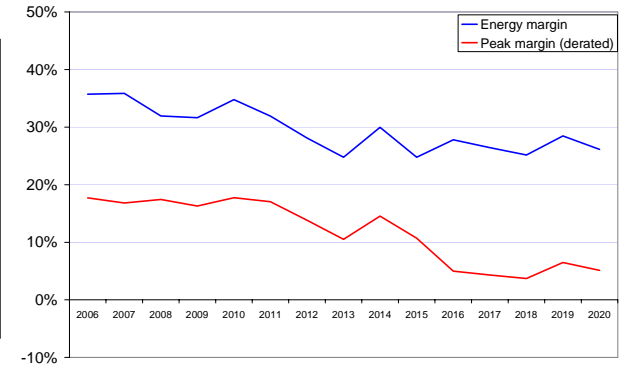


# 5.1.5 Status Quo – DTI Base Case

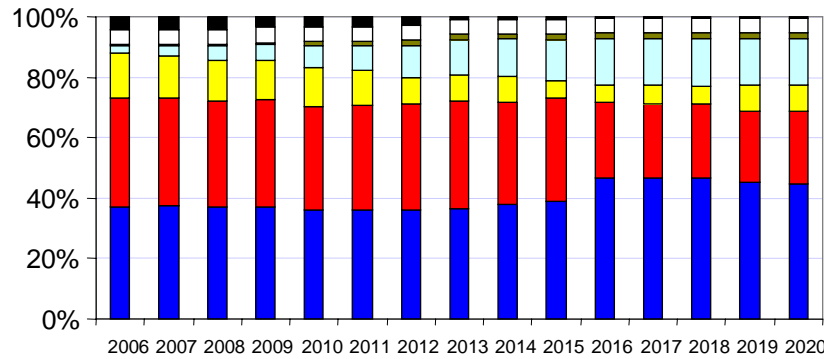
New plant by type



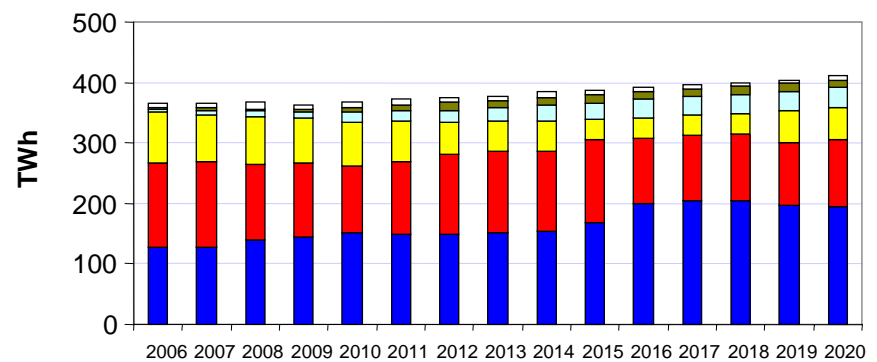
Supply margins



Capacity mix



Output



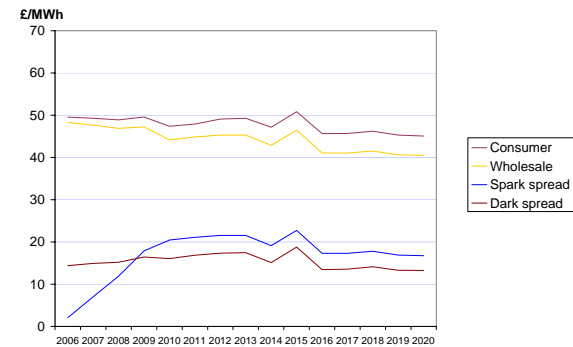
■ Gas ■ Coal ■ Nuclear □ Wind ■ Biomass □ Hydro ■ Other

## 5.1.5 Status Quo – DTI Base Case: Notes

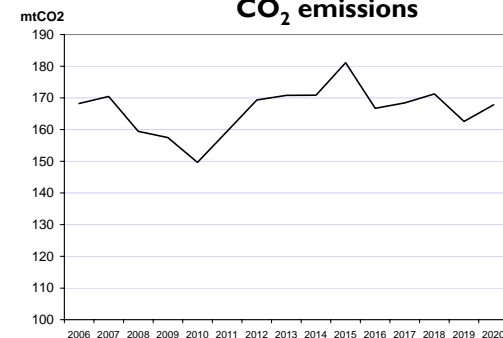
### Comments

- In this scenario, nuclear is the most economic technology. On the assumption that the planning environment supports a new nuclear build programme, 3.6 GW of nuclear would become operational by 2019 and a further 3.6 GW by 2025. (Exactly when the new plant would come on-line would be determined by the availability of construction capacity).
- CCGT is the most economic thermal technology until around 2017, when advanced super-critical coal becomes the least expensive on the back of continuing falls in coal prices. This leads to the first advanced super-critical plant becoming operational in 2023 (outside of the main study period, 2006-2020).
- The energy margin falls from current levels and then remains in the range of 25% to 30% between 2012 and 2020. The post-2015 retirements caused by LCPD are reasonably well anticipated with an additional 2.8GW of CCGT plant becoming operational in 2014, and then a further 5.2GW in 2016.
- As in other scenarios, the peak capacity margin falls significantly in 2016, although the effect is least severe under the DTI Base Case.
- CO<sub>2</sub> emissions fall significantly in the early years since the falling gas prices (and high carbon and coal prices) leads to a reverse in the gas to coal switching trend. Thereafter rising demand, static gas prices and falling coal prices lead to a return to current levels of emissions.
- This scenario assumes market consolidation from the start of the study period and the vertically integrated companies continue to expand their market share at the expense of independents.

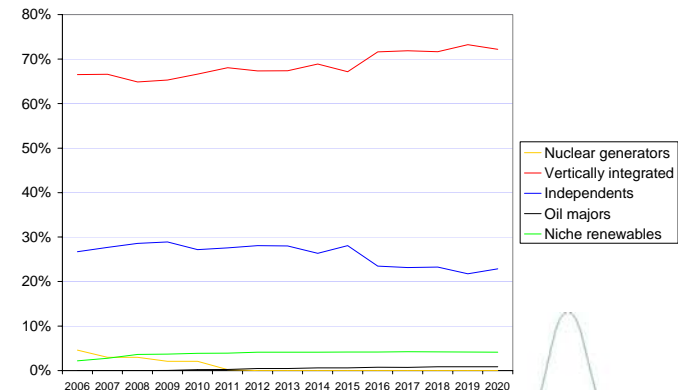
### Electricity prices



### CO<sub>2</sub> emissions



### Generation market shares



## 5.1.6 Status Quo – Summary metrics – (I)

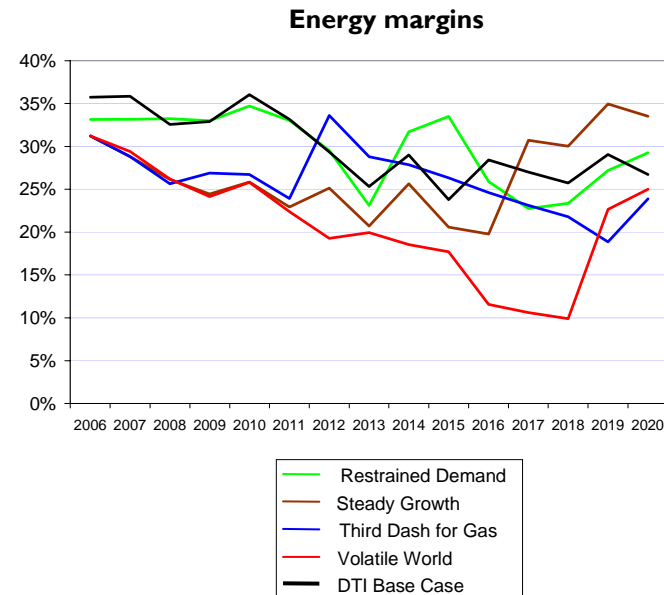
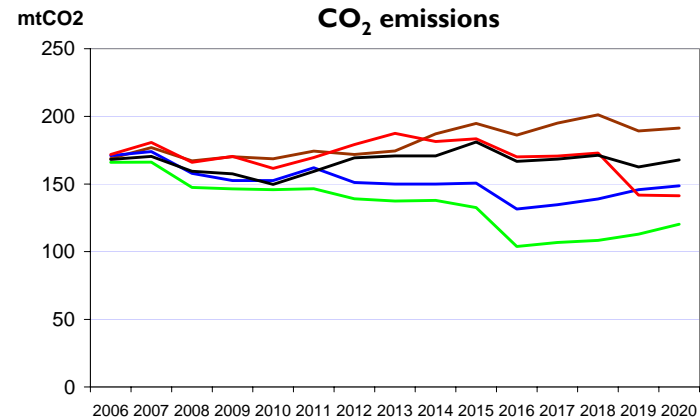
2006 – 2020

Metric		Restrained Demand	Steady Growth	Third Dash for Gas	Volatile World	DTI Base Case
Total generation costs (£bn)		145.9	175.9	162.4	210.7	164.2
Total consumer costs (£bn)		179.6	234.7	205.8	314.6	213.3
Annual average CO <sub>2</sub> emissions		134.5	181.2	151.4	169.9	168.3
Supply margins	Minimum energy margin	22.8%	19.8%	18.9%	10.4%	23.8%
	Minimum peak capacity margin	1.8%	0.9%	2.2%	-5.5%	4.1%
Generation diversity (2020)	% capacity of top 1	58.6%	36.0%	55.0%	35.9%	42.4%
	% capacity of top 2	74.7%	68.1%	73.0%	64.6%	66.1%

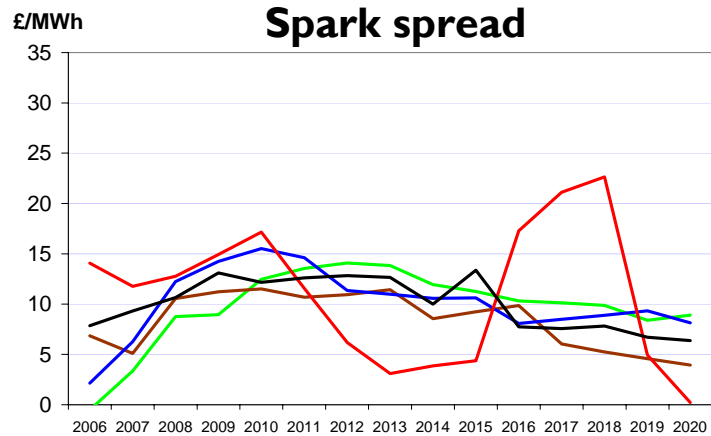
## 5.1.6 Status Quo – Summary metrics – (1): Notes

### Comments

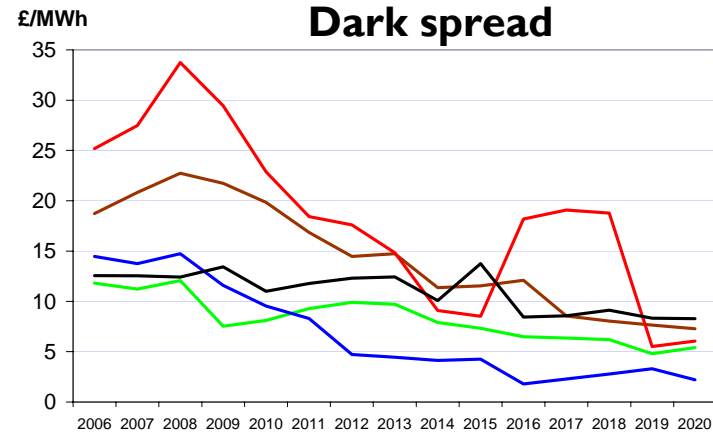
- Generation costs include subsidies (where these make up part of the investment costs) and have the same definition as ‘resource costs’ as defined in the Energy Review Guidance document.
- A rate of 3.5% is used to discount the future cost streams as specified in the Energy Review Guidance document.
- The differences in generation costs between scenarios largely reflect the differences in fuel costs. The higher costs in Third Dash for Gas relative to Restrained Demand are a function of the higher demand in that scenario.
- The variations in consumer costs also reflect the market structure, with the NPV of generator gross profits higher in Steady Growth (£67bn), Volatile World (£112bn) and DTI Base Case (£57bn) than in Restrained Demand (£40bn) and Third Dash for Gas (£53bn).
- Carbon dioxide emissions are a function of the fuel mix and demand levels. The only deviation from the general trends is in the later years of Volatile World when a significant proportion of low carbon technologies enter the market.
- There is a wide variation in energy margins between the scenarios (which is also reflected in the peak capacity margins). The general trend of the energy margin in the scenarios, other than Volatile World, is a slight decline from current levels. (In Steady Growth the energy margin has recovered back to current levels by the end of the study period.) Under Volatile World there is a steady decline until 2018 by which time the energy margin is less than 10%. After that point, the resulting high prices and the reduction in sequestration costs, leads to strong new plant build together with new nuclear plant becoming operational.
- From a diversity perspective, Restrained Demand and Third Dash for Gas (and to a lesser extent DTI Base Case) would be a cause for concern, with over double the amount of gas generation compared to current levels. In Steady Growth and Volatile World, generation diversity remains similar to current levels but with declining nuclear output being compensated for by increases from renewables.



# 5.1.6 Status Quo – Summary metrics – (2)



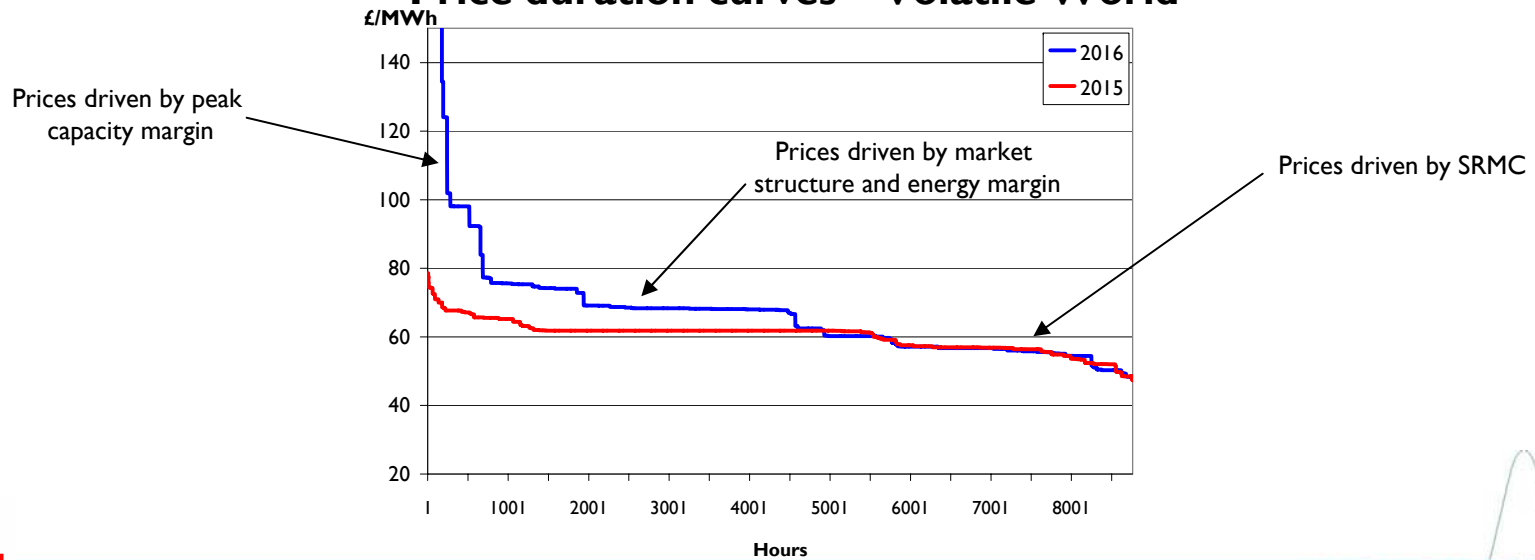
Note: Based on 50% efficiency



Note: Based on 35% efficiency

— Restrained Demand   
 — Steady Growth   
 — Third Dash for Gas   
 — Volatile World   
 — DTI Base Case

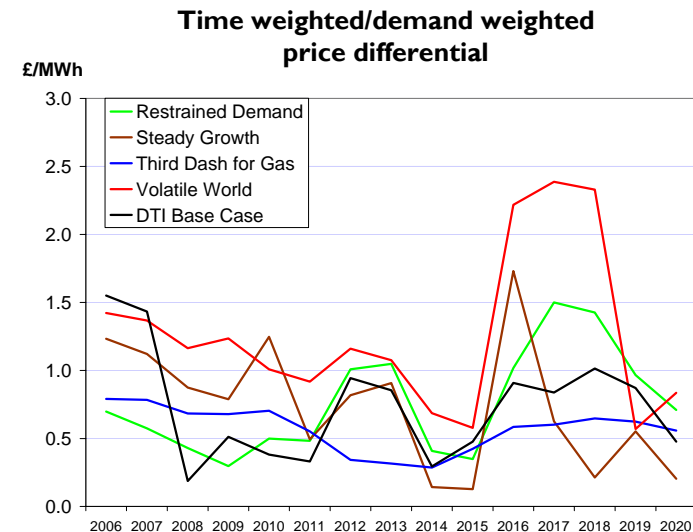
## Price duration curves – Volatile World



## 5.1.6 Status Quo – Summary metrics – (2): Notes

### Comments

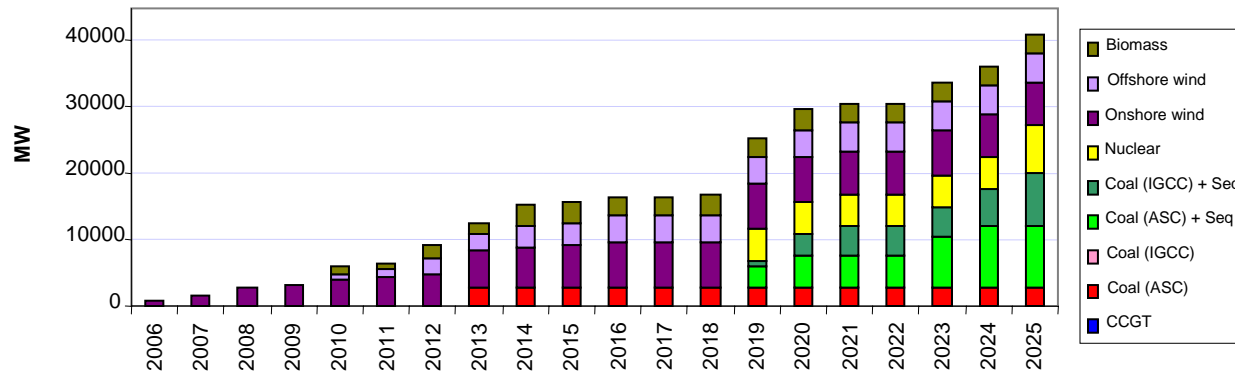
- There is generally an increase in the annual average dark and spark spreads in the early years as fuel prices fall more quickly than electricity prices.
- With the exception of Volatile World, annual average spark and dark spreads do not increase significantly with the tightening energy margins post-2015.
- This suggests that the annual prices are largely driven by baseload prices which themselves are driven by short run marginal costs.
- However the tightening peak capacity margin does lead to higher peak prices. This can be seen from the graph on the right which shows the differential between time and demand weighted prices. In all scenarios, the differential increases significantly when the peak capacity margin is tighter. Prices are also likely to be much more volatile in this case, but analysis of peak price volatility is beyond the scope of this study.
- In Volatile World, the incumbents are able to benefit from their dominant positions and tightening energy margin, significantly pushing up mid-merit prices. This effect is having an impact on the annual average prices as well as the price shape, as can be seen in the comparison of the price duration curves for 2015 and 2016 above.
- A general effect that the modelling is showing is that the increasing amount of intermittent renewables is lowering the ability of generators to push up prices. Compared to a high mid-merit plant with a similar annual availability (~30%), wind plant offers very little strategic value. The impact appears to be a general lowering of mid-merit prices but an increase in the volatility of high mid-merit and peak prices resulting from the intermittency.
- It should be noted that the dark spreads shown above include carbon costs and are based on existing coal plant efficiencies. New higher efficiency coal plant will benefit from significantly higher dark spreads. This would be increased further for plant with carbon capture (assuming the saving in carbon costs outweigh the degradation in efficiency).



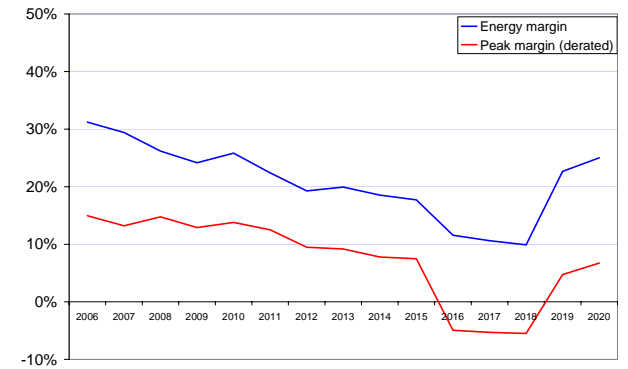
# 5.2.1 Policy option impact – COCs

## Volatile World – without Capacity Obligation Certificates

New plant by type

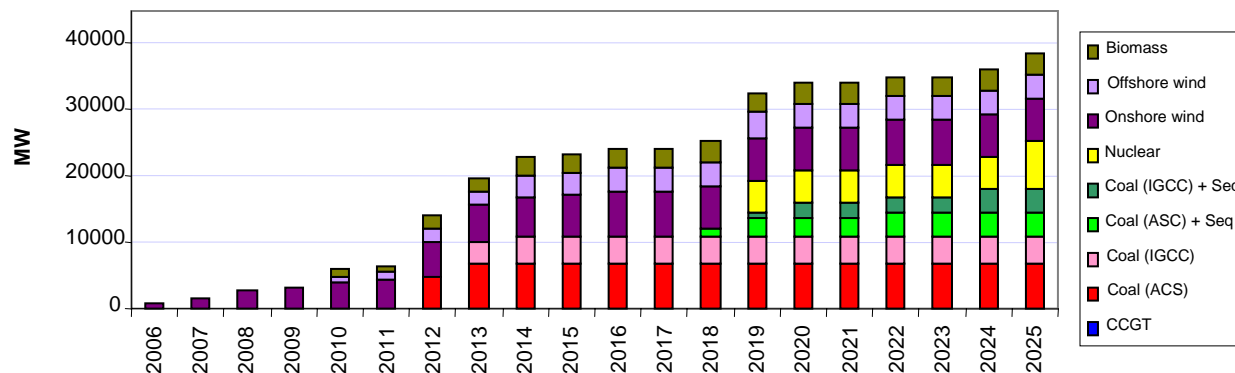


Supply margins

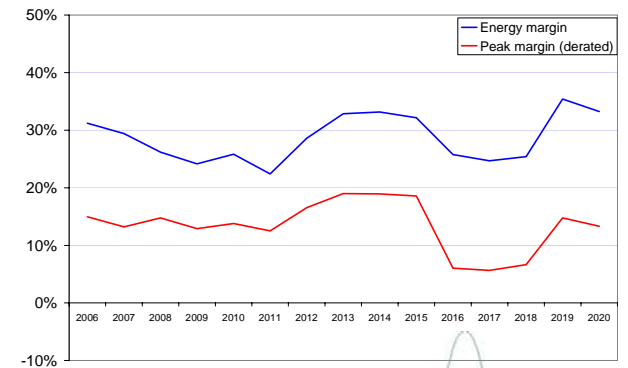


## Volatile World – with Capacity Obligation Certificates

New plant by type



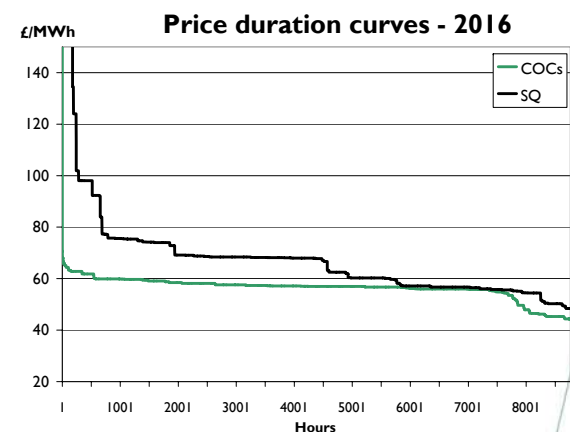
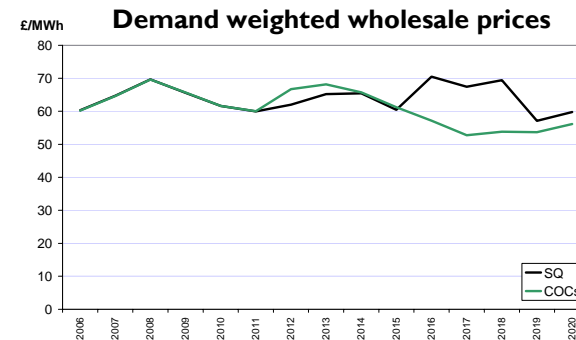
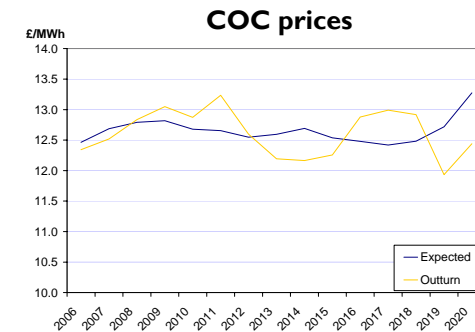
Supply margins



## 5.2.1 Policy option impact – COCs: Notes

### Comments

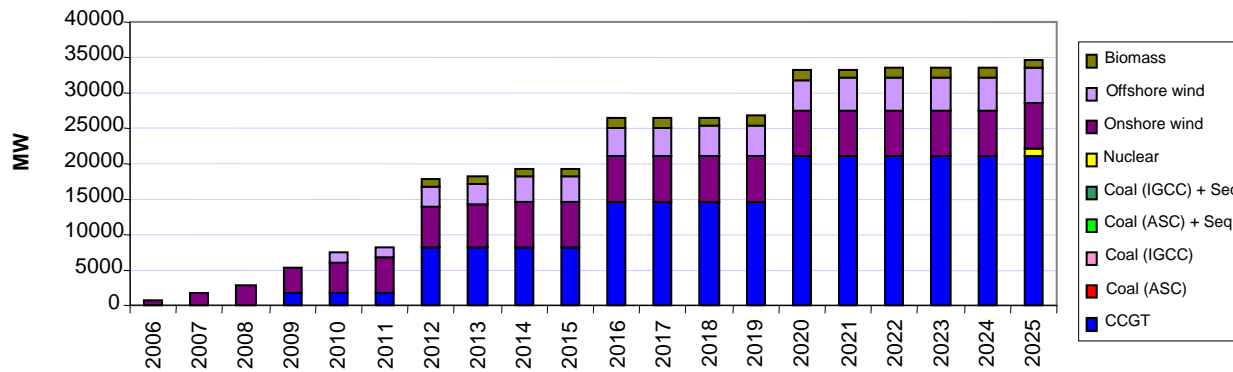
- This example illustrates the impact of Capacity Obligation Certificates on Volatile World, the scenario with the lowest energy margins under Status Quo.
- The policy option parameters are the following:
  - Target energy margin set at 35%
  - Buy out price set at £12/hr for every MW of installed capacity (calculated per annum assuming baseload operation).
  - Only new capacity qualifies
  - Cut-off period per plant: 10 years.
- The graph on the right shows the expected COC price and the outturn COC price as calculated by the Investment Decision Model. There is some volatility but in general the prices track just above the buy-out price which suggests that the policy option incentivises build just below the target.
- This can be seen when looking at the impact of COCs on the energy margin. It clearly removes the downward trend in energy margin whilst never quite sustaining the energy margin at 35% (the intended target).
- The policy has a significant benefit on the peak capacity margin but it remains low in a number of years.
- The main reason that this policy is more effective at addressing the energy margin than capacity margin is the way it is targeted only at new plant. This encourages new entry from plant seeking high load factors, but accelerates the closure of mid-merit and peaking capacity.
- Redefining the Capacity Obligation Certificate to cover all plant would be likely to address this problem although would almost certainly be more expensive. The alternative is a policy which is more targeted at peak availability.
- The wholesale price falls as a result of the COCs encouraging more plant into the market, as well as increasing the overall system efficiency by replacing the older plant. On average the COCs lower wholesale prices by £2.80 /MWh in Volatile World, although this is mainly impacting towards the end of the study period. The average additional costs to consumers of the COCs policy is £4.75/MWh over the same period.
- The graph on the right shows the impact that COCs have on the price duration curve in 2016. This flatter price profile would also lead to far less volatility in peak prices.



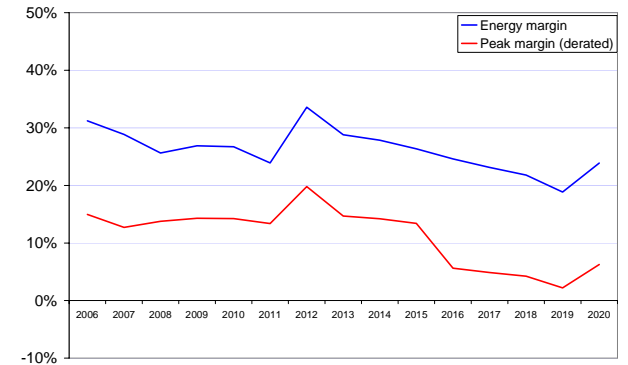
## 5.2.2 Policy option impact – DOCs

### Third Dash for Gas – without Diversity Obligation Certificates

New plant by type

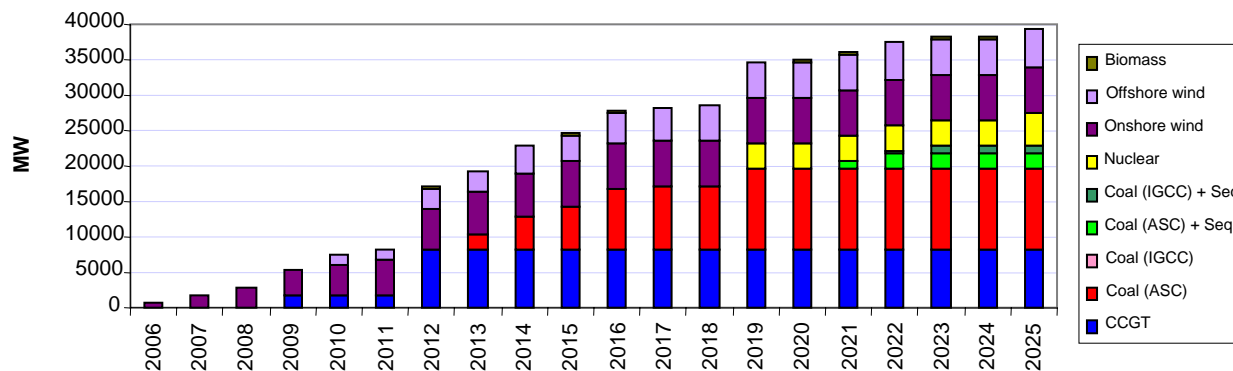


Supply margins

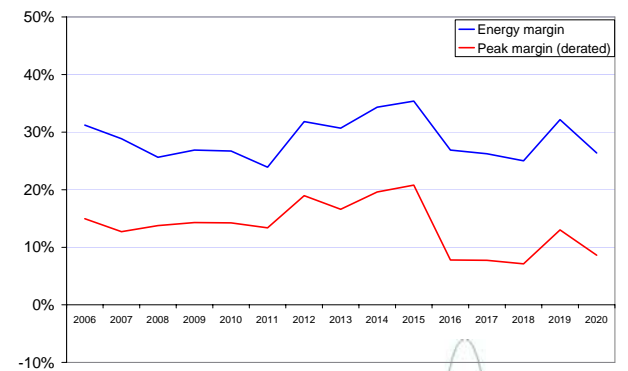


### Third Dash for Gas – with Diversity Obligation Certificates

New plant by type



Supply margins

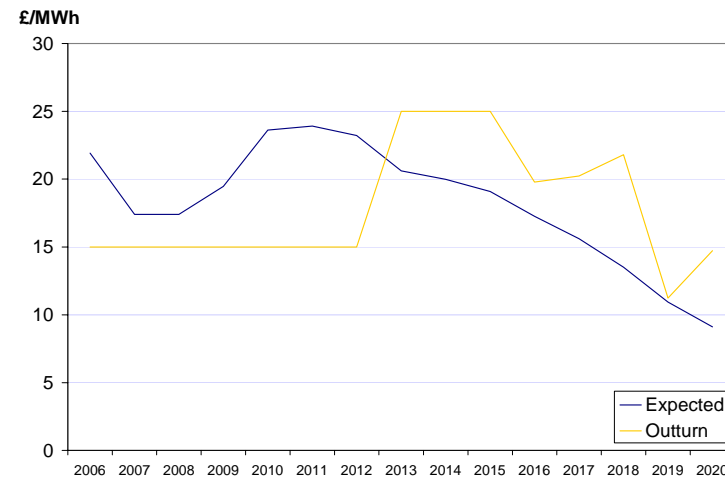


## 5.2.2 Policy option impact – DOCs: Notes

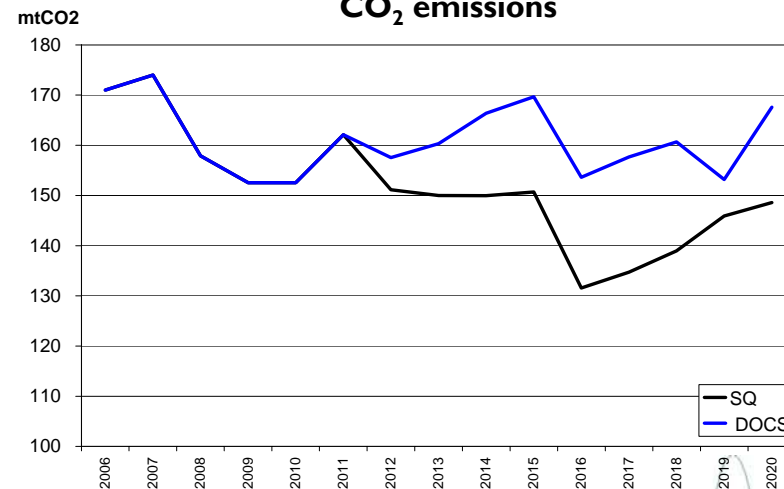
### Comments

- This example illustrates the impact of Diversity Obligation Certificates on Third Dash for Gas, one of the least diverse scenarios under Status Quo.
- The policy option parameters are the following:
  - Non gas plant and renewables qualify
  - Assumed to cut off after ½ economic lifetime of plant
  - Buy-out price set at £15/hr for every MW of installed capacity (calculated per annum assuming baseload operation).
  - Target set to 10% to 2009 and then rising to 25% by 2020
- The graph on the right shows the expected DOC price and outturn DOC price as calculated by the IDM. (Until 2013 there is no DOC qualifying capacity on the system and hence the outturn price has been defaulted to the buy-out price.) The DOC prices start well above the buy-out price before declining as more DOC qualifying capacity becomes operational. Beyond 2020, the DOC price would probably start to recover as the original DOC plants' entitlements start to roll off.
- The DOC policy is shown to be effective at displacing a large proportion of the CCGT build, and with a diverse range of technologies: initially ASC coal, and then ASC and IGCC coal with carbon capture, plus nuclear.
- Increasing the buy-out price or target DOC generation levels or extending the cut-off periods could all lead to a complete displacement of gas build.
- The downside of the DOCs policy on Third Dash for Gas is that it increases the carbon dioxide emissions initially. However, by encouraging non-carbon emitting technologies also, this impact diminishes over time.

### DOCs prices



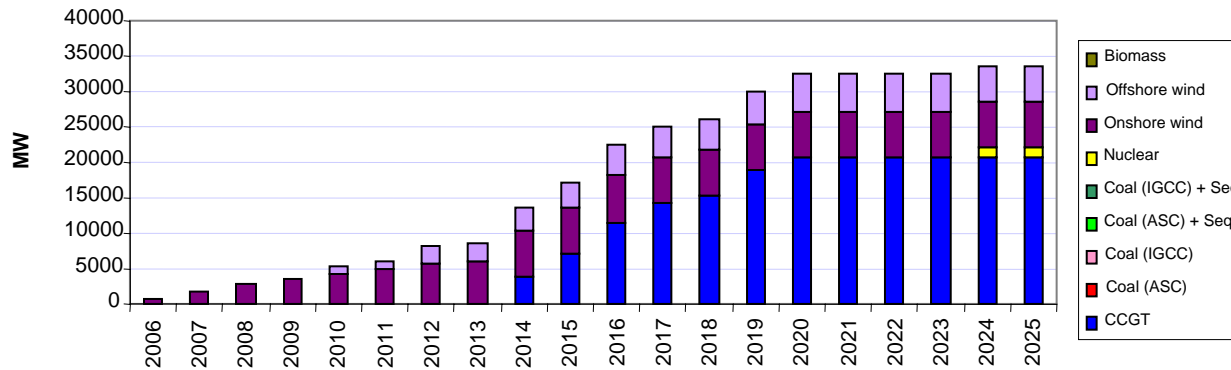
### CO<sub>2</sub> emissions



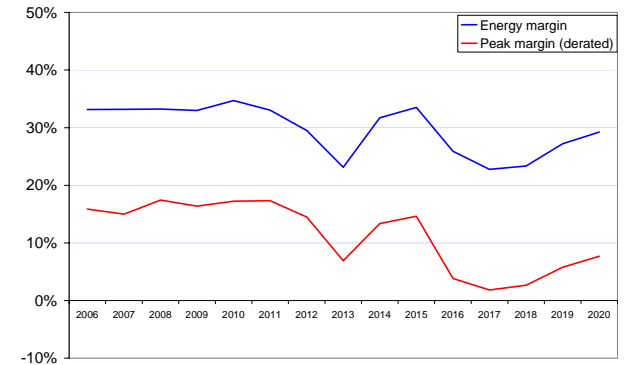
## 5.2.3 Policy option impact – NOCs

### Restrained Demand – without Nuclear Obligation Certificates

New plant by type

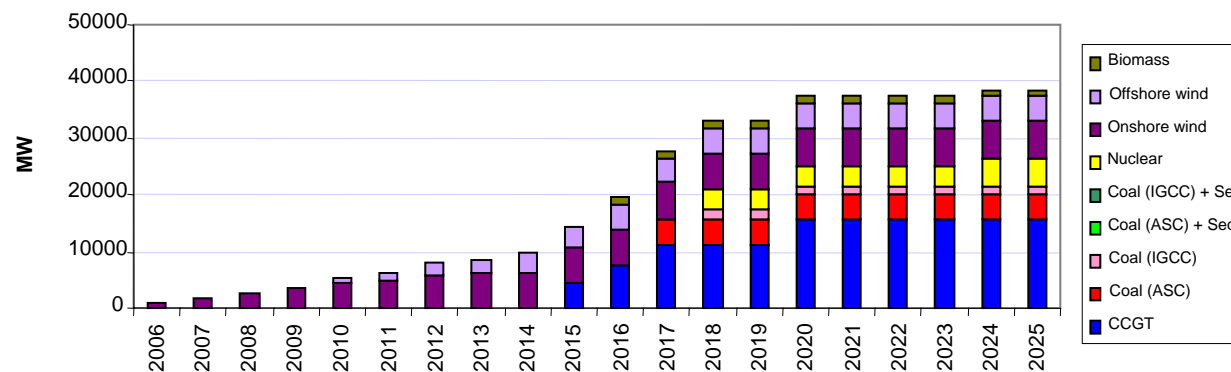


Supply margins

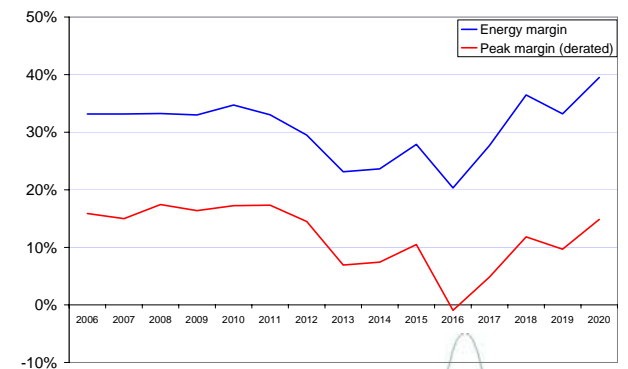


### Restrained Demand – with Nuclear Obligation Certificates

New plant by type



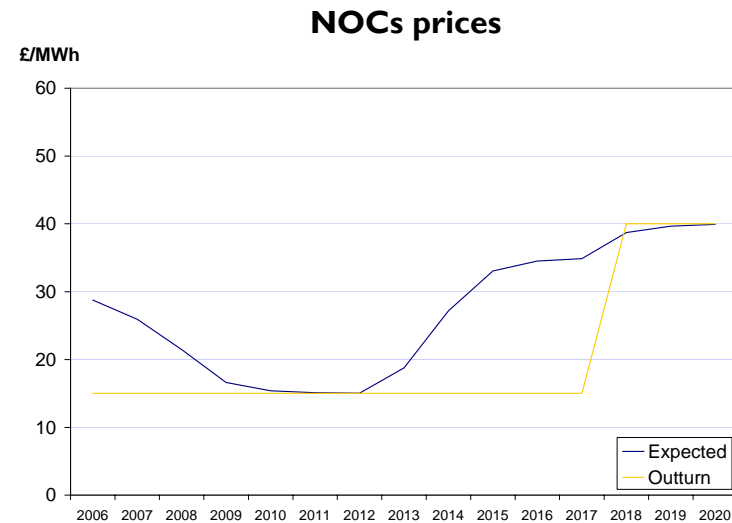
Supply margins



## 5.2.3 Policy option impact – NOCs: Notes

### Comments

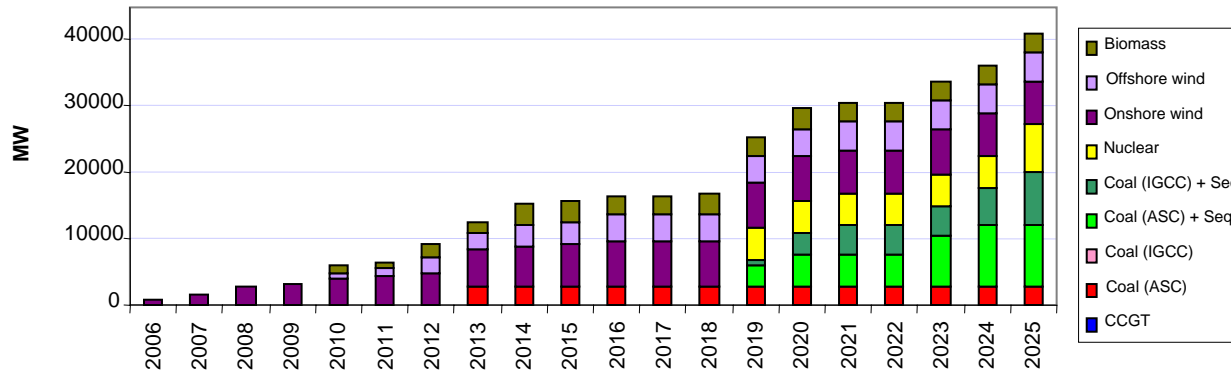
- This example illustrates the impact of Nuclear Obligation Certificates on Restrained Demand.
- The policy option parameters are the following:
  - Assumed to cut-off after 20 years
  - Buy out price set to £15/hr for every MW of installed capacity (calculated per annum assuming baseload operation).
  - Planning process assumed to be speeded up
  - Nuclear plant can be built by British Energy, EdF, EON and RWE
- The graph on the right illustrates the expected and outturn NOC prices as calculated by the IDM. Because of the very long planning and construction times involved in building nuclear plant, no NOC qualifying plant becomes operational before 2018. (Prior to that the NOC price defaults to the buy-out price.)
- It can be seen that the NOC policy option is successful in bringing forward and encouraging nuclear build.
- An unexpected side effect of this policy option is that new coal build has been encouraged. This may be a consequence of these particular scenario assumptions and hence not too much significance should be attached to this outcome, although it is a useful illustration of the possibility of unintended consequences of different policy options.
- The explanation in this case is that the sudden installation of a large amount of nuclear capacity has disincentivised the CCGT build that would have become operational in the period 2013-2015 (compare the 2 two energy margin graphs above to see this effect). This is leading to a sustained period of lower energy margins which is pushing up investors expectations of price (at least in the short term) bringing new coal build into the money. This effect is not seen when NOCs are applied to Third Dash for Gas.
- The general effect of deterring other new build is exacerbating an already tight peak capacity margin in 2016.



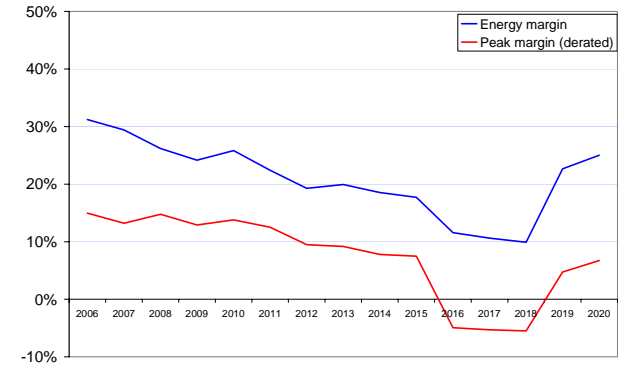
# 5.2.4 Policy option impact – Tendering

## Volatile World – without Tendering

New plant by type

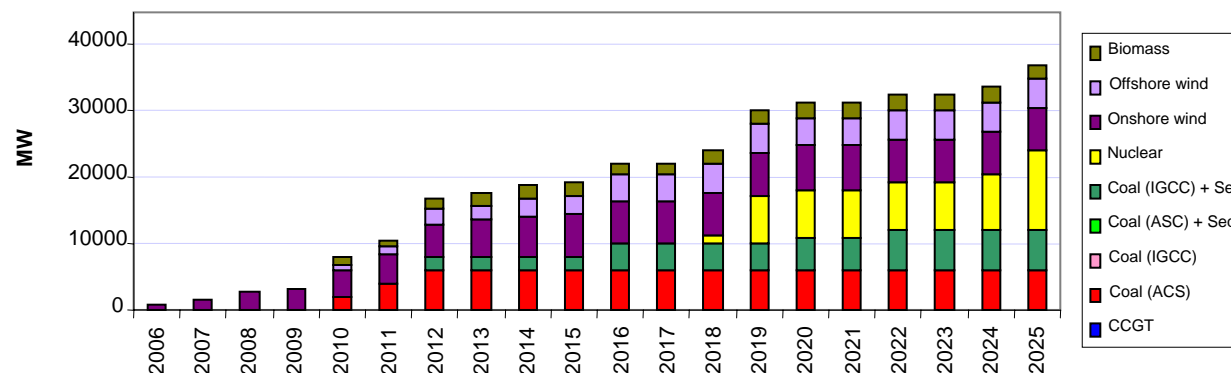


Supply margins

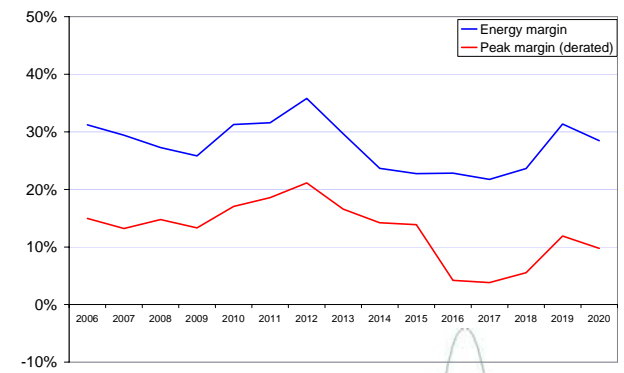


## Volatile World – with Tendering

New plant by type



Supply margins

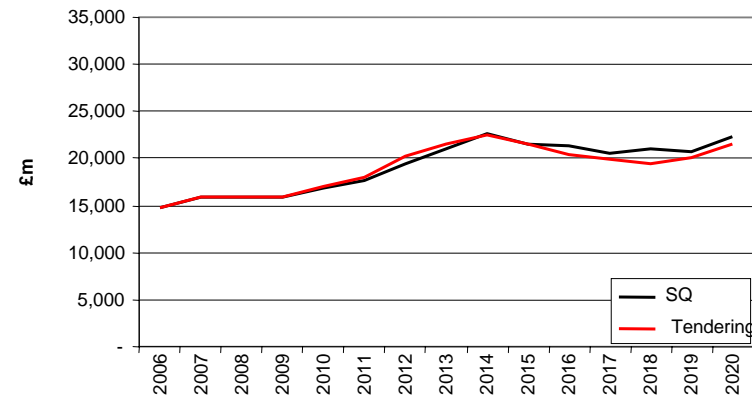


## 5.2.4 Policy option impact – Tendering: Notes

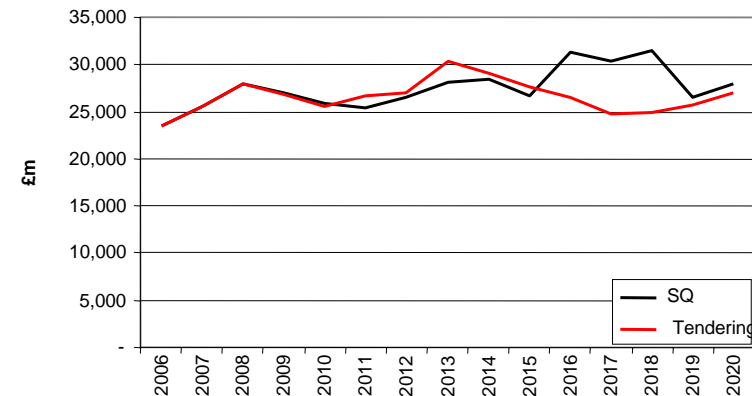
### Comments

- In this example, Tendering has been applied to Volatile World.
- Tendering does not prove to be an effective means of increasing the energy margin because plant built by the TSO tends to simply replace that which would have been built by a private investor. It is not until all the private investment has been displaced that increasing the amount of tendered capacity starts to improve the energy margin.
- In this example, the following capacity is tendered for by the TSO (financed by the Government):
  - 2 GW of advanced super-critical coal in 2007, 2008, 2009
  - 2 GW of IGCC coal plus sequestration in 2008, 2012
  - 1.2 GW of nuclear in 2012, 2013, 2018, 2019
  - Total 14.8 GW over 15 year period
- Leaving aside the negative impact on the liberalised electricity market that tendering could have, it has the advantage of allowing the Government to control the capacity mix thus providing a lever for encouraging low carbon technologies such as nuclear and carbon capture.
- A dilemma is presented by the impending post-2015 energy margin fall: whether to build coal plant with carbon capture which would still be uneconomic at that time, or to take the pragmatic approach of building some ASC coal plant (possibly capture ready) to plug the energy margin gap, until the low carbon technologies are economic. In this example we have assumed the latter case.
- Because we have assumed that the TSO/Government pursues the economic route, and due to the low financing costs, the overall generation costs are slightly lower with Tendering. (If an ‘opportunity’ based cost of capital is used, reflecting a more ‘commercial’ rate the generation costs would be higher.) Consumer costs are considerably less because we avoid the higher spark and dark spreads associated with the very tight energy margin under Status Quo.

**Generation Costs – Volatile World**



**Consumer costs – Volatile World**



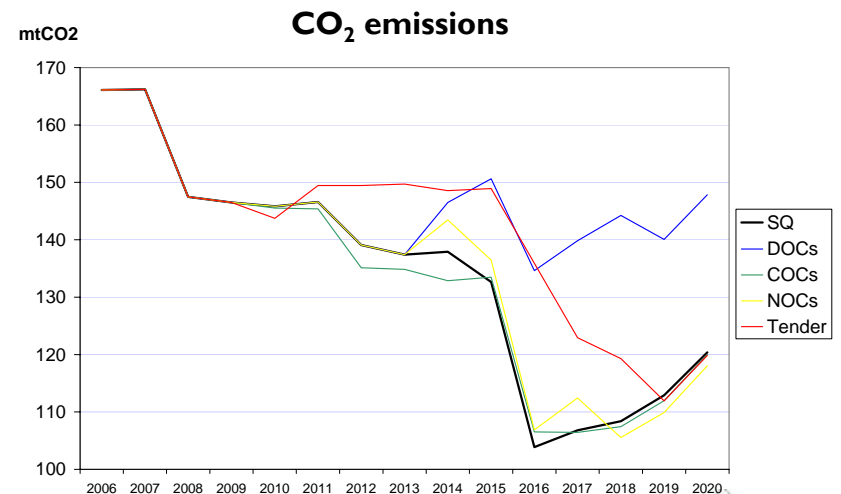
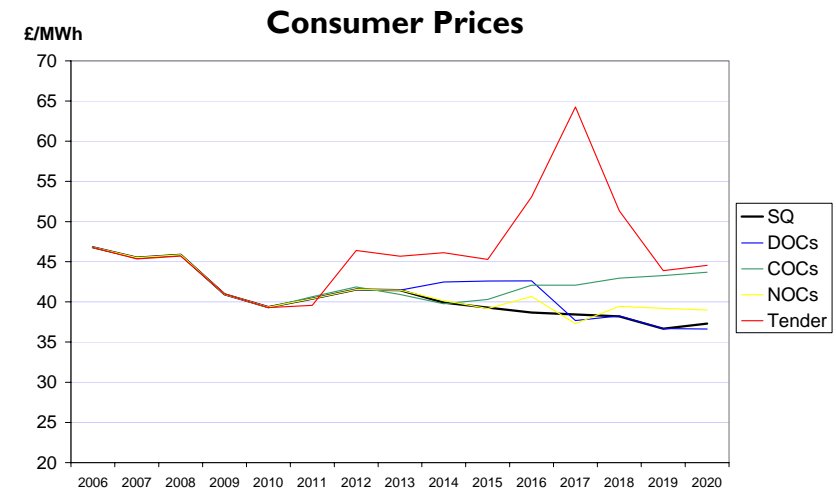
## 5.3.1 Summary metrics - Restrained Demand – (I)

Metric		SQ	DOCs	COCs	NOCs	Tendering
Total generation costs (£bn)		145.9	148.0	148.5	146.9	151.0
Total consumer costs (£bn)		179.6	181.9	186.0	181.2	204.3
Annual average CO <sub>2</sub> emissions		134.5	146.6	133.7	135.2	141.7
Supply margins	Minimum energy margin	22.8%	22.0%	26.9%	20.3%	22.1%
	Minimum peak capacity margin	1.8%	1.0%	4.6%	-0.9%	1.1%
Generation diversity (2020)	% capacity of top 1	68.7%	41.7%	63.0%	49.8%	46.2%
	% capacity of top 2	82.6%	71.2%	72.6%	68.3%	71.0%

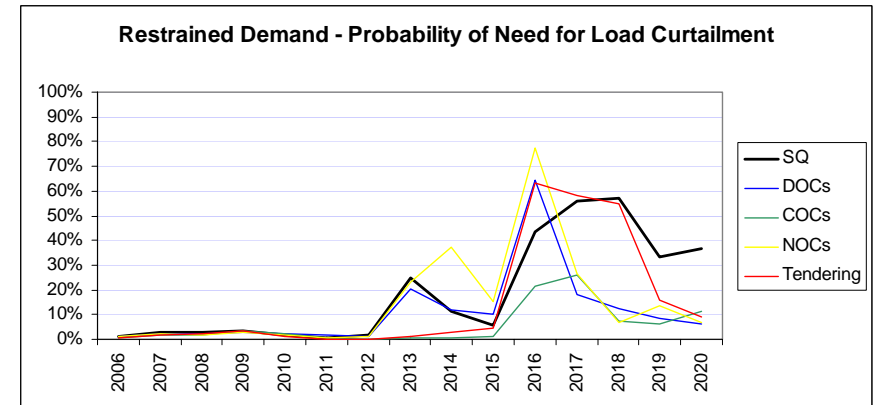
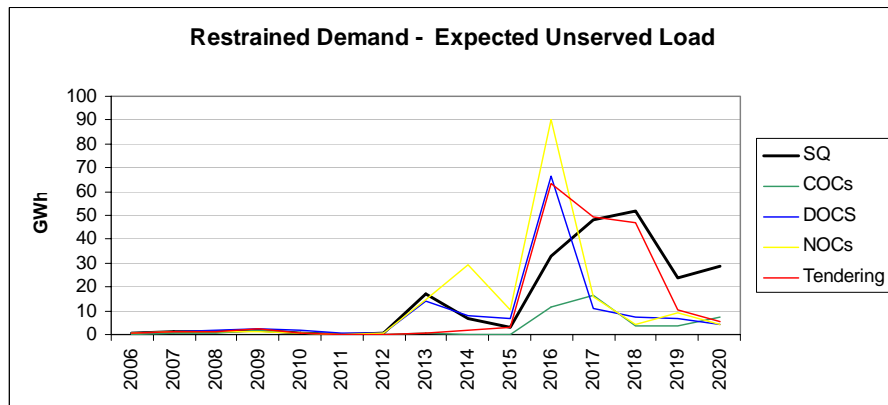
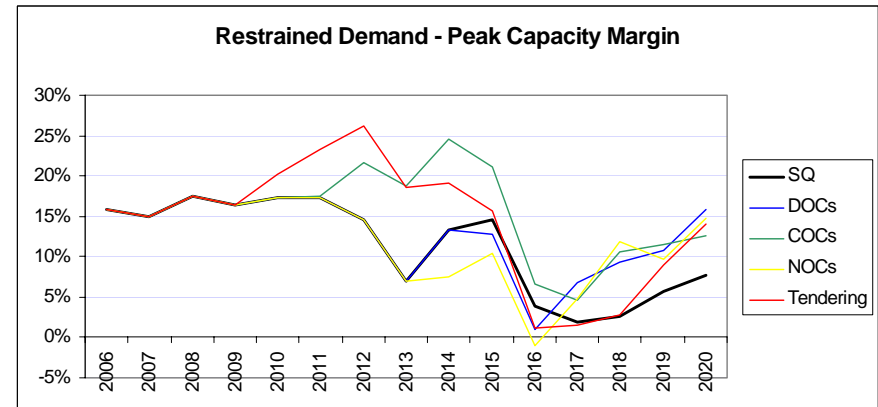
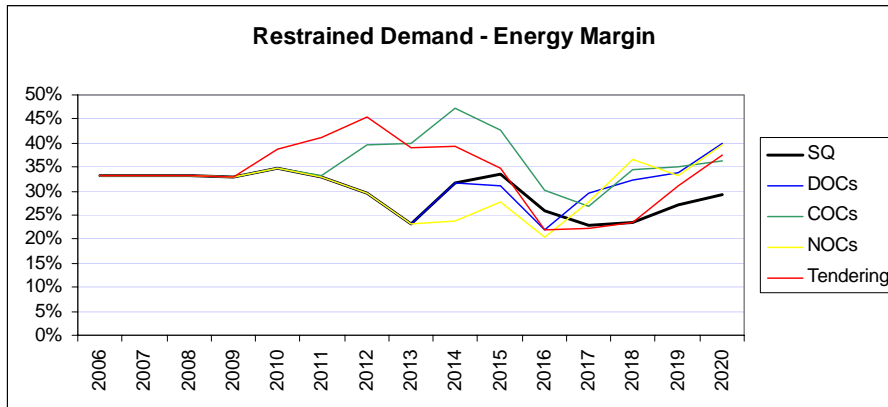
## 5.3.1 Summary metrics – Restrained Demand – (1)

### Comments

- The table above illustrates the impact of all four policy options on the Restrained Demand scenario.
- The total generation costs of all policy options are greater than in the Status Quo case since the resulting solutions are deviating from the most economic case as dictated by the market. (The capacity for Tendering was based on the Volatile World scenario, and hence despite the low cost of capital provided by the government, a non-economic mix is built thus increasing the generation costs.)
- It should be noted that new nuclear plant are only operational for 2 years within the study period, and since costs are accounted for on an annualised basis during the plant's economic lifetime, the bulk of the costs and benefits of NOCs policy are arising outside the study period.
- The results in the table are presented as NPVs discounted at 3.5%. Since the results for the policy options vary little in the earlier years, the differences between policy options are dampened. For example, the consumer price graph over time, shown on the right, illustrates a high degree of variation in the later years.
- The cost to consumers is higher under all policy options, although not significantly so on an NPV basis with the exception of Tendering.
- There are 3 explanations for the higher consumer costs under Tendering:
  1. It leads to a lower energy margin in the later years as the capacity build is based on a Volatile World.
  2. The market competitiveness diminishes in a world of Government interventions
  3. Uneconomic plant are introduced to the market.
- The improvements in diversity that result from DOCs and Tendering are coming at the expense of higher carbon dioxide emissions.
- The consumer costs for Tendering are increased by a £1.9bn loss for the TSO associated with the annual auctions of tendered capacity. It is assumed that this is recovered in transmissions charges.



## 5.3.1 Summary metrics - Restrained Demand – (2)



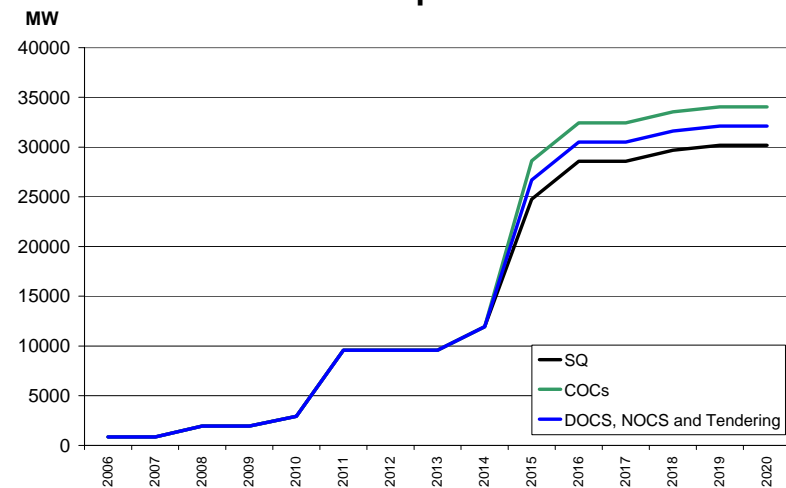
Note: Unserved load is the probability weighted expected unserved load across 500 simulations  
 The probability of load curtailment is the probability of the loss of load in at least 1 hour in the year

## 5.3.1 Summary metrics – Restrained Demand – (2): Notes

### Comments

- The unserved load represents the probability weighted unserved load under 500 simulations. This does not necessarily mean that any load will be lost in any particular year, but over a number of years the average loss that can be expected.
- It is only if the probability of the need for load curtailment (as shown in the graph on the bottom right above) is greater than 50%, that a loss of load in one or more hours in the year becomes likely.
- The probability of the need for load curtailment only becomes significant after 2012 under all policy options.
- The maximum individual hourly loss at the 95% percentile confidence level under Status Quo is 2.8GW (out of a total of 447,000 GWh), which occurs in 2018.
- For comparison the volumes of unserved load relating to transmission outages were:
  - 900 MWh in 2003/04
  - 888 MWh in 2004/05
- The impact of COCs on the energy margin and peak capacity margin is positive although it does not provide the same benefit as was seen in the Volatile World example. This is because it accelerates the closure of already marginally economic coal plant.
- The same detrimental impact on peak capacity margin in 2016 of NOCs as in the Third Dash for Gas example can be seen.
- In the later years, in addition to their diversity benefit, DOCs are improving the energy margin and peak capacity margin positions.
- The NPV of the total value of lost load is shown under each policy option in the table below. (This assumes a value of lost load of £15,000/MWh. These calculations assume no correlation between outages of different plant.)

Cumulative plant closures



Total value of lost load

£m	SQ	DOCs	COCs	NOCs	TEN
Restrained Demand	2,180.78	1,408.63	484.62	1,936.60	1,876.18

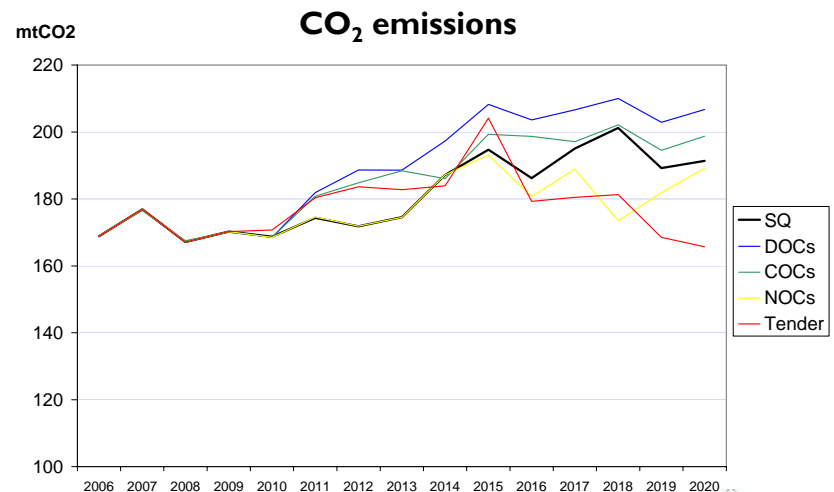
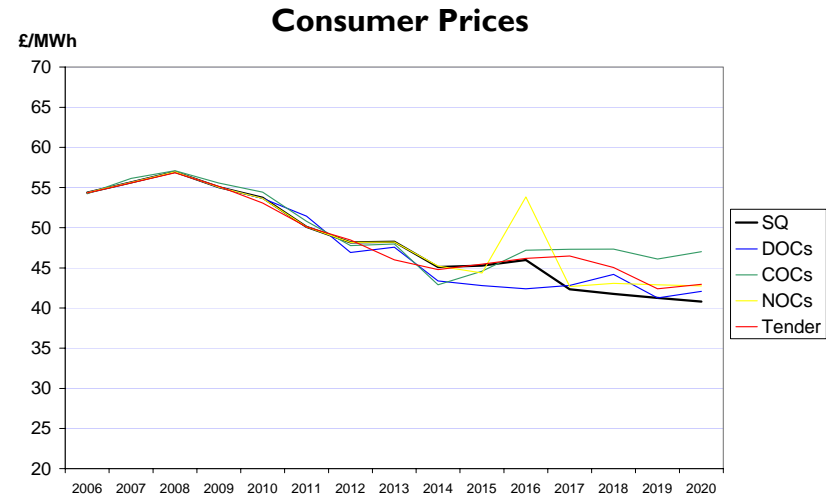
## 5.3.2 Summary metrics – Steady Growth – (I)

Metric		SQ	DOCs	COCs	NOCs	Tendering
Total generation costs (£bn)		175.9	176.9	179.0	175.5	174.7
Total consumer costs (£bn)		234.7	233.3	240.9	238.2	236.2
Annual average CO <sub>2</sub> emissions		181.2	189.8	185.5	177.8	177.6
Supply margins	Minimum energy margin	19.8%	22.8%	22.8%	18.1%	21.0%
	Minimum peak capacity margin	0.9%	6.0%	7.5%	1.8%	3.3%
Generation diversity (2020)	% capacity of top 1	40.7%	40.1%	36.0%	36.5%	36.3%
	% capacity of top 2	78.2%	69.0%	71.2%	68.6%	65.9%

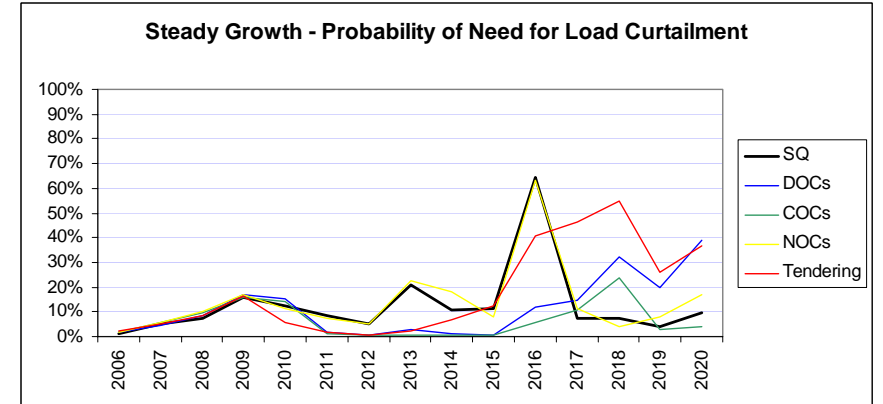
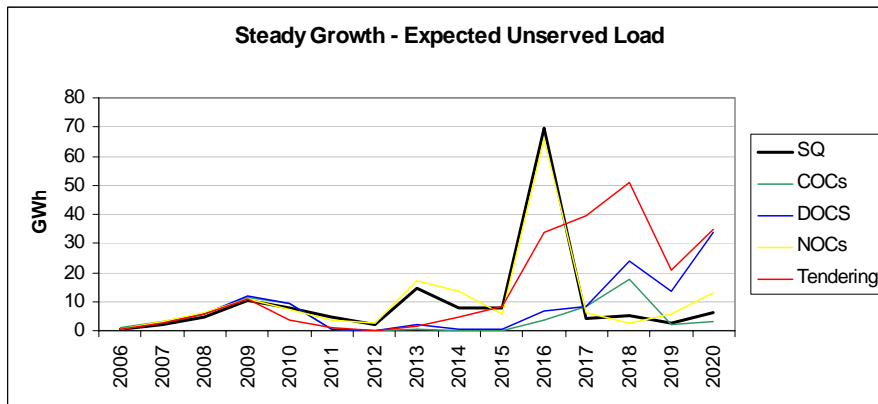
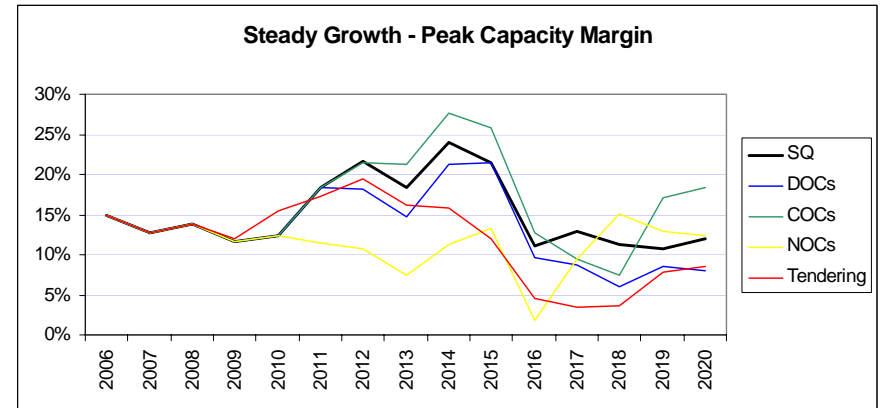
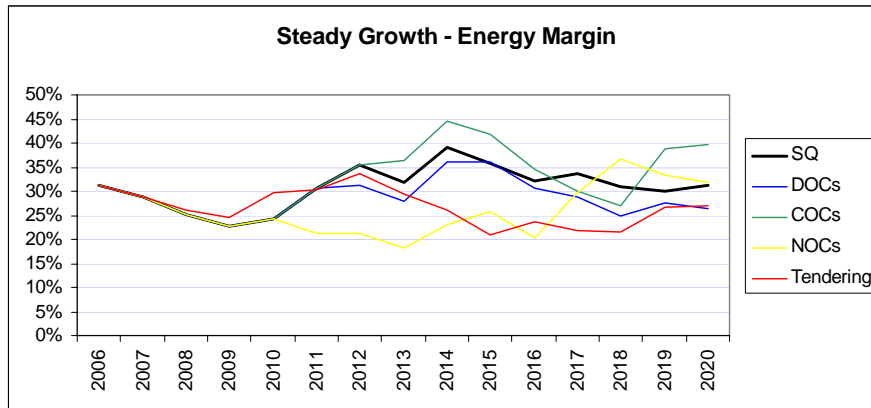
## 5.3.2 Summary metrics – Steady Growth (I): Notes

### Comments

- The table above illustrates the impact of all four policy options on the Steady Growth scenario.
- As is the case for Restrained Demand, DOCs and COCs have the impact of pushing up the generation costs. Under Tendering, generation costs fall since the investments made by the TSO/Government are similar to those that would have been made by private investment, yet benefit from the lower cost of capital provided by Government financing. NOCs are slightly lower cost, but most of the costs/benefits of this policy option fall outside the study period.
- In the scenarios that favour non gas technologies such as Steady Growth, DOCs and COCs have generally similar overall effects despite different deployment mechanisms.
- Both DOCs and COCs have the effect of suppressing wholesale prices. Under the COC policy this is more than offset by the additional cost of the COCs. However, in scenarios such as Steady Growth where non gas capacity is already favoured, the DOC price collapses with an overall reduction in costs to consumers. (This result is very sensitive to the exact parameters chosen for the DOC policy.)
- The drop in the energy margin in 2016 under NOCs causes prices to spike up.
- The impact of DOCs on the mix of new capacity is far less pronounced under Steady Growth when compared to the Third Dash for Gas example. This is because it is mostly non gas plant being built under Status Quo any way. However, the remaining gas build is replaced with coal, thus leading to higher carbon emissions.
- Carbon emissions are also higher with COCs since further new coal build is being encouraged at the expense of older CCGTs.
- NOCs and Tendering are the most effective options for stemming the steady increase in carbon dioxide emissions under Steady Growth.
- The consumer costs for Tendering are reduced by a £0.6bn profit for the TSO associated with the annual auctions of tendered capacity. It is assumed that this profit is netted off transmission charges.



## 5.3.2 Summary metrics – Steady Growth – (2)

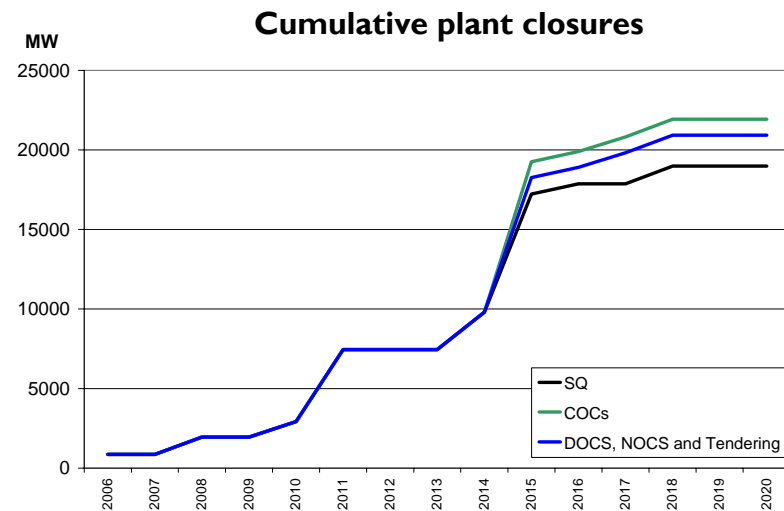


Note: Unserved load is the probability weighted expected unserved load across 500 simulations  
 The probability of load curtailment is the probability of the loss of load in at least 1 hour in the year

## 5.3.2 Summary metrics – Steady Growth – (2): Notes

### Comments

- From an energy margin and peak capacity margin perspective the Steady Growth scenario under Status Quo is better than some of the other scenarios.
- The maximum individual hourly loss at the 95% percentile confidence level under Status Quo is 2.7GW which occurs in 2016.
- Interestingly COCs do lead to an increase in energy and peak capacity margins in the earlier years, but actually produce a lower minimum across the study period than Status Quo (in 2018). This is because the initial incentives lead to overbuild causing the COC price to collapse deterring new build just prior to the post-2015 LCPD related closures.
- This illustrates the point that whilst COCs can deliver a higher energy and peak capacity margin over a longer time period, in any one year there could be deviations. This is particularly the case for peak capacity margin, which is not directly incentivised by the COC regime as implemented here. Amendments to the policy design might be considered to address this consequence.
- The NPV of the total value of lost load is shown under each policy option in the table on the below. (This assumes a value of lost load of £15,000/MWh. These calculations assume no correlation between outages of different plant.)



### Total value of lost load

£m	SQ	DOCs	COCs	NOCs	TEN
Steady Growth	1,641.27	1,238.32	762.06	1,794.63	2,224.30

### 5.3.3 Summary metrics – Third Dash for Gas – (I)

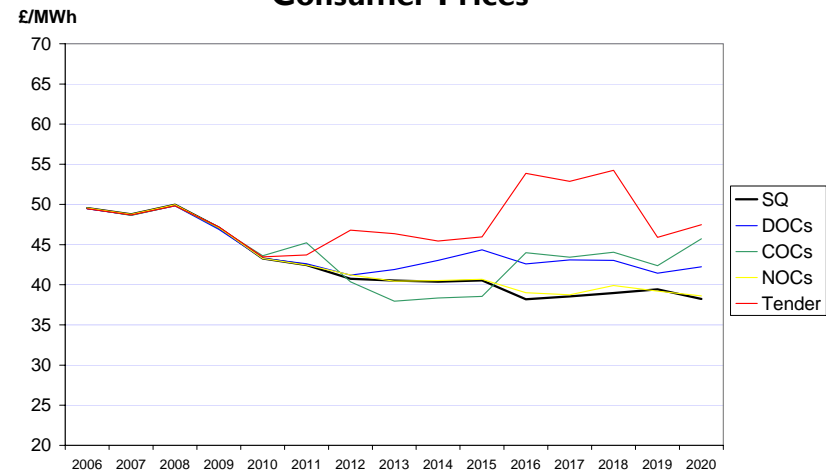
Metric		SQ	DOCs	COCs	NOCs	Tendering
Total generation costs (£bn)		162.4	163.9	162.7	161.8	166.8
Total consumer costs (£bn)		205.8	213.7	212.0	206.6	234.4
Annual average CO <sub>2</sub> emissions		151.4	161.1	145.2	148.6	163.1
Supply margins	Minimum energy margin	18.9%	23.9%	14.1%	20.4%	20.7%
	Minimum peak capacity margin	2.2%	7.1%	-0.8%	2.8%	4.2%
Generation diversity (2020)	% capacity of top 1	63.1%	39.7%	67.0%	52.0%	38.9%
	% capacity of top 2	83.1%	79.1%	79.5%	69.6%	69.8%

### 5.3.3 Summary metrics – Third Dash for Gas – (I)

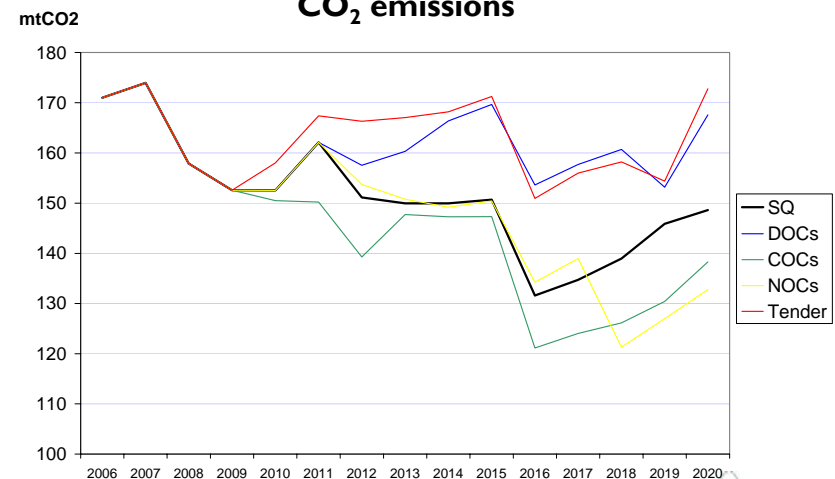
#### Comments

- The table above illustrates the impact of all four policy options on the Third Dash for Gas scenario.
- The impact of the policy options on generation costs is similar to that witnessed under Restrained Demand. The one exception is that COCs only lead to a small increase in generation costs, as a result of speeding the displacement of less efficient plant.
- The policy options all lead to an increase in costs to consumers, particularly Tendering, for the same reasons as under Restrained Demand.
- DOCs and Tendering both lead to an increase in carbon dioxide emissions resulting from the displacement of new gas build with new coal build. By incentivising the replacement of existing coal plant with new gas plant, COCs have a positive impact in reducing carbon emissions under this scenario. Under NOCs, carbon emissions track Status Quo until the new nuclear plant become operational, rivalling COCs as the lowest carbon emitting policy option by 2018.
- The consumer costs for Tendering are increased by a £3.5bn loss for the TSO associated with the annual auctions of tendered capacity.

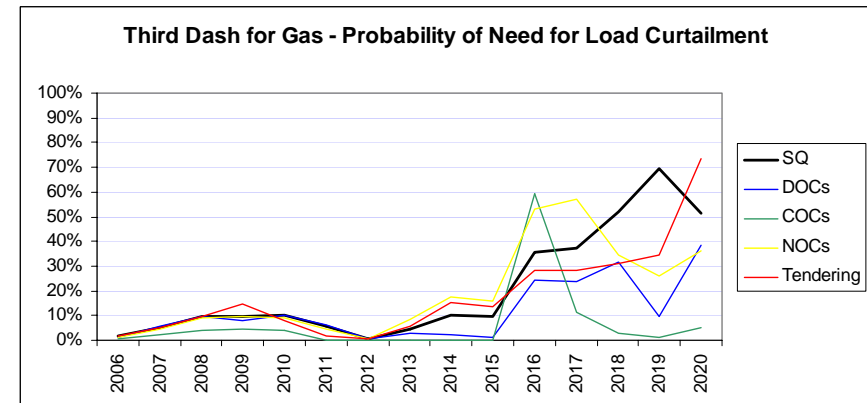
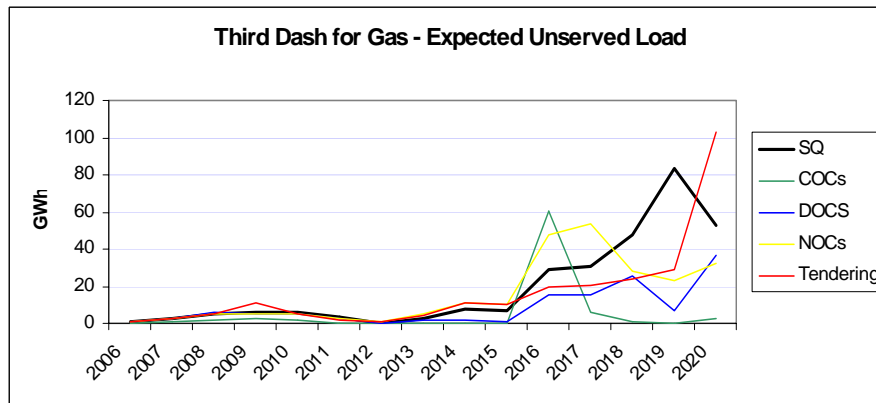
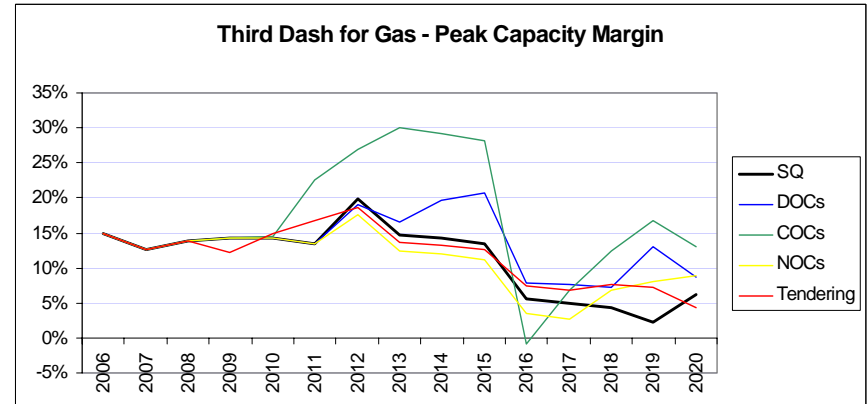
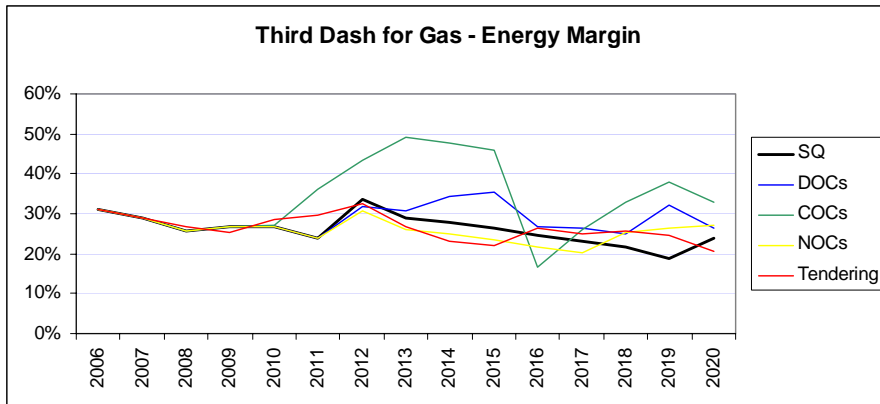
#### Consumer Prices



#### CO<sub>2</sub> emissions



## 5.3.3 Summary metrics – Third Dash for Gas – (2)

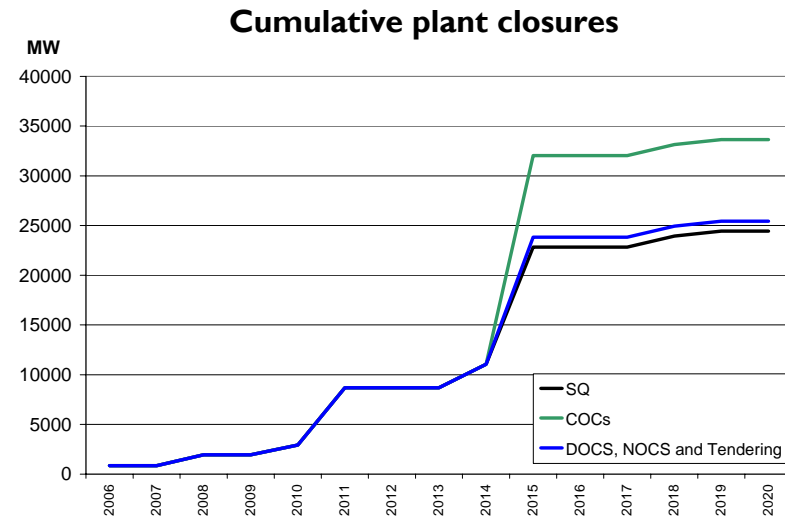


Note: Unserved load is the probability weighted expected unserved load across 500 simulations  
 The probability of load curtailment is the probability of the loss of load in at least 1 hour in the year

### 5.3.3 Summary metrics – Third Dash for Gas – (2): Notes

#### Comments

- The volatile impact that COCs can have on the energy and peak capacity margins first seen in Steady Growth, is even more extreme under Third Dash for Gas. The energy margin reaches 50% in 2013 before a significant collapse with the closure of 12 GW of coal and oil capacity in 2015.
- The impact on peak capacity margin is equally extreme, falling negative in 2016.
- As was the case under Restrained Demand, DOCs provide a slight benefit to energy and peak capacity margins. (This leaves aside the potential benefit of diversity in avoiding correlated plant availability restrictions.)
- The impact of NOCs on the peak capacity margin in 2016 is not as extreme as under Restrained Demand.
- The NPV of the total value of lost load is shown under each policy option in the table below. (This assumes a value of lost load of £15,000/MWh. These calculations assume no correlation between outages of different plant.)



#### Total value of lost load

£m	SQ	DOCs	COCs	NOCs	TEN
Third Dash for Gas	2,788.02	1,283.99	814.69	2,371.29	2,441.67

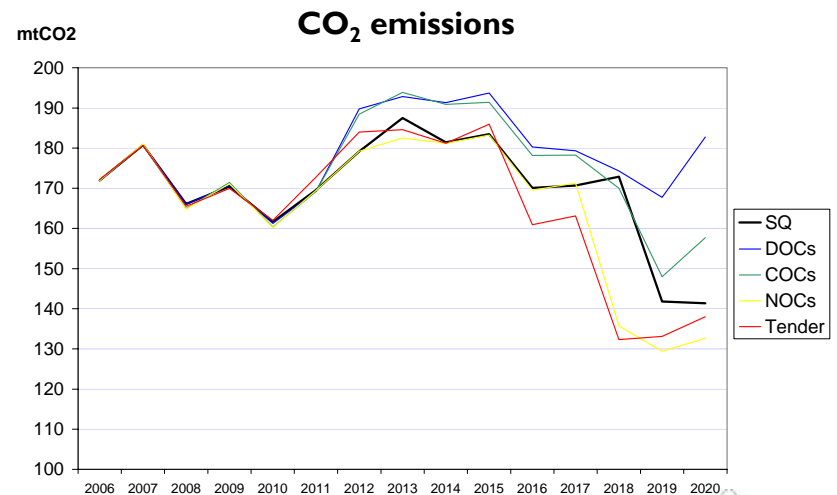
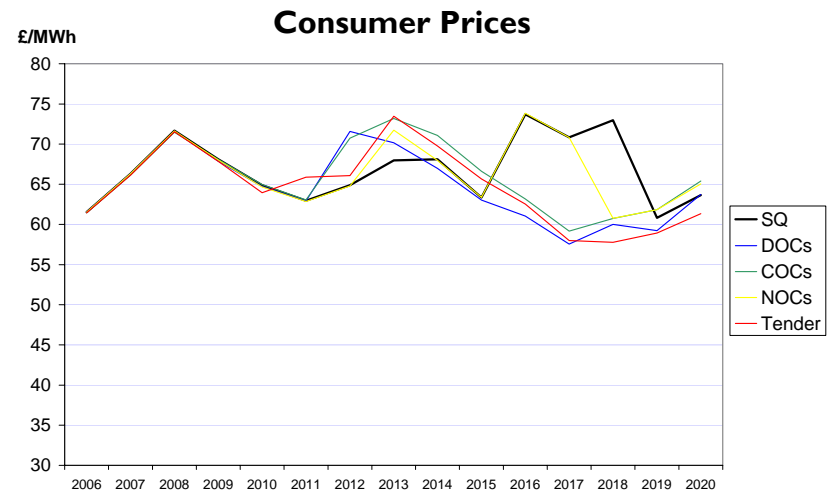
## 5.3.4 Summary metrics – Volatile World – (I)

Metric		SQ	DOCs	COCs	NOCs	Tendering
Total generation costs (£bn)		210.7	216.0	215.1	209.6	210.0
Total consumer costs (£bn)		314.6	305.4	310.9	312.9	298.6
Annual average CO <sub>2</sub> emissions		169.9	178.1	174.4	165.6	165.8
Supply margins	Minimum energy margin	10.4%	22.4%	22.4%	10.6%	21.7%
	Minimum peak capacity margin	-5.1%	6.0%	5.6%	-5.3%	3.8%
Generation diversity (2020)	% capacity of top 1	38.1%	36.5%	39.7%	34.6%	34.9%
	% capacity of top 2	71.2%	65.1%	67.0%	62.7%	62.7%

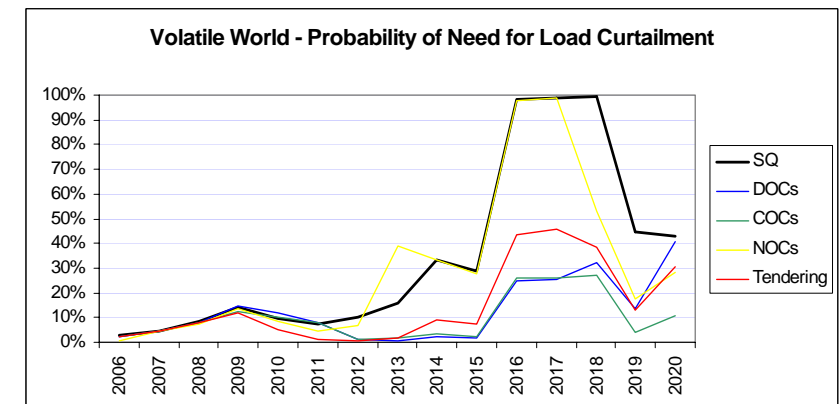
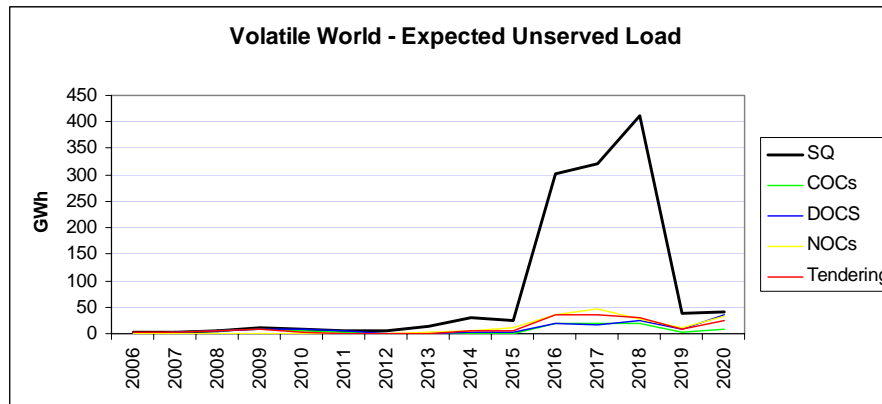
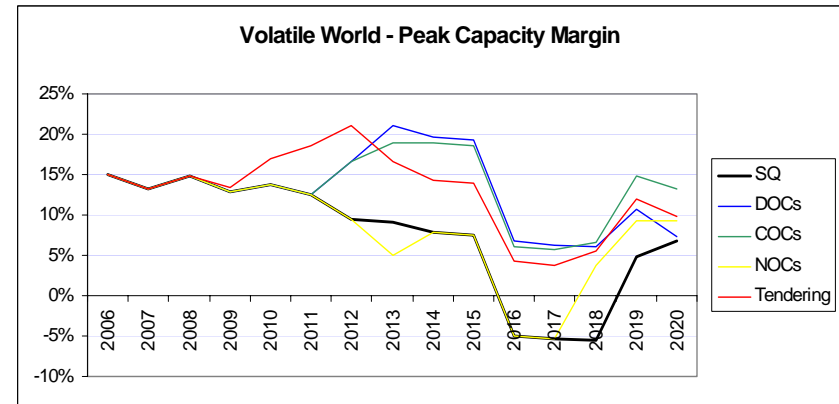
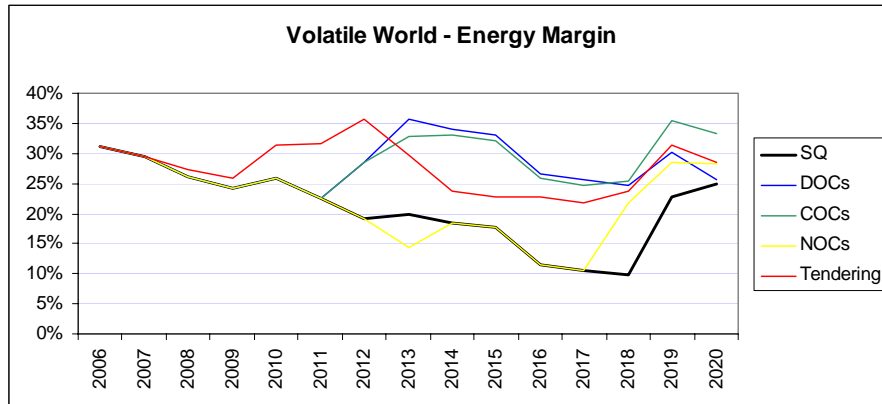
## 5.3.4 Summary metrics – Volatile World – (I)

### Comments

- The table above illustrates the impact of all four policy options on the Volatile World scenario.
- The main difference when compared with other scenarios is that all the policy options reduce consumer costs compared to Status Quo largely as a result of averting the 2016-2018 energy margin squeeze that was leading to high prices. (This is only partially the case for NOCs due to the long lead time to commission nuclear plant.)
- Generation costs are higher under DOCs and COCs since fully written down existing plant are being replaced by new plant which requires a return on equity. The converse is true for NOCs as there is a delay before the new plant comes on stream. The lower generation costs under Tendering are a reflection of the government's lower cost of capital.
- The consumer costs for Tendering are reduced by a £7.5bn profit for the TSO associated with the annual auctions of tendered capacity.



## 5.3.4 Summary metrics – Volatile World – (2)

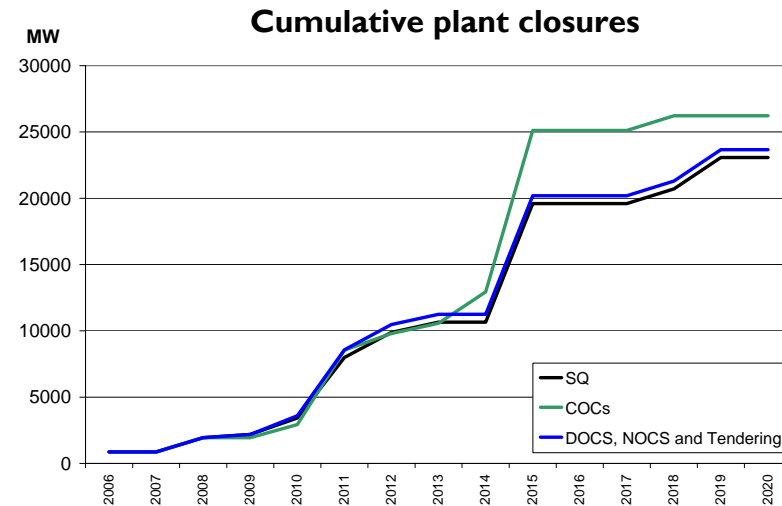


Note: Unserved load is the probability weighted expected unserved load across 500 simulations  
 The probability of load curtailment is the probability of the loss of load in at least 1 hour in the year

## 5.3.4 Summary metrics – Volatile World – (2): Notes

### Comments

- The COCs and Tendering policy options were designed to address the energy margin problem under Volatile World and hence are effective at addressing this problem.
- Since DOCs are acting to incentivise further the technologies which are already the most economic, they have a very similar effect to COCs in improving the energy and peak capacity margins.
- The positive impact of NOCs on the energy and peak capacity margins comes too late to avert the problem in 2016.
- The expected unserved load and probability of load curtailment are very significant under Status Quo and NOCs.
- The maximum individual hourly loss at the 95% percentile confidence level under Status Quo is 8.3GW which occurs in 2018.
- The NPV of the total value of lost load is shown under each policy option in the table on the right. (This assumes a value of lost load of £15,000/MWh. These calculations assume no correlation between outages of different plant.)



### Total value of lost load

£m	SQ	DOCs	COCs	NOCs	TEN
Volatile World	12,209.34	1,426.52	1,009.76	8,043.76	1,754.87

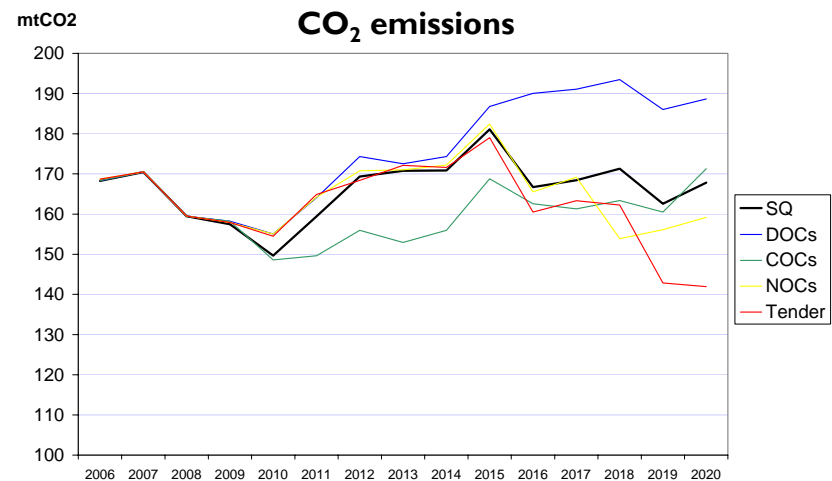
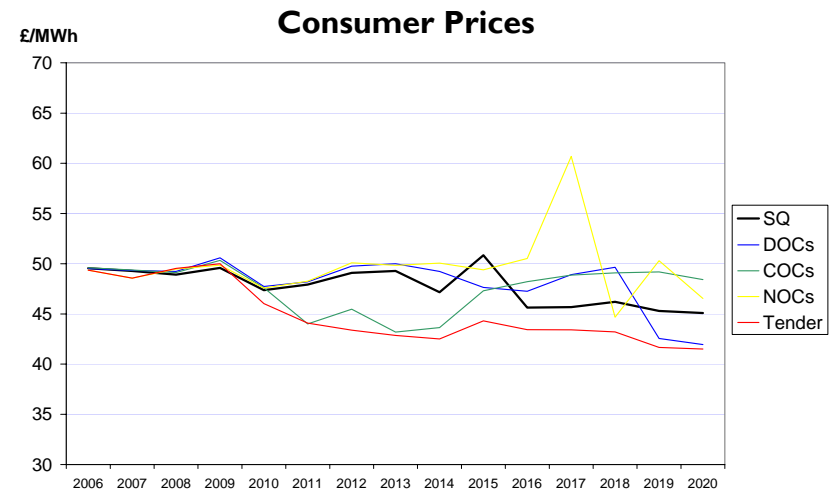
## 5.3.5 Summary metrics – DTI Base Case – (I)

Metric		SQ	DOCs	COCs	NOCs	Tendering
Total generation costs (£bn)		164.2	163.3	166.6	164.1	161.8
Total consumer costs (£bn)		213.3	213.0	210.4	215.6	205.7
Annual average CO <sub>2</sub> emissions		166.2	176.0	159.9	164.7	169.7
Supply margins	Minimum energy margin	23.8%	24.4%	25.5%	22.0%	25.0%
	Minimum peak capacity margin	4.1%	4.3%	3.6%	0.7%	4.0%
Generation diversity (2020)	% capacity of top 1	42.4%	38.7%	39.8%	41.5%	37.1%
	% capacity of top 2	66.1%	66.9%	68.1%	65.5%	66.9%

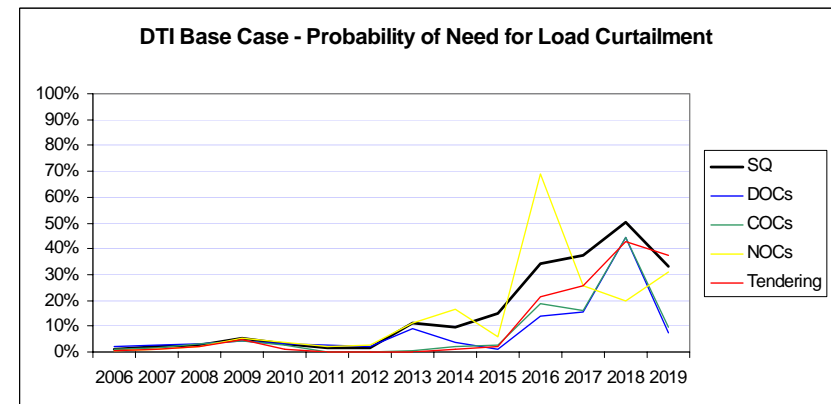
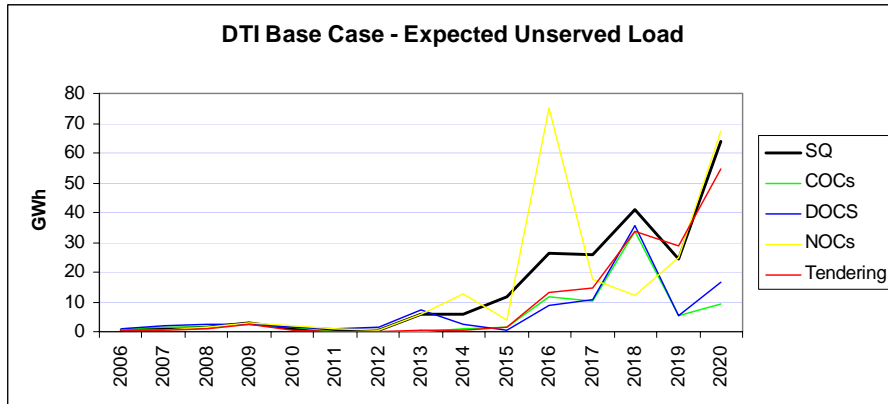
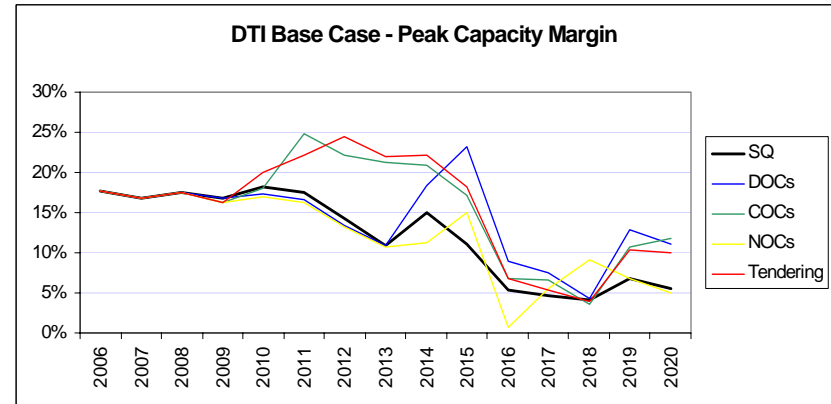
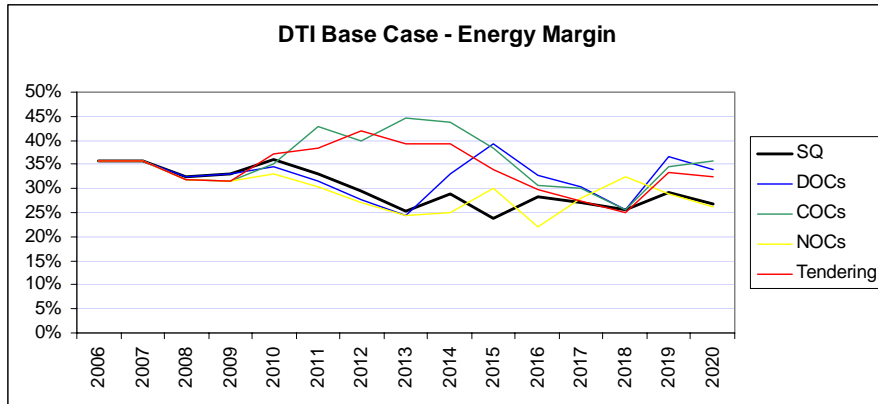
## 5.3.5 Summary metrics – DTI Base Case – (I)

### Comments

- The table above illustrates the impact of all four policy options on the DTI Base Case scenario.
- Generation costs are higher under COCs compared to Status Quo due to the encouragement of new investment to replace older plant. Generation costs under Tendering are lower since the technology choices are generally economic and the lower cost of capital of the government leads to lower investment costs. DOCs have lower generation costs than the Status Quo which is a surprising result, since DOCs would normally incentivise less economic plant. Investment and fixed costs are higher, but variable operating costs are lower. The reason is that in this scenario coal prices continue to fall whilst gas prices levelise. Coal that was initially uneconomic rapidly becomes very economic on a short run marginal cost basis with falling coal prices. (Had coal prices moved higher rather than lower, DOCs would have turned out to be a very expensive option.) NOCs have similar generation costs to Status Quo. Due to the significant amount of build of new nuclear plant under Status Quo, the impact of NOCs is fairly limited generally.
- Consumer costs are consistently lower under Tendering than in Status Quo. This is a different result from a number of the other scenarios. Here, the impact of the lower generation costs and higher energy margins is outweighing the negative impact on market competitiveness, leading to lower overall costs.
- COCs are leading to lower overall consumer costs than Status Quo but there is considerable variability. In the earlier years, the increased energy margins lead to lower prices. However, in the later years the increasing direct cost of COCs leads to higher overall costs for consumers.
- The consumer costs for Tendering are reduced by a £3.4bn profit for the TSO associated with the annual auctions of tendered capacity.



# 5.3.5 Summary metrics – DTI Base Case – (2)

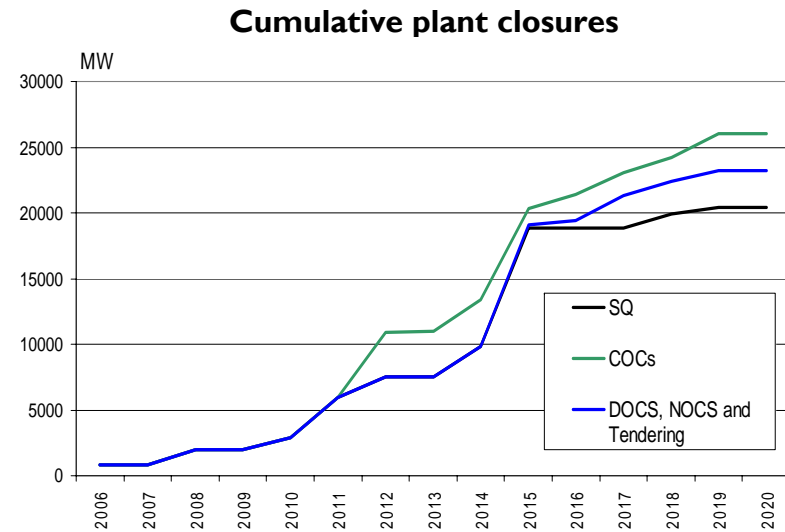


Note: Unserved load is the probability weighted expected unserved load across 500 simulations  
 The probability of load curtailment is the probability of the loss of load in at least 1 hour in the year

### 5.3.5 Summary metrics – DTI Base Case – (2): Notes

#### Comments

- As in other scenarios, COCs and Tendering lead generally to higher annual energy margins and peak capacity margins. In 2018, however, the margins under COCs and Tendering are approximately the same as Status Quo.
- NOCs are having the same detrimental impact on the peak capacity margin in 2016 as seen in Restrained Demand.
- The NPV of the total value of lost load is shown under each policy option in the table on the right. (This assumes a value of lost load of £15,000/MWh. These calculations assume no correlation between outages of different plant.)



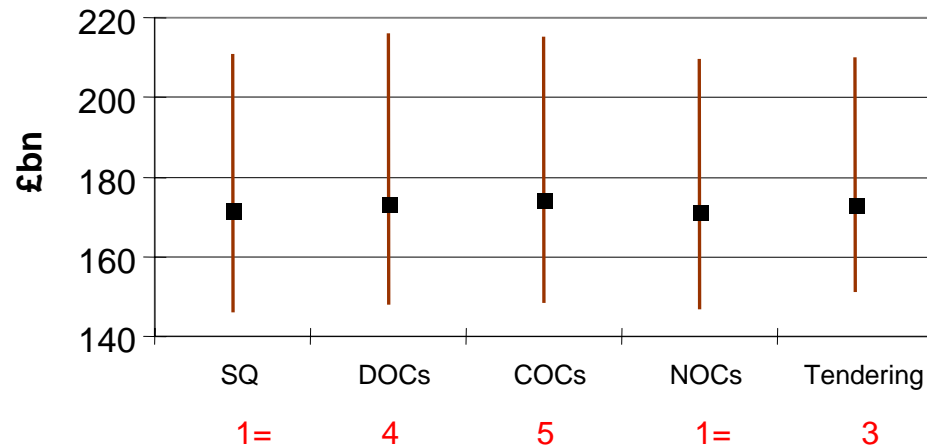
Total value of lost load

£m	SQ	DOCs	COCs	NOCs	TEN
DTI Base Case	2,081.36	993.73	810.66	2,252.57	1,450.91

## 5.4 Policy option comparison – generation costs

NPV of generation costs

Generation costs (£bn)	SQ	DOCs	COCs	NOCs	TEN
Restrained Demand	145.9	148.0	148.5	146.9	151.0
Steady Growth	175.9	176.9	179.0	175.5	174.7
Third Dash for Gas	162.4	163.9	162.7	161.8	166.8
Volatile World	210.7	216.0	215.1	209.6	210.0
DTI Base Case	164.2	163.3	166.6	164.1	161.8
Average	171.8	173.6	174.4	171.6	172.9



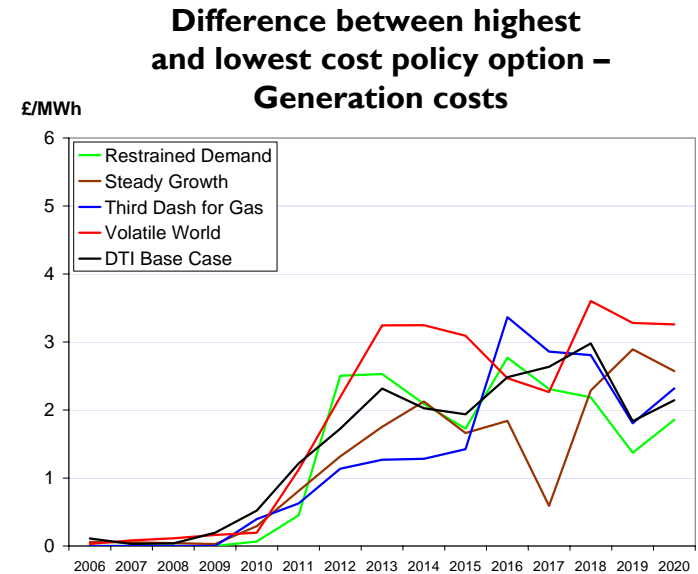
■ Average across 5 scenarios

— Range across 5 scenarios

## 5.4 Policy option comparison – generation costs: Notes

### Comments

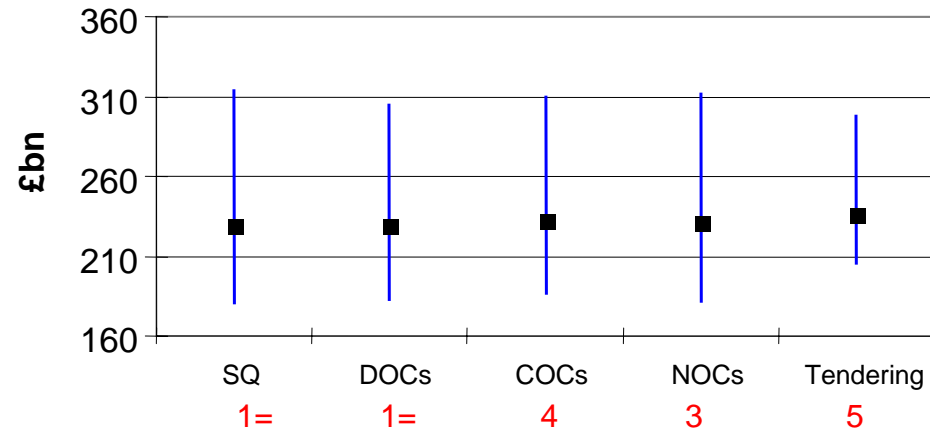
- COCs are the most expensive policy from a generation cost perspective, since it is encouraging new plant to be built and existing plant to close.
- DOCs are also generally costly since typically less economic plant are being encouraged relative to more economic plant.
- The generation cost of Tendering when averaged across the 5 scenarios are not significantly higher than Status Quo. However, there are two opposing factors having an effect. Under some scenarios (Restrained Demand, Third Dash for Gas) the choice of technologies are uneconomic leading to higher overall generation costs. However in scenarios where the choices are largely economic (Steady Growth, Volatile World and DTI Base Case) the low cost of capital for the government is leading to lower generation costs. It could be argued that the appropriate cost of capital for the government should not be the risk free rate, but an 'opportunity' based cost of capital relating to the displacement of private investment. Using a 'commercial' rate for the cost of capital under Tendering would add approximately £2.7bn to the NPV of generation costs making it the highest cost policy option in terms of generation costs.
- The generation costs of NOCs are similar to the Status Quo. This is largely explained by the fact that the costs and benefits of the NOCs policy fall largely outside the study period (2006-2020).
- The difference between the policy options on an NPV basis is reduced by the fact that there are few differences in the earlier years. The graph on the right illustrates the difference in generation costs in £/MWh between the lowest and highest cost policy options in each year.
- It is interesting to note that the spread in outcomes across the scenarios (the length of the bars) is much larger than the spread of outcomes across the policy options (the differences across the black squares). Some of this is explained by the NPV effect, since there is little variation between policy options in the first five years (whereas there is a big variations across the scenarios in these years). However, it illustrates the point that external factors are likely to have a much greater impact on the development of the electricity market than any of these policy options will.



## 5.4 Policy option comparison – consumer costs

NPV of consumer costs

Consumer costs (£bn)	SQ	DOCs	COCs	NOCs	TEN
Restrained Demand	179.6	181.9	186.0	181.2	204.3
Steady Growth	234.7	233.3	240.9	238.2	236.2
Third Dash for Gas	205.8	213.7	212.0	206.6	234.4
Volatile World	314.6	305.4	310.9	312.9	298.6
DTI Base Case	213.3	213.0	210.4	215.6	205.7
Average	229.6	229.5	232.0	230.9	235.8



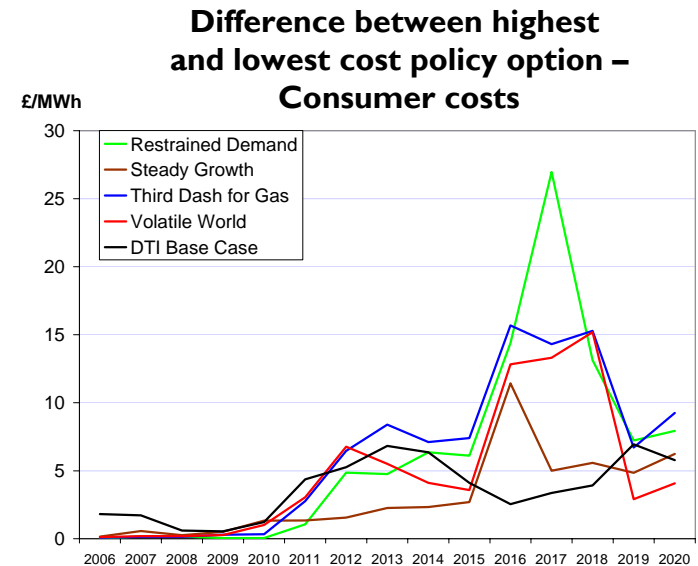
■ Average across 5 scenarios

▬ Range across 5 scenarios

## 5.4 Policy option comparison – consumer costs: Notes

### Comments

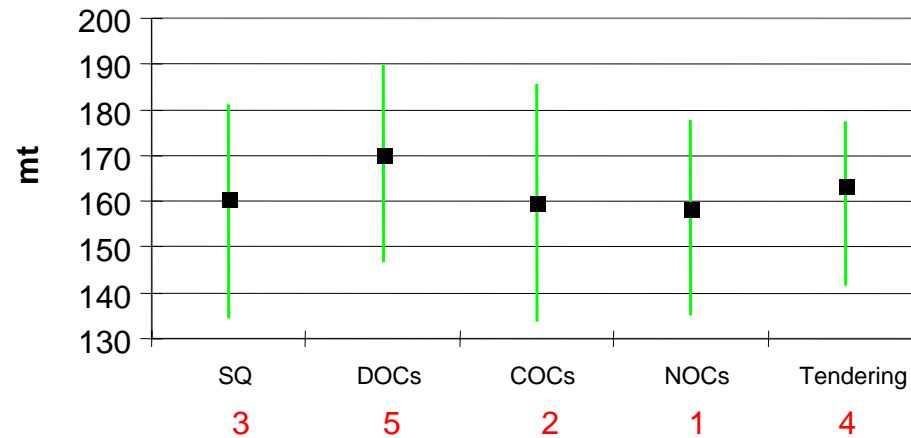
- From a consumer perspective, DOCs appears to be no more expensive than the Status Quo. This result should be treated with some caution since it is heavily influenced by what happens in the Steady Growth and Volatile World scenarios where DOCs are acting to incentivise further plant that would have been built anyway. This is leading to a subsequent collapse in DOC price as the target is being easily met. Under COCs, the price remains high since the 35% energy margin is yet to be met. In Restrained Demand and Third Dash for Gas, the consumers are being exposed to the non-economic technology choices.
- Tendering is the most expensive policy option for consumers overall, partly as a result of the non economic technology choices in some scenarios and partly due to the impact it is having on market competition. It is one of the lower cost options under Volatile World since it is effectively addressing the energy margin problem thus lowering market prices. It is also a low cost option in the DTI Base Case.
- The differences between the policy options on an NPV basis is reduced by the fact that there are few differences in the earlier years, and the averaging between scenarios. The graph of the right illustrates the difference in consumer costs in £/MWh between the lowest and highest cost policy options in each year.
- In certain years the costs to consumers are significantly different under the different policy options.



## 5.4 Policy option comparison – CO<sub>2</sub> emissions

Annual average CO<sub>2</sub> emissions

CO2 emissions (mt)	SQ	DOCs	COCs	NOCs	TEN
Restrained Demand	134.5	146.6	133.7	135.2	141.7
Steady Growth	181.2	189.8	185.5	177.8	177.6
Third Dash for Gas	151.4	161.1	145.2	148.6	163.1
Volatile World	169.9	178.1	174.4	165.6	165.8
DTI Base Case	166.2	176.0	159.9	164.7	169.7
Average	160.7	170.3	159.7	158.4	163.6



■ Average across 5 scenarios

█ Range across 5 scenarios

## 5.4 Policy option comparison – CO<sub>2</sub> emissions: Notes

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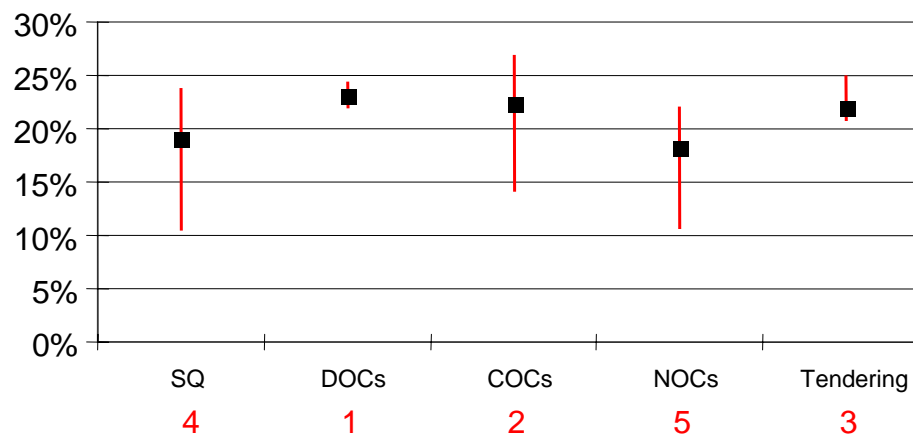
### Comments

- From a CO<sub>2</sub> emissions perspective, DOCs is the worst policy option since it generally acts to favour coal over CCGT build. This is particularly the case in the earlier years of the study period. Once nuclear and carbon capture become viable options, DOCs can help to reduce CO<sub>2</sub> emissions.
- NOCs generally leads to the lowest CO<sub>2</sub> emissions. However, since new nuclear plant are only becoming operational towards the end of the study period, the full benefit of nuclear plant in reducing CO<sub>2</sub> emissions is not being shown.
- The impact of COCs on CO<sub>2</sub> emissions depends on the scenario. In the gas favouring scenarios (Restrained Demand, Third Dash for Gas and DTI Base Case) they act to accelerate the replacement of inefficient old coal stations with new high efficiency gas stations. In the coal favouring scenarios (Steady Growth and Volatile World), additional new coal plant is putting further pressure on the output of gas plant. Also, by encouraging new coal plant in earlier years, less coal with carbon capture is subsequently being built as the economics start to favour this technology. (This result may be different if the coal plant being built in the early years were “capture ready”.)
- Tendering tends to have the opposite effect to COCs on CO<sub>2</sub> emissions. Where coal is favoured, the support for sequestration helps to reduce emissions. However, this effect is more than offset in the gas favouring scenarios due to the replacement of gas build with coal.

## 5.4 Policy option comparison – minimum energy margin

Minimum annual energy margin

Energy margin (%)	SQ	DOCs	COCs	NOCs	TEN
Restrained Demand	22.8%	22.0%	26.9%	20.3%	22.1%
Steady Growth	19.8%	22.8%	22.8%	18.1%	21.0%
Third Dash for Gas	18.9%	23.9%	14.1%	20.4%	20.7%
Volatile World	10.4%	22.4%	22.4%	10.6%	21.7%
DTI Base Case	23.8%	24.4%	25.5%	22.0%	25.0%
Average	19.1%	23.1%	22.3%	18.3%	22.1%



■ Average across 5 scenarios

| Range across 5 scenarios

## 5.4 Policy option comparison – minimum energy margin: Notes

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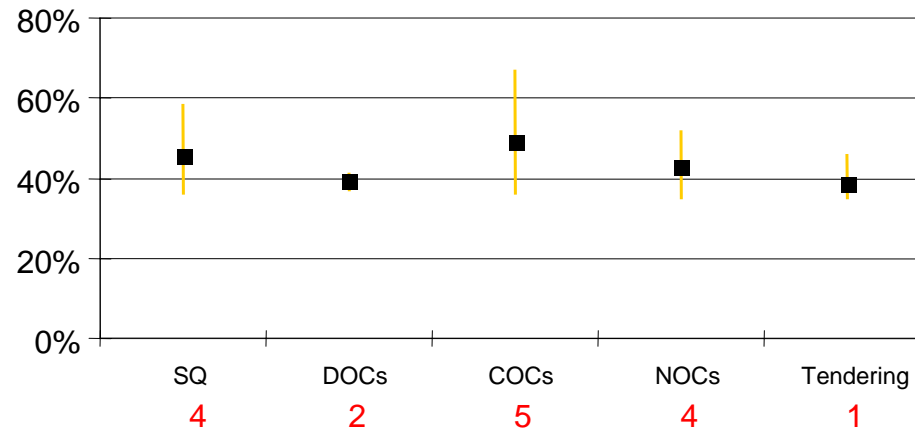
### Comments

- In 2006, the annual energy margin is approximately 35%.
- Surprisingly COCs are not necessarily the best policy option against this metric. If the metric was calculated on the overall energy margin (or total unserved load) across the study period they would be. However, it is based on the minimum energy margin in any one year, and hence the post-2015 energy margin ‘collapses’ resulting from over build in the early years in Steady Growth and particularly in Third Dash for Gas are causing it to be scored lower.
- Overall, DOCs is shown to produce the best results on minimum energy margin.
- Overall, the Status Quo appears a bad option from an energy margin perspective although in Restrained Demand and Steady Growth, the analysis suggests that intervening could be counterproductive for certain years.

## 5.4 Policy option comparison – diversity

% capacity of most dominant technology in 2020

% Most dominant tech	SQ	DOCs	COCs	NOCs	TEN
Restrained Demand	58.6%	41.3%	63.0%	49.8%	46.2%
Steady Growth	36.0%	40.1%	36.0%	36.5%	36.3%
Third Dash for Gas	55.0%	39.7%	67.0%	52.0%	38.9%
Volatile World	35.9%	36.5%	39.7%	34.6%	34.9%
DTI Base Case	42.4%	38.7%	39.8%	41.5%	37.1%
Average	45.6%	39.3%	49.1%	42.9%	38.7%



Average across 5 scenarios
  Range across 5 scenarios

## 5.4 Policy option comparison – diversity: Notes

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### Comments

- In 2006, the proportion of gas-fired plant in the capacity mix is approximately 35%.
- COCs are generally bad for diversity since they act to reinforce the advantage of CCGTs in the gas favouring scenarios.
- The Status Quo also generally leads to decreasing diversity since gas is favoured in 3 of the 5 scenarios.
- On average, Tendering is the best from a diversity perspective since the Government can control the type of capacity being built to a large extent.
- DOCs are effective in limiting the increase of gas dominance, and interestingly there is a very low difference in the diversity levels achieved across the scenarios.

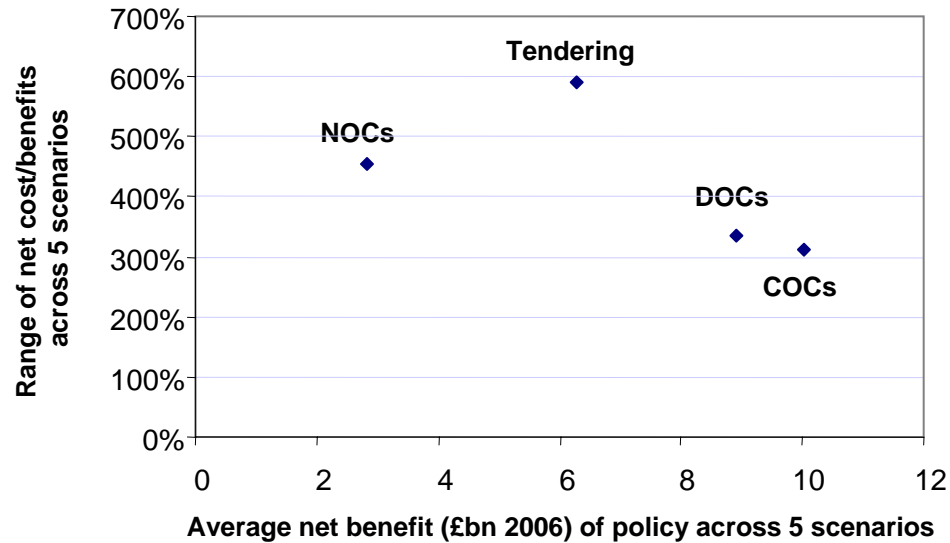
## 5.5 Net cost/benefit

**Net cost/benefit (NPV of benefits less costs, 2006-2020)**

Total net benefit (£bn)	DOCs	COCs	NOCs	Tendering
Restrained Demand	2.63	5.49	1.07	-4.65
Steady Growth	0.71	0.80	-0.55	-0.54
Third Dash for Gas	5.42	8.57	0.68	-1.06
Volatile World	30.39	31.94	12.25	32.51
DTI Base Case	5.34	3.35	0.62	5.15
Average	8.90	10.03	2.81	6.28

Note: + ve = net benefit, -ve = net cost

**Risks/benefits of different policy options**



## 5.5 Net cost/benefit: Notes

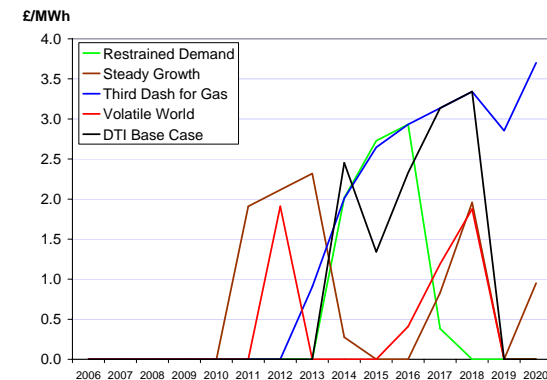
### Comments

- The graph above shows the average net benefit (as defined in section 4.2) of each policy option compared to the Status Quo against the range of scenario outcomes (difference between highest and lowest scenario value) relative to the average across all five scenarios (a proxy for the risk of the policy option).
- These results are very sensitive to the assumptions used for the social cost of carbon, the value of lost load and the risk of correlated plant outages. The averaging across the 5 scenarios is used for indicative purposes rather than as an accurate statistical measure.
- The table on the right shows the break down of the average net benefit by the three components of the calculation. Note that the “Lower generation costs” already include the cost of EUAs. The value of lower carbon emissions is based on the additional benefit based on the social cost of carbon where this is higher than the EUA cost. (Where the social cost of carbon is lower than the EUA cost the benefit is reduced rather than increased.)
- Based on this analysis, all 4 policy options show a net benefit relative to the Status Quo when averaged across the scenarios. However, this is typically less than 5% of the total generation costs. The main component of this benefit relates to the improvements in security of supply. Intervention generally leads to higher generation costs, and may or may not have an emissions benefit depending on whether diversity or lower carbon is the priority.
- Since there is little variation between policy options in the earlier years, there is a tendency for the NPV analysis to dampen the differences in net cost/benefit between policy options and the Status Quo. The two graphs on the right show the direct costs of DOCs and COCs to customers through the study period. It demonstrates that the variation in possible costs (and by extension benefits) of policy options year-on-year and between scenarios could be significant. (Note: The costs of DOCs and COCs will be offset to a greater or lesser degree by resulting reductions in the wholesale price.)
- Using this framework, it appears that the DOC and COC policies have similar overall benefit and risk. Tendering shows a lower benefit and is apparently more risky. This result seems intuitive given the risk associated with the significant amount of market intervention associated with Tendering. NOCs appear to have low benefit and high risk, although since most of the costs, benefits and risks of new nuclear plant fall outside of the study period (2006-2020) it is difficult to draw conclusions on the net cost/benefit of policies that promote nuclear over the longer term.

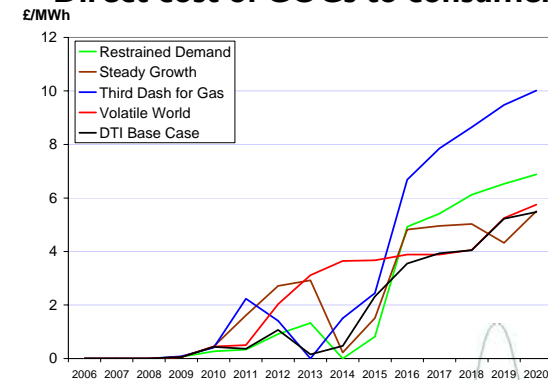
### Breakdown of net benefits

£bn (2006)	DOCs	COCs	NOCs	Tendering
Lower generation costs	-1.81	-2.56	0.24	-1.03
Lower carbon emissions	-0.20	0.15	-0.04	-0.24
Improved security of supply	10.91	12.44	2.61	7.55
<b>Net benefit</b>	<b>8.90</b>	<b>10.03</b>	<b>2.81</b>	<b>6.26</b>

### Direct cost of DOCs to consumers



### Direct cost of COCs to consumers

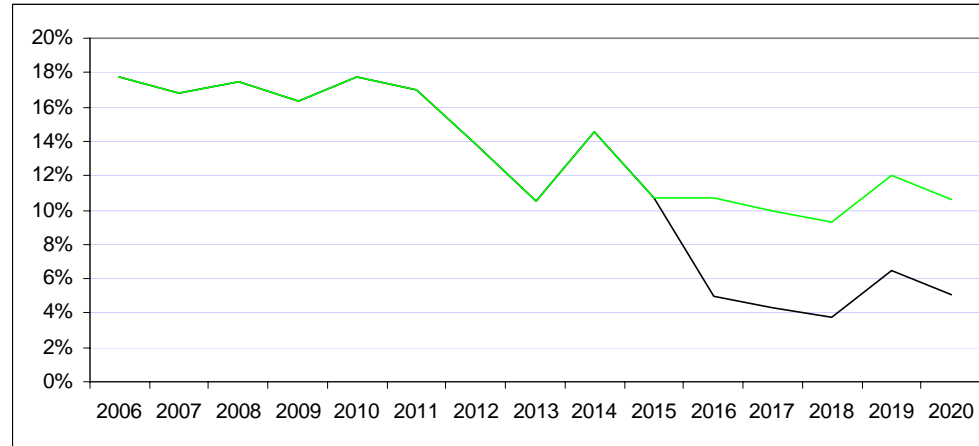


## 6. Policy option sensitivities

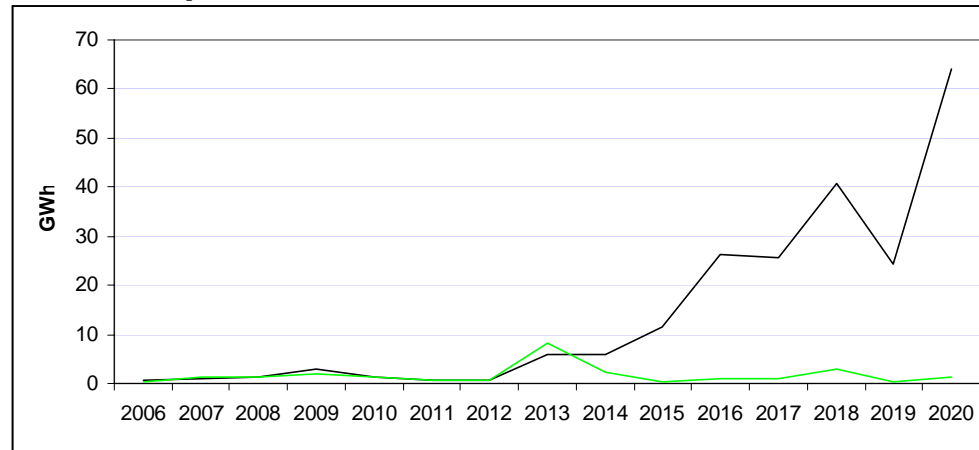
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# 6.1 Tendering peak capacity

Peak capacity margin (derated) – DTI Base Case



Expected unserved load – DTI Base Case



— Status Quo — Peak capacity tender

## 6.1 Tendering peak capacity: Notes

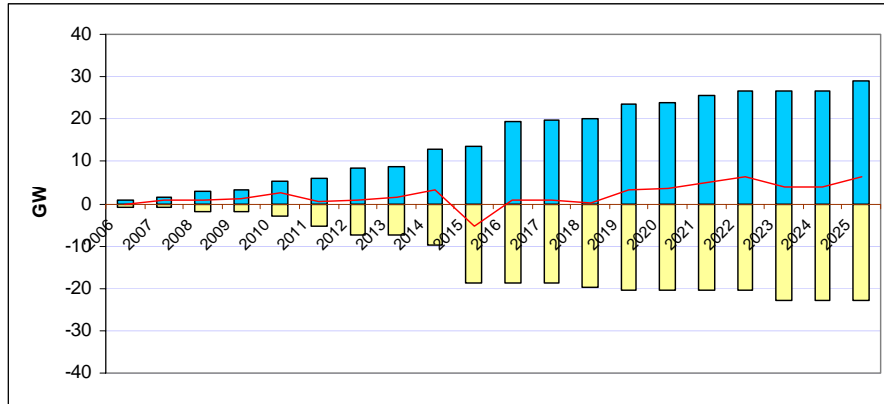
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### Comments

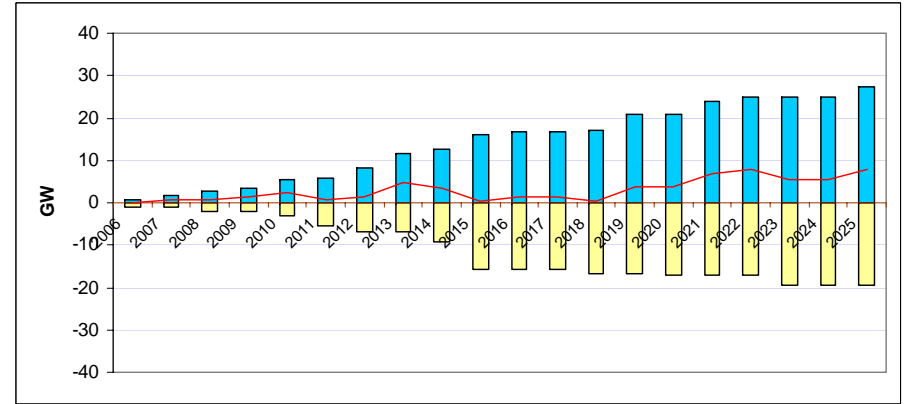
- Target to maintain peak capacity margin at or above 10%
- TSO tenders for 4 GW of OCGT capacity with distillate backup to become operational in 2016
- Under the DTI Base Case, the annual output from these peaking plant is very low, ranging from 0.9 GWh to 5.3 GWh. Hence, under average demand conditions there is little impact on prices. However, they should lead to reduced price volatility.
- Based on the loss of load modelling (which captures the effect of uncertain demand and availability), there is a significant reduction in the expected unserved load. A reduction of 228 GWh across the study period (2006-2020) is achieved. (This reduction would be greater if correlation between plant outages was considered.)
- Based on a NPV of the annualised investment costs (across the study period) of the 4 GW of OCGT plant of £512m (in 2006), but excluding the operating costs and the revenues the plant may earn, the net benefit would be positive if the value of lost load is £2250/MWh or greater.
- If the analysis assumed an opportunity based cost of capital (i.e. replacing the Government cost of capital with a commercial rate), the benefit would be positive if the value of lost load is £3000/MWh or greater.
- These values are significantly below the value of lost load assumed in this study (£15,000/MWh). This raises the question of why investors are not looking to build peak capacity. The reasons for this may include:
  - The real value of lost load is probably a curve with certain customer types placing a much lower value on it (e.g. large I&C consumers willing to shift load to avoid triads at much lower values in terms of reduced transmission charges)
  - Investors have little visibility of what is the market value of lost load
  - I&C customers are currently unwilling to contract long term to secure their load.

# 6.2 Policy option sensitivity – Carbon allocation policy –(I)

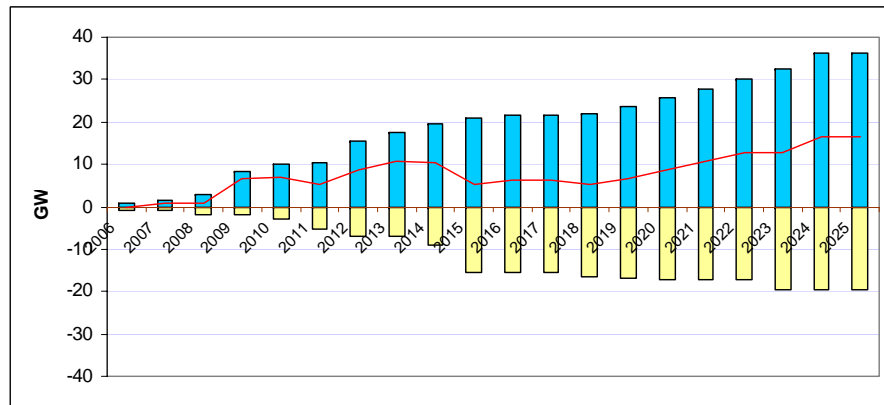
Status Quo



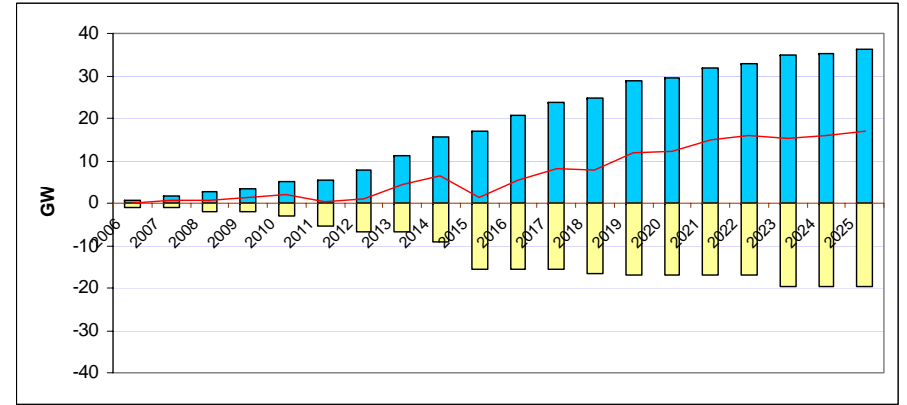
Allocations based on 50% of CCGT requirements



Allocations based on 100% of CCGT requirements



Allocations based on 50% of actual requirements



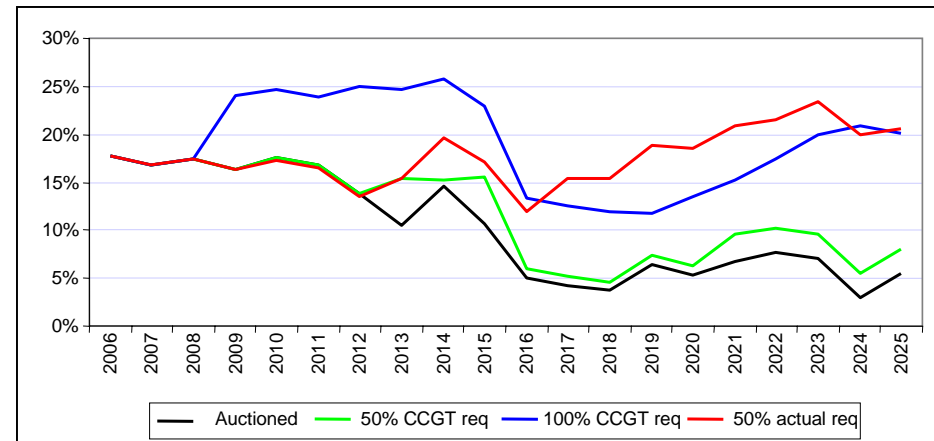
Build Retirement Net

## 6.2 Policy option sensitivity – Carbon allocation policy – (I): Notes

### Comments

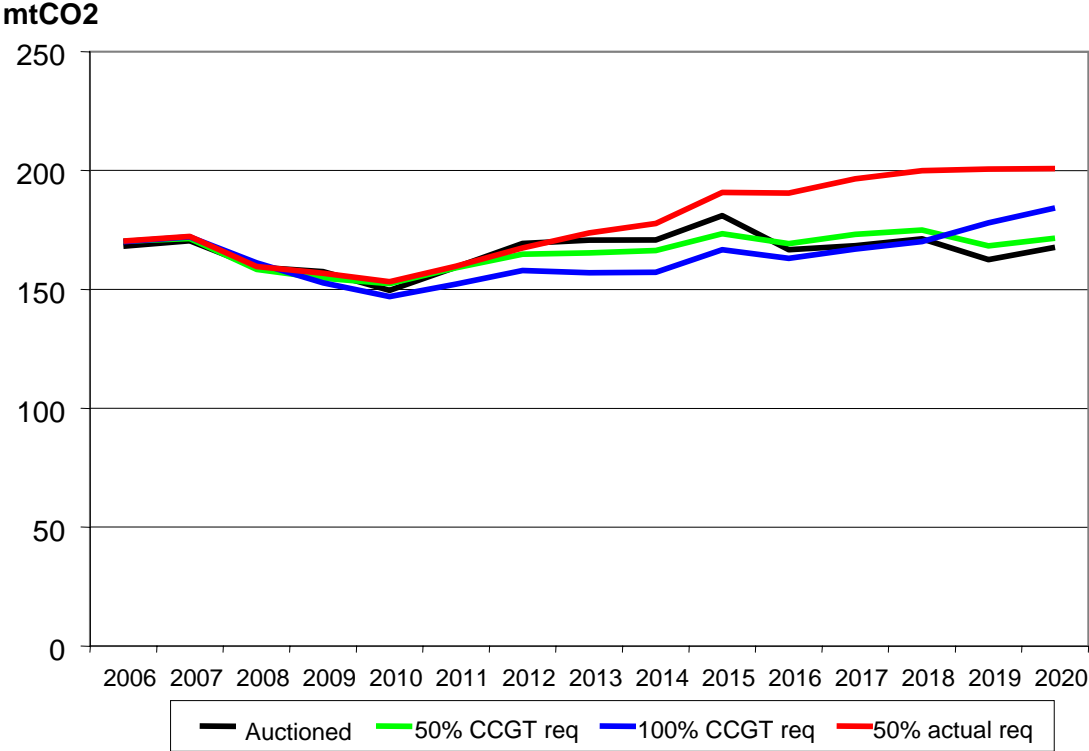
- To separate the impact of carbon allocation policy (which is the subject of other DTI studies) we have assumed throughout the analysis that all carbon allowances are auctioned, including the New Entrant Reserve, from EU ETS Phase II onwards.
- However, in this sensitivity to the DTI Base Case we illustrate the impact if allowances were to be allocated to existing plant and New Entrant Reserve (thermal plant only) in EU ETS Phase II and beyond under the following 3 options: 50% of CCGT requirements, 100% of CCGT requirements, 50% of actual requirements.
- Note: this is for illustrative purposes and not necessarily an indication of likely policy.
- The allocation of free allowances has a positive benefit on both the annual energy margins and peak capacity margins. It leads to greater build and deferment of retirements.
- However, for free allocations to be effective in stimulating new build, there needs to be good visibility on future policy, so that these benefits can be factored confidently in to new build investment cases.
- In this scenario, allocating based on 50% of a CCGT's requirements has a small positive benefit. Allocating based on 100% of a CCGT's requirements or on 50% of actual requirements has a much more significant impact. Under the DTI Base Case, the former has the bigger impact in the early years where CCGTs are the most economic; the latter has the bigger impact in the later years when new clean coal is economic (see graph in top right).
- It should be recognised that carbon allocations under EU ETS would only be effective in promoting investment in new capacity or major enhancements to existing plant, if it is possible to provide good visibility going forward of both allocation policy and carbon prices.

Impact on peak capacity margin



# 6.2 Policy option sensitivity – Carbon allocation policy – (2)

CO<sub>2</sub> emissions under different allowance allocation policies

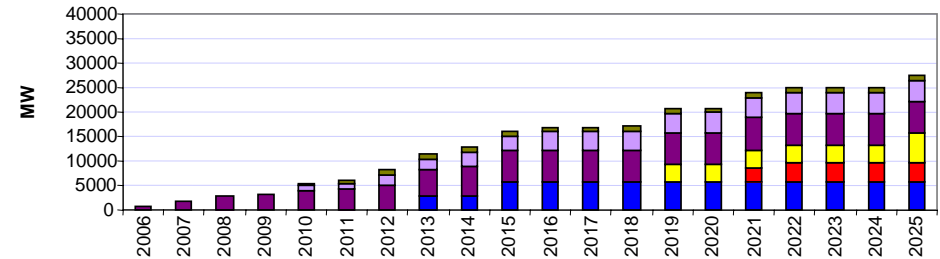


## 6.2 Policy option sensitivity – Carbon allocation policy – (2): Notes

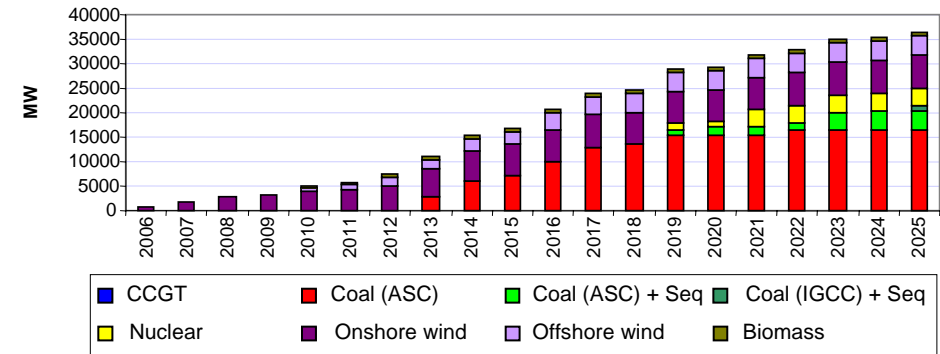
### Comments

- Allocating allowances based on 100% of a CCGT's requirements leads to lower CO<sub>2</sub> emissions compared to the case where all allocations are auctioned. This results from the greater amount of new CCGT build which increases generation from gas at the expense of coal, and improves the average system efficiency.
- Allocations based on 50% of a CCGT's requirements has limited impact compared to the all auctioned case.
- The case where allocations are based on 50% of actual requirements leads to higher CO<sub>2</sub> emissions. This is because the type of new build shifts from gas to coal. This can be seen in the graphs on the right which compare the build profiles under the 50% CCGT requirements case and the 50% actual requirements case.

**New build profile (50% CCGT requirements)**



**New build profile (50% actual requirements)**



# 7. Conclusions

## 7. Conclusions – on Status Quo

- In the past, investment in the competitive market has been driven by fuel price differentials; there is no track record of scarcity of generation capacity bringing forward investment in the GB market
- If scarcity is the main driver, the results indicate that the energy margin over the next 8-10 years would trend slightly below current levels, with only a small risk of unserved load (in the absence of gas supply problems)
- However, the anticipated concentration of plant retirements coincident with the end of the LCPD is likely to disturb this ‘equilibrium’ and could lead to more significant quantities of unserved load for a period post-2015, before beginning to recover towards 2020
- The growing proportion of intermittent renewables will make it increasingly costly to provide a solution which ‘guarantees’ security of supply at times of peak
- The market may find a solution that involves greater demand side response
- Diversity is quite likely to fall; despite recent higher gas prices, CCGT investment is still relatively attractive given its beneficial risk profile

## 7. Conclusions – on Policy Option choice

- The range of outcomes across the scenarios illustrates that external factors are likely to have far greater impact on the generation investment landscape than any individual policy option
- Tendering seems unattractive as an intervention (except possibly for peaking capacity) because tendered investments will tend to substitute private sector ones, so all investments have to be tendered in order to have an impact on the capacity mix and energy margin
- Certificate based interventions to promote more new capacity and/or diversity seem feasible and are likely to have relatively low cost
- However, the impact of these schemes would depend on the detailed design of any option and there is a risk of unintended consequences
- If policy makers were attracted to intervening through a certificate scheme, it would be necessary to design it carefully
- The timeframe of the study (2006-2020) is too short to assess fully the contribution of new nuclear plant to the GB electricity market
- The long term impacts of any market intervention need to be carefully considered before implementation

# 7. Conclusions – on Energy Review objectives

- The fact that none of the policy options analysed in the study scored highly across all of the cost/benefit metrics illustrates the inherent conflicts in a number of the policy objectives of the Energy Review
- Examples of conflicts:
  - Removing free carbon allocations may remove windfall profits for generators but may result in deferred investment in new build
  - Promoting diversity improves security of supply but increases carbon emissions
  - Tendering capacity can promote a diverse generation mix, low carbon technologies and a healthy energy margin but has a detrimental impact on market competition
  - Rewarding new capacity can increase security of supply but may lead to a sub-optimal economic solution
- Further prioritisation of the Energy Review policy objectives may be required in order to determine with confidence the best solution for the GB electricity market

## 7. Conclusions – on timing

- The analysis suggests that immediate intervention is not required unless:
  - Even the relatively low risk of loss of load over the next 8 years is politically unacceptable
  - The risk to gas supply security is greater than has been assumed in this study
  - The possible increases in carbon emissions from the power sector are politically unacceptable
  - Promotion of new nuclear is part of longer term policy objectives (i.e. post-2020), and due to the long lead times involved requires measures to be taken sooner rather than later
- However, any intervention (or decision not to intervene) must be implemented with sufficient time to create the stable investment landscape required to deliver new capacity before 2016, taking account of the lead times for various plant types

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