Optimised Market Design for the Energiewende – reducing risks to lower the cost of capital

Graham Weale, Honorary Professor - Ruhr Universität Bochum

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Introduction

1. Everywhere in liberalised markets (Europe and US) a high amount of investors' capital in power plants has been destroyed over 20 years
2. The risks for investment in firm capacity required for supply security with an Energy-Only Market are poorly understood and extremely high
3. The risks/financing costs for investment in renewables are also higher than necessary
4. Low cost debt has played a major role in the energy transitions but so far has been mainly applied to renewables
5. With planned coal plant closure in Germany and elsewhere it is vital to provide the required firm and renewable capacity at the lowest costs
6. Focussing separately on the annual depreciation and financing costs is the key to a new market design to significantly reduce consumers' costs

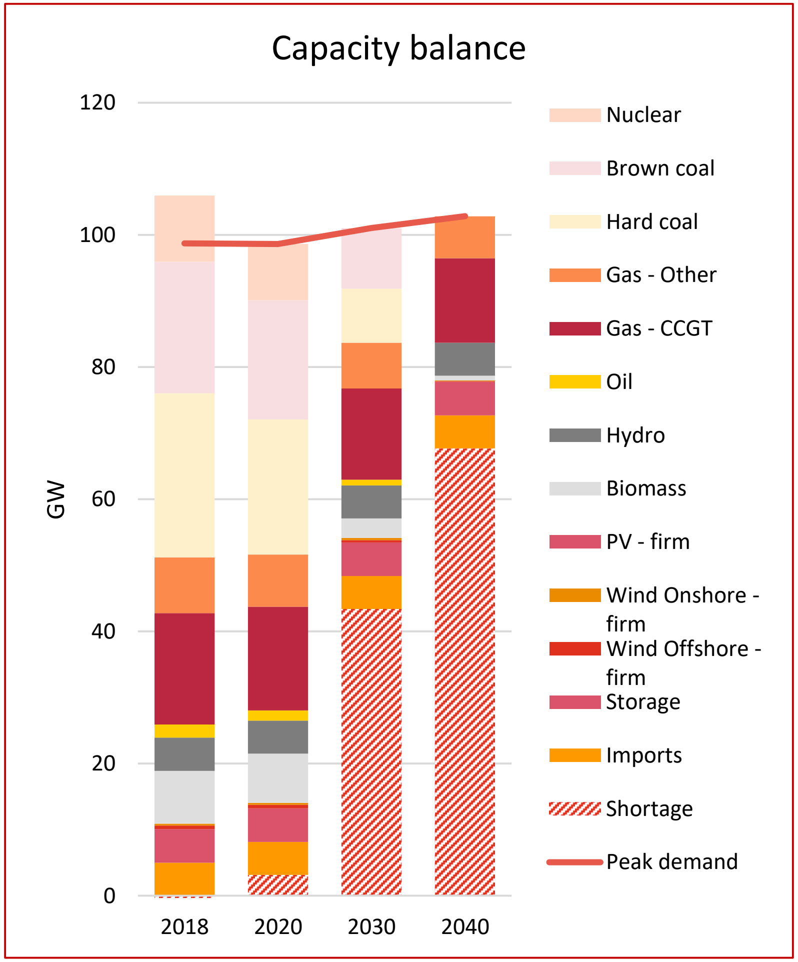
Note: This paper is based on a project undertaken jointly by the author and PwC Global Utilities Practice

Agenda

1. Investment requirements in Germany 2021-20
2. Correct approach for project cost of capital
3. Risk and financing costs for plant in different market designs
4. Conclusion and recommendations

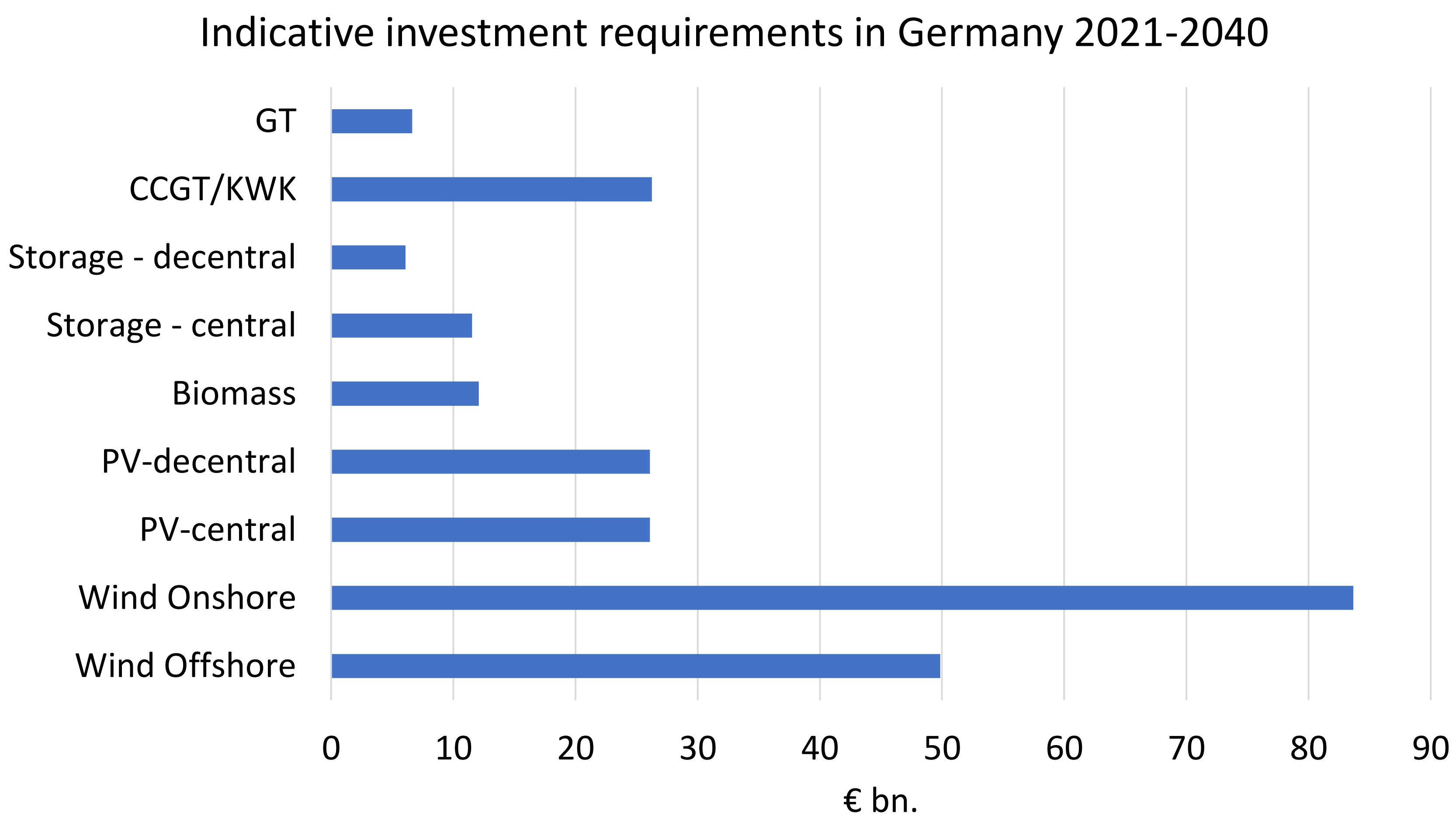
1. A capacity crisis is looming in Germany, exacerbated by coal plant closures…

- A large capacity gap is emerging
- Based on the hard lessons of the past power companies may be reluctant to invest in new capacity or storage
  - Current pipeline is very low
- Firm capacity is as important for the Energiewende as the growth of renewables
- Neighbouring countries, especially France, may be losing capacity, so Germany will have to be more independent in covering its peak demand



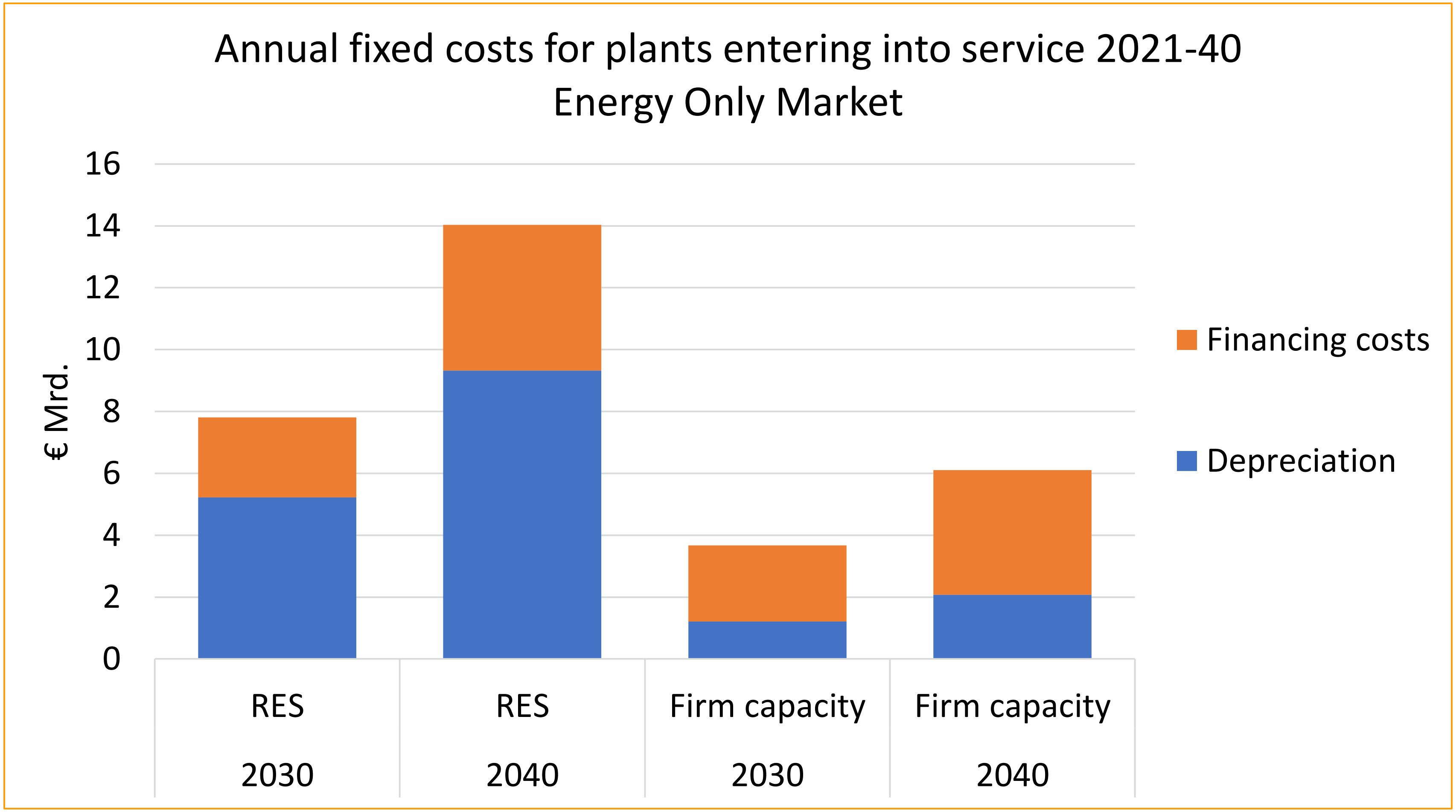
Source: PwC

… so that ca. € 250 bn. needs investing 2021-2040…



Source: PwC Global Utilities Practice

… leading to the following annuity costs in the Energy-Only Market, split into depreciation and financing costs



Source: Author and PwC

2. Correct approach for project cost of capital

- For project evaluation most power companies take their balance sheet weighted average cost of capital (WACC) and then apply a small project-specific surcharge to determine the project discount rate
  - Varies across the years based on long-term interest rates for debt, historic determination of company's ß and the market risk premium
- Two problems:
  - Approach is backward- rather than forward-looking
  - For a diversified company the project risk may be considerably higher or lower than the overall company risk
- It is not correct to apply similar discount rates to highly regulated businesses with low risk and fixed return and to power plants in merchant markets
- For thermal power plant projects the risks were poorly understood and the discount rates were much too low → many wrong investment decisions!

The challenge of recovering fixed costs for thermal plants and storage

- Intransparent computer models masked the challenges and therefore the risks
- A plant recovers its fixed investment and operating (O & M) costs from up to three sources:

  (i) Infra-marginal rent (ii) Scarcity-prices (iii) Capacity payments where they exist
- An awareness of what proportion of fixed costs can be recovered from each source and with what risks is essential to a sound appraisal of any thermal/storage project
- Additional complication – the fixed costs depend upon the discount rate and therefore market design – they are higher in an Energy-Only Market than with a Capacity Market, which exacerbates the problem → more fixed cost to recover at a higher discount rate
- Risks and indicative discount rates for the three sources:

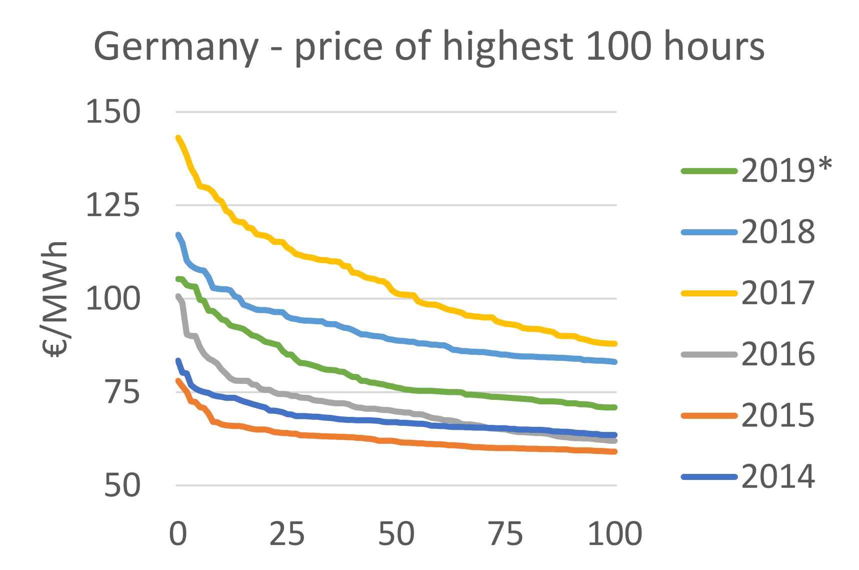
Income source	Risks	Discount rate (real)
Infra-marginal rent	Depends on position of plant in relation to price-setting plants and gradient of merit-order curve	3-5%
Scarcity-prices	Whether they will exist at all or be sustained at average level over economic life of plant	10-15%
Capacity prices	Very low in a long-term capacity market	1-3%

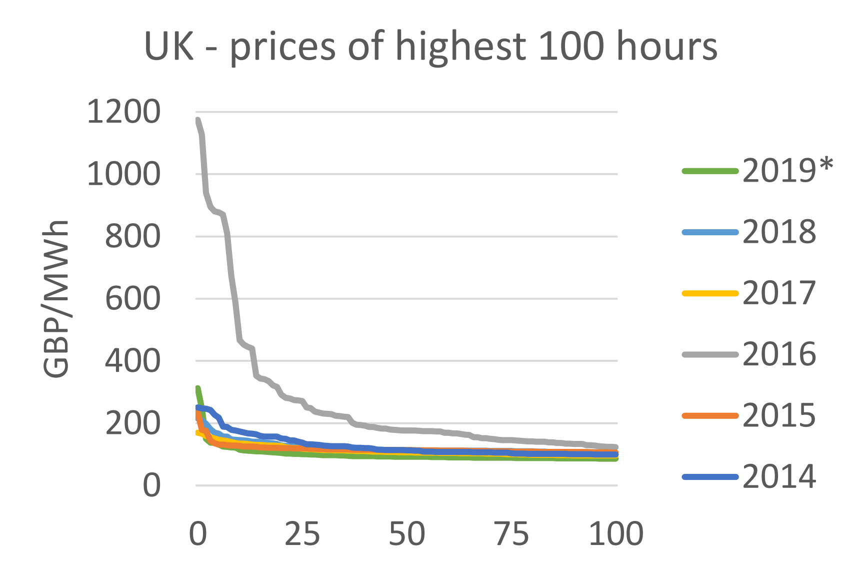
Source: Author and PwC

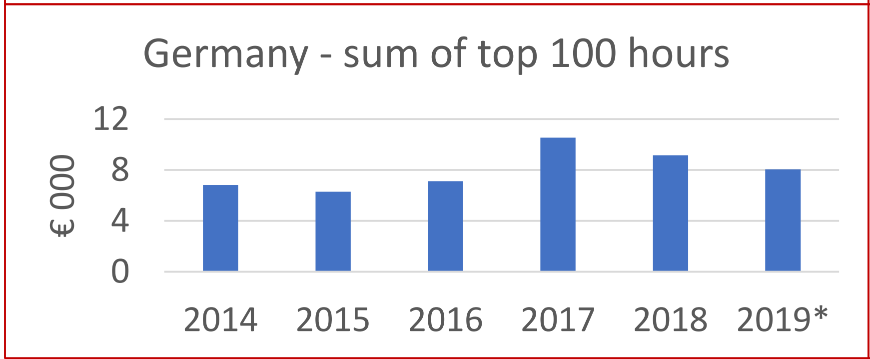
Challenge in judging risks and cost of capital for fixed recovery from scarcity pricing

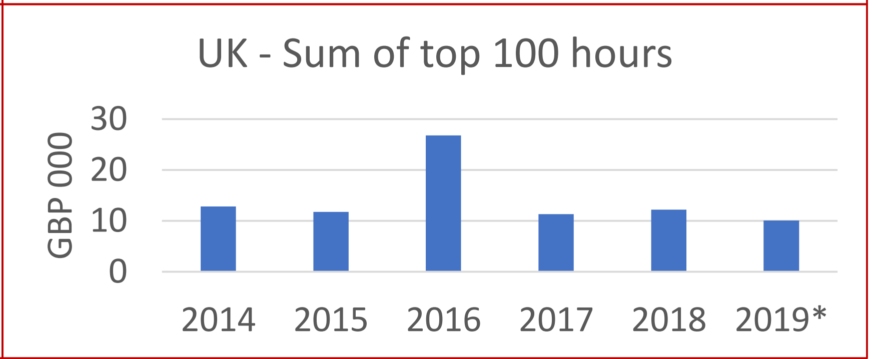
- Despite the rhetoric there has been very little experience of scarcity pricing anywhere in the world
- Over last six years prices have been well below necessary levels to support investment and no sign yet of an upward trend
- How to calculate the expected value and standard deviation from a potential future population?
- Simulations of future prices are available and would be one source
- Expert views range from a 15% to 25% cost of capital to reflect risk
- More important question – will politicians allow prices to rise to necessary levels and remain there over plant life?
- A somewhat arbitrary choice of capital costs is therefore unavoidable

Highest prices since 2014 – far too low to support investment and no upward trend









Source: Montel

Derivation of discount rates based on utility financing structures and required returns

Financing Structure and Respective Cost of Capital

	Equity	Debt	Comment
1. Financing Structure			
Fixed cost part covered by:			
- Infra-marginal rent (both EOM* and CM*)	40%	60%	Typical utility structure
- Scarcity pricing (only EOM)	100%	0%	
- Capacity payment (only CM)	20%	80%	As for Onshore Wind
2. Nominal Returns/Interest pre-tax			
- Infra-marginal rent	11.5%	2.5%	
- Scarcity pricing	15.0%		Ultra-high risk
- Capacity payment	8.0%	2.5%	Less risky than for infra-marginal rent
3. Real Returns/Interest pre-tax			Assumes 2% inflation
- Infra-marginal rent	9.5%	0.5%	
- Scarcity pricing	13.0%		
- Capacity payment	6.0%	0.5%	
4. Resultant Capital Costs to reflect Capital Structure and respective returns (Real)	**Pre-tax**	**Post-tax @30%**	
- Infra-marginal rent	4.1%	2.9%	
- Scarcity pricing	13.0%	9.1%	
- Capacity payment	1.6%	1.1%	
5. WACC for CCGT under different market designs (real)			
- Energy Only Market	11.0%		
- Capacity Market	2.7%		

Source: PwC Global Utilities Practice

* EOM = Energy Only Market and CM = Capacity Market

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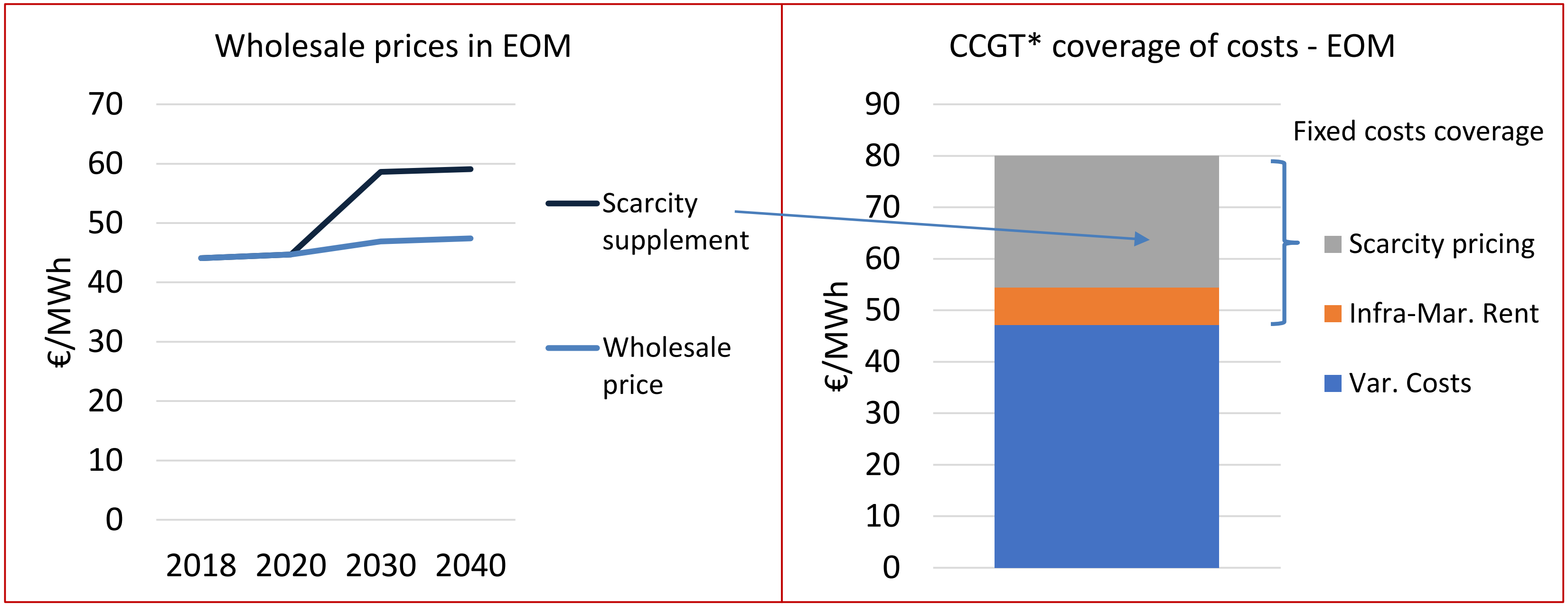
3. Risks and financing costs of plants in different market designs: fixed costs for CCGT in Energy-Only Market



- A scarcity price of ca. € 26 / MWh is required over the planned 4000 operating hours, equivalent to ca. € 12 / MWh over 8760 hours

Notes: (1) Infra-marginal rent is the difference between the price captured and the plant variable costs

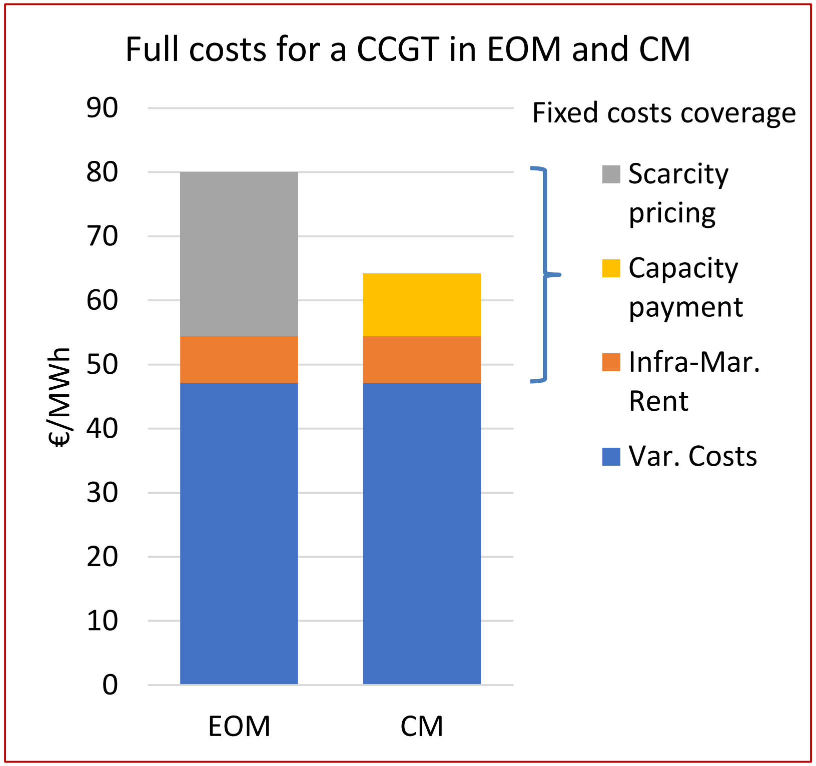
(2) The scarcity price component for the CCGT is higher than the average scarcity supplement, because it needs to be realised over the plant operating hours

* CCGT = Combined Cycle Gas Turbine

Source: Author and PwC

A capacity market is one way to reduce risks and financing costs

- Conversely a capacity market (CM) for required new capacity leads to much lower costs because:
  i. The risks and therefore the cost of capital are much lower and
  ii. In this concept only new plants benefit from the payments, whereas in the EOM once any new capacity is required the market price needs to rise sharply and all thermal plants benefit at the cost to consumers
- The fixed cost in a CM is 17 €/MWh vs. 33 €/MWh for the EOM therefore the full cost per MWh is € 64 / MWh vs. € 80 / MWh in the EOM
- The difference to consumers between the two systems in 2030 is estimated at some 6 € bn. – 6% of total costs including taxes



CCGT = Combined Cycle Gas Turbine
EOM = Energy Only Market
CM = Capacity Market

Source: Author and PwC

The risks and financing costs for renewables can be further reduced

- The government aims for a full integration of renewables into the power market, but this is not possible whilst they are being introduced independently of wholesale market signals
- **Since the government has set clear renewables targets it is more important to meet these targets at the absolute lowest cost, than to put weight on market integration**
- There are four means to reduce risks and financing costs:

i. Change the auction from a surcharge to contract-for-difference basis to eliminate price risk

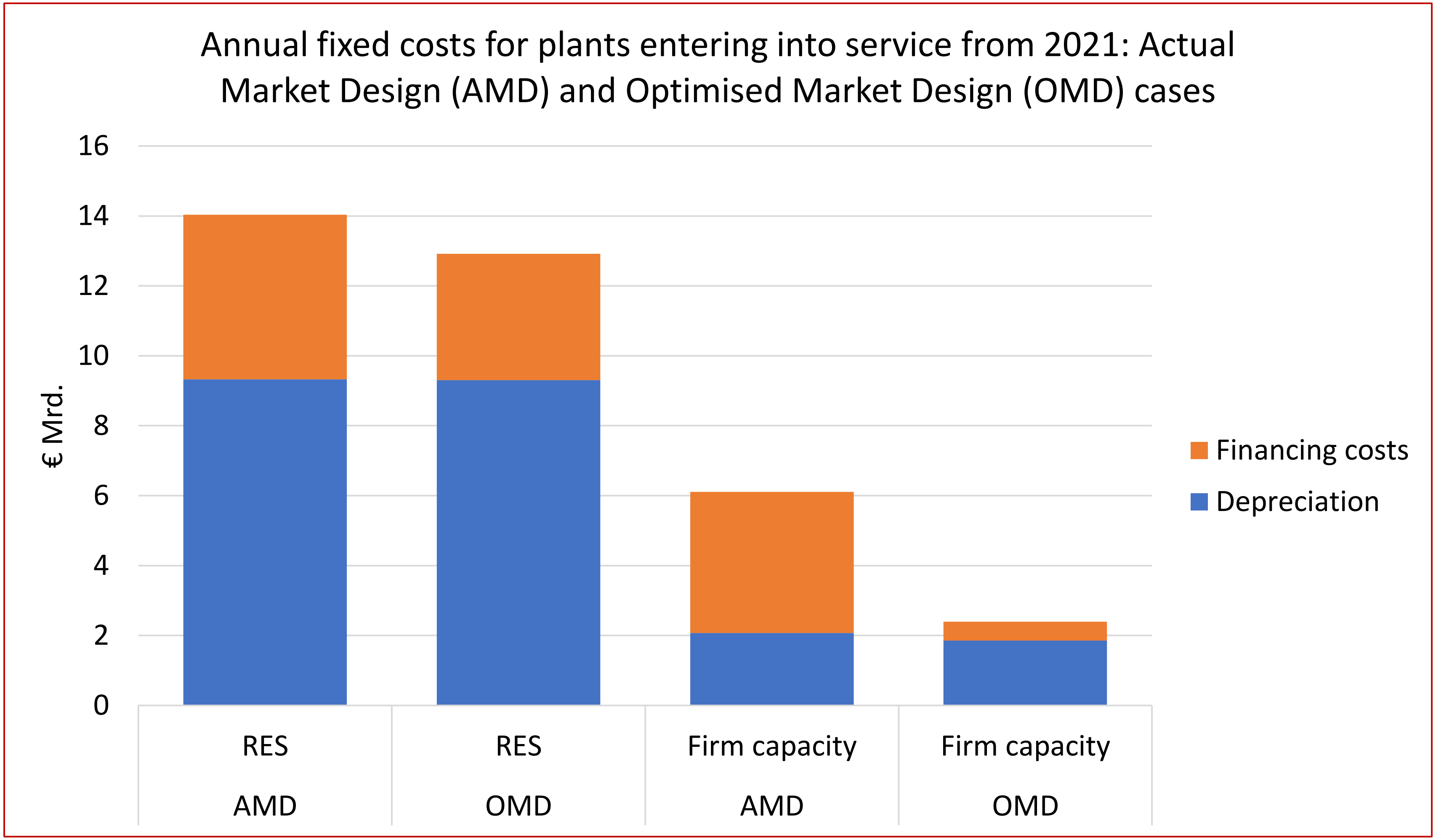
ii. Move further and base the auction on an annual price per unit of capacity, and share the risks of higher/lower annual wind factors between investors and consumers

iii. Include an inflation index on the debt as many finance institutes value an inflation hedge

iv. Move towards longer-term debt to reduce refinancing uncertainty

- With such means it may be possible to reduce average financing costs by 0.5-1.0%, saving an estimated 0.6-1.1 € bn. by 2040

6. Conclusion and recommendations: scope to reduce consumer costs for plants entering service 2021-2040



Recommendations

- Expose the issues relating to scarcity pricing and the magnitude of the financing costs in the annual costs to be covered by consumers
- Required new thermal plants for supply security should benefit will not be built if investors have learned lessons from the past
- Low-cost debt has played a crucial role in the financing of renewables – the future cost of transitions will be lower if it also finances necessary firm capacity
- A capacity market is one means to enable the necessary financing costs to be reduced by maximum use of low-cost debt
- Renewables plants should be remunerated essentially on a capacity-basis, but with provisions to share residual risks between investors and consumers
- Government needs to determine correct trade-off between degree of competition and meeting goals at lowest cost

THANK YOU FOR YOUR ATTENTION

Graham.Weale@RUB.com