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CAN AN ENERGY-ONLY MARKET FULLY REMUNERATE INVESTMENT? EMPIRICAL EVIDENCE SINCE 2005

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Can an Energy-Only Market fully remunerate investment? Empirical evidence since 2005

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Abstract

The challenges of relying upon the Energy-Only Market (EOM) to adequately remunerate power plants have been widely discussed. However very little empirical information is available showing what percentage of the fixed costs have been recovered since liberalisation was introduced. This paper presents the results of a detailed investigation into the level of cost recovery from the wholesale market for thermal, nuclear, and renewable plants in France and Germany for selected years within the period 2005-2019. The analysis shows that only second-generation nuclear plants recovered their full costs; the average level of cost recovery (over the period covered and the two countries taken together) was 40% for CCGTs, 55% for hard coal plants, 30% for wind plants and 60% for utility-scale solar plants. As an alternative means of profitability determination the internal rate of return (IRR) was estimated and found to be below zero for CCGTs and wind plants; coal plants recorded an IRR of 2-3%, nuclear plants 7-8% and PV plants 0-2%. These compare with a typical utility cost of capital of 7%. The investigation also sought to assess whether data on the variability of returns and its comparison with the appropriate stock-market index could help inform the appropriate cost of capital for such power plants. The monthly volatility of returns was much lower than for the stock-market index, although over the period considered large structural shifts in the returns were observed. Therefore there were no results which could be applied in addressing the cost of capital issue. The conclusion is that the returns from the EOM are structurally too low, rather than particularly high risk, so that it is not possible to invest in such plants relying on revenue from the wholesale market alone.

Keywords: Market design, Energy-only-market, Capacity market, Scarcity-pricing, Infra-marginal rent, Fixed costs recovery.

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I. INTRODUCTION

The purpose of this investigation is to determine the extent to which selected power plants (thermal, nuclear and renewable) recovered their fixed costs from the wholesale markets in France and Germany since the arrival of liberalisation as far as available data would allow. As a complementary approach the IRRs of the power plants were estimated and compared with the typical utility cost of capital. The aim is to provide an empirical contribution to the hitherto largely theoretical discussion as to whether the wholesale market, commonly designated as an Energy Only Market (EOM), supported by any potential income from supplying other services enabled full cost recovery.

As a starting point, the strong consensus is that the EOM should theoretically be sufficient under perfect competition (Léautier 2017). Conceptually, the EOM is a market design where generators are remunerated for each unit of electricity produced and where prices vary freely depending on the supply-demand equilibrium. In the absence of market power, the price is set by the marginal plant, either at its marginal price, or above if scarcity materialises. In this context, prices should reflect market scarcity in hours at very high prices in case of under-capacity. Fixed costs have to be recovered from the infra-marginal rent and, when present, the scarcity rent.

However, various peculiarities of the power market, mainly on the demand side, together with particular social and political requirements dampen its efficiency. Crampton and Ockenfells (2013) identified the problem of most consumers paying annual average rather than hourly prices. Agora Energy (2014) confirm that the EOM would be optimal from a social welfare perspective but see that in reality it is hindered both by demand-side limitations and regulatory uncertainty. Keppler (2017) draws attention to the security of supply externalities and asymmetric investment incentives between producers and consumers. Hogan (2017) is a strong proponent of the EOM and like Agora reasonably points out that the main reason for "missing money" since the advent of liberalisation has been excessive capacity.

Scarcity-pricing is a vital component of a successfully functioning EOM and at a theoretical level Petitet et al. (2017) have compared its merits with that of a capacity market.

Implementing a capacity market providing an additional source of fixed income has been the most discussed option, although it is far from the only alternative solution to compensate for expected under-recovery from the wholesale market. For over ten years different types of capacity markets have been introduced in Europe, North America and elsewhere. Bublitz et al. (2019) have comprehensively reviewed their functioning to date. There is also a body of literature addressing economic profitability tests as part of the introduction of capacity remuneration mechanisms in various European countries which can be found on the EU DG Competition website.

Although there is currently no consensus on which market design is empirically most efficient, there is a relatively high agreement on the low profitability of dispatchable plants in the post 2008 period. The extent of this issue as well as the reasons for it remain to some extent unsettled. Some argue that investment cycles contribute to the problem, and others that out-of-the-market investment in renewable plants is a major factor.

A separate line of investigation relates to the level of risk to which power plants are exposed in a merchant market and therefore what cost of capital should be applied to reflect this. The normal approach of corporate investors is to take their weighted average cost of capital (WACC) and add a small premium both to ensure that the project would add value and to reflect the specific project risks. This project sought to investigate whether, and to what extent, empirical analysis of historical project returns could help determine the appropriate cost of capital for similar projects. Peluchon (2019) has proposed a means whereby the ß-factors for physical assets may be calculated by reference to a final stock market index.

II. EMPIRICAL APPROACH

2.1. Methodology

The analysis was based around typical power plants with no special characteristics or advantages in relation to a theoretical prototype, such as being of a combined-heat-and-power configuration, being built on a brownfield site with lower construction costs or having favourable contracts for the supply of fossil fuels and/or for the offtake of power. In practice almost every power station does have some advantages which helps make the investment decision and could result in somewhat better returns than those calculated in this project.

The method consisted of estimating for each plant type (i) the full annual costs to include financing, depreciation and O&M and (ii) the net variable margin earned from dispatching the plant on an hourly basis for those hours in which the margin was positive, as determined from the commodity prices used.

With regard to estimation of the IRRs the average net cash margin realised for the years when data was available was treated as an annual constant for the project economic life. The fact that profitability in the early years (important for discounted cash flow analysis) of the project may have improved the result and the latter years (especially if the plant was prematurely closed) had the reverse effect could not be taken into account. This is an unavoidable limitation of the empirical approach.

Here it must be recognised that the period for which data was available was significantly shorter than the plant life and therefore afforded only a limited insight. Inclusion of data from the earlier years when the plant was operating (which was not available) and the latter years up to the end of its economic life could have moved the average result obtained for the available period in either direction. In addition regulatory developments unforeseen when the original investment decisions were made tended to shorten the actual working life of certain thermal plants: there has been a general programme of coal plant closures and nuclear plants in Germany had their working lives curtailed by edict and due to the rapid sprouting of renewable capacity some CCGTs were closed earlier than envisaged.

The only alternative methodology would have relied upon access to management accounts of plant operators, which for confidentiality reasons would not be available although they would show the benefit of whatever special advantages and additional income streams the plants enjoyed. But again these would only have covered a part of the expected economic life.

Plant technology, especially for renewables, was in a continuous state of development, and therefore there was a challenge in selecting the appropriate type of plant (i.e. its specific costs, and thermal efficiency) which should be used. Considering the relative consensus around the low margins of generators since the 2000s, the state-of-the-art plant were taken as reference to ensure that the calculated the operating margins measured would provide an upper bound of remuneration for each technology. However to the best knowledge of the stakeholders neither the specific costs nor thermal efficiency improved significantly over the period covered. With respect to nuclear plants, a typical second-generation example was chosen.

The analysis seeks to calculate the level of profitability of such state-of-the-art plants based on realised wholesale prices. In a simplified framework theoretically reflecting the functioning of an EOM, the generators earn a margin every time the hourly price is higher than their (linear) variable cost. The level of the calculated hourly margins is summated to form yearly margins which can then compared to the annual fixed costs in order to determine how much of the total costs was recovered from the wholesale market alone.

An intensive data processing effort was necessary to build up an hourly database including costs and wholesale prices so to be able to derive potential production profiles and margins. The database includes the maximum number of years for which all necessary data was available within the period 2005-19; 2020 was excluded due to the Covid-19 impact. As part of the transparency objective, only publicly available data sources were used. While the creation of an internal market in the EU has come with a growing centralization of data (ENTSO-E, Eurostat etc) and the computation of novel indicators, the data-series often do not go so far back in the 2000s and have varying starting points.

Figure 1 shows what data was available by year. It was unfortunate that data for gas was not available for 2005-07 for Germany and for 2005-10 for France, since these years preceded both the global financial crisis and the accelerated build-out of renewables and would likely have shown higher cost recovery than in the latter years. Unavoidably, the time-window analysed was in all cases much shorter than the expected economic life of any plant and cannot give an ultimate verdict on how the plant overall would have performed.

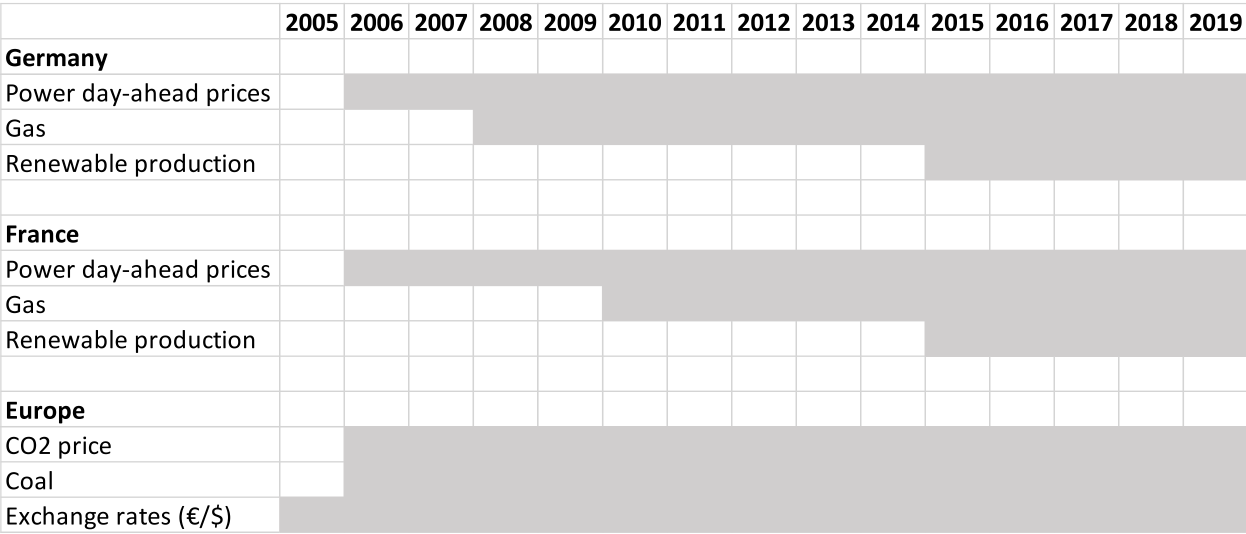

Figure 1 Availability of data by year

The following plant categories were included:

- Thermal plants: combined cycle gas plant (CCGT), supercritical coal plant
- Second-generation nuclear plant (i.e. the type brought into service in the 1980s)
- Renewables plants: onshore wind, offshore wind and utility-scale PV.

The analysis was undertaken for two countries – Germany and France. Together they represent a substantial share of the total European market and through market-coupling which began in 2010 the wholesale prices and therefore the margins in a significant number of hours each year were similar.

There were two key elements to be calculated for each plant:

- The fixed annual costs (independent of actual utilisation), which were considered as constant over time
- The cash margin earned each year.

All analysis was undertaken in nominal currency.

2.2. Fixed annual costs

The data to determine the fixed annual costs for each plant type consists of the specific capital cost, economic project life, discount rate and operational and maintenance (O & M) costs. A key data source was the Fraunhofer Report from 2018 to which industry knowledge from the project stakeholders was added as in Table 1 below. These are best estimates of the costs for plants which would have been brought into operation from around 1985 in the case of 2nd generation nuclear plants, 2000-2015 in the case of hard coal and CCGTs and from 2010 in the case of renewables plants. Another source, Projected Costs of Generating Electricity 2020 from the IEA was considered, but there were very wide ranges for the specific costs, and it was not always clear which categories of plants were being covered. A further report – Cost of Energy (LCOE) - written by Trinomics for the European Commission has limited estimates of the specific costs for certain types of plants.

	CCGT	HARD COAL	NUCLEAR (2ND GEN.)	ONSHORE WIND	OFFSHORE WIND	SOLAR PV
SPECIFIC COST (€/KW)	950	1650	2500	1750	3900	700
O & M % OF SPECIFIC COST	1.1%	1.6%	3.3%	1.7%	2.6%	0.0%
PROJECT LIFE (YEARS)	25	40	40	25	25	25
DISCOUNT RATE	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
EFFICIENCY (HCV)	52.0%	44.0%				
CO2 TONNES/MWH FUEL INPUT	0.181	0.340				
NON-FUEL VARIABLE COSTS (€/MWH$_E$)	2.0	5.0	6.4	5.0	5.0	0.0
FUEL COSTS FOR URANIUM/MWHE			5,0			

Table 1 Cost and technical information for thermal and renewable power plants

The economic life of a project can only be an estimate, and experience has shown that some plants have not survived as long as expected whilst others have remained in operation for longer, enjoying the "golden end" when depreciation no longer has to be deducted. Figures for CCGTs and hard coal are industry standards, whereas a life of 40 years was applied to second-generation nuclear plants. Indeed, such plants were designed to last 40 years and even if lifetime extensions have been granted since, this would not have been taken into account at the time of investment. In addition, lifetime extensions are costly, so to be consistent additional costs would have to be factored in.

However if a 60-year life would be assumed the annual depreciation would be lower, but the financing costs somewhat higher, and the O&M cost identical leading to an 8% reduction in full costs (excluding the additional investment for the life extension), so the end result would not materially change.

Decommissioning costs for all plants are disregarded, but even in the case of nuclear plants, due to the long time period over which this takes place and the powerful force of compound interest on the fund set aside for this purpose, such costs would only affect the results minimally. Time off-line for maintenance was also not included.

The discount rate is a particularly critical element, whose choice has a major impact on the fixed annual financing costs. Industry transparency on this is limited, but one company, RWE AG, includes in its Annual Report (2015) not only the company weighted average cost of capital (WACC), but also an explanation as to how this figure is derived. For a selected horizon year, 2015, the calculated WACC after tax is 6.0%. (nominal). Reference to other RWE annual reports show that this figure varies little (+/- 1.0%) from year-to-year.

A separate issue is whether the same WACC should be applied to all power generation projects, from nuclear through to PV solar. In practice almost all renewable investment decisions have relied upon subsidies; only recently have some project developers made offers in tender rounds which would rely entirely on the wholesale price, although it is not certain that such projects will be actually realised. The empirical analysis behind this paper seeks to explore what returns would have been hypothetically achieved from the wholesale market alone. No attempt was made to differentiate the levels of risk to which various types of power plant would have been subject and adjust the WACCs accordingly.

In evaluating projects companies typically add a project-related margin in the region of 0.5-2.0% both to ensure that the project would be adding value to company and also to reflect the deemed risk of the particular project. A figure of 7.0% has therefore been applied in the calculations to all plant types including renewables, which with support from subsidies have much lower risks and therefore normally lower discount rates in the range of 2-4%.

The resultant annual fixed costs, based on the uniform discount rate of 7.0% post tax for the different types of plants are shown in Figure 2 below.

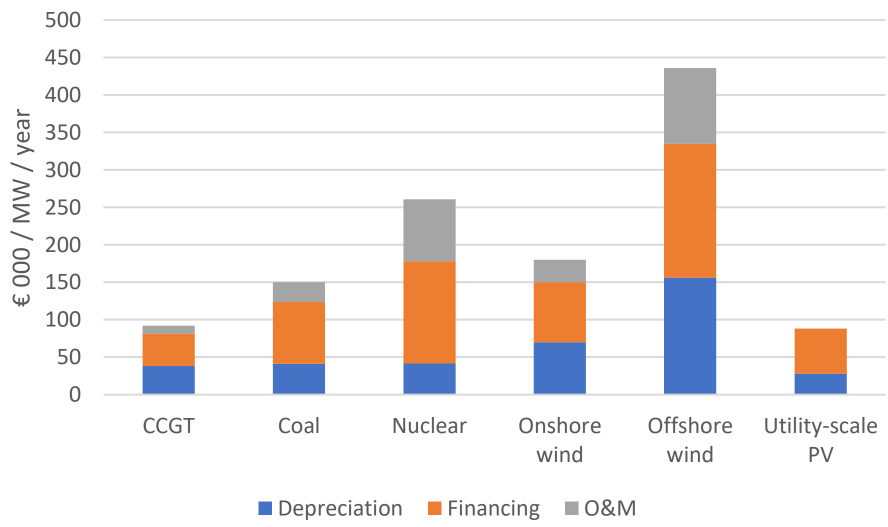

Figure 2 Depreciation, financing costs and O&M costs for selected plants

2.3. Cash margins from generation

The data shown in Table 2 to determine the cash margins (otherwise defined as the clean spark or dark spread) earned from actual dispatching for this analysis consisted of:

- Market data: hourly day-ahead power prices, daily gas and weekly coal prices, daily carbon prices and daily exchange rates. Transport costs were excluded.
- Technical data: plant efficiency and carbon content of fossil fuels
- Renewable production data: energy output by hour.

	GERMANY[5]	FRANCE
POWER PRICES	EPEX Spot – hourly	EPEX Spot – hourly
COAL PRICES	CIF ARA (Eurocoal[6]) – weekly	ARA (Eurocoal) – weekly
GAS PRICES	EGIX[7] – daily	PEG – daily
CARBON PRICES	EU-ETS[8] – daily	
RENEWABLE PRODUCTION	ENTSO-E – hourly	
RENEWABLE CAPACITY	IRENA Renewable Capacity Statistics 2021	
EXCHANGE RATES	WEO – daily	

Table 2 Sources of market and operational data

While power prices are used as available on EPEX, the other commodities are not necessarily traded every day or available at the hourly granularity. For all of them, the reference date is the delivery date when available – not the trading date, and the common rule used to fill in missing values is to use the next available data. For instance, the EUA and the EGIX are not traded/computed on weekends, the Monday value is thus used as a proxy for Saturdays and Sundays. Similarly, the coal prices are weekly, and it is considered that a given price applies to the whole week after the CIF ARA quotation.

A key part of the approach lay in assuming that all technologies behaved competitively based on the wholesale market incentives and with linear costs. This means that the resulting production profiles and margins do not account for potentially distorting schemes, such as renewable subsidies, or dispatching being driven partially by heat demand in the case of combined heat and power plants, which represent a prominent part of the coal and gas capacity in Germany.

With respect to renewables, the methodology being slightly different – their infra-marginality does not determine whether they produce, production data was directly used to derive their load factor. ENTSO-E's transparency platform provides this information on a 15-minute time step, and the four quarter of the hour are averaged to get an hourly production which is further divided by the installed capacity in the corresponding area determine on a yearly basis.

As discussed above, the revenues and cost recovery of conventional generation (CCGT, hard coal and nuclear) on the wholesale market will depend on whether their variable cost allows them to be infra-marginal. As we took state of the art plants, they should have the lowest costs amongst all

[5] Germany and Austria formed a single zone until 1.10.201, which change was reflected in the data used.
[6] Eurocoal mentions *IHS McCloskey Coal Report as a source for this data.*
[7] EGIX is the arithmetic average price of all daily values on the two German market areas for a given front month contract and is calculated and published on all exchange trading days as well (GASPOOL, NCG).
[8] The EU-ETS was implemented in 2005. Allocations were initially free but from 2013 had to be purchased. calculations. At all times they had an opportunity cost which was included in the margin calculation.

existing plants of their technology and thus produce more often. CO_2 prices are accounted for in the fuel costs of thermal generators, while nuclear fuel is considered to cost a flat 5€/MWh (excluding recycling).

The thermal plants were assumed to be operating in each hour when the cash margins, defined as below, were positive.

Margin in any hour (€/MWh) = Day-ahead price – (Fuel price + CO_2 price x CO_2 fuel content/MWh)/ efficiency – other variable costs

The total margin for the year was simply the sum of the hourly margins.

The margins would be earned, in the case of thermal and nuclear plants, from infra-marginal rent and occasionally scarcity pricing, and in the case of renewables almost entirely from infra-marginal rent, since scarcity pricing occurs more frequently when renewable production is very low.

In the case of renewables plants the ENTSO-E transparency platform provided hourly data on the total generation for each category of renewables. From the IRENA Renewable Capacity Statistics the operating capacity at the start and end of each year was available, enabling the average available capacity to be determined as a simple average of those two figures. The actual production per typical MW of installed capacity for each hour could therefore be determined, so that:

Margin in any hour (€/MWh) = Day-ahead price x Percentage production per MW – variable costs.

In a typical commercial operation some additional income may be earned by plants (essentially thermal, rather than renewable) from the supply of regulatory services. This is believed to be low in relation to mainstream income from power generation and there is no transparent source of information which would enable this to be estimated, even to a very approximate level. Therefore, such sources of income were excluded.

Similarly, ramping costs were also excluded.

2.4. Contribution from scarcity pricing

In theory, under the assumptions of the Energy-Only Market, scarcity pricing should arise with a frequency and level which will enable plants to recover their full costs from the wholesale market. Although no European electricity market is commonly considered as a fully functioning EOM, this theory clearly drives regulatory decisions, and an important line of enquiry was a determination of the contribution which scarcity pricing made to the total cash margins.

Estimation of scarcity pricing was made, for the hours when the wholesale price was in excess of 125 €/MWh, as the difference between the actual price and this figure. Although somewhat arbitrary, the figure represents a point above the variable cost of the marginal plant (e.g. a low-efficiency oil or gas plant). Also because very high scarcity prices are needed to cover fixed and investment costs, well in excess of 1000 €/MWh, the exact level for the threshold is unimportant.

2.5. Significant events arising over the period covered

The process of liberalization of electricity markets in the EU was initiated through the First Energy Package (electricity) adopted in 1996 and implemented in 1998 by the Member States. It sought to foster a competitive environment in national electricity sectors, especially by unbundling generation, transmission and retail as well as breaking up national monopolies, except regarding the grid, for which TSOs and DSOs were created.

The Second Energy Package deepened the liberalization by requiring a legal unbundling and creating national regulating agencies (NRAs). It also enabled consumers to be able to freely choose their supplier. Measures included in this package had to come to force at the national level no later than 2007 (2004 for certain measures).

The 2009 Third Energy Package already targeted the Internal Energy Market with, among other requirements, the creation of the ACER (Agency for Cooperation of European Regulators), ENTSO-E (European association for the cooperation of transmission system operators for electricity) in order to foster cross border cooperation and create common network codes.

In parallel, power pools emerged, offering an increasing number of products: Powernext (2001) for the French market and EEX AG in Germany which joined up in 2008 to create EPEX Spot.

Figure 3 below shows the main events which occurred over the period covered.

Event	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Renewables % generation DE[9]	10						20				30				40
Renewables % generation FR	10													20	
Fast build-out of PV in DE						X	X	X							
Fukishima and German nuclear closures							X								
2nd Energy Package			X												
Global Financial Crisis – reduced power demand				X											
Emissions Trading System	Phase 1			Phase 2					Phase 3						
Creation of EPEX Spot				X											
3rd Energy Package					X										
20-20-20 Emission reduction, efficiency and renewable goals					X										
Market coupling						X									
Capacity market (France)													X		
Network reserve in Germany							X								

Figure 3 Significant events occurring during period covered

III. RESULTS

3.1. Recovery of full costs – thermal plants

The headline conclusion is that, except for second-generation nuclear plants, the average level of full cost recovery from the wholesale market (over the period covered and the two countries taken together) was well under 100%. It was 40% for CCGTs, 55% for hard coal plants, 30% for wind plants

[9] Shows when particular percentages have been exceeded

and 60% for utility-scale solar plants. However, it is important to point out that comparison of both countries was only possible from 2010 onwards, a year which was something of a watershed at least in the case of Germany for which results from the two earlier years were available and where much higher cost recovery levels were found.

An overriding explanatory factor was that wholesale prices since 2008 were overall at a much lower level than beforehand and had been expected by investors at the time they made their decisions. An excellent analysis of the factors behind the price collapse between 2008-2015 is given by Hirth (2016) as shown in Figure 4 below. The reduction in commodity prices, CO2 prices, and electricity demand can all be attributed to the Global Financial Crisis of 2009.

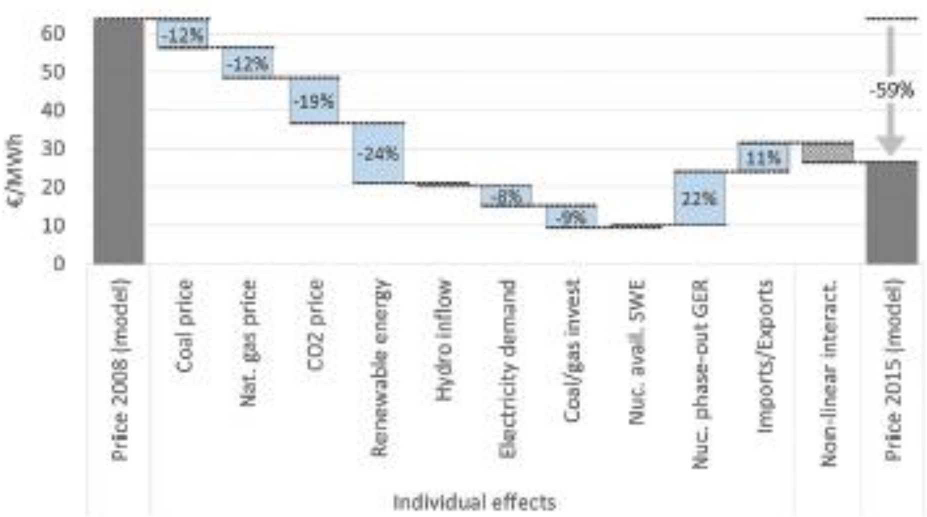

Figure 4 Factors explaining the price collapse between 2008 and 2015[10]

The following charts show the results. The depreciation and O&M costs have been shown, since these absolutely must be covered before the financing costs are taken into account. In Figure 5 it is seen that except in Germany, the thermal plants did not even recover those two cost elements, whereas in France they did so, especially for hard coal. Conversely in the case of nuclear plants the full costs were broadly covered in both countries.

The alternative analysis of estimating the IRRs assuming that the average cash returns earned over the period for which data was available would have prevailed over the entire project life are shown in Table 3

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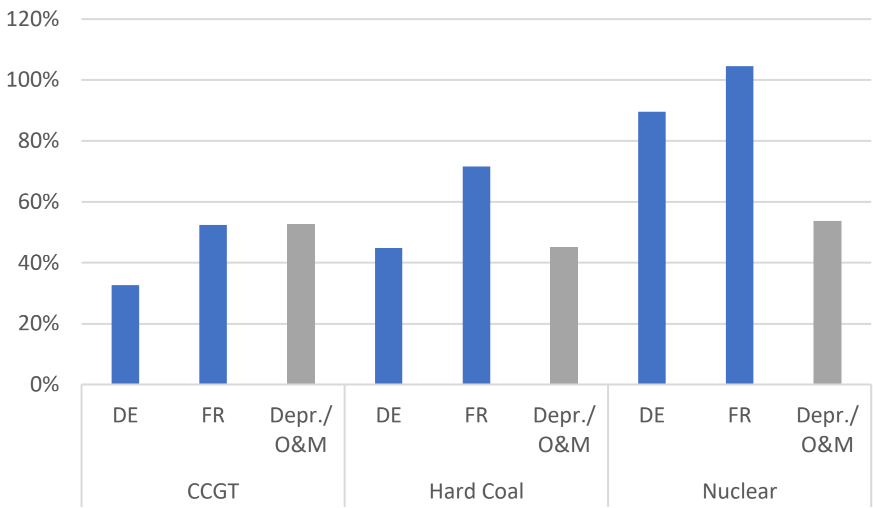

Figure 5 Average recovery of full costs from wholesale market (2010-19)

	Germany	**France**
CCGT	< 0%	< 0%
Hard coal	2,3%	4,4%
Nuclear	8,2%	7,3%
Wind onshore	<< 0%	<< 0%
Wind offshore	<< 0%	NA
PV Solar	0,4%	2,4%

Table 3 Estimated IRRs earned by different types of power plant

The results giving development over time in Figure 6 are particularly interesting and show that for the years with necessary data (2008/9) a typical CCGT in Germany did at least recover its full costs, but from 2011 onwards not even the sum of depreciation plus O&M costs were recovered. The extreme range of annual cost recovery, between over 140% and barely more than 10%, highlights the high risks to which such investments were exposed.

The IRRs shown in Table 3 Estimated IRRs earned by different types of power plant in Table 3 should be compared with the WACCs assumed of 7.0% and confirm the alternative analysis that, except for the 2nd generation nuclear plants, the estimated returns from the wholesale market over the expected project life would have been well below company requirements.

The actual margin made by a plant in any year depends on a multiplicity of factors including fossil fuel and carbon prices, renewables production and the supply-demand balance. The Global Financial Crisis, as mentioned above, was a major factor affecting profitability, causing power demand to sink to around 3% below its expected level for several years and bringing down with commodity and CO2 prices. In addition, improved market-coupling across Europe effectively increased the level of available capacity. Not all of these developments would have reasonably been anticipated at the time final investment decisions were made about the plants concerned.

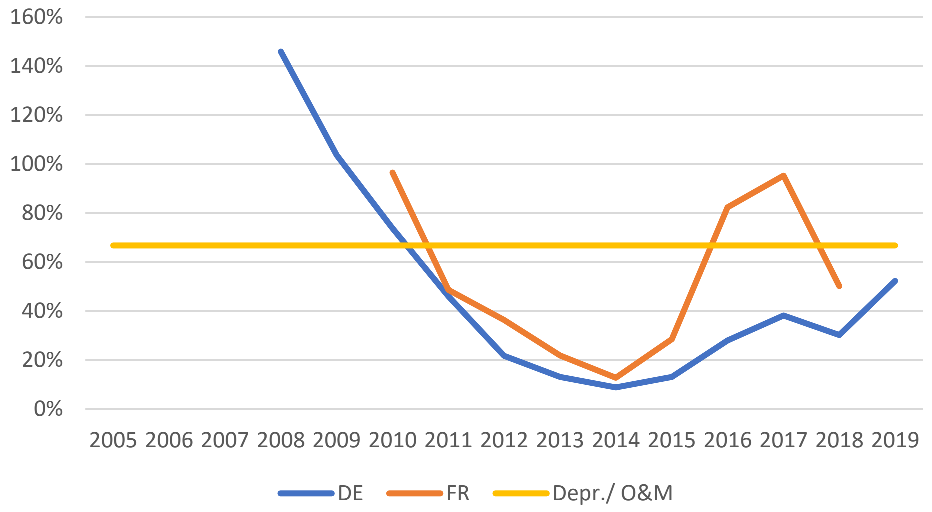

Figure 6 CCGTs - extent of full cost recovery

Figure 7 shows that only in two years from the somewhat wider time-window of available data did hard-coal plants fully recover their full costs, and in the case of one year only - 2008 - with a considerable super-profit.

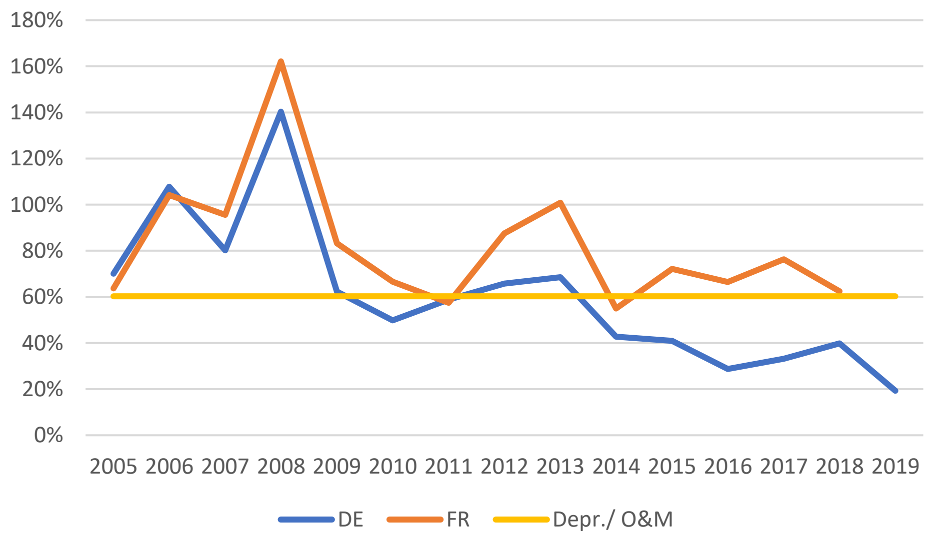

Figure 7 Hard coal - extent of full cost recovery

Nuclear plants (second generation) enjoyed better returns in almost all years at least recovering their full costs, as seen in Figure 8 and the reasons why they did so much better than the thermal counterparts are threefold:

- Long lives, so that the depreciation costs are relatively low

- A high level of utilisation, typically well over 90%
- Low variable costs so they capture much more infra-marginal rent than thermal plants.

This performance should have made future nuclear plants attractive, especially in view of the rising price of carbon and restricted ground space to build renewable plants. However, investment in nuclear generation is highly political and often requires government approval. In addition, this analysis has considered the case of second-generation reactors which have been built in series, benefitting from cost reductions. The new generation of reactors have much higher specific costs. For instance, the first three EPR plants (Flammenville in France, Olkiluoto in Finland, and Hinkley Point C in the UK) which are "first of a kind" have costs between three and five times the reference figure used for second-generation plants. This is due to design and supply chain issues as well as extra costs resulting from the safety requirements being significantly tightened after construction had begun. Taylor (2009) has discussed the different risks faced by investors in nuclear plants.

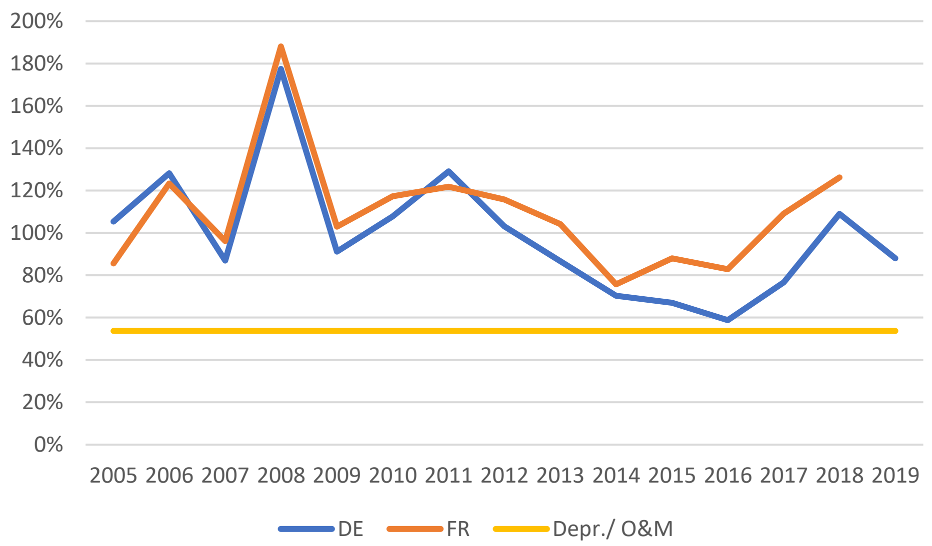

Figure 8 Nuclear (2nd gen.) - extent of full cost recovery

3.2. Role of scarcity pricing

Scarcity-pricing is the phenomenon which proponents of the EOM expect to rely upon to enable plants to recover their full costs. Figure 9 and Figure 10 show respectively the number of hours per year with scarcity pricing (prices over 125 €/MWh) and the additional margins to which such pricing led. To put their contributions into context, the full costs needing to be recovered by different types of thermal plants are for CCGTs, hard coal and nuclear respectively around 100, 150 and 250 €/MW/year. The necessary gas prices were not available to evaluate margins in the years 2005-7, but significantly even in 2008 and 2009 – the best years recorded - scarcity pricing in Germany only played a minor role. Notwithstanding the missing data for the years 2005-7 the conclusion is that over a 16-year period scarcity pricing has at best made only a modest contribution to meeting the full costs and is far from adequate to compensate for low infra-marginal rent.

As its name implies, such pricing only arises at times of scarcity, which is generally not when renewable sources are producing a significant amount of energy. Therefore very little contribution can be expected from such a source towards the full cost of renewables plants.

Since scarcity-pricing has overall so far been found totally inadequate to bring returns on most types of power plants to the levels required by investors the introduction of capacity remuneration mechanisms (CRMs) has been widely discussed and implemented in a number of countries, inside and outside Europe. Regulators in some countries/regions (e.g. the UK and the PJM market in the USA) claim that CRMs have successfully brought necessary capacity into the markets which would otherwise have been lacking. But experiences overall are mixed, and others are of the view that CRMs have unnecessarily burdened consumers.

Except for second generation nuclear plants, for the years covered power plants have manifestly failed to recover their fixed costs, sometimes not even covering depreciation. Therefore either a CRM or some alternative solution will be required to incentivise the investment in capacity required for supply security. The details will be country-specific and depend upon the energy-mix, structure of demand and extent of flexibility in balancing supply and demand.

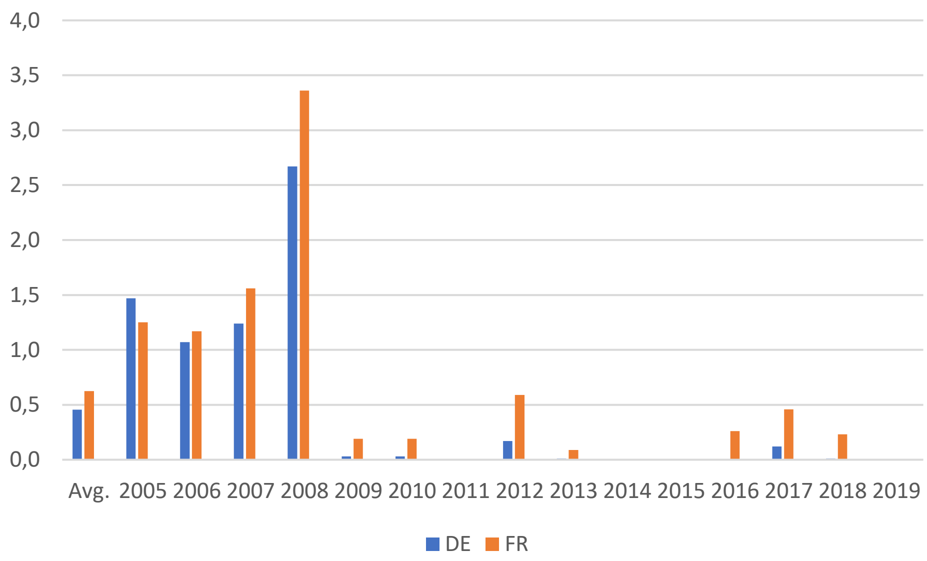

Figure 9 Hours with scarcity pricing (scale x100)

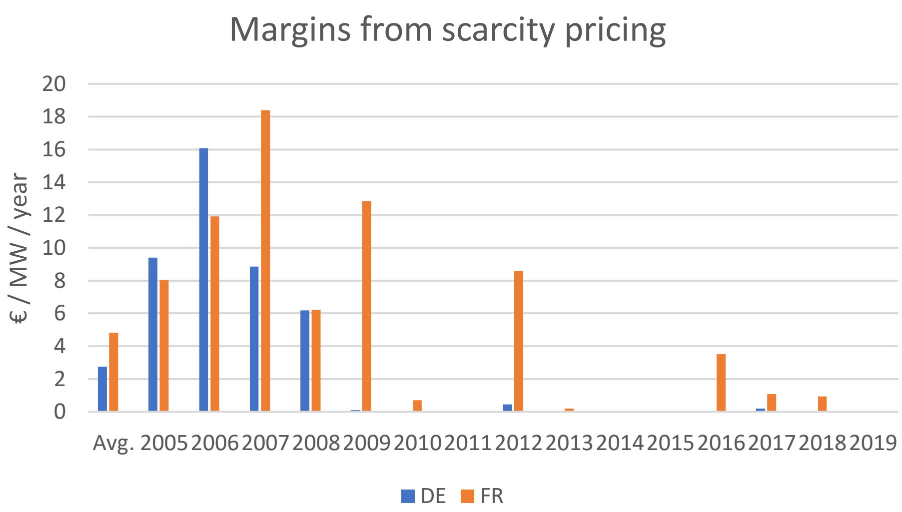

Figure 10 Margins from scarcity pricing

3.3. Recovery of full costs – renewables plants

Turning to renewable plants it is seen in Figure 11 that first, wind plants typically only recovered some 30% of their full costs within the five years analysed, well under the sum of depreciation and O&M costs, and second, that the level of cost recovery has been less volatile than that seen for the thermal plants. Conversely PV solar plants have broadly recovered these two cost elements, France having done better than Germany due to the higher levels of irradiation and lower renewables penetration. Figure 12 - Figure 14 show how the level of cost recovery varied over time – the range in the short period considered is low except for PV solar plants. A report from the IEA and NEA (2020) gives a view on the energy value by technology and region relative to the share of renewables.

The clear conclusion is that renewables are not on track to recover their full costs from the wholesale market alone. In this context it is interesting to consider that in recent years developers of wind farms have proposed to build plants up to 2025 without any subsidies. Whilst it is not certain that such farms will actually be built, it is clear what optimistic combinations of lower full costs and higher wholesale prices would be required for such developers to realise their implicit expectations.

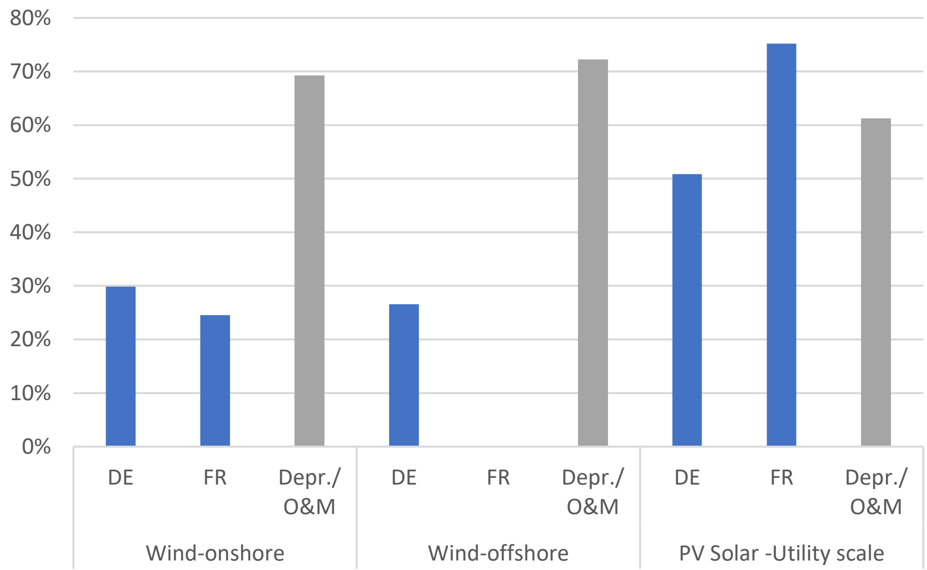

Figure 11 Average recovery of full costs from wholesale market (2015-19)

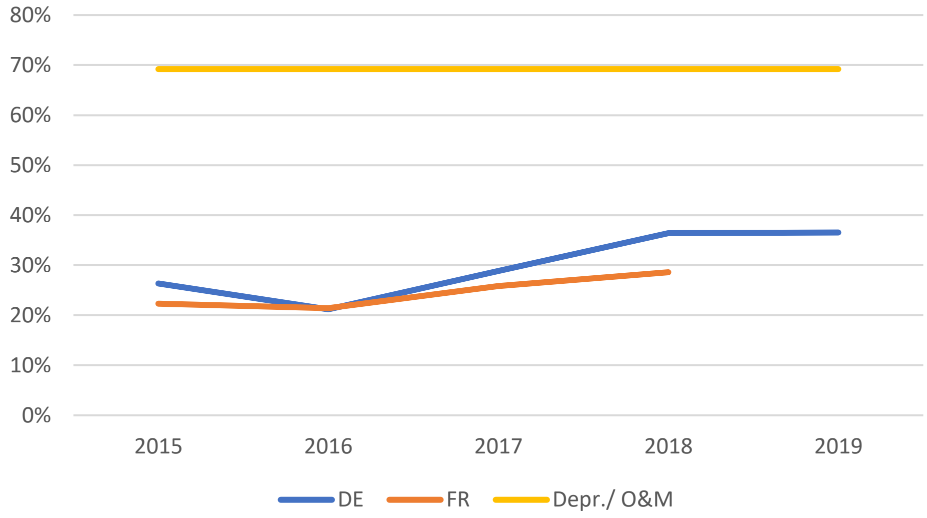

Figure 12 Wind onshore - extent of full cost recovery

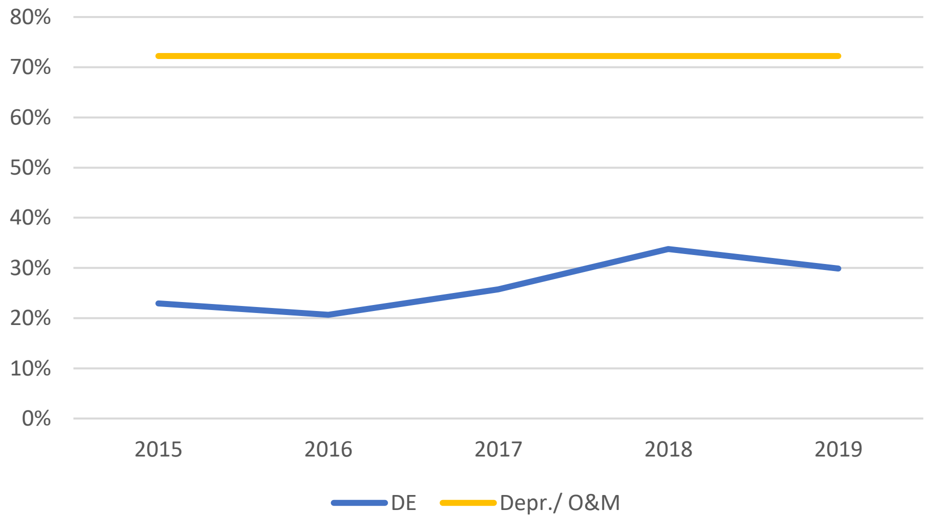

Figure 13 Wind offshore - extent of full cost recovery

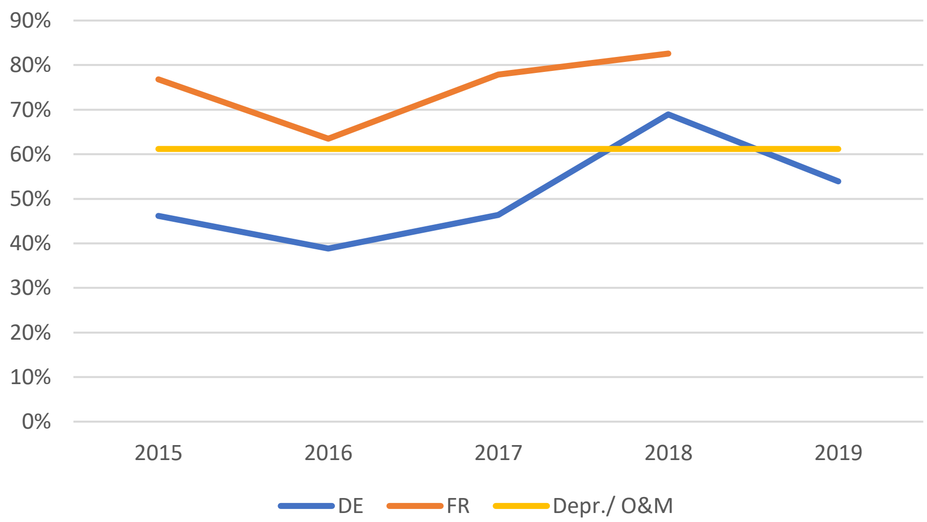

Figure 14 PV solar (utility scale)- extent of full cost recovery

3.4. Level of volatility in returns and potential implications for cost of capital

The last part of the analysis consisted of comparing the volatility of the margins (or returns) with that of the stock market. A comparison of the monthly and average annual returns of a CCGT (Figure 15) in Germany and the DAX-30 stock index (Figure 16) is instructive in several respects. The returns are defined respectively as:

- Return on CCGT = (Margin i.e. clean spark spread – O&M costs – depreciation) / specific investment cost
- Return on Stock index = Increase in value over a month / initial level of index.

The comparison of two types of return with obviously different definitions, one relating to a physical asset and one to the market index, is inherently problematic. The former is open to alternative definitions, which would affect the absolute level but not the volatility. Regarding the methodology, deductions of the O&M cash costs is clearly appropriate, but that of depreciation less clear, as there is no direct analogue in the case of the stock index return; but it cannot be avoided that the value of the physical asset is eroded over time. In addition, the liquidity is much lower for as asset such as a generating plant compared with an asset on the stock market. However, whichever way the call is made, the volatility will not be affected.

Based on the above definitions it is seen that:

- Typical returns of the stock index are higher than for the plant – a physical rather than financial asset, raising the question as to why available funds might be applied to power plants rather than financial assets
- Both assets exhibit a significant number of years with negative returns
- A succession of downward steps to a more stable but much lower level was found for the CCGT, with no comparable development in the stock index
- There is no obvious correlation between annual returns of the CCGT and those of the stock index.

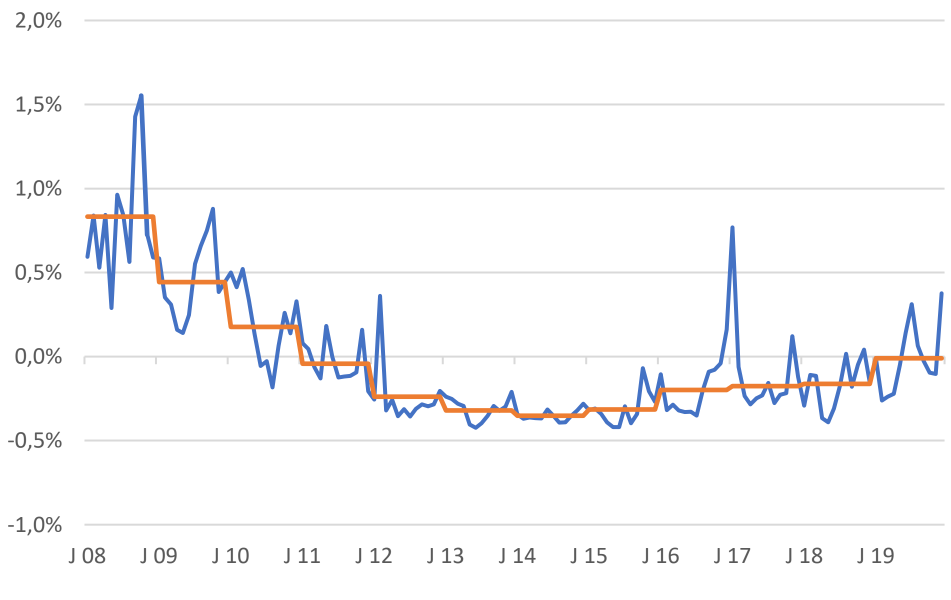

Figure 15 CCGT - DE - Monthly returns with annual averages

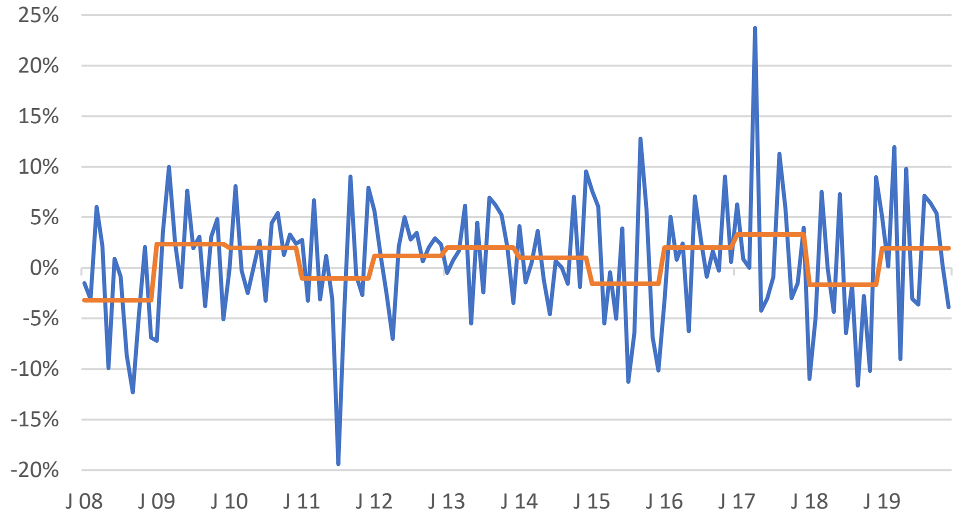

Figure 16 DAX30 - DE - Monthly returns with annual averages

The monthly volatility of both sets of returns measured in blocks of 36 months, in line with standard practice for the financial sector, can be readily compared as in Table 4 below. An alternative view of the results is given in Table 5. where the standard deviations are divided by the average monthly returns. These show, irrespective of the time period considered, that returns on the stock index are in a totally different league as compared to those for power plants. It was appropriate to investigate whether any information could be harnessed from this analysis which might help determine the level of risk and cost of capital for particular power plants, but the results show this is not possible and is explainable by the very different concepts – financial and physical assets – which were being compared.

	DAX30	**CCGT**	**Hard Coal**	**Nuclear**	**Onshore Wind**	**Offshore Wind**	**Solar PV**
2008-10	5,1%	0,36%	0,42%	0,42%			
2011-13	5,3%	0,17%	0,12%	0,20%			
2014-16	5,6%	0,12%	0,10%	0,13%			
2017-19	11,1%	0,22%	0,17%	0,23%	0,10%	0,09%	0,24%
2008-19	7,2%	0,37%	0,29%	0,33%	0,14%	0,14%	0,23%

Table 4 Standard deviation of plant and returns

	DAX30	**CCGT**	**Hard Coal**	**Nuclear**	**Onshore Wind**	**Offshore Wind**	**Solar PV**
2008-10	5,5	0,9	1,0	0,4			
2011-13	5,7	0,5	0,3	0,2			
2014-16	6,0	0,3	0,3	0,1			
2017-19	11,9	0,6	0,4	0,2	1,0	0,9	1,6
2008-19	7,6	1,0	0,7	0,3	1,3	1,3	1,5

Table 5 Standard deviation of returns / monthly average return

Two issues relating to risk and level of return

Two issues must be clearly distinguished:

- Whether expected returns are structurally too low, because various distortions and market failure prevent the wholesale market from adequately remunerating investments

- The level of risk – i.e. range of likely returns either over the economic life of the plant, or over any 36-month period, following the approach of financial markets.

Given the evidence of CCGT returns in Germany as in Figure 6 on p.13 it is difficult to come to the firm conclusion that expected returns will always be structurally too low. Returns were adequate in the period prior to 2010. However for the last decade (2010-2019) the results for thermal plants are unambiguous – the returns were totally inadequate unless significant additional source of income had been available. The recent implementation of security of supply measures (strategic reserve in Germany and capacity market in France) in recent years suggest that regulators have reached similar conclusions.

Assessing the level of risk and then using this to help determine the appropriate discount rate is also problematic. Within any 36-month period the variability of returns and therefore risk is much lower than for the stock market as Table 4 makes clear. Conversely the huge reduction in returns from the period prior to 2010 shows the level of risk facing the average level of returns, rather than the monthly variability.

Unfortunately there is no mathematical science which can cope with such a trend, and still less could the monthly data be used for the CAPM. Therefore there is no feasible means of using the data available to determine beta factors for power plants – physical rather than financial assets.

IV. **CONCLUSION**

On average for the time-periods for which data was available only nuclear plants of the second generation recovered their full costs from the wholesale market or earned returns at least in line with the deemed cost of capital. For the 10-year period to 2019 CCGTs in German recovered scarcely more than half the sum of the depreciation and O&M costs, around only 35% of full costs; their IRRs were therefore negative. In France the CCGTs fared slightly better and overall hard coal plants did better than CCGTs, but on average for the two countries only recovered 50% of their full costs, corresponding to IRRs of 2-4%.

Wind plants recovered only around 25% of their full costs from the wholesale market (and therefore would have suffered negative IRRs) whereas PV solar plants achieved an average of 60% for the two countries, corresponding to low IRRs, well below the WACCs.

Based on the available data the clear conclusion for these two countries and over the time period covered that the remuneration available from the wholesale market was far from adequate to remunerate the plants. The question then arises as to whether there were special circumstances applying, which will both be avoided in the future and not replaced by a different set of such circumstances, or whether the results suggest that the wholesale market is unlikely ever to be sufficient.

Theory shows that the EOM could work under perfect competition assumption, that is, amongst others, if the market would be totally devoid of all kinds of distortion or political interference.

However, such a framework is inherently theoretical and the conditions for the EOM to be optimal are not empirically verified. Given the very high social and political sensitivity of the market, public authorities are likely to keep on intervening on the market to meet its targets in terms of environment, affordability and supply security.

The particular distortions include:

- The out-of-the-market introduction of renewable plants, including in some cases a floor but no cap to the return earned

- A substantial amount of combined heat and power capacity, which is often dispatched based on heat, rather than power requirements

- Barriers to closing plants which are not covering their cash costs

- Security of supply considerations, which tend to militate against scarcity pricing, at least with the frequency and levels necessary to fill the gap between earnings from infra-marginal rent and the full cost of plants.

Figure 3 on p.10 is helpful in providing a background to the reduction in margins. The main development, in Germany rather than France, is the strong growth of renewable power, much of which was only compensating for the steady closure of nuclear plants – two developments which were driven entirely by regulatory rather than market forces.

Lastly there were two other sets of factors contributing to low returns. The Global Financial Crisis of 2008 led to a reduction in European power demand of some 3% for several years and simultaneously brought down the newly implemented CO_2 price. The power companies themselves may be considered to have over-invested, discounting the trend into renewables and also cashing in the voluminous free allocations of CO_2 certificates to which they were entitled. In addition, they very reasonably invested heavily into existing coal-fired plants to make them more flexible as required to fit in with the intermittent renewable production. Those coal-fired plants then supplanted gas plants as a major source of flexibility and therefore became price-setting at considerably lower variable costs than if the gas plants had been doing the same job.

Closing plants does not always happen as easily as classical micro-economics would suggest. In Germany the regulator can prevent plants classified as "system-relevant" from closing and in the case of gas-fired plants the operators themselves had to make a careful call as to whether poor margins would persist, or there were grounds to expect an improvement.

In short, there was a collection of developments, mainly negative, not all of which could reasonably have been foreseen and quantified at the time when most of the investments were made. These tended to militate against periodic supply-tightening and prevented scarcity pricing from contributing significantly to the wholesale price.

With respect to renewable plants the analysis suggests strongly that subsidies will continue to be required in the future, since depreciation of wind plants not fully covered. Whilst there is hope that renewables' costs will continue to decline in absolute terms and in relation to the wholesale price, there are also strong reasons as to why they might stabilise or even increase: tightness in different parts of the supply chain, land scarcity, leading to its value being bid up, and cannibalisation with increased curtailment.

There is however one development which may directionally improve the returns on plants by providing an additional source of income. The integration of increasingly high shares of renewables tend to increase the need for flexibility to maintain security of supply while pushing flexible thermal plants out of the market. This tendency is well identified, and market designs are being modified to improve short-term pricing and flexibility procurement in order to provide market signals in line with system needs.

Relevance of the analysis for future market design and investment decisions

To continue decarbonizing electricity production investments in renewables plants and firm capacity in the form of flexible units (peakers or storage) are to play a key role, especially for countries seeking to come close to 100% renewables. Except for gas-fired or biofuel combined heat and power plants very little, if any, other forms of thermal power plant will be built within the wholesale market. However there was recently a case in Germany of a CCGT plant being commissioned by a Transmission System Operator to provide supply security, but with its fixed costs being paid for by that operator and to be recovered from customers.

With respect to renewables, the analysis shows no sign of the wholesale market being able to cover the full costs in the near term, so a second source of income will continue to be required. Moreover, given that renewables growth depends currently essentially upon national auction arrangements, even if the wholesale price were to be high enough in the long run to cover the full costs, a different consideration then comes into play: the government would not want to see developers making super-profits. Therefore for that reason future remuneration may not be based entirely on wholesale prices.

In a market with a very high proportion of variable renewable production, peakers and storage plants are essential. They live off high hourly price volatility, the levels and frequencies of which are extremely difficult to forecast. Therefore it would only be brave investors who would build such assets relying on the wholesale price alone. A fundamental problem is that scarcity prices only rise with sufficient frequency and to the necessary levels when capacity is tight, the very same situation where blackouts threaten to arise. Despite all the rhetoric regarding smart-meters and increased demand response it is, at present, not credible that these means will be sufficient to avoid tight supplies, so players will need incentives to build firm capacity outside the wholesale market.

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