Recommendations for implementation of long term markets (energy and capacity) 2020 - 2050

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Executive Summary

Nowadays, important evolutions have modified balance of incomes in the electricity sector, leading to falling prices of electricity on the markets. In reaction to this, investments in new energy generation capacities decreased and some capacities were even decommissioned.

In Europe and around the world, plenty of capacity mechanisms (CM) have been implemented besides energy markets, or are planned to be implemented soon. Poland, Sweden, PJM in USA, France, Great Britain, Colombia, Ireland, Spain, and Chile have all implemented CMs. Whereas the CM implemented in these countries are not designed in the same way, they have interesting specificities.

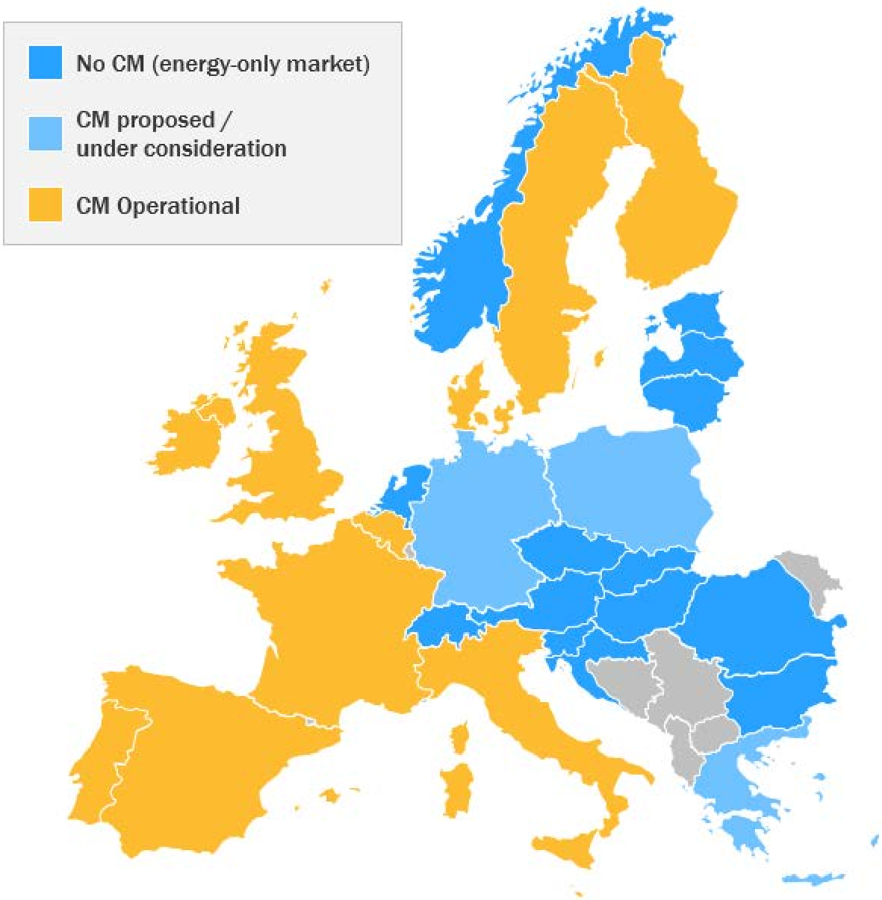

Figure 1 - Capacity mechanisms in Europe in 2015. Source: ACER's survey of NRAs.

Through our analysis of best practices in CM design, we came to the conclusion that a CM with the following features should be developed, if any: product firmness requirement, penalty for non-delivery, lead-time of about three years. Concerning the choice between price-based or quantity-based mechanisms, we propose to retain a mixed approach in-between both. It consists for the regulator in defining the price-quantity demand function. Thus, the regulator limits the systemic risks for the system and has better chance to drive the mix to the desired quantity with an acceptable cost. Cross-border participation is also needed. Even if different options are still discussed, it seems to the project that explicit integration of cross-border potential in every national security of supply mechanism is a necessity. Lastly, we observed that centralized or decentralized procurements are both interesting and that this issue needs a more detailed quantitative analysis.

Capacity markets are designed to modify investor behaviors. Nevertheless, every technology has a different OPEX / CAPEX cost structure, which is of highest importance for investors. In comparison with coal-fired power plants or CCGTs, variable renewables, nuclear plants, but also peaking units (e.g. OCGTs) are highly capital-intensive generation units. For those reasons, investors will not take the same risk in building coal-fired plants, CCGTs, nuclear plants, OCGTs, or wind and solar systems.

A generation mix moving towards decarbonisation implies heavy investments in most European systems. These fixed costs will have a large impact on the total cost of electricity supply. Thus, any mechanism that reduces the risks for investors will, at the same time, reduce the costs for the consumers. RES support schemes or capacity mechanisms ensure, on the one hand a reduction in financing costs, and on the other hand, they encourage investors to maintain future security of supply.

Capacity mechanisms aim at encouraging investors (and possibly consumers) to maintain future security of supply levels within acceptable ranges without the need for markets to produce large price spikes for electricity, which normally have a high socio political cost. But, besides this, and above all, they allow achieving a reduction in the cost of the insurance provided by peaking units by lowering their capital costs. Moreover, Demand Response, which has a high capacity value, could also largely benefit from revenues provided by capacity mechanisms to accelerate their development.

While the phasing out of explicit RES support mechanisms is seen as a long-term objective by many stakeholders. However, the nature of the costs of the new capacities may make it more cost-efficient to combine a carbon tax (or another carbon price-setting mechanism) and the use of support mechanisms to further decarbonize the power mix by replacing conventional base load with RES generation. Such schemes could indeed make RES cheaper by a better predictability of their revenues over the long term. In other words, whereas support mechanisms aim at encouraging investors to develop RES to reach penetration targets, they also result in a reduction of the cost of decarbonization by lowering the capital cost of these technologies.

These mechanisms will, besides the existing energy markets, provide new incentives allowing investors to decide whether to build new generation units or maintain available competitive existing ones.

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List of abbreviations

ATC	Available transmission capacity
BRP	Balance Responsible Party
BSP	Balancing Service Provider
CAPEX	Capital Expenditures
CM	Capacity Mechanism
CONE	Cost of the New Entrant
ENTSO-E	European Network of Transmission System Operators for Electricity
ETS	Emissions trading scheme
FIP	Feed-in Premium
FIT	Feed-in Tariff
GHG	Greenhouse gas
IGCC	International Grid Control Cooperation
KPI	Key Performance Indicator
LCOE	Levelized cost of Electricity
LSE	Load-Serving Entity
NREAP	National Renewable Energy Action Plan
OPEX	Operational Expenditures
PHES	Pumped Hydro Energy Storage
SoS	Security of supply
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
WACC	Weighted Average Cost of Capital
WP	Work Package

1 Introduction

Europe's electricity sector is experiencing a phase of great transition. In the early 1990's, the liberalisation process led to the unbundling of the electricity activities that could be conducted competitively (generation and retail) from the natural monopolies (transmission and distribution) and consequently to the development of national energy markets. In a second phase, a pan European wholesale electricity market emerged. At the same time, the development of RES production has taken place thanks to effective support schemes. Solar and wind energy, along with other renewable energy sources such as small hydroelectricity and biomass, represent around 10 % of the European energy production today (9.6 % in 2013) and will grow to 20 % in 2020 if the target is achieved and beyond 27 % in 2030. In the meanwhile, demand is stagnating due to a relatively low economic growth and energy efficiency measures. These important evolutions modified balance of incomes in the electricity sector, leading to falling prices on the wholesale market. In reaction to this, there have been less investments in new capacities – except for technologies receiving support – and some existing capacities were even decommissioned.

These evolutions and the new investment context they created led to concerns about the security of supply of many Member States of the Union. Some governments have expressed doubts on the maturity of energy markets and, more specifically, their appropriateness to produce the investment signals needed to ensure an adequate generation mix, able to provide the needed level of security of supply. This issue is not recent. The viability of energy-only markets and the potential need for additional revenues for capacity have been discussed since the introduction of the first power markets. Security of supply targets are not taken into account in the energy market. The theory of energy-only markets is based on the fact that the price set in shortage situations to the marginal utility of consumers, i.e. to an extremely high level, will encourage investment in generating assets up to a collectively optimal level. But this theoretical argument does not hold in practice for several reasons: (i) consumers are not really capable of expressing this marginal utility and it is replaced by security of supply criteria which may be converted into economic terms but (ii) the maximum prices enabled in wholesale markets are most of the time much lower than the result of such a conversion. Beyond these constituent limits of the energy-only markets, in practice, they also raise the question of the financial capability to support investments in peaking units that will be run and earn money only once in ten years (for instance): if no economic signal is given to investors for their contribution to the insurance that demand can be met at a predefined level of risk (or level of security of supply), owners of peaking units have, indeed, to settle with incomes that may be too uncertain for private firms. The necessity of a complementary remuneration has therefore, to be assessed with regard to the adequacy criterion, the level of the price cap and the level of risk in each particular situation. The current downwards trend of energy market prices, caused by the combined effect of the limited *ex-ante* predictability of the impact of support to renewables on their development, the low current fossil fuel prices, due amongst others to the large-scale mining for shale gas in the US and a lack of demand growth, the currently low CO_2 price caused by the excess of permits following the economic crisis, and the stagnating demand, led nevertheless many Member States to introduce capacity market mechanisms. Those mechanisms are designed to ensure the appropriate level of capacities for the national security of supply of the Member States.

Moreover, the evolution of the generation mix towards decarbonisation implies a more capital-intensive mix. In fact, coal-fired plants and closed-cycle gas turbines are more OPEX-intensive than CAPEX-intensive; it is the other way around for solar and wind energy. RES generation deployment is mainly driven by investment costs and very capital-intensive. Nuclear plants also have much higher investment costs than operational costs. Contrary to what is often thought, the oil or gas peaking generators are also very capital-intensive: the cost of their investment is much more important than their operation costs, which are high per unit of energy produced, but investment costs are even much higher in proportion of very little actually generated energy, these plants being only very rarely used.

New policy instruments have been set up to drive the long-term outcomes of the electricity market. The European Emission Trading Scheme and, more generally, measures taken to price carbon emissions, are seen as an economically efficient way to reduce the emissions of greenhouse gases in the EU by internalizing their social cost into the investment and operating decisions. Support mechanisms have been used to help low-carbon generating technologies to develop; they have diverted a substantial share of the capacities from directly selling their electricity in the wholesale market. Finally, capacity remuneration mechanisms have been seen as an effective way to ensure security of supply and are currently being applied across Europe. These new instruments profoundly change the logic underlying investment decisions. The most efficient design for such mechanisms has been studied within the Market4RES project in a previous report on “Developments affecting the design of long-term markets” [1]. Some quantitative studies on the need to set them up have been carried out and their hypotheses, methodology and outcomes are described in another report on “Quantitative evaluation of policies for post 2020 RES-E targets” [2].

The resulting changes will be analyzed in this report. In chapter 1, the variety of existing and planned Capacity Mechanisms (CM) around the world is explained. Then, we will briefly go through the good practices for RES support schemes that do not disturb the energy market. Most of these RES support considerations are also discussed in Market4RES report D6.2.

In chapter 2, we will show the extent to which total costs of producing electricity from different technologies are affected by investment costs (CAPEX) and operating costs (OPEX), respectively, and show how the decarbonisation of generation changes the capital structure of the generation mix. Following these ideas, we will develop how RES support schemes are necessary to ease investments in the highly capital-intensive variable renewable generation technologies. Then, we will explain why capacity markets are more necessary today than ever in order to allow the development, at a lower cost, of highly capital-intensive capacities. Finally, we will explain how market capacities could participate actively in the market to fulfill the security of supply at a lower cost for society.

In chapter 3, the impacts on cross-border trade of CRM and also of RES support schemes are described.

Finally, we will conclude by proposing recommendations for the implementation of long-term energy/capacity markets for the period beyond 2020.

2 Overview of capacity mechanisms

2.1 Classification of CM

In Europe and around the world, plenty of capacity mechanisms (CM) have been implemented beside energy markets, or are planned to be implemented soon. Poland, Sweden, PJM in USA, France, Great Britain, Colombia, Ireland, Spain, and Chile have all implemented CMs. Whereas the CM implemented in these countries are not designed in the same way, they have interesting specificities.

The Market4RES report D3.1 [1] provides a definition of the concept of capacity mechanism, which is used here, in order to set a solid ground for discussions. A capacity mechanism is an instrument to value generation or demand response availability, normally but not always leading to a revenue stream for capacity owners on top of the revenue they draw from energy sales. Beyond the usual distinction between volume-based and price-based mechanisms, the analyses carried out in the 3rd work package of the Market4RES project and described in the aforementioned report studied the relevance of the different options for additional design elements. Capacity mechanisms were thus studied with respect to the following features:

- the product,
- whether the mechanism is price-based or quantity-based, i.e. whether the level of price is determined administratively to conduct the investment in the proper quantity of capacity or the quantity of capacity is set and securitized, setting up a market and thus a price that is paid to capacity owners in exchange of such securities,
- the party defining the quantity of the product to be purchased,
- the counterparty purchasing the product in the mechanism,
- the way foreign resources could participate.

According to these criteria, a nomenclature of the different types of capacity mechanisms can be established as follows: strategic reserve, *ex ante* capacity obligation, *ex-post* capacity obligation, capacity auction, reliability options, capacity payment, and capacity subscription. However, we must be very precise in the definition of each of these mechanisms to avoid any ambiguity or misunderstanding about them. Examples of these categories will be developed in the next section. It should also be reminded that capacity mechanisms are a wider family than the one described under the term “capacity market”, the latter specifically referring to markets where parties with a capacity deficit can buy from parties with a surplus.

2.2 Description of some implemented systems

In Poland and Sweden, **strategic reserve** mechanisms are implemented alongside the energy market. System operators directly contract a small proportion of capacity to provide an additional reserve that should only be dispatched when all other available capacity in the market is operating. In Sweden, providers enter into bilateral negotiations with the TSO. In Poland there is a bilateral and competitive bidding. In both cases, the strategic reserve capacities are separated from the wholesale power market. They are called by the TSO only when the standard energy market solutions could not fulfill extreme loads or events. The strategic reserve capacities receive an income from the TSO compensating their absence in the wholesale market. In other countries like Norway, Belgium, Germany, there are also some products similar to strategic reserves. Strategic reserves are therefore a quite common tool used by governments and TSOs to reinforce their security of supply. Nevertheless, it is interesting to notice that when strategic reserves are called, they have an impact on wholesale electricity prices: since some capacities do not compete in these markets, it is more likely that the price reaches high levels and, in particular, the threshold price beyond which the reserve is used.

In USA, PJM first developed an *Ex Ante* Capacity Obligation model and changed it more recently to a Capacity Auction model, similar to the mechanism set up in Great Britain. In the ***Ex-Ante* Capacity Obligation model (also known as Central Obligation model)**, the central authority determines the volume of physical capacity that is required. The obligation to procure the capacity is passed onto Load Serving Entities (LSEs), based on the peak load that each LSE has served before, establishing the obligation before the actual realization *i.e.* on an *ex-ante* basis. Load Serving Entities satisfy their obligations *via* a wide range of possibilities including self-supply, bilateral contracts and, naturally, demand response. They have incentives to decrease their peak load during one year so as to reduce their obligation for the next year. However, decreasing their peak load will have no real-time impact on their obligation volumes.

More recently PJM implemented a **Capacity Auction** model following the same approach as in Great Britain. A Central Authority determines the volume of physical capacity required and centrally procures this volume from the market. An elastic demand curve, where the price depends on the volume, may be used as an alternative to a fixed demand.

In France, an ***Ex Post* Capacity Obligation model (also known as De-centralized Obligation model)** was implemented. The responsibility to procure capacity is passed on to the Load Serving Entities which have to cover their obligation by procuring capacity certificates or reducing their actual load. The final obligation is checked *a posteriori* by the TSO. The actual measured load is the basis for the calculation of the obligation, which is established based on a predetermined methodology with parameters that are set *a priori* in the market rules (before the start of the process of certification of capacities). Typically, the methodology is used to adjust for weather conditions and ensure that the LSEs would have sufficient capacity in predetermined extreme conditions (in the French example, the decennial cold wave). The total (country/region level) obligation is the sum of the obligations of the LSEs, but plays no direct role in the model. This is the core difference between an *ex ante* and *ex post* model: in the first case, a total obligation is defined for the country and dispatched on LSEs. In the second case, only the obligation computation methodology and parameters are defined by the TSO. Then, LSEs have degrees of freedom to try to influence (reduce) their obligation volumes for the same period, if they judge that it is economically feasible. This is an important difference which explains the terms of “central obligation” for the *Ex Ante* model and of “decentralized obligation” for the *Ex Post* model.

In Colombia, **reliability options** involve the delivery of a physical volume when the security of supply is at risk. The product is structured as a financial instrument. Models presently in operation typically involve a Central Authority setting the volume to be procured, and then applies a central procurement process of the options. The option strike price is set as a measure of the security of supply and in effect sets a price cap in the market, while the generator's volatile revenue stream through high prices is substituted with the more long term and foreseeable option premium. When the security of supply is at risk, the option is exercised (market price > option strike price) and the generator must physically deliver the agreed amount otherwise it will face a financial exposure to the spot price on the spot market. In some cases an additional penalty for non-performance may apply.

In Spain, Ireland, and Chile, a **fixed payment per MW of installed capacity** is determined or negotiated when a capacity provider enters the market and provided by the system operator to that provider for the term of that agreement.

2.3 Qualitative assessment of design options for CM

The Market4RES report D3.1 [1] includes a qualitative assessment of different design options for CM. Below recommendations following this assessment are described. The study did not compare energy only market with the different CRM approaches, as this was the purpose of one of the study described in chapter 7 of the Market4RES report D5.2 [2]. The focus was on assessing different design options for CRM for cases where such markets are deemed as necessary in a Member State. The result of this assessment is described below.

Concerning the product, there is a great diversity of possible characteristics of the CM products. It is a good option to include **firmness requirement** in the product, meaning that generating units' owners or demand response operators receive an amount of capacity "credits" or "certificates" reflecting the expected or measured availability of their capacities during scarcity periods (their revenues from the capacity mechanism will then depend on this amount of credits and their price). A **penalty for non-delivery** is also necessary to develop an efficient incentive when scarcity occurs. Finally, the study does not conclude specifically about how long lead times should be, but a lead time of **about three years** seems reasonable in the European context, since shorter lead times may disqualify projects which take longer to be built and reduce the mechanism's efficiency in hedging the risks associated with projects of new plants.

Concerning whether the mechanism should be price-based or quantity-based: a price-based mechanism would miss its objective if the authority fixed the price at an unsuitable level; yet such a level is difficult to calibrate. A quantity-based mechanism does not have such pitfall, but requires a good level of competitive pressure to work properly. Therefore, the case can be made for hybrid **price and quantity-based mechanisms** as illustrated in the Figure below.

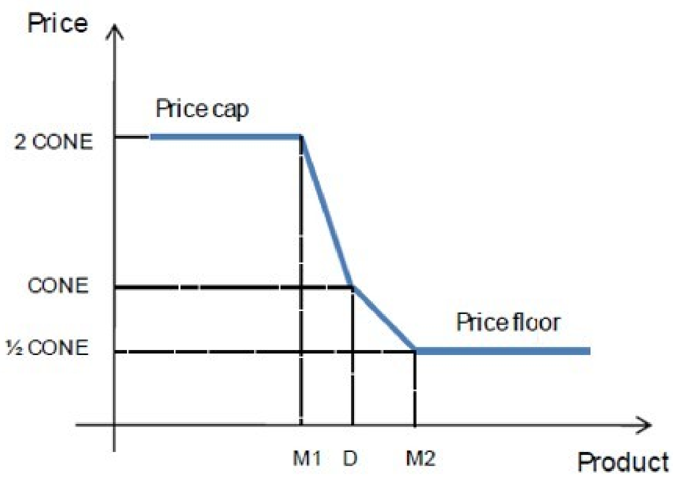

Figure 2: Price-Quantity demand function for the product

This example comes from the mechanism set up by the New England ISO where the curve is based on one price floor and one price cap. In between, there is a targeted reference (D) that achieves the reliability at the CONE (cost of the new entrant). A price-quantity curve requirement contributes to limiting market power and also provides information to agents about how far or near the system is from suffering scarcity. When the regulator defines this price-quantity demand function, it limits the cost risks for the whole system.

The implementation of price-based mechanisms in the European regulation seems to be more complex than quantity-based mechanisms. We have to keep in mind the distinction between missing money and missing capacity, as underlined by the European Commission [11]: "*In liberalized markets, investments are not guaranteed by the State. Only where there is a real threat to generation adequacy and security of supply as a result of closure or mothballing does the financial viability of existing plant become a matter of public concern. It is very important that there should not be state support to compensate operators for lost income or bad investment decisions*.".

Concerning the party defining the quantity of the product to be purchased, the project recommends bilateral CM. In centralized CM, the central entity in charge of defining the quantity to be procured is likely to be risk adverse. Because this entity does not bear the costs of its decisions, the authority will naturally raise incentives which could lead to an overinvestment on the long term: overcapacity and excessive capacity payments. On the contrary, bilateral CM are more flexible to overcome contingencies (e.g. if demand has not grown as much as expected, if some capacities have not been available at the foreseen rate, etc.).

Concerning the counterparty purchasing the product in the mechanism, both centralized and bilateral procurements are very competitive options, depending on the weight attributed to each characteristic. Three main design alternatives exist, which all have good results, as follows:

- <u>Centralized</u>: one central entity is in charge of defining products and the procurement is carried out by means of a centralized auction;

- Decentralized with a standard product defined by the central authority. Market parties bear the responsibility of procuring this standard product on bilateral or organized markets;
- Decentralized without a standard product defined by the central authority. Market parties have the responsibility to design some elements of the product and to procure it.

Table 1 shows the results of the qualitative analysis of these three options in terms of efficiency (marginal cost reflectivity, cost causality, diversity of product traded in the market, economies of scale and lumpiness in investment, vertical market power), implementability and the existence of previous experiences with them. It tends to show that the three options could be envisaged and, in particular, a centralized mechanism or a bilateral one with non-standard products. On the one hand, the centralized option allows economies of scale and better mitigating market power. On the other hand, the bilateral mechanism with non-standard products offers a higher diversity of products and, depending on the details of its design, it can perform similarly as good as the centralized one in terms of marginal cost reflectivity and offers a better cost causality. The bilateral mechanism with non-standard products is the only one that has no serious weak point (corresponding to a "poor" grade in the table).

		Centralized (standard products and auction)	Bilateral / Decentralized	
			standard products and bilateral	non-standard products and bilateral
Efficiency	*Marginal cost reflictivility*	Very Good	Good / Very Good	Good / Very Good
	Cost causality	Fair / Good	Fair / Good / Very Good	Fair / Good / Very Good
	Diversity of products	Poor / Fair	Poor / Fair	Very Good
	Economies of scale and lumpiness	Very Good	Fair / Good	Fair / Good
	Vertical Market power	Very Good	Fair	Fair
Implementability		Very Good	Very Good	Very Good
Experience		Very Good	Very Good	Very Good

Table 1. Summary of the assessment of procurement mechanism design options. Source: Market4RES report D3.1 [1], p. 29.

This qualitative assessment also included a study of different **options for cross-border participation of resources.** It concluded that the (explicit) participation of foreign capacities was desirable because, as shown in Table 2, it was more efficient than having different isolated domestic capacity mechanisms, far easier to implement and simpler than a Europe-wide capacity mechanism and more fair than their implicit participation through the statistical account of the interconnections. However cross-border participation options are analyzed further in a dedicated chapter of this report, because of the importance of this point in the current discussion on the impacts of capacity mechanisms on the internal European electricity market and because the practical details of the participation of foreign capacities had not been discussed at the time of publication of this report.

	Single and homogeneous CRM for all Europe	Statistical account of the interconnections	Participation of foreign capacities	Different isolated CRM
Efficiency	Fair	Fair / Good	Fair / Good / Very Good	Poor
Implementability	Poor	Good	Fair	Fair
Simplicity & transparency	Poor	Very Good	Fair	Very Good
Fainess	Good	Poor	Fair	Poor

Table 2. Summary of the assessment of cross-border participation design options. Source: Market4RES report D3.1 [1], p. 33.

3 Drivers for investments in generating capacities: risk and security of supply considerations

3.1 Investment and operating costs in electricity generation

Whereas operating costs are mainly variable costs, depending on the amount of electricity generated by a power plant, investment costs are typically sunk costs when the investment has been done.

The decarbonisation of the generation mix, which is already underway, has deeply changed the cost structure of the European generation mix. The figure below illustrates the typical cost structure of several generation technologies, using the hypothesis data of WP5 in the 2020 scenario (costs from the IEA and CO2 price of 30 €/tCO_2) and under the assumption that the installed capacities and the operation of the generation fleet is optimized as calculated by a simulation model such as the one used in the studies described in chapters 5 and 6 of Market4RES' report D5.2 [2].

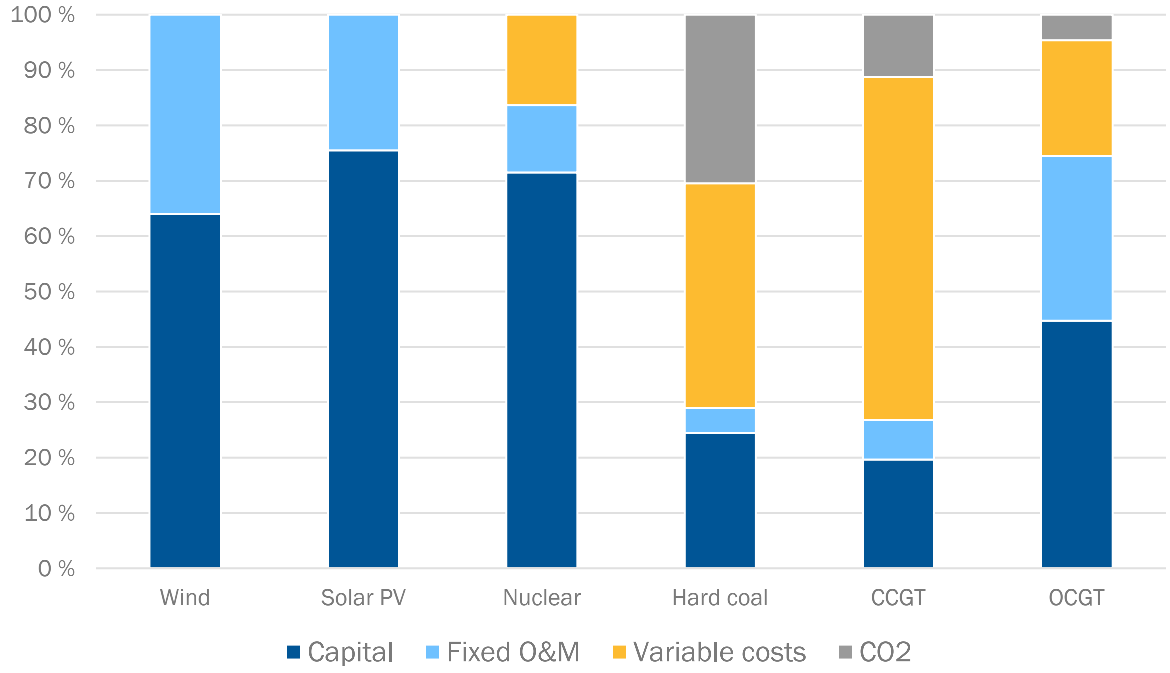

Figure 3: Split of the total cost of supply per unit of energy generated for several technologies

As shown, wind- and solar-power have a very different cost structure than e.g. hard coal and CCGT plants; capital costs are higher whereas variable costs are negligible. The share of capital cost is also high for nuclear plants. For OCGTs, the result is also interesting: it is often thought that variable costs are high for peaking units, but this is true and false at the same time. In fact, whereas they have the highest fuel cost in absolute terms for each MWh generated, these fuel costs remain relatively small when compared with the fixed-costs intensity; this is due to the fact that these fixed costs have to be amortized over a very limited amount of generated energy. Of course, this calculation depends significantly on the number of hours during which OCGT are producing electricity, which, in turn, depends on what other technologies are available in the mix (again, in this analysis, both the generation fleet and its operation have been optimized).

As a consequence of the relatively low capital cost share for CCGTs and coal-fired units, reducing the cost of capital has limited impacts on the total cost of electricity supply in a system dominated by such generation technologies. However, the impact is much greater when investors are deploying variable RES, nuclear power or peaking units that are required to decarbonize electricity or to ensure a proper level of security of supply.

Banks granting a loan for a project will demand the repayment of some share of the principal plus predefined interests every month or every year. Meanwhile, shareholders are ready to invest in a project only if they are confident that the project will, once built, generate enough cash on top of the operating costs, debt service and taxes to pay a dividend worth the risk they take. Therefore, the cost of capital is usually referred to through the notion of weighted average cost of capital (WACC) of a project, that is the average yearly return expected (before taxes) by the banks and (after taxes) by the shareholders, who brought the money required for the project to be built. It is logically expressed in terms of a percentage of the total investment.

Figure 5 shows typical Levelized Cost Of Electricity (LCOE, that is the complete cost of one MWh of electricity generated, including both operation and maintenance costs and capital costs, expressed in present monetary terms through the actualization of the future money flows of a project) as a function of the WACC, under the same hypotheses as above, i.e. within an optimized generation fleet.

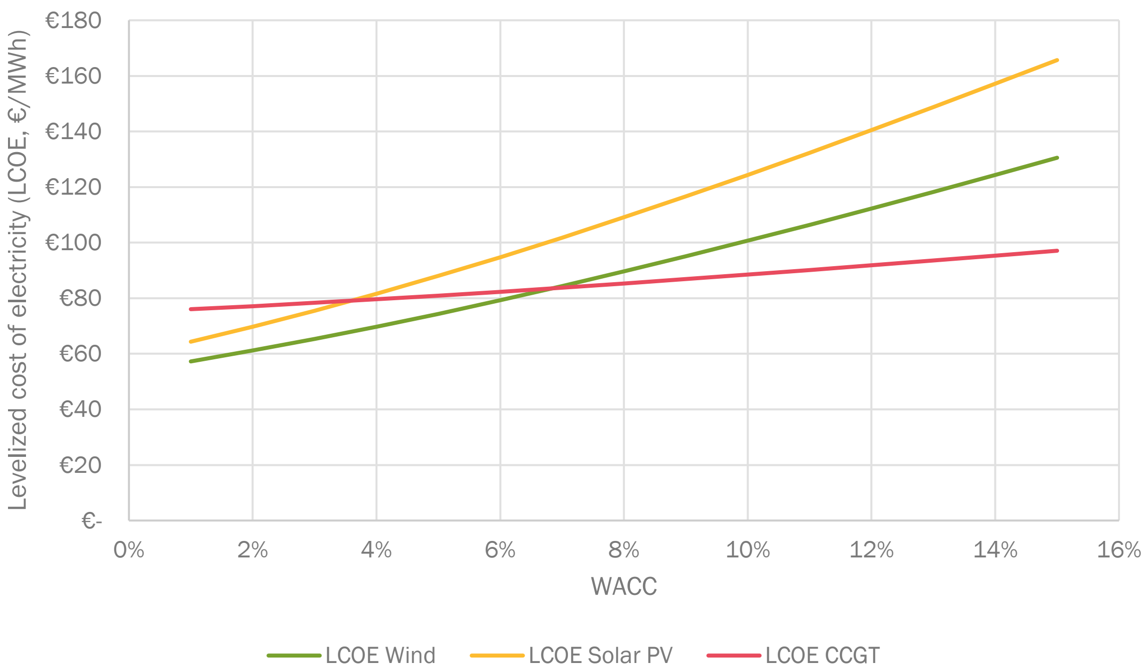

Figure 4: Levelized cost of electricity, as a function of the WACC, for three selected technologies

As shown, the unit cost of capital-intensive technologies is much more responsive to the WACC level. Yet, in a given macroeconomic context (growth, profitability of the stock market, monetary policy, etc.), the risk taken by investors is the main driver of the cost of capital. In other words, reducing the risk taken by investors becomes a major lever of cost reduction in an industry which is increasingly dominated by capital costs.

RES support schemes and capacity mechanisms can reduce the risks by providing investors a better long-term visibility of the projects' revenues. This implies that, beyond ensuring that the environment and security of supply targets are met, they can also bring gains for electricity consumers through the reduction of capital costs.

Quantitative studies have been performed within this project and described in chapters 6 and 7 of the Market4RES' report D5.2 [2] to assess the impact of these mechanisms in terms of risk mitigation. The first one explores the relevance of enduring RES support mechanisms in decarbonizing the power sector, in comparison with letting the market and the CO_2 price determine how much RES capacity should be installed and where. The second one focuses on capacity mechanisms. These studies and their conclusions will be commented on in the next sections, beginning with the former.

3.2 Quantitative study of the impact of markets, regarding firm capacity investments, on investors' beahavior

In this study, we have analyzed investment behavior to quantify how several market designs related to the provision of firm capacity affect the risk percieved by investors, and therefore their behavior, namely:

(i) an energy-only market with a price cap (at 3,000 €/MWh), as it exists today in the CWE region,
(ii) an energy market (still with a price cap at 3,000 €/MWh) paired with a capacity market,
(iii) and an energy-only market with a scarcity pricing mechanism during peak load hours (at 20,000 €/MWh, scarcity pricing corresponding to the French security of supply criterion of three hours of loss of load duration per year on average).

These designs were simulated on the long term with a tool named SIDES (for Simulator of Investment Decisions in the Electricity Sector) which implements a System Dynamics modelling and integrates both new investments and closure decisions. Being able to simulate decommissioning decisions, this is indeed very important when studying mature markets like the current European markets, which have a lack of demand growth and a large deployment of renewables. The numeric simulations were carried out building on the common hypotheses developed for the long-term works of the Market4RES project and described in detail in the D5.1 report [3]. More precisely, the year-by-year evolution and, for every year, the hourly dispatch of the generation mix of one specific country (France), taken isolated, was computed between 2015 and 2030, given a single starting point in 2015 and the three 2030 scenarios defined in the aforementioned report. The trajectory of RES installed capacity is supposed to be given as an exogenous parameter and triggered by support mechanisms aiming at reaching targets for 2030. The rest of the generating fleet evolves year by year following endogenous (i.e. determined by the model) investment decisions based on the expected profitability of the existing assets and of new projects. These investments and decommissioning decisions are assessed with regard to a set of assumptions about the structure of the annual demand curve, the energy policy and macroeconomic scenarios. The modelling considers a single representative agent, whose objective is to maximize its profit. This investor is technologically neutral and anticipates the future on a five year period. When this agent has to invest, he makes the assumption that the profit in the fifth year will remain the same until the decommissioning of the aging plant at the end of its life time. Very importantly, it must be noted that in this study, the investing agent is modelled with no risk aversion. In this model, investors take investment and closure decisions in new conventional units (investment in RES being exogenous) with regard to the possibility to recover their fixed costs or, more precisely, to recover operating fixed and variable costs for existing plants on the one side, and to recover all fixed costs (including capital and operating costs) to trigger investment decisions on the other side.

The main features of the system dynamic model are described below. See report D5.1 [3], specifying the post-2020 studies and scenarios in the Market4RES project and another recent publication by M. Petitet *et al.* [4] for further details.

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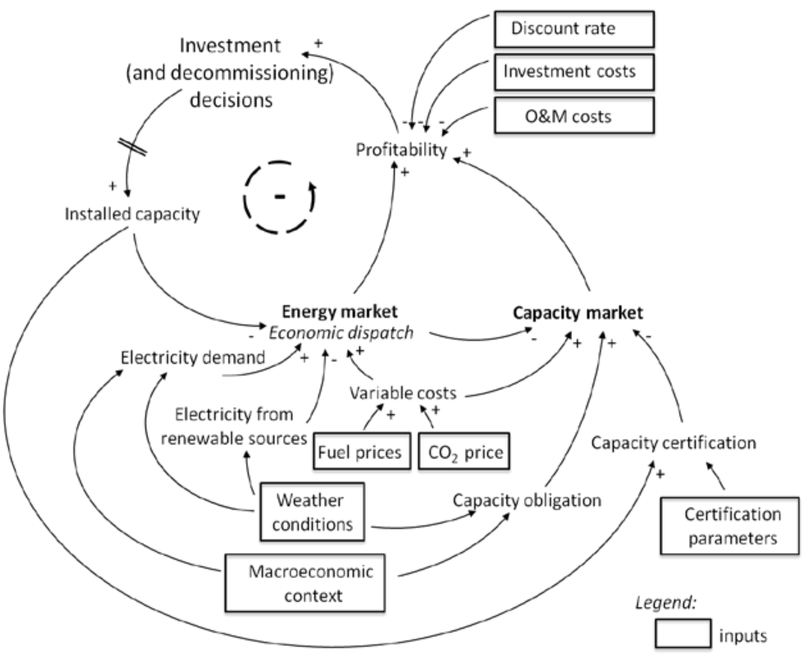

Figure 5: SIDE's system dynamic model process

One of the main assumptions made in the SIDES model is that centralized investment and decommissioning processes are decided by a single agent who is price-taker in the short-term market and the capacity market (when such a mechanism is included in the simulation); he acts in the long-term so that each of its power plants is profitable (therefore, he has no market power over the long-run either).

The model has a certain degree of "myopia" built into it, as investment, mothballing and closing decisions are taken after a profitability assessment concerning the five years following its decisions (although assets have a longer economic life-time).

No political interference with economic decision-making is considered to affect the decisions taken by the investing agent during the simulated period of time (e.g. administrative closure of some plants), except for that being related to the definition of the scenarios (RES capacities' trajectories, price of CO_2 and installed capacities at the beginning of the simulation).

3.2.1 Simulated market designs

Three set-ups for the market designs were simulated. 1) Energy-only market with a price cap set at 3,000 €/MWh (equal to the EPEX SPOT price cap), 2) Energy-only market with a price cap equal to the social value of loss of load. This last value is the theoretical one for an energy-only market when the generation is not sufficient to serve the total electricity demand. In the simulation we will use 20,000€/MWh. 3) Energy market with a price cap set at 3,000 €/MWh, in combination with a capacity market. It is assumed that the costs of the capacity mechanisms will be totally transferred to the final customers through the retail prices.

A capacity market needs the definition of a capacity adequacy target, which it is supposed to aim at reaching, and is, therefore, one of the main parameters of the mechanism. In our simulations, we will use a loss of load expectation of 3 hours per year on average, over the considered weather scenarios. This target corresponds to the capacity need of the system under a normalized set of extreme conditions. The certification of guaranteed available power plants is determined taking into account the forced outage rate of the considered power plants for each technology (as described in report D5.2 of the Market4RES project [2]). The RES certification level reflects the average availability of those resources during peak hours. Finally, the intersection of the capacity supply and demand will define every year the capacity price. In our model, the demand, i.e. the capacity need corresponding to the chosen adequacy criterion, is considered as inelastic and its level is aligned with the capacity adequacy target. The supply depends of every participant's bids. For existing power plants, the bid price is the difference between the anticipated energy revenues and annual operational and maintenance costs. For power plants to be built (projects), the bids represent the extra income needed in addition to the investment to be profitable or, more precisely, the difference between the anticipated revenues and fixed costs (annual amortization of the investment plus operation and maintenance costs). Lastly, renewables are supposed to benefit from a support scheme covering their total costs, which ensures their profitability through out-of-market supports. Thus, they bid their capacity at a price of zero.

3.2.2 Results and analysis

The following graph illustrates the total costs (including operating costs, cost of non-served load and costs for new investments but excluding the cost of prior investments in the fleet present at the beginning of the simulation, which is the same in all cases) for each scenario and market design. These costs are averaged over the 21 years of the simulation. In these simulations, where no risk aversion is taken into account, it appears that the scenario with scarcity pricing at 20,000 €/MWh (EOM20) and the one with the capacity mechanism are equivalent in terms of social welfare (or in terms of total costs) even if there are small differences due to the granularity of investment decisions. This could lead to the conclusion that the solution to the missing money problem could consist in abolishing the price caps in the wholesale market, which seems easier to implement than capacity mechanisms.

Nevertheless, it is important to notice that the impact of risk on investment decisions is not taken into account here.

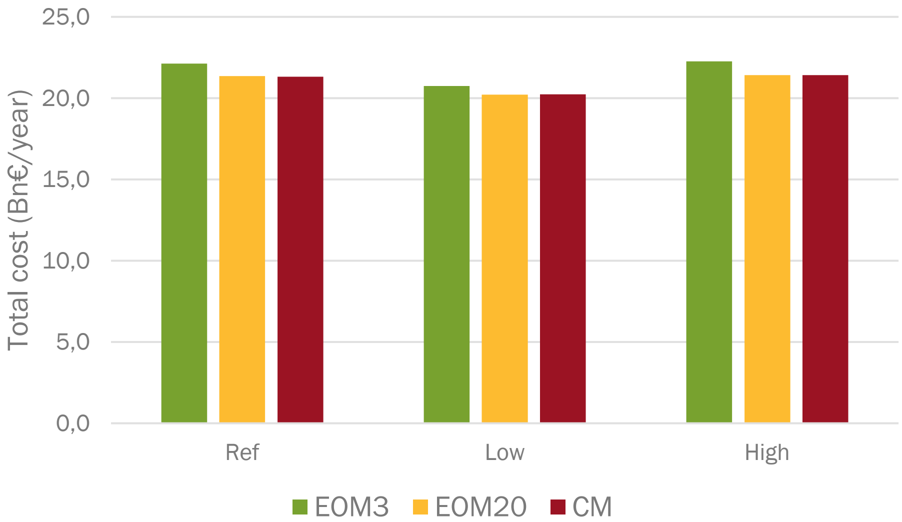

Figure 6: Total cost (Bn€/year) by scenario and market design
Small discrepancies can be observed between EOM20 and CM: they are of the order of magnitude of the granularity of the investment decisions in the simulation tool
(“Ref”, “Low” and “High” designate the three macroeconomic scenarios defined in Market4RES report D5.1 [3]).

The variability of the revenues of the peaking generating units across all weather scenarios of the simulation is shown in the graph below. Like for the first graph, these results have been averaged over the 21 years of the simulation.

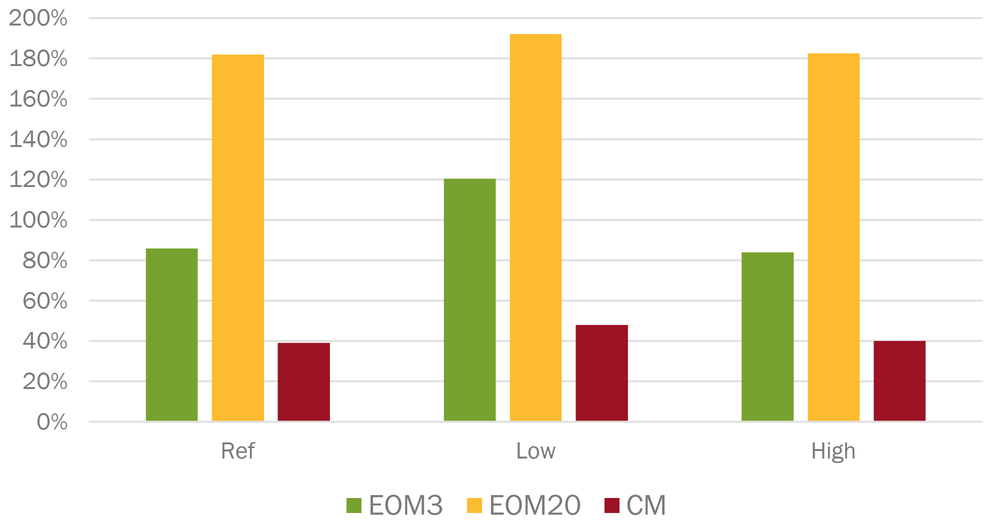

Figure 7 Variability of the revenues of a peaking generating unit
(relative standard deviation of the revenues across all weather scenarios)

For each macroeconomic scenario, the variability of these power plants' revenues from one weather scenario to the other is much lower under a design including a capacity mechanism and a price cap at 3,000 €/MWh than under a price cap-free energy only-market.

The extent to which a power plant's revenues change from a weather scenario to the other has an impact on how it can be financed, in particular when it comes to debt. When they grant a loan to a company for a specific project, banks try to measure the propensity of the project to pay the financial fees demanded in exchange of the loan. If its revenues are highly variable depending on the realized weather conditions, they will either ask for higher returns or reduce the amounts they are ready to lend to the project carrier.

This idea may be better explained by a more specific example: Figure 8 shows the revenues computed in the simulation for a peaking unit in 2030 in one of the three macroeconomic scenarios, according to the realized weather scenario. It appears that under an energy-only market with scarcity pricing, such a unit makes as much as 65 % of its expected revenues in one of the weather scenarios (#11) whereas it earns average revenues in three others (#1, #4 and #10), very small ones in another (#2), and nothing at all in seven scenarios, i.e. more than half of the time.

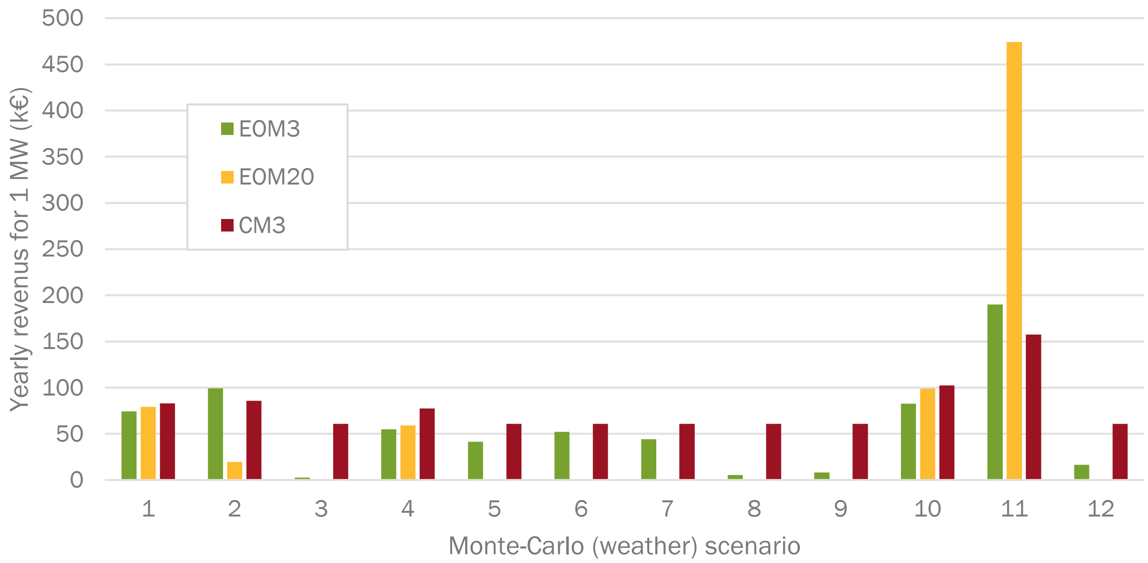

Figure 8. Revenues of a peaking unit in 2030 according to the weather scenario and the market design option in the "reference" macroeconomic scenario

In such a situation, it is very unlikely that a financial institution would accept to grant a loan to a peaking unit project, meaning that it would have to be financed through equity alone and therefore be more expensive than if it had benefitted from a more stable revenue as it is the case in the energy-only market with a low cap price (EOM3 - but to the detriment of the security of supply that is not ensured) or to an even greater extent in the case of an energy-only market complemented with a capacity mechanism (CM3).

The consequence is that the cost of capital is underestimated in the simulation of the energy-only market with scarcity pricing and that, if risk aversion had been taken into account in the study, the risk mitigation through the capacity mechanism would have resulted in a lower total cost than under scarcity pricing.

It implies that capacity mechanism solution must be preferred to the energy-only market design with scarcity pricing: a capacity mechanisms does not only ensure adequacy (providing a benefit when compared with an energy-only market with a 3,000 €/MWh cap), but it also mitigates the risk of peaking units projects, enabling their financing through cheaper capital to the benefit of the consumers (when compared with an energy-only market with scarcity pricing).

More recently, another study [5] was performed by M. Petitet with the same modelling approach, but taking the representation of risk aversion into account in the assessment of the investment and decommissioning decisions. It confirmed that the very high risk taken by investors in peaking units facing a scarcity pricing in an energy-only market led a risk-adverse (therefore more realistic) agent to develop a more costly generation mix than if it had benefitted from the revenues stabilization provided by a capacity mechanism. In addition to finding that a market design comprising a capacity mechanism appears to be the best choice in presence of risk aversion (and this whatever the level of risk aversion) it also underlines that the performance of an energy-only market with scarcity pricing is very sensitive to the level of risk aversion.

3.2.3 Conclusion of the study

In this study, we first observed that capacity mechanisms and scarcity pricing led to the same level of social welfare in a virtual world where economic agents would not care about risk. In theory, it therefore seems that setting up a capacity mechanism or a scarcity pricing is equivalent.

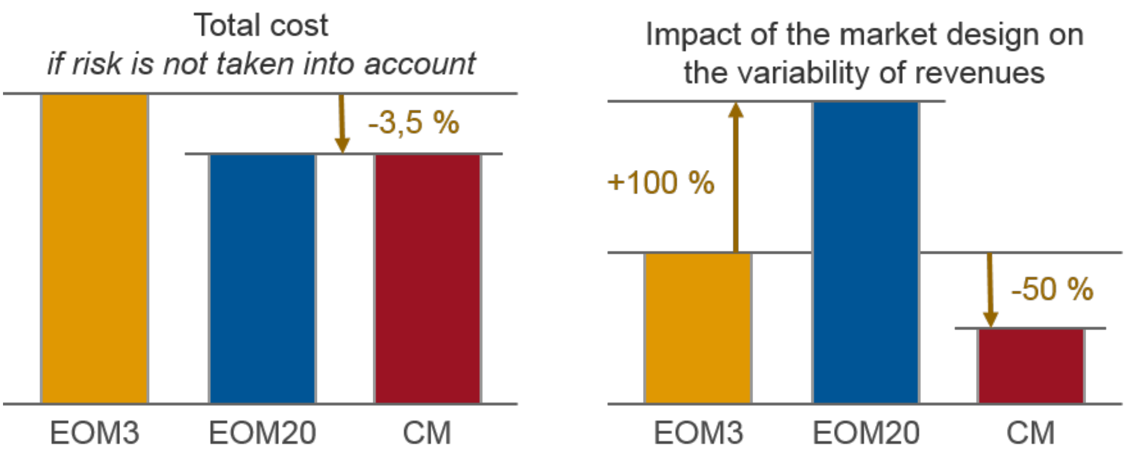

Figure 9. Costs (in a risk free world) and variability of the revenues of an OCGT for the three compared designs

But this is only true if agents are risk-neutral, which is a very strong assumption. When agents are risk-adverse, the role of a risk-mitigation played by capacity mechanisms reduces the cost of ensuring security of supply in comparison with scarcity pricing, therefore leading to better more efficient and lower total costs (or, equivalently, to a higher social welfare).

3.3 Quantitative study on RES support schemes

While capacity mechanisms aim at ensuring security of supply, efficient decarbonisation incentives should also reflect the social cost of pollution from electricity generation. CO_2 pricing is efficient in selecting among technologies with a lower greenhouse gases emissions factor and reducing the climate footprint of power. The point developed in this part is based on a study described in chapter 6 of the Market4RES report D5.2 [2]. It explores the extent to which $C0_2$ pricing is the best way to reach our climate objectives at the lowest cost for society, in a double perspective: that of the mix optimization for a given set of costs of generating technologies, and that of the risk taken by investors and its impact on these costs.

Before describing the results of the study, we will illustrate two general factors of relevance for the discussion: relation between market exposure and capital costs, and the risks taken by investors under different support schemes for renewables. To this purpose, Figure 9 proposes a schematic description of the effect of two antagonistic levers of cost reduction in electricity production in the context of the instruments of renewable policies. Renewables have traditionally benefitted from support schemes that have ensured relatively predictable revenues for investors, but no incentive for producers to run their assets when their production had more value. As a consequence, the costs were kept relatively low but, the energy they produce has a relatively low value (sometimes it even has a negative value). In the opinion of many decision-makers, renewables should be exposed to market prices so that their production could be optimized, taken the system's situation into account. On the graph, this is described by the ascending blue curve: with an increasing level of exposure to market prices, the cost of the energy transition should be minimized. But in the meanwhile, market revenues are often much less predictable than those from a feed-in tariff and, as the upwards-sloping blue curve shows, it should increase the cost of RES projects.

Thus, the cost of the energy transition results from both the cost of these RES projects and the value the electricity they generate has for the system. Therefore, both contradictory effects should be taken into account and the full integration of RES to the markets may not be the best solution over the long term: an intermediate market design could possibly be the most appropriate solution.

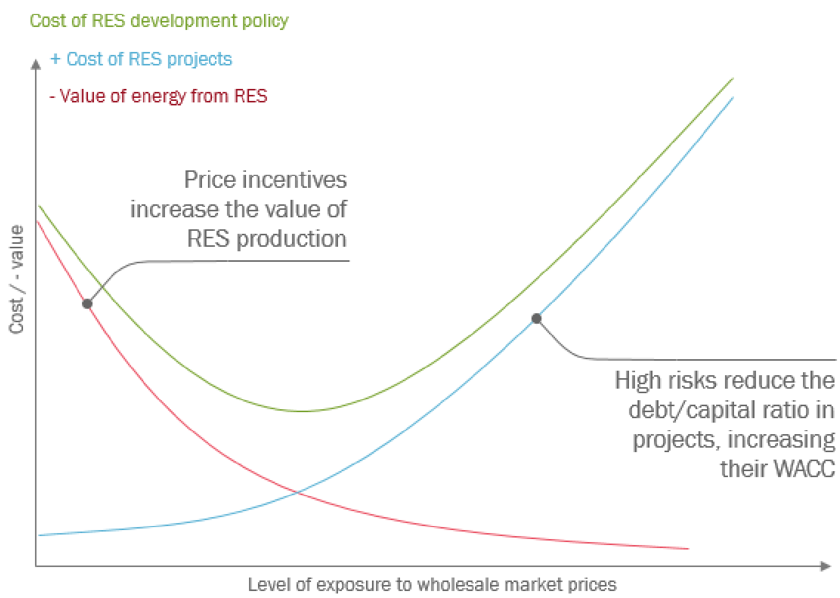

Figure 10: Illustration of the impact of risk and price incentives on the cost of the energy transition

The above-mentioned graph illustrates the impact of market price exposure on the cost and value of renewable projects. As the level of exposure to market price increases, the operation of renewable generation is optimized considering the constraints of the rest of the mix and the value of its production increases. In the meanwhile, the risk taken by investors increases and so does the cost of the capital required to build the project. The graph shows that fully exposing renewables to the market price may not necessarily be the best option since the social optimum could be in-between the two opposites, i.e. a level of exposure leading to a reasonable debt/ratio in the projects, but also increasing the value of RES energy.

3.3.1 Support schemes and risks for renewable projects

A power plant's revenues generally results from a produced quantity sold at a given average unit price. The uncertainty on the volume that will be generated and the uncertainty on the price at which it will be sold (or the spread between the price at which it is sold and the cost of the corresponding fuel in the more general case) are among the most important risk factors for such a project, although some other sources of risk exist (e.g. regulatory risk, natural disasters, etc.). Figure 10 presents qualitatively the risks borne by a variable renewable project developer according to the support scheme he benefits from: the squares represent the revenues as the product of a volume of sales and a unit price and are split when the project has several different sources of revenues (e.g. the market plus a premium). The arrows represent the dimension about which the project developer has uncertainty (but their length does not represent the relative weight or magnitude of these uncertainties). As we can see, there is a wide variety of support schemes available, with very different implications on the risk taken by investors in projects that benefit from them.

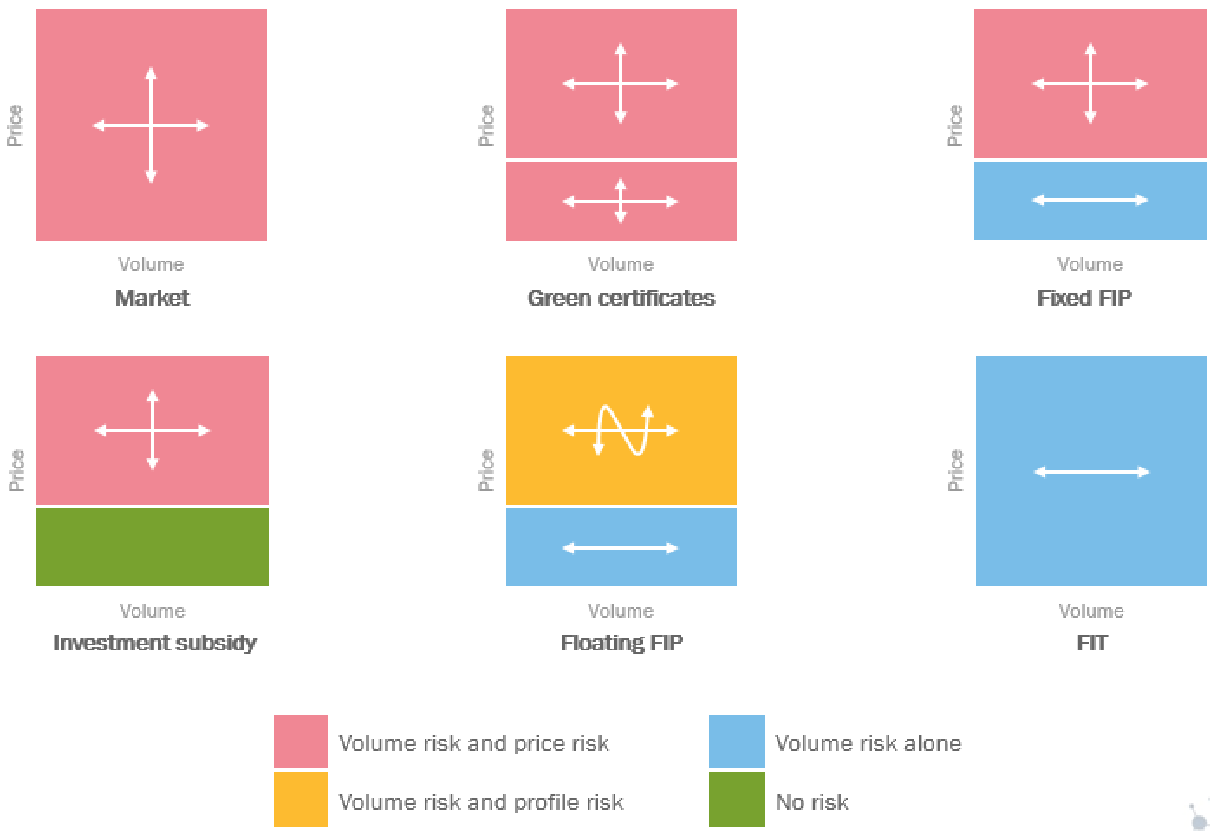

Figure 11: Type of risks supported by investors according to the type of support scheme

3.3.2 Methodology and main assumptions

The study described in chapter 6 of Market4RES report D5.2 [2] also focuses on the long-term evolution of the generation fleet, but through an optimization prim. We have used a tool that calculates the least-cost generation mix, both with respect to installed capacities and their yearly dispatch (on an hourly basis). Account is therefore taken of fixed and variable costs. The optimization is carried out subject to a set of policy constraints with respect to RES, and either a tax on CO_2 or a global cap on CO_2 emissions, plus some explicit constraints on technology deployment in each country.

To keep the problem tractable in a reasonable time, the geographic extent of the simulation is limited to Spain, France and Germany (and the interconnection between them). Constraints applying on installed capacities are described in Figure 11.

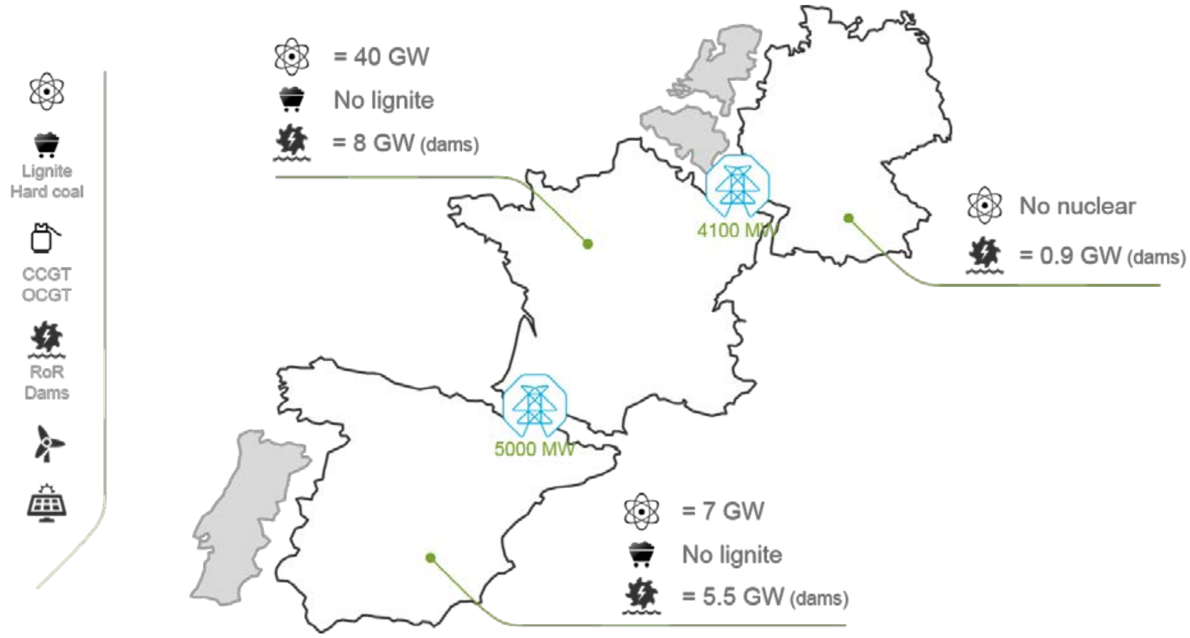

Figure 12. Perimeter and mix constraints of the study on RES support mechanism

3.3.3 Assumptions about discount rates

The central assumption in this study are the discount rates that are chosen to represent the financing conditions in different macroeconomic scenarios, and the modification of those conditions for different technologies according to the market arrangements and corresponding risks

The three Market4RES 2030 scenarios [3] define a default WACC:

1. “Reference” scenario: 8 %,
2. “Low” scenario: 12 %,
3. “High” scenario: 8 %.

Beyond 2020 [6], a prior European project, explored the influence of different RES-policy instruments on the WACC and estimated that it should be 30 % higher for a project earning its revenues from the energy market alone (including the impact of the carbon pricing under the ETS), or the energy market complemented with a green certificate system, than for a project earning its revenues from a feed-in tariff. We have therefore applied this hypothesis to the default WACC defined in each scenario to obtain the WACC applying to supported technologies, resulting in WACCs of, respectively, 6.2 %, 9.2 %and 6.2 % for the three aforementioned scenarios.

After the analysis was carried out for these three scenarios, the sensitivity to the capital cost hypotheses was explored by performing the same computations but assuming the following alternative rates:

4. Beyond 2020 original estimate, i.e. a WACC of 7.5 % for wind and PV when they benefit from a support scheme and of 9.8 % for non-supported technologies. Here we have however not taken account of the "technology-specific risk factor" that was mentioned in the Beyond 2020 report [6]. According to the authors of this report, this rate should in fact be reduced even further for onshore wind and solar PV; this is due to the relative maturity of these two technologies in comparison with many others but also for PV to the fact that some investors seem to be willing to invest under the market profitability of an asset exhibiting this level of risk.
5. The project Beyond 2020 analysed how support schemes can reduce capital cost by reducing risks e.g. through feed-in tariffs by a factor of 1.3. However, renewable industry associations in the Market4RES project (WindEurope and SolarPower Europe) think that this advantage may be of an even greater magnitude. Therefore, we have chosen a WACC equal to 5 % for projects supported by feed-in tariffs, and 10 % if there is no support scheme.

Regarding these WACCs, it should be noted that we have not considered any difference between the countries; this is, however, optimistic since it should depend on how stable investors think the market and support framework is and their assessment of this stability may change from one country to the other.

Scenario	WACC of wind and PV projects when they benefit from a FIT	WACC for all other technologies and for wind and PV w/o support scheme
Reference	6.2 %	8 %
Low	9.2 %	12 %
High	6.2 %	8 %
Original Beyond 2020	*7.5 %*	*9.8 %*
"optimistic"	*10 %*	*5 %*

Table 3. Summary of the WACC assumptions made in the study on RES support schemes

The graph in Figure 12 shows an example of WACC calculation as a function of the ratio of debt to the whole amount of capital in the project (and provided the cost of debt does not depend on this ratio, which is not true when the share of debt gets closer to 100 %). The calculation of WACC is based on assumptions that are relatively close to what can be observed for many renewable projects. The rate of return of equity is computed based on the classic capital asset pricing model (CAPM) as the sum of:

- a risk-free rate (r_f), chosen equal to 2 % (based on recent average of treasury bonds returns),
- and the difference between the expected return of the capital market (r_m), supposed equal to 8.5 % here (based on the average of the CAC 40 index returns over the last decade) and the risk-free rate, multiplied by a coefficient (β), representing the correlation of the project's risk with the risk of the capital market.

As financial institutions usually accept the assumption that they are taking no risk when lending money to renewable projects, the return of debt (r_{debt}) was taken equal to the risk-free rate (2 %) and, finally, a corporate tax rate (τ_{tax}) of 35 % was assumed.

The WACC is, then, given by the following formula, where K represents the amount of equity and D the amount of debt in the project:

$$WACC = \frac{K}{D+K}.\left(r_f + \beta.\left(r_m - r_f\right)\right) + \frac{D}{D+K}.(1-\tau_{tax}).r_{debt}$$

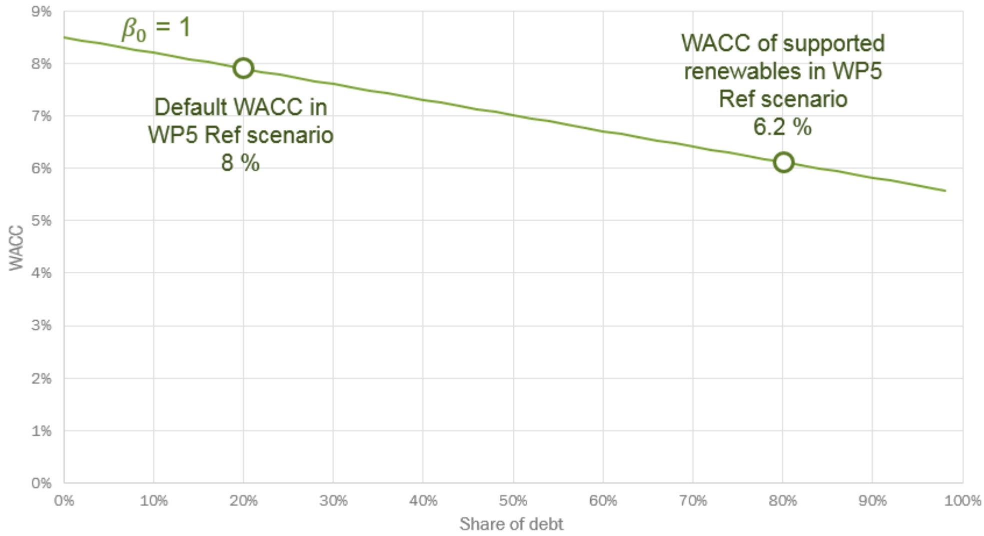

Figure 13: WACC computed as a function of the share of debt in the project

The resulting plot of the WACC as a function of the share of debt in the project is downwards sloping since, here, debt is assumed to be cheaper than equity (and this is all the truer as there is a corporate tax). But, whereas one would expect the WACC to tend towards the return of debt (2 %) when the proportion of debt reaches 100 %, it does not; this is due to the fact that the beta coefficient actually also increases with the indebtment of the project, because more debt to serve makes the service of shareholders less certain and equity all the riskier (the dependency will not be detailed here because it is not the point of this report, but one could easily convince oneself of this fact by expressing the beta coefficient as a function of the revenues and costs of the project, including the service of debt).

Although renewables are largely financed through debt (see for instance the report published on this issue by the French regulator in 2014 [7]) conventional projects usually succeed in raising less debt. Thus, the previous graph supports the fact that the WACC would be quite different for a conventional project selling its electricity in the market with a debt ratio of 20 % and a supported renewable project financed through 80 % of debt. Being able to find these figures through a theoretical argument based on typical assumptions made the WACC hypotheses described above appear as reasonable.

3.3.4 Market designs explored (and variants)

In the long term, both CO_2 pricing and support to RES result in reduced CO_2 emissions. The study described in chapter 6 of Market4RES' deliverable D5.2 [2] compares the total system costs for combinations for CO_2 prices and RES support levels that gives the same CO_2 emission level from power generation. The following combinations were studied:

1. CO_2 price only. A tradable emissions permits system is included; there is no subsidy scheme supporting the development of RES.
2. Only RES support. The RES support is tuned to give the same total emission as in 1. The risk of RES projects is lower in virtue of the support mechanism and their WACC is assumed to correspond to that observed in presence of a feed-in tariff system.
3. A mix of both CO_2 price and RES support. The CO_2 price is specified, and then the RES support level is tuned to give the same emission as in 1 and 2 Actually, 3 includes several combinations of the balance of the two incentives.

The emissions target always concerns the whole area included in the study. Similarly, when a support scheme is set up, it is supposed to be regional (allowing investors to choose the best location of their power plant among the three considered countries) and technology-neutral (investors have the choice between wind and solar photovoltaic).

National, technology specific RES targets (thus a predefined proportion of each technology and in each country) have been explored as well, because they better correspond to the current European context. However, the comparison of such national, technology specific RES targets with a situation where the whole mix is optimized in reference to a sole CO_2 price mixes several optimization effects and is more difficult to interpret. For this reason, the conclusions, although similar to those on regional, technology neutral support schemes (but to a lesser extent) are not detailed in the present report.

3.3.5 Main results

Only the main results of the simulations are described in the following. More detailed results are described in Market4RES report D5.2 [2].

One relevant precaution to take when assessing the outcomes of these simulations relates to the fact that our modelling is too limited here to understand well enough what would happen if we were to decarbonize relatively strongly without CO_2 pricing. In fact, the simulations show such a high cost that it would undoubtedly trigger investment in flexibilities that are not represented in the tool we used, lowering the total cost. However, this cost should remain well above that observed with a higher price of CO_2. For this reason, the results corresponding to the cases where the price of CO_2 was equal to zero (support schemes only) or relatively low (up to 20 €/tCO_2) will not be presented in this section. If an ambitious RES development policy is however accompanied with a carbon price (through any kind of instrument) of more than 30 €/tCO_2, the cost goes down to a reasonable level that is probably more compatible with the limits of our modelling tools.

Figure 13 shows the total annual cost of the whole power system for these different combinations of CO2 price and RES support. The results shown here correspond to the "Reference scenario", which is one of three macroeconomic scenarios considered. If only a CO_2 price was applied to reach the target level for emissions (i.e. quota system only), the corresponding price of CO_2 from the simulation was 174 €/tCO_2. The cost of CO2 emissions is however not included in the total cost in this graph, firstly because it is useless to the comparison to the extent that the CO_2 emissions are, by construction, the same in each case, and secondly because it would require choosing a CO_2 price to calculate this cost, that would necessarily have been arbitrary. The colors of the bars allow distinguishing between the cost of RES and the cost of the conventional fleet. The bar representing the total cost of the system optimized under a cap and trade with a total CO_2 allowance of 249 MtCO_2 has an orange part that represents the additional capital costs incurred by RES projects due to the fact that their WACC is higher than in the other policy options (computed as the difference between the cost of RES amortized at a yearly rate of 8 % and their cost amortized at 6.2 %).

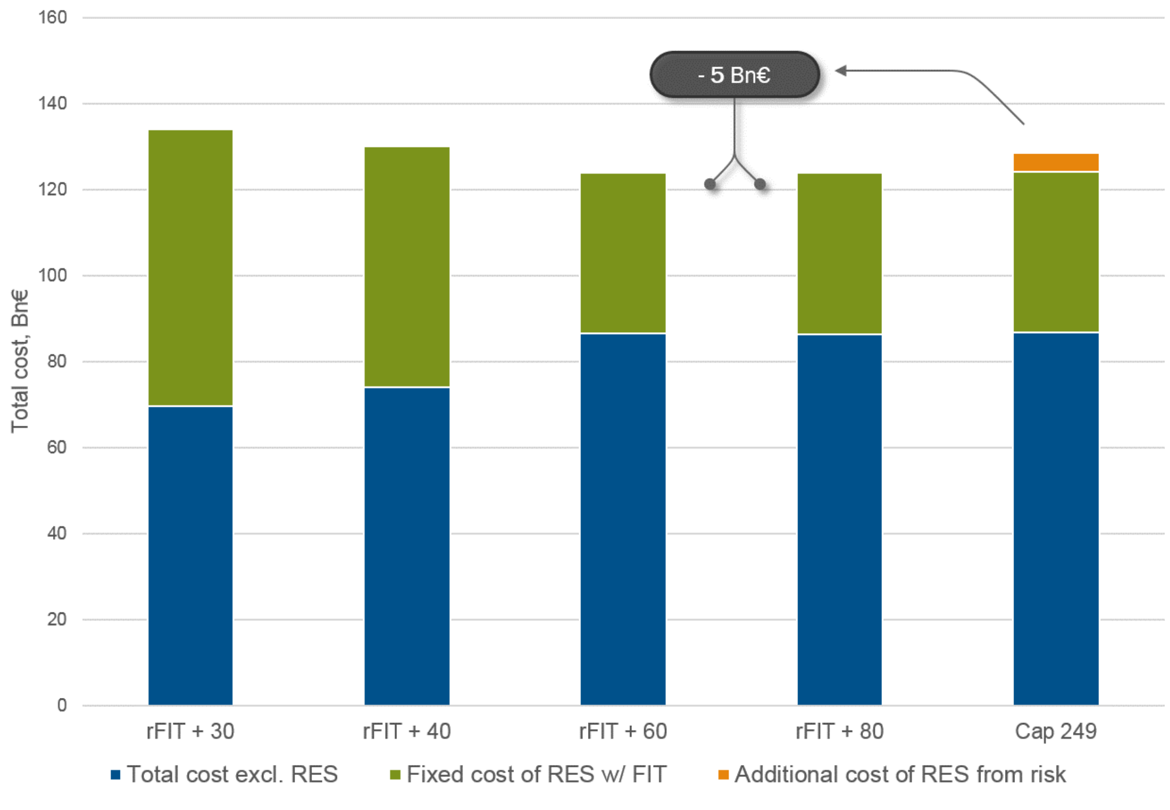

Figure 14. Total costs (excluding the cost of CO_2) as a function of the market arrangement: explicit regional support (FIT-like) to renewables associated with a carbon tax versus carbon pricing alone. rFIT + 30 means "regional, technology neutral RES support scheme associated with a carbon tax of 30 €/t". Cap 249 refers to the situation where only a CO2 cap (of 249 millions of tons of CO_2) is imposed to the model (cap and trade).

First, it can be deduced that the tradable permits design is more efficient in decarbonizing power than merely inserting very high shares of RES into the power system until reaching the same GHG emissions level. Indeed, even if the "support scheme only" option is not represented on this graph, because the system costs are high enough to make some non-represented flexibilities profitable, if such flexibilities were available (in both cases), they would not have sufficed to make the "support scheme only" policy option cheaper than the cap and trade policy option (because they would have been available in that case, too).

The generation fleet and the dispatch obtained under the "cap and trade" policy option continue to be cheaper than those resulting from a RES support accompanied by CO_2 pricing, provided the price of CO_2 remains under 50 €/tCO_2. However, it can be observed that above a certain CO_2 price level, the "RES support scheme" option is cheaper than the "tradable permits" option. In fact two effects enter into competition: pricing carbon allows to reap the low-hanging fruits in terms of decarbonization options, i.e. mainly switching from coal to gas, hence a lower cost of the "tradable emissions permits" in comparison with the "RES support scheme with no CO_2" pricing option: given the cost hypotheses the former is the most efficient to decarbonizethe power sector. But in the meanwhile, in this case, RES have no support mechanism and are developed given a revenue fluctuating with the wholesale market price. Therefore, the cost of their capital is higher (8 % in the Reference scenario) than if RES had been supported (6.2 %). This increases the total cost of the "tradable emissions permit" design option which becomes, given the relatively high share of renewables in these scenarios, higher by a few percent than the cost of the hybrid option consisting in a CO_2 tax at a level around 60 €/tCO_2 and developing renewables to further decarbonize electricity through support mechanisms.

It should be noted that the cost assumptions in this study were made during a period where the cost of gas was very high whereas the cost of coal was low. Would they be chosen today, the required CO_2 tax price to trigger the switch from coal to gas - and, in all likelihood, the CO_2 tax price above which there would be a cost reduction in an hybrid system in comparison with the CO_2 price-only solution – would be much lower, probably in the range of 20-30 €/tCO_2.

3.3.6 Analysis and conclusion of the study

In all scenarios tested, getting to a predefined level of greenhouse gas emissions thanks to carbon pricing at the correct level, for instance through a tradable quotas system, is more efficient than reaching this same level only by supporting RES investments without putting a price on CO_2. Indeed, RES are a relatively expensive decarbonization option given the costs assumptions used in our simulation in comparison for instance with switching from coal to gas. Assuming risk neutrality of all the market agents and perfect competition, carbon pricing allows to reflect perfectly (in theory at least) the value of the externality, entrusting market players with the task of choosing the cheapest options.

The computations show that, thanks to a lower capital cost for RES, the overall system costs become lower if a combination of CO_2 price (for example through a tax) and support schemes for RES are implemented.

Thus, while the phasing out of explicit support mechanisms has been seen as a necessary step forward on the path to market integration of RES, the nature of the costs of the new capacities may make it more cost-efficient to reap the easy decarbonisation actions through a carbon tax (or another carbon price setting mechanism) and then use support mechanisms to go further in decarbonisation by replacing conventional units with RES thanks to support schemes, that increase their competitiveness both through increasing expected profits and through the reduction of price risk.

4 Impact of capacity mechanisms on cross-border trade

The participation of foreign capacities in capacity mechanism has been analyzed in the Market4RES' report D3.1 [1], and its main recommendations have been detailed in the first chapter of this report. It concluded that the most desirable option was an explicit participation of the foreign capacities in national capacity mechanisms. Nonetheless, we propose to further discuss this option, because of the relevance of this point in the current discussion on the impacts of capacity mechanisms on the internal European electricity market. Through the interconnections, foreign capacities do contribute to the national security of supply of a country having implemented a capacity mechanism. This contribution has to be reflected in the functioning of the mechanism, at least in a statistical manner. Otherwise it would drive to the development of more capacities than required. Taking foreign capacities into account in an explicit manner enable them to be paid for their contribution to security of supply in the country where the capacity mechanism is set up and, therefore, favors the creation of a level playing field between all capacities.

For the European Commission, the creation of an Energy Union is one of its main priorities. Following the Target Model for the liberalisation and decarbonisation of the Energy Union, the European Commission is now instructing Capacity Mechanisms issues, worried about a development of capacity markets on a national basis (in Great Britain, Spain, Belgium, France, Ireland, Italy, Sweden, Poland, etc.) that could impact the functioning of the internal market and investment decisions.

For this reason, it is important to take into consideration the participation of national and international generators in the CM market design. Nevertheless, there are many options to implement that participation, such as:

- Implicit contribution of interconnections and of abroad capacities or demand response in the determination of the national security of supply criteria
- Explicit contribution of interconnections in the national security of supply
- Explicit contribution of abroad capacities (including demand response) in the national security of supply
- Explicit contribution of both interconnections, abroad capacities (including) demand response) in the national security of supply

Regarding their relevance and feasibility, some legal and economic matters remain to be solved at a national and European level. For instance, the possibility of simultaneous supply shortage in two countries raises governance issues about the priority participation of those generators or demand response. The verification of the services supplied by foreigner generators and demand response brings up legal and technical issues. Last but not least, the effective contribution of the capacities to one national security of supply or to the other is difficult to evaluate. To illustrate this latter challenge, we provide a theoretical example and a practical case below.

In this example, a capacity remuneration market is designed by and for country A. Cross-border participation of capacities (demand response or generators) installed in country B relies on the principle that country B's capacities need to be available at the national load peak of country A and if needed, to produce energy for the benefit of country A only. This mechanism therefore relies on the availability of interconnection capacities between countries A and B during the load peak of country A.

The following map illustrates this issue in the French case: the constraints on cross border interconnections during the French load peak. It is very obvious that the foreign capacities play an important role in the French security of supply. But one can also easily understand that the real participation from capacities abroad to the French security of supply depends of a mix between availability of generation and demand response on the one hand, and of interconnection capacities on the other hand. One without the second or the contrary is much less worthy for a national capacity market mechanism.

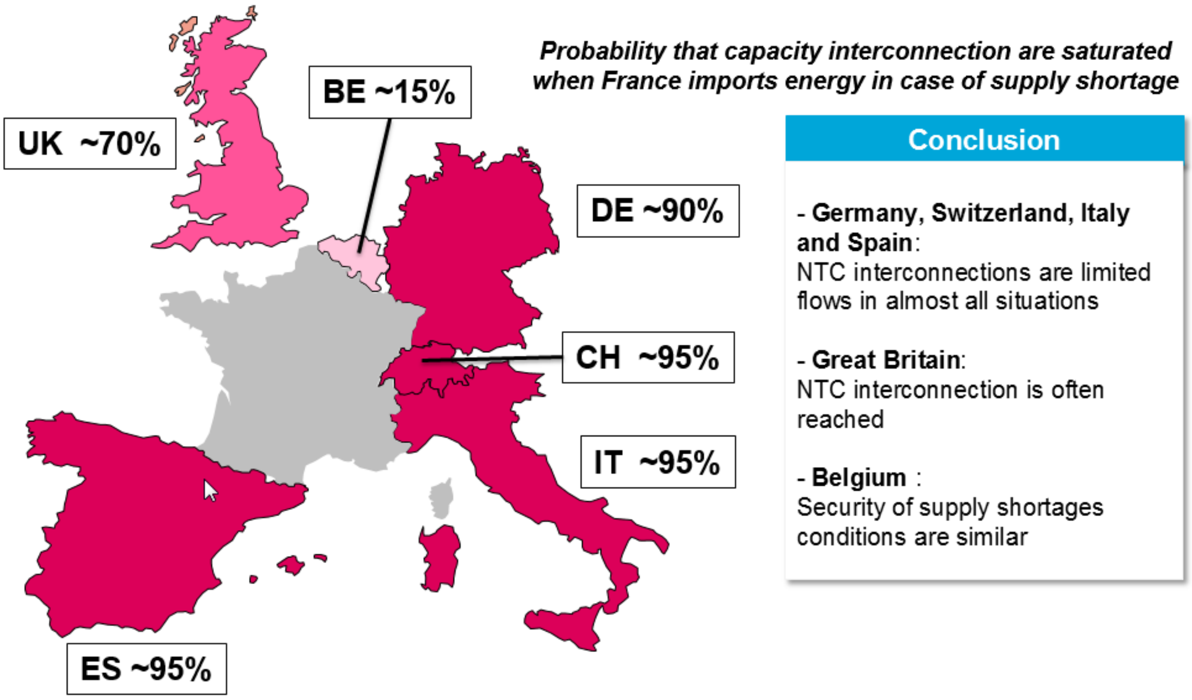

Figure 15: Probability of interconnection saturation when France imports energy in case of supply shortage (source: RTE, public consultation document, 2015)

An accurate mechanism should lead to economic signals in the direction of interconnection capacities and in that of generators and demand response parties, since the reduction of the loss of load in a given country is only possible through the simultaneous explicit participation of interconnections and foreign capacities.

Such a mechanism would rest upon:

- The allocation of interconnection capacities during national load peak to some producers or demand/response operators installed outside of the national network, essential to the participation of those capacities to the national security of supply,

- The definition of certificates for generators or demand response operators installed outside of the national network based on the obligation fulfilled by the entities.

It would, however, not be easy to make such a mechanism compatible with the present state of European law. In particular, in case of simultaneous shortage, the current European legal framework doesn't allow firm commitments of national entities to participate to another State in a difficult situation. Actually, the article 42 of the 2009/72/CE directive [8] allows member States to take extreme action in case of necessity but they also have to respect equity between national and extra national contracts:

> *"In the event of a sudden crisis in the energy market and where the physical safety or security of persons, apparatus or installations or system integrity is threatened, a Member State may temporarily take the necessary safeguard measures. Such measures must cause the least possible disturbance in the functioning of the internal market and must not be wider in scope than is strictly necessary to remedy the sudden difficulties which have arisen.*
>
> *The Member State concerned shall, without delay, notify those measures to the other Member States, and to the Commission, which may decide that the Member State concerned must amend or abolish such measures, insofar as they distort competition and adversely affect trade in a manner which is at variance with the common interest."*

Nevertheless, the directive 2005/89/CE [9] on security of electricity supply and investment in infrastructures stresses that member states could not in this case be inequitable between national and international contracts: *« In taking the measures referred to in Article 24 of Directive 2003/54/EC and in Article 6 of Regulation (EC) No 1228/2003, Member States shall not discriminate between cross-border contracts and national contracts. ».*

Taking that principle into consideration, a pragmatic approach may consist in developing an explicit participation from interconnections only, which is the solution selected in Great Britain. This proposition contains a good balance between the necessity of taking into account international help to the security of supply and the legal and technical issues. This choice has been analyzed in the same way by the European Commission (SA.35980 – C (2014) 5083) [10]: *"The Commission recognizes the complexities of effectively allowing cross border participation in a capacity mechanism. The Commission welcomes the commitment of the UK to facilitate the participation of interconnectors […]. The Commission recalls that the EEAG require schemes to be adjusted in the event that common arrangements are adopted to facilitate cross border participation in such schemes."*

If the interconnections of the country are constrained in load peak, this method seems particularly relevant since the market studies prove that in this case the (foreign) capacity scarcity is mostly due to the limit of the interconnection capacity, rather than to that of the foreign generating units.

As shown in Market4RES report D3.1 [1], capacity mechanisms should implement a firm capacity requirement (see the paragraph on “firm supply component” within section 2.3.3), but this implies being able to measure this firm capacity, thus a certification and control process. Moreover (as shown in section 2.7 of the same report), such a process should be fair towards extra-national generators and demand response operators by allowing their participation. Generators participating in a capacity remuneration market have, therefore, to be controlled on the same grounds, regardless of their localization. Controlling the availability of foreign capacities can be a challenge. In France for instance, the balancing mechanism is a powerful legal tool allowing to control availability of generators/demand response since all generators connected to the network have the obligation to propose their availability on the balancing mechanism, which could thus be tested. Such a tool to monitor and control the actual capacity level may not exist in other countries.

Following the idea of reciprocity, we can imagine that one European capacity could intend to participate to every European capacity remuneration mechanism if the load peaks were different and interconnections capacity available. These possibilities would imply a European control in order to be sure that the same capacity is not selected (and paid) several times in different capacity markets for the same peak periods. It therefore implies a strong control coordination.

Reciprocity is also an important principle for cross-border participation to capacity mechanisms. Where no reciprocity is enforced, there is a risk of money transfer from the country allowing cross-border participation to the one not allowing, benefiting to the latter which would “free-ride” the capacity built to ensure adequacy in the former.

Finally, just like constrains on the energy flows between countries lead to a scarcity rent incentivizing the development of interconnections, the participation of interconnections to capacity mechanisms would allow to take their capacity value into account in projects development assessment.

5 Conclusions

Many countries are currently testing different market designs to meet their objectives of security of supply. The different design options will lead to different results. Throughout our analysis of current CM designs, we have come to the conclusion that a CM, if implemented, should have the following features: product firmness requirement, penalty for non-delivery, lead-time of about three years. Concerning the choice between price-based or quantity-based mechanisms, we propose to retain a mixed approach in-between both. It consists for the regulator in defining the price-quantity demand function. Thus, the regulator limits the systemic risks for the system and has a better chance to drive the system to the desired level of security of supply within an acceptable cost. The definition of the quantity and the product exchanged should be made on a bilateral basis, if feasible. The cross-border participation is also needed. Even if different options are still discussed, it seems to the project that the explicit integration of the cross-border potential in every national security of supply scheme is relevant. Lastly, we observed that both centralized and decentralized procurement option are interesting and that this issue needs a more detailed quantitative analysis.

Such a capacity mechanisms will, besides the existing energy markets, provide new incentives for investments in new generation units or to maintain available competitive existing ones, in amounts consistent with the required security of supply level. The demand side response could also benefit from those new sources of revenues to accelerate its development.

The evolution towards a more capital-intensive electricity supply, through increasing shares of renewables, increases the importance of keeping financing costs low through the reduction of risks. Whereas optimization through the market price brought great benefits in the less capital-intensive system of the 1990s and early 2000s, the nature of the technologies that have to be developed in the next decades to reach our policy objectives is different, since their cost are mainly capital costs and their dispatch optimization potential is more limited. As a consequence, risk-mitigation instruments can be appropriate. Investments in highly capital-intensive technologies such as RES indeed benefit from risk mitigations measures provided by RES support schemes. Our study shows that it is certainly more efficient to get to a predefined level of RES emissions thanks to carbon pricing rather than by only driving decarbonisation through increasing the RES penetration, but it also demonstrates that a CO_2 price alone is not the most efficient tool to decarbonize the European electricity system. The reason is that a support scheme for RES, such as a feed-in tariff, lead to lower capital costs due to lower risks. Thus, a combination of a RES support scheme and carbon pricing (for instance under the form of a tax) turned out to give a more cost-efficient outcome than a cap and trade system in our simulations. In such an hybrid design as a carbon tax combined with ambitious RES targets achieved through a low-risk support scheme, the carbon pricing scheme should allow to reach low hanging carbon abatement options while the development of RES generation should allow the system to get further in the decarbonization process: a partial de-optimization of the mix in comparison with the theoretical first-best (i.e. the CO_2 cap and trade system without any RES constraint and subsequent support instrument) is more than compensated by the cost reduction through revenue stabilization. Once RES technologies have got to an appropriate level of maturity, RES support schemes may therefore be replaced by pure revenue stabilization ones, like long term energy markets either of a centralized or decentralized nature.

Thus, while the phasing out of explicit support mechanisms is seen as a long-term objective by many stakeholders, the nature of the costs of the new capacities may make it more cost-efficient to reap the easy decarbonisation actions through a carbon tax (or another carbon price setting mechanism) and then use support mechanisms to go further in decarbonisation by contributing to the development of technologies that allow the further replacement of base load conventional generation with RES generation on the basis of the long-term costs.

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