Artelys | OPTIMIZATION SOLUTIONS

France-Germany Study

Energy transition and capacity mechanisms

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1 Introduction

In most countries of the world, the electricity sector is undergoing a structural transition, driven by requirements of efficiency and sustainability: renewable capacity is witnessing a continuous growth, making the need of flexibility increase, while electricity market prices tend to decrease.

In the medium-term, the power system will have to deal with increasing levels of risk, which will take different forms in France and Germany, which are the two countries this study focuses on. In France, the risk is related to the thermo-sensitive power demand, whereas in Germany the risks are related to the high penetration of intermittent renewable power generation. Both of these facets of risk lead to a high volatility of the residual demand from one hour to the next, and therefore require the power system to be more flexible. In this context, the question of whether the current market design will be able to ensure a satisfactory level of security of supply through an adequate remuneration of it actors is open.

Market design is therefore a crucial point whose appropriate treatment could ensure the sustainability of the current and future power systems. An inadequate market design could in contrast lead to a massive decommissioning of power plants, including the most flexible ones, which will directly impact the security of supply in both France and Germany. The security of supply at the European level could also be at risk since France and Germany host the two largest power systems in Europe.

To face these new challenges, several solutions are being planned or implemented in different countries. These solutions all involve combinations of the following ingredients:

- improvements of the **energy-only markets**, without price caps and with higher demand-response capacities, to let the system send more accurate price signals during times of scarcity,
- **capacity reliability mechanisms**, among them capacity mechanisms based on a targeted level of security of supply at a national level, or other mechanisms such as strategic / capacity reserves where the system operator puts aside some capacity to ensure security of supply in exceptional circumstances.

As will be discussed in this study, a crucial ingredient that highly influences the effectiveness of mechanisms aimed at ensuring security of supply is the level of international coordination.

In this context, this study focuses on assessing the impacts in 2030 of different market designs in France and Germany on the security of supply and on social welfare, evaluated through a modeling of the investment behavior of market participants. This study has been commissioned by UFE and BDEW, two major European institutions bringing together the main actors of the Franco-German power system.

Section 2 is devoted to the description of the power system model for France and Germany. Section 3 analyses investment risks in new capacity for the different studied market designs. Actor behavior modeling, along with the resulting supply mixes are presented in Section 4.

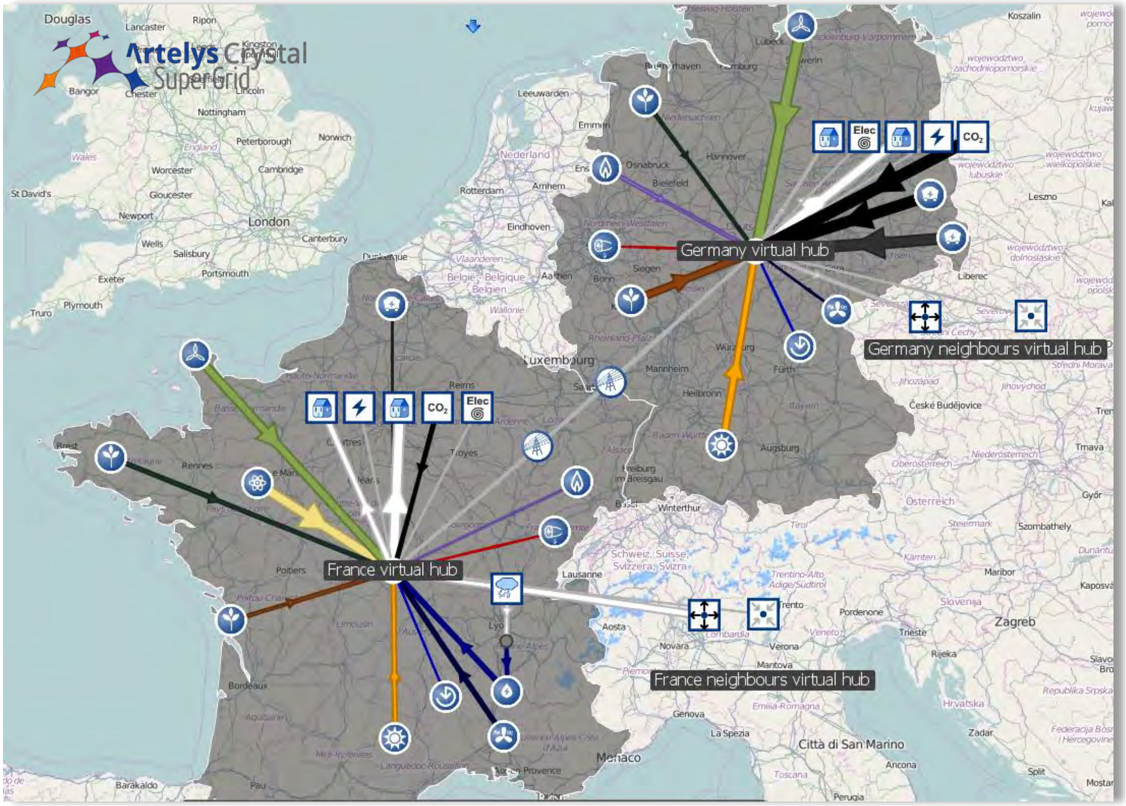

Figure 1: Franco-German power system in Artelys Crystal SuperGrid

2 Power system modelling

This section is devoted to presenting the key methodological choices of this work, along with the reasons these choices were made, in order to be fully equipped to interpret the results.

2.1 A cost-based approach

For a given generating mix, the electric system operations are supposed to be cost-minimizing. This means that at all times, a power plant is brought online only if the remaining power plants have higher or equal variable costs. In other words, available power plants are ranked based on ascending order of variable costs, which defines the order – the *merit order* – in which plants are to be brought online.

The following graph shows how the 2030 French production is dispatched between production fleets to meet the demand. One can refer to section 2.4 for more details regarding the assumptions underlying the construction of the 2030 power system.

Each color stands for a given production fleet, fleets' productions are stacked in accordance with the merit order, and demand is represented by the black line. Differences between supply and demand correspond to imports and exports.

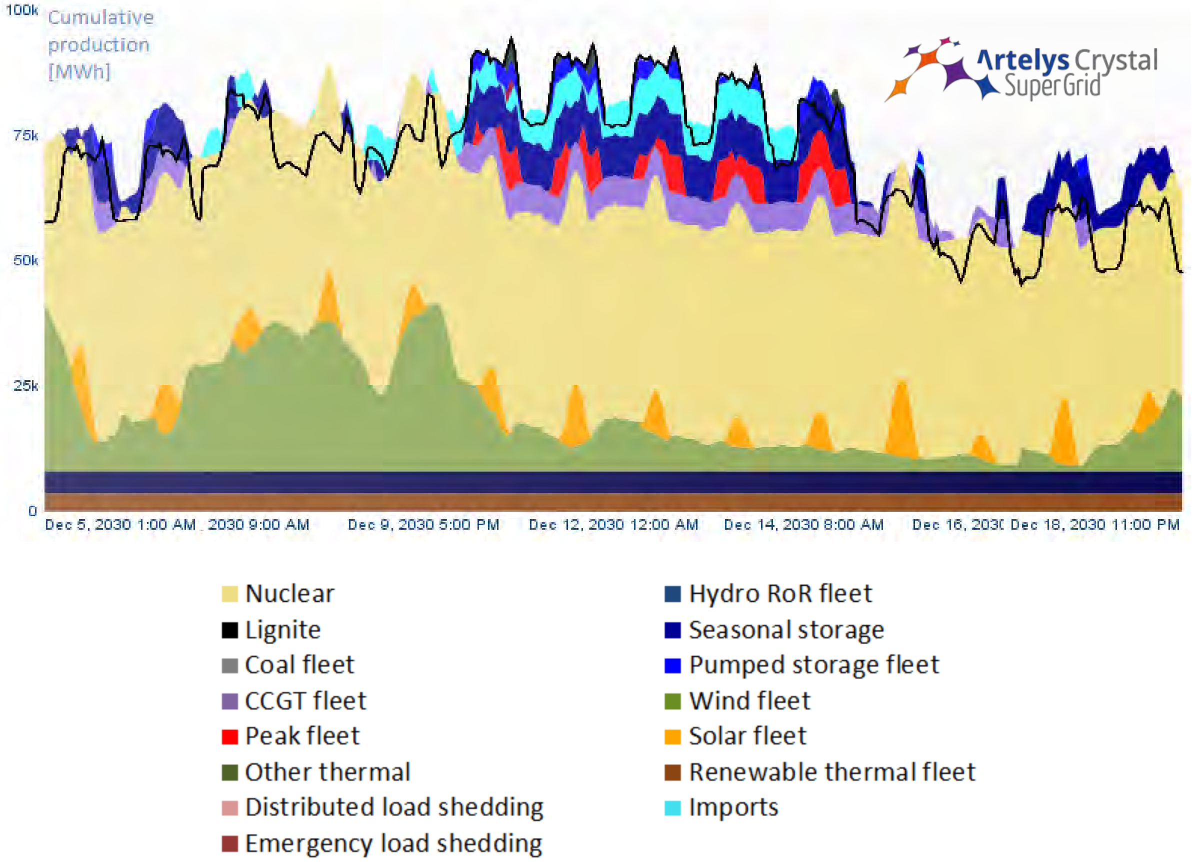

Figure 2: Cumulative production in France, extracted from power management simulations
Climatic scenario 23 - Dec, 5th to Dec, 19th 2030

This graph exhibits the fact that expensive peaking plants (represented in red) or emergency demand response (represented in grey) are only called when cheaper production plants are not able to meet the demand by themselves. The period between December 12 and December 14 is characterized by small wind (represented in green) and solar (in orange) productions. During this period, nuclear (in light yellow) and gas (in purple) power plants are not able to complement the intermittent production to reach the demand. By contrast, from December 6 to December 9 wind power plants' production is such that nuclear power plants do not need to run at full capacity to satisfy the French demand. Since German base fleets' costs (coal and lignite) are higher than the ones of French nuclear units, the extra available nuclear capacity in France is used to meet Germany's needs, which is why French cumulative production is greater than the national demand.

One of the main difficulties of power management lies in the variability of the demand on every time scale, since production dispatch has to be adjusted "in real-time" to meet the demand. This variability is all the more intense when an important share of intermittent power generation is integrated into the mix, since its variability is added to the demand's one. An appropriate representation of the variability of both the demand and of renewable production has to be included in the modeling effort in order to identify periods during which the most expensive power plants are to be taken online, and thereby the effects of variability on marginal costs and on producers' revenues.

The time step used in the simulation has therefore to be selected in such a way as to allow for a proper depiction of the power plants' operations and to capture the variability of both the demand and intermittent productions. Since yearly, monthly and daily time steps do not fulfil these requirements, it has been decided to establish the supply-demand equilibrium on an hourly time-step. In this way, it is ensured that variability is well captured, leading to realistic economic outcomes in terms of production costs and producers' revenues.

Finally, since storage is an important player in the considered energy mixes, working on a demand monotone (as is sometimes the case for economic analyses) would not allow for a suitable representation of the links between time steps. Indeed, storage relates time steps between them in an asymmetrical way, different order of appearance being nonequivalent. A chronological representation has therefore been used in this study.

2.2 A model of the generation mix

The power model which is used in this study has been designed to fulfil two requirements:

- First, it has to be able to simulate the operations of the French and German energy mixes over a range of climatic scenarios by minimizing the average global welfare, and thereby to dimension their capacities.
- Second, it has to embed a depiction of the actors' dynamics, which permits to assess the producers' production and revenues according to a range of different market designs.

The French and German power mixes are each represented by a node to which the respective production fleets (aggregated by type of power plant) and demand-response programs are associated. The electric interconnection between France and Germany is linking the two aforementioned nodes and permits power exchange.

The detailed list of the production fleets which are considered in this study is provided in Appendix A, together with their operational constraints. Both distributed load shedding (from domestic consumers) and emergency load shedding (from industrial consumers willing to reduce their consumption during periods of high prices) programs are implemented in the model.

A simplified model of imports-exports with the rest of Europe is implemented in order to ensure the study is based on a realistic picture of the European power system. The loss of load is modeled by adding a virtual plant running at a very high variable cost (15k€ per MWh).

Finally, operational constraints such as power gradients, minimum and maximum loads, energy conservation, etc. are modeled in a detailed way.

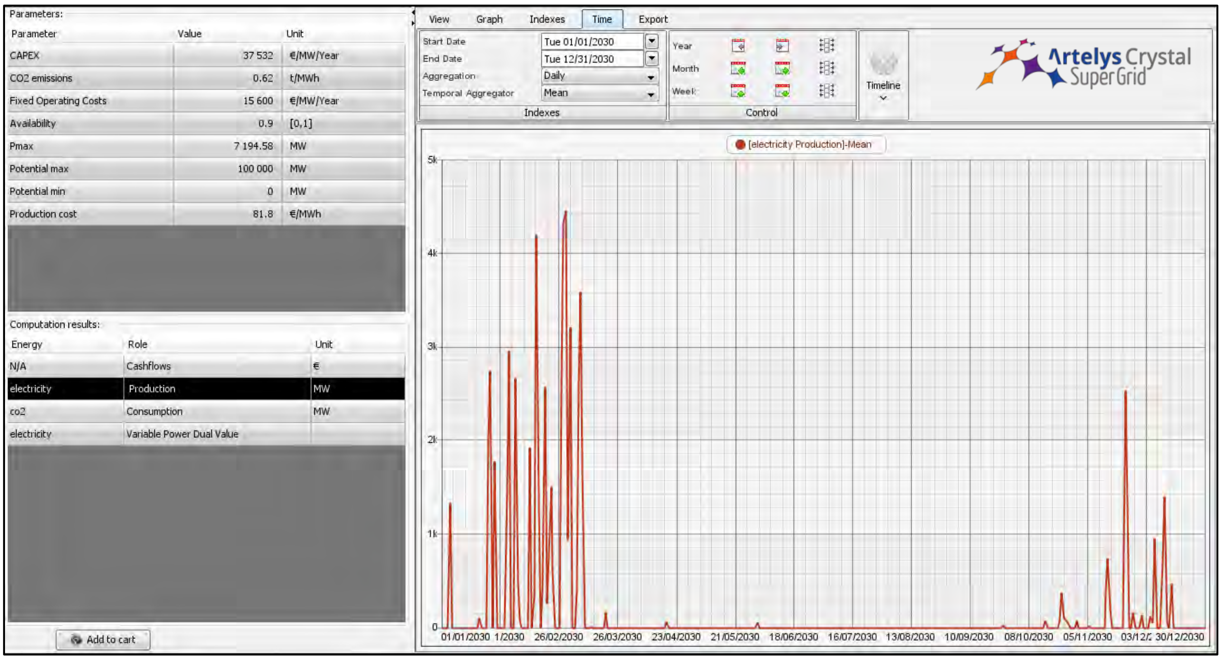

Figure 3: Asset view of 'France peak fleet' within Artelys Crystal Supergrid

The resulting model is able to dimension the capacities of conventional thermal assets and of the Franco-German interconnection by minimizing the overall costs under operational constraints for a range of climatic scenarios.

Moreover, the operations of both the power plants and the interconnection are optimized with an hourly time resolution, for 50 climatic scenarios. One thereby gets access to the production of each of the fleets and the marginal costs for both France and Germany.

The model is therefore well-suited to assess the influence of market design on the security of supply on the producers' revenues.

2.3 Uncertainties modelling

Since security of supply is the prime interest of this study, a key factor that has to be taken into account is the climatic conditions' variability. The latter can be translated into risks for the security of supply of both France and Germany, which turn out to be of different nature and importance. Indeed, in France, the main risk related to the security of supply is coming from the consumption peak occurring in winter, due to the high share of electrical heating in France. In Germany, the risk is related to the structure of its generation mix, and in particular to the importance of its share of intermittent wind and solar power. The intrinsic variability of these sources may be critical for the security of the German power system.

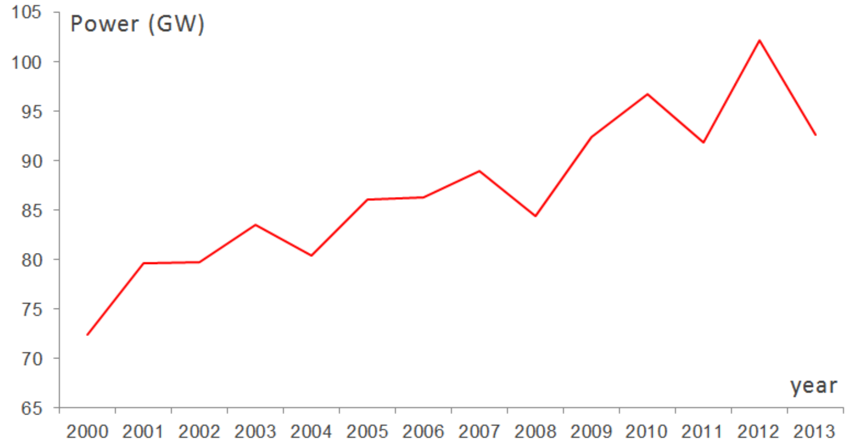

Figure 4: Annual consumption peak power in France from year 2000 to year 2013 (source: RTE)

These uncertainties also have a high incidence on the short-term price levels in an energy-only market, and therefore an impact on producers' revenues. For a given generation mix, the average price will be higher in cold winters than in warm winters. Climatic variability therefore translates into an uncertainty for producers regarding their revenues. This effect is even higher for production plants that are used only for peak hours, as they only get revenues (short-term price minus variable costs of production) when a more expensive unit (or load shedding) is called at the same time.

50 climatic scenarios were built to depict the variability of both demand and production by renewables. These scenarios are based on realized generation and consumption data in both countries in order to take into account the correlation of these different time series and to be able to assess adequately the security of supply at the Franco-German level. In particular, a close attention has been paid to the correlation between renewables generation in Germany and temperatures in France as these two parameters have the most significant impact on the security of supply. See Appendix A for more details.

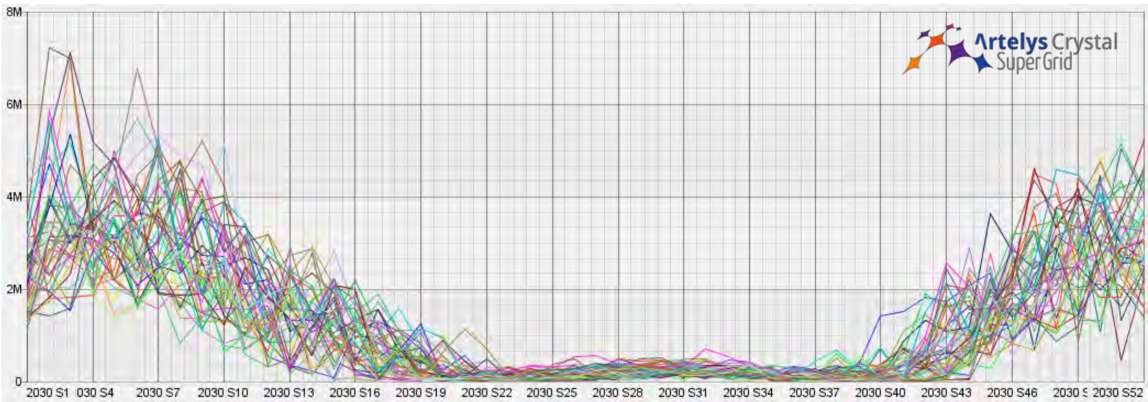

Figure 5: Scenarios of French thermo-sensitive consumption within Artelys Crystal Supergrid scenario view

These scenarios are used to assess the security of supply for a range of market designs, as explained in section 3, and will allow to measure the risk for producers in terms of profitability of their investments.

2.4 A virtual reference 2030 mix

In this section the design and computation of the reference 2030 energy mixes is described. The virtual reference mix satisfies the following two requirements:

- First, they take assumptions regarding the evolution between the present situation and 2030 into account, in particular the strong increase of renewables in both France and Germany and the projections regarding the evolution of installed nuclear and lignite capacities are depicted.
- Second, the 2030 generation mixes avoid structural dis-adaptation, in order to ensure the observed effects can entirely be attributed to market designs.

To answer these two requirements, public national and international forecasts data were used for storage facilities, demand-side management, consumption, imports/exports balance and installed capacities for Renewable Energy Sources (RES) as well as nuclear and lignite power plants[1]. Conventional thermal power plants (namely: coal, CCGT and peak fleets) and France-Germany interconnection installed capacities were optimized, using a welfare-maximizing capacity expansion model to get a reasonable starting point for the study.

The resulting virtual reference mix is close to ENTSO-E's forecasts, and coherent with the different scenarios considered by the French TSO, RTE[2], on one hand, and the German Federal Ministry for Economic Affairs and Energy (BMWi) on the other hand. The remainder of the section presents, first, the main assumptions used to produce the 2030 generation mixes, and secondly, the resulting thermal generation mixes. Detailed information can be found in Appendix A.

One must bear in mind that this virtual reference mix is a virtual optimum which is not reachable in real economic conditions since investors tend to display a certain level of risk aversion.

[1] Sources: ENTSO-E TYNDP 2014, RTE Bilan prévisionnel 2014, EWI / GWS / Prognos, Study commissioned by the German Federal Ministry of Economic Affairs and Economy; In particular, RES hypothesis were taken from the average of two ENTSO-E scenarios for France, and from EWI/GWS/Prognos for Germany.

[2] In particular, assumptions of nuclear installed capacity, demand, and exports in France are close to the "diversification" scenario of RTE.

2.4.1 Main assumptions

INSTALLED CAPACITIES

The 2030 installed capacities in the virtual reference mix are presented in the following table:

	Installed capacities (MW)	
Technology	France	Germany
Nuclear	48 000	0
Lignite	0	17 000
Hydro run-of-river	13 100	4 000
Seasonal hydro storage	9 300	0
Pumped hydro storage	4 300	8 000
Other thermal	4 200	2 880
Solar	30 800	68 000
Wind	36 200	59 000
Renewable thermal	5 800	7 000

Table 1: Generating power plants' installed capacities

POWER DEMAND

The demand is assumed to consist of two parts: a fixed non-thermo-sensitive part and a thermo-sensitive part.

The thermo-sensitive component mainly represents electric heating and air conditioning. It has been generated for each of the 50 climatic scenarios, based on historical data. It has further been adapted to take into account climate change and the evolution of electricity used for appliances and consumer electronics. France has a higher thermo-sensitivity than Germany, as shown on the graph below, which results in more acute and more intense winter peaks.

The fixed non-thermo-sensitive component represents other domestic and tertiary usages (such as electric appliances), industrial consumption and transports.

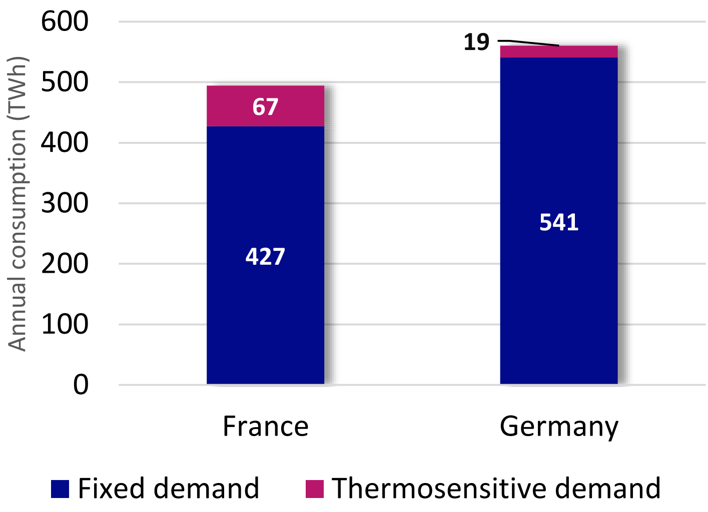

Figure 6: Assumptions of demand in France and Germany by 2030, averaged over 50 climatic scenarios

With this model, for the most unfavorable climatic scenarios, peaks of residual demand (national demand minus solar and wind electricity generation) can reach up to 113 GW in France and 99 GW in Germany[3].

DEMAND-SIDE MANAGEMENT

Demand-side management capacities are expected to significantly increase during the two next decades, thanks to new technologies (such as smart and connected equipment) and new habits, making demand more responsive to price levels.

Demand-side management mechanisms are broken down in the following two categories:

- **Distributed load shedding**, representing the capacities of domestic demand-response. They are modelled as having a nil marginal cost and can be used up to 100 equivalent hours per year. While it has no cost of use, it is in practice only activated during peak time since the total available volume is limited.
- **Emergency load shedding**, activated when the price goes above 400€/MWh corresponding to industrial load shedding. Since it is about four times as expensive as peak fleets, this demand-response capacity is only used as a last resort to avoid loss of load.

[3] In France, the impact of extremely poor weather conditions is high due to the significant share of electric heating in the domestic sector combined to extremely low temperatures. In Germany, the impact of extreme weather conditions is increased compared to the current situation due to the planned growth of the share of heat pumps in domestic heating combined with the global increase of consumption. In addition, the increasing use of electricity in the transport sector will impact on overall electricity consumption.

	Demand-side management capacities (MW)	
	France	Germany
Distributed load shedding	7 000	2 500
Emergency load shedding (400€/MWh)	4 000	5 000

Table 2: Demand-side management capacities.

Note that these assumptions have a relatively low impact on the analysis made in this study as a lower share of DSM will simply result on a higher peak fleet optimized capacity in the virtual reference mix.

Imports and exports with the rest of Europe

While the Franco-German interconnection is explicitly modelled and optimized, imports and exports with other countries are also represented within the model.

To be coherent with the relatively high assumption on nuclear installed capacity in France, France's export balance with neighboring countries other than Germany is considered to keep being significantly positive: the average yearly balance over the climatic scenarios is assumed to be 50 TWh. On the other hand, Germany's imports and exports are supposed to be balanced. Note that since installed capacities of the conventional thermal fleet are optimized for the virtual reference mix, a different assumption on import/export balance would not alter significantly the results of the study.

VARIABLE COSTS OF PRODUCTION

The following table presents the assumptions regarding the variable costs of production. They are composed of fuel costs on the one hand, and CO_2 emissions' costs on the other hand, **the price of CO_2 being set at 33 €/t**.

Variable costs of Production			
Technology	Fuel costs (€/MWh)	CO_2 emissions (t/MWh)	Total variable cost (€/MWh)
Nuclear	6.4	0	6.4
Coal	25	0.89	54
Lignite	15	0.99	48
CCGT	52	0.40	65
Peak fleet	82	0.62	100
Other thermal	82	0.62	100

Table 3: Variable production costs

These assumptions are based on projections carried out by the International Energy Agency (*World Energy Outlook 2013* and *CO_2 Emissions from Fuel Combustion*).

2.4.2 Optimizing thermal and interconnection capacities

CONVENTIONAL THERMAL INSTALLED CAPACITIES

Conventional thermal power plants' capacities being optimized via a cost-minimizing approach, assumptions regarding their fixed costs also have to be provided. Two types of fixed costs are considered: annualized investment costs, which correspond to annual capital costs, and fixed operating costs, which are typically wages paid to employees. An actualization rate of 7.25%[4] is used throughout this study, over the scheduled lifetime of investments.

[4] This actualization rate is for instance used by the French authority on energy regulation (Commission de régulation de l'énergie – CRE).

Fixed costs – optimized fleets			
Technology	Annualized total fixed cost (€/MW.year)	Lifetime (years)	Total fixed cost (€/MW)
Coal	150 000	25	1 700 000
CCGT	95 000	20	980 000
Peak fleet	53 000	20	550 000

Table 4: Optimized fleets' fixed costs

The obtained installed capacities are presented below.

	Installed capacities (MW)	
Technology	France	Germany
Coal	0	17 500
CCGT	6 300	27 200
Peak fleet	8 300	5 300

Table 5: Conventional thermal optimized capacities

INTERCONNECTION

The France-Germany interconnection is also optimized simultaneously to conventional thermal fleets using a cost of 40 000€/MW/year. The result of this optimization is presented in the following table:

FR-DE Transmission	Installed Capacity (MW)	Average annual flows (TWh)
France to Germany	6 900	20,5
Germany to France	6 900	5,5

Table 6: Power transmission lines capacities obtained via the optimization procedure

The installed capacity obtained by the uncapped optimization is 6900 GW. The current net transfer capacity is 4400 MW from Germany to France, and 2450 MW from France to Germany.

This shows the economic value of having well interconnected systems:

- The interconnection allows for a better management of generation fleets across the whole zone

- A high capacity of interconnection allows for a better use of generation during peak hours and therefore results in a reduction of the necessary capacity to face difficult situations, which reduces investment costs.

3 Investment risks for different market designs

The revenues of a given producer are influenced by a broad range of factors, such as the total demand, climatic conditions, the capacities and production costs of all other actors, the availability of its assets, etc. The aim of this study is to identify and quantify the influence of market design on producers' revenues.

Two types of energy-only markets are considered: an energy-only market with price cap at 3k€/MWh, and an energy-only market without price cap. In the second case, the market price can attain 15k€/MWh which is the value of loss of load in the model. Capacity reliability mechanisms are also considered.

This section is devoted to computing the producers' revenues for the different market designs. In particular, the influence of the risks felt by producers in energy-only markets and in capacity markets, in particular the risks related to weather uncertainties, will be assessed.

3.1 Impact of market design upon annual revenues distribution

For a given power supply mix and a given climatic scenario (influencing both the thermo-sensitive demand and renewables production – more details are provided in Appendix A), assets' revenues are evaluated by optimally dispatching the production with an hourly time resolution on a one-year time horizon. The optimal planning results in production curves for each fleet as well as in marginal costs of electricity for both countries, which, together with the market design, are used to evaluate the producers' revenues[5].

3.1.1 Revenues assessment methodology for energy-only markets

ENERGY-ONLY MARKET WITHOUT PRICE CAP

In energy-only markets without price cap, as well as in all other market designs studied below, it is assumed that the production is dispatched between the fleets according to the merit order: the fleets are taken online in the order of increasing variable production costs. (Technical constraints which may slightly modify a strictly economic dispatch have been taken into account).

The hourly electricity prices are obtained through the optimal dispatch marginal costs. These values correspond to the cost of producing one more MWh and are computed as the dual values of the supply-demand equilibrium constraint at each time step. Since the capacity of the interconnection linking France and Germany is limited, marginal costs do not necessarily converge across the whole

[5] When assuming perfectly competitive markets and perfect foresight, market prices are found to be given by the marginal production costs. Therefore, using a cost-based approach is entirely justified in the context of this study. However, this modeling approach does not simulate the actual trading of power, and therefore does not give an exact representation of the revenues derived from the actual market.

zone, therefore the **marginal cost of production may be different in France and in Germany**. According to the results of our power system simulations, marginal costs are the same in France and Germany during 85% of the time steps.

For a given climatic scenario, the annual remuneration consists of the product between the vector of hourly production (in MWh) and the vector of marginal costs (in € per MWh)[6]:

$$\mathrm{AnnualRemuneration} = \sum_{t} \mathrm{generatedEnergy_t} \cdot \mathrm{marginalCost_t}$$

To obtain producers' annual revenues, one has to subtract production costs from the annual remunerations:

$$\mathrm{AnnualRevenuesInEOM} = \sum_{t} \mathrm{generatedEnergy_t} \cdot (\mathrm{marginalCost_t} - \mathrm{variableCost})$$

The variableCost parameter represents the cost of production per MWh, including fuel costs and CO_2 emission costs. Note that this parameter is assumed not to depend on time.

This revenue is called the **infra-marginal rent**.

ENERGY-ONLY MARKET WITH A PRICE CAP

During peak hours, the power system might not be able to meet the power demand, even if emergency demand-response is used. In this case, the marginal cost of the system strongly increases and reaches the value of loss of load.

In a perfect market, setting a high value of loss of load is required to ensure peaking units obtain satisfactory revenues, and thereby that the mix remains stable in the long run. However a price cap[7] is often applied, as is the case today in the day-ahead market in the power exchange covering France and Germany.

To compute revenues in this market design, marginal costs are simply to be capped compared to the previous situation. Annual revenues are given by the following formula:

$$\mathrm{AnnualRevenuesInEOM} = \sum_{t} \mathrm{generatedEnergy_t} \cdot (\min(\mathrm{marginalCost_t}, \mathrm{priceCap}) - \mathrm{variableCost})$$

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[6] For the sake of readability, the climatic scenario index has been suppressed.

[7] Technical or political limit

VARIABILITY OF THE INFRA-MARGINAL RENT

In a perfect market, producers only receive revenues when the marginal cost of production is higher than their own variable cost. Since the value of loss of load is usually much higher than any variable production cost, some assets may rely on scarcity situations to be remunerated, as is shown in the following graphs.

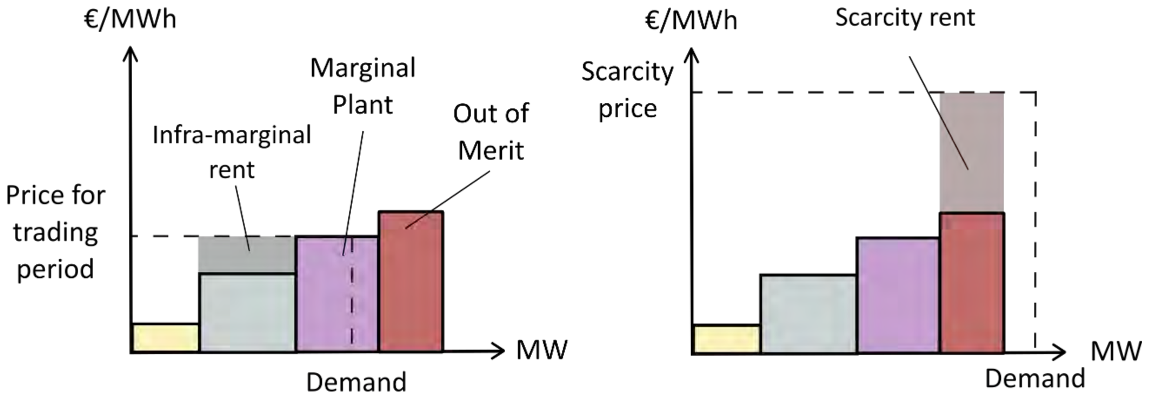

Figure 7: Merit order, marginal costs, infra-marginal and scarcity rent.

The two graphs on Figure 7 illustrate the basics of price formation in a perfect market. When the demand is lower than the available capacity (left), the price is set by the variable cost of the marginal power plant. The other generating assets (grey and yellow) receive an infra-marginal rent. When the demand is higher than the available capacity (right), the EOM price corresponds to a scarcity price, which is either given by the value of loss of load, or set to a technically- or politically-fixed limit. In this case, all generating assets receive a scarcity rent.

One may notice that the occurrence of scarcity prices is also dependent on actual bidding restrictions in the wholesale market and the public and political acceptance of price spikes which are not taken into account in the model.

This highlights the structural problem for peak producers and DSM: their only revenues originate from periods during which expensive demand-response is activated or when there is some demand curtailment. Base producers are relatively less impacted by this phenomenon than peak producers, since their revenues are generated over a greater set of hours, i.e. those when more expensive assets are producing. For instance, coal fleets perceive a revenue during at least 2000 hours, which is when the CCGT are brought online.

3.1.2 Simulation results

REVENUES OF ACTORS OF THE VIRTUAL REFERENCE MIX WITHOUT PRICE CAP

Assets' revenues are computed for the generating fleets composing the virtual reference mix. A large dispersion of annual revenues over the climatic scenarios can be witnessed: climatic scenarios with very cold periods and low wind have long periods of high prices, while the marginal costs remain low for other scenarios.

To illustrate these points, the revenues in an energy-only market without price cap are presented below, for thermal fleets in Germany and in France, for the 50 climatic yearly scenarios.

Figures are given in percentage of the annual fixed costs.

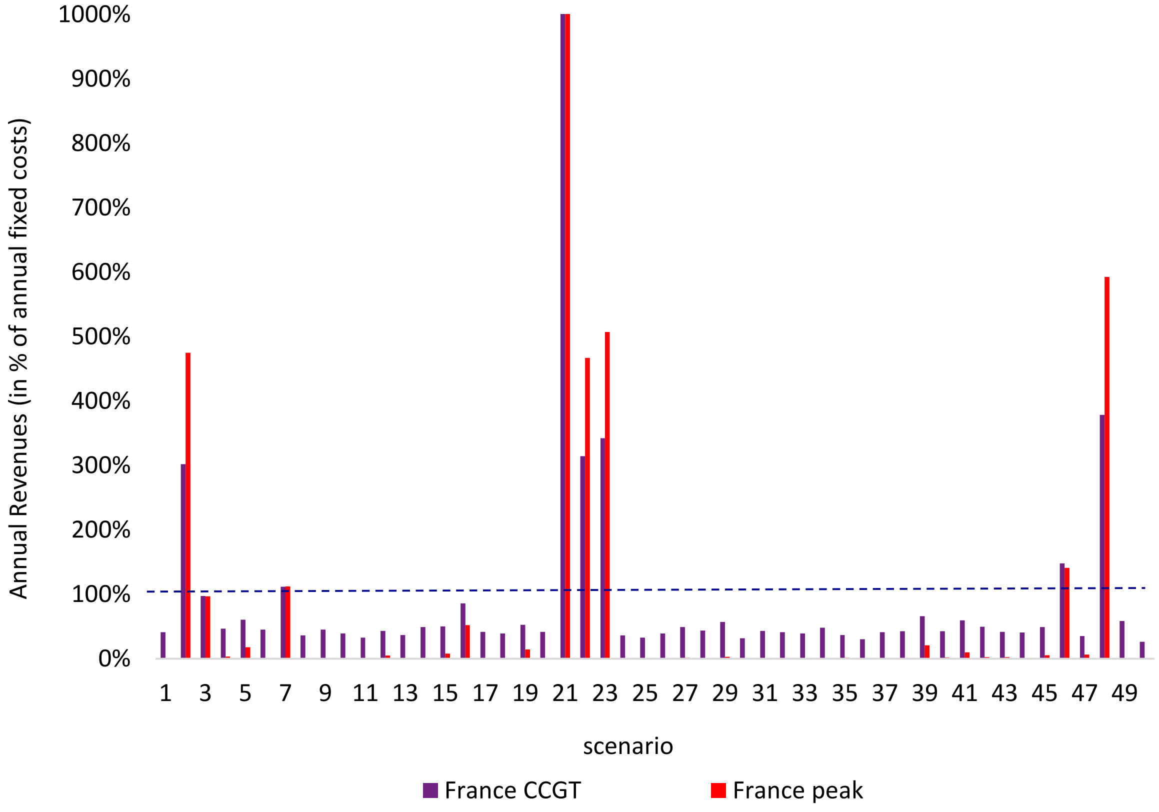

Figure 8: French assets' annual revenues without price cap

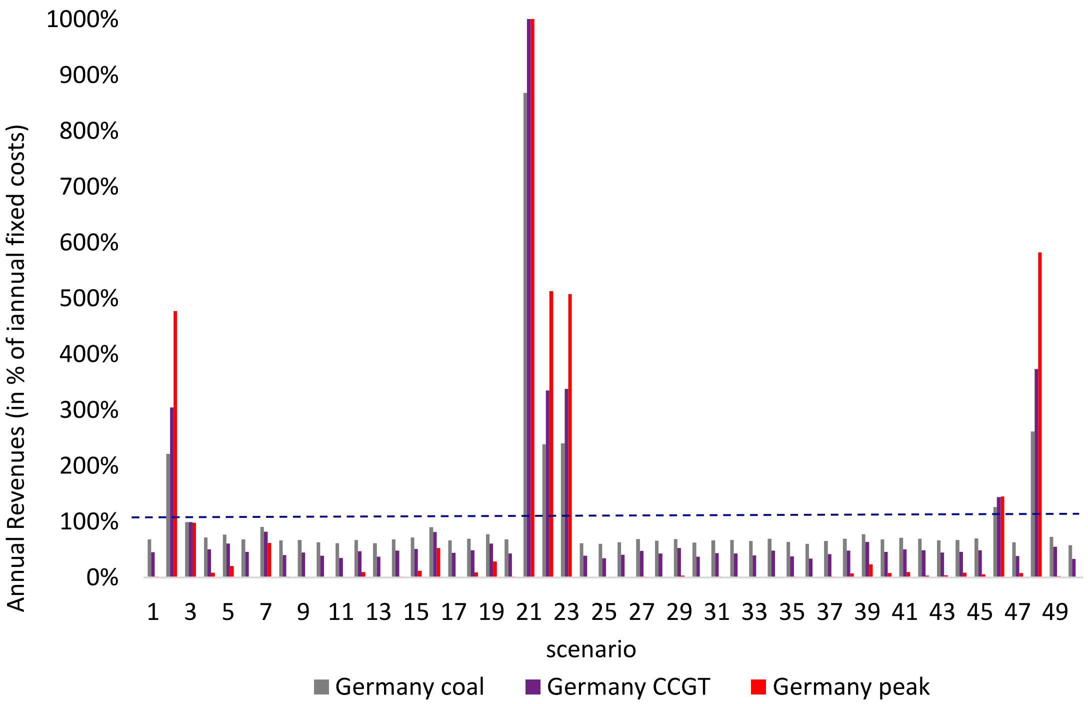

Figure 9: German assets' annual revenues without price cap

As shown in the previous graphs, peaking fleets' revenues can attain up to 25 times their annual fixed costs, but only for a limited number of scenarios in which temperatures are low and peaks of consumption coincide with a drop of wind and solar generation. For the majority of the scenarios, they do not get any revenue since marginal costs never exceed peaking unit variable costs. This phenomenon is also present for coal and CCGT fleets, but the revenues dispersion is lower, since they benefit from more regular revenues (when peaking units are called) even during warm scenarios.

Note that, in this virtual and riskless reference mix, since (i) the generation mixes are adapted (i.e. they are obtained according to the procedure presented in section 2.4) and (ii) the market is assumed to be perfect, the average revenues of each of the optimized thermal fleet exactly amounts to its annual fixed costs[8].

Revenues of actors of the virtual reference mix with price cap at 3k€/MWh

In an energy market with a lower price cap of 3k€/MWh, the dispersion of revenues is slightly lower, but since the level of revenues also decreases, the level of risk remains high. To illustrate this point, the annual revenues for French assets for the 50 climatic scenarios are presented below.

[8] To get further information on these microeconomics results, one can refer – for instance – to *Energie, Economie et politiques*, J-P. Hansen, J. Percebois.

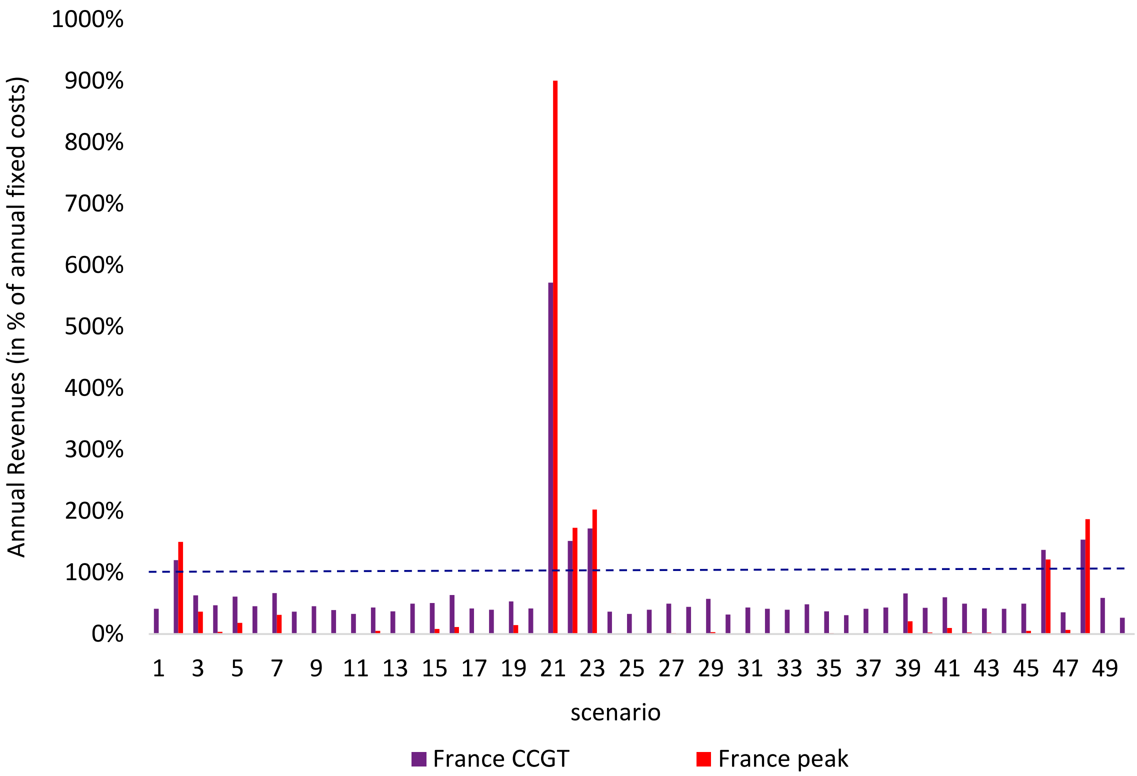

Figure 10: French assets' annual revenues with a 3k€/MWh price cap

The exact same effect can be observed on German assets' annual remunerations.

Note that in the case of a 3k€/MWh price cap, which is lower than the value of loss of load (15k€/MWh in the model), the average revenues of each thermal fleet does not allow them to cover their annual fixed costs. The difference of revenues between EOM with and without price cap finds its origin in times when the marginal cost is at least 3k€/MWh, that is only when there is some loss of load (since there are no units with variable costs higher than 3k€/MWh). During these time steps, revenues are limited by the price cap and therefore the annual revenues are insufficient to cover fixed costs. For instance, in this virtual reference mix, peak fleets only cover 40% of their fixed costs if price is capped at 3k€/MWh.

3.1.3 Revenues assessment for capacity reliability mechanism

In order to ensure security of supply, several countries have studied or implemented capacity reliability mechanisms of different forms. This study focuses on a capacity market in which, to meet a security of supply criterion, capacity providers are remunerated. In particular, the capacity price is not set a priori, but is the result of the market clearing. The methodology used to compute capacity prices can be found in section 4.1.3.

Revenues' definition with a capacity reliability mechanism

When introducing a capacity mechanism, capacity providers receive a remuneration which depends on the market price of capacity. Capacity providers therefore earn revenues from the energy market and from the CRM.

The annual revenues for a given producer is then given by:

$$\mathrm{AnnualRevenues} = \mathrm{AnnualRevenuesInEOM} + \mathrm{Capacity} \cdot \mathrm{capacityPrice}$$

It should be noted that the remuneration obtained in a capacity reliability mechanism (CRM) is independent of the climatic scenario. Indeed, each producer is remunerated for the capacity that he could deliver during peak hours[9]. The remuneration is therefore independent of the actual production of the asset. If their capacities are needed to ensure security of supply, all capacity providers are thereby granted a remuneration even in unfavorable climatic conditions (leading to no energy market revenues). This mechanism therefore reduces the investment risks as can be read from the following graph.

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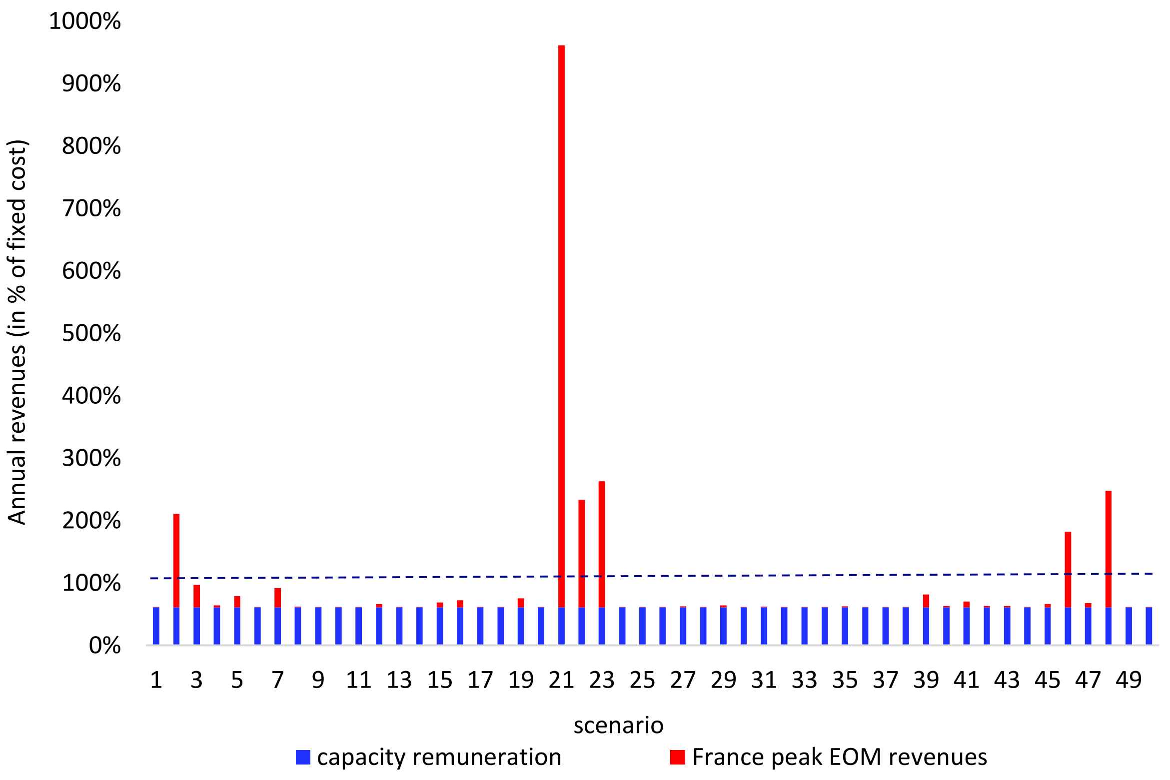

Figure 11: French peak fleets annual remunerations with a price cap of 3k€/MWh and a capacity reliability mechanism

[9] For instance, the average available capacity for peak fleets is 90% of their installed capacities.

In the previous graph, an arbitrary capacity price has been chosen to highlight the effect of a CRM remuneration on capacity providers' revenues structure. The methodology used to compute capacity prices is explained in section 4.1.3.

3.2 Investment risk assessment over asset lifetime

3.2.1 Methodology

As exhibited in section 3.1, annual revenues are highly dependent on the climatic conditions. From an investor point of view, it is the revenues over the whole lifetime of an asset that matters. As one does not know in advance the climatic conditions for the next 25 years, only a distribution of these revenues can be given. The methodology to generate these distributions of revenues over the asset lifetime is described below.

Revenues distribution over assets' lifetime

As shown in 3.1, annual revenues are concentrated in specific yearly climatic scenarios in which temperatures are low and peaks of consumption coincide with a drop of wind and solar generation. The two main factors that will therefore impact lifetime revenues are first the frequency of occurrence of this type of years and secondly the point in time when this type of years take place. Indeed, a high revenue in year one matters more than a high revenue in the last year of the operational lifetime of the asset [10].

In order to take these particularities into account, the assessment of lifetime revenues of the asset is based on a computation of its net present value. For a given order of climatic scenarios, one scenario being picked for each year in the lifetime of the asset, the lifetime revenues are then:

$$\text{lifetimeRevenues} = \sum_{\substack{\text{t in} \\ \text{lifetime}}} \frac{1}{(1+\text{r})^{\text{t}}} \text{annualRevenues}_t$$

An actualization rate of $r = 7.25\%$ is used throughout this study.

To assess a distribution of these revenues, we compute this value for 10000 orders of T years where T is the scheduled lifetime of the asset. This is done by randomly picking T climatic scenarios from the previously introduced set of 50 yearly climatic scenarios. Successive years are assumed to be independent: 50^T different possible sequences can be generated for an asset of lifetime T. The computation of lifetime revenues is then done for each one of the 10000 draws, which gives us a distribution of revenues.

Risk Premium

From an investor's point of view, the attractiveness of an investment is usually determined by comparing the expected revenues to the fixed costs. However investors commonly show a certain

[10] This phenomenon is generally called *preference for the present.*

degree of risk aversion. This is a rational approach which is due to the fact that in reality investors do not have perfect foresight. To take risk aversion into account, the value assigned to a potential investment is given by the expected revenues from which a risk premium is subtracted.

$$\text{investmentValue} = \text{E}[\text{lifetimeRevenue}] - \alpha \cdot \text{riskPremium}$$

The α parameter weighs the relative importance given to risk by investors.

The risk premium is often assumed to depend on the distribution of the expected revenues. If revenues are dispersed, the risk premium will be high and the value attributed to the investment will be lowered. The risk premium is defined as follows:

$$\text{riskPremium} = \frac{\text{semiVariance}(\text{lifetimeRevenue})}{2 \cdot \text{E}[\text{lifetimeRevenue}]}$$

Usually, for a symmetric distribution, the risk premium is computed using the variance instead of the semi-variance[11]. From an investor's standpoint, the risk consists in getting a revenue that is less than the fixed cost: it is therefore only the left part of the curve that matters, which is why the semi-variance is preferred to the variance in the case of non-symmetric distributions.

Note that the risk premium is homogeneous to a revenue. In the following, it is therefore expressed in % of the total fixed costs of the investment.

This framework is derived from the utility theory and risk aversion formulation originally exposed by von Neumann and Morgenstern, in their seminal book: Theory of Games and Economic Behavior, Princeton University Press, 1953. The above formula corresponds to further developments by Arrow (Essays in the Theory of Risk Bearing, North-Holland Amsterdam, 1971). The following paper provides some insight into the experimental and empirical issues: Holt and Laury, Risk aversion and Incentive Effects, American Economic Review, 2002.

3.2.2 Results analyses

As seen in part 3.1, the variability of the EOM-derived annual revenues' distribution over the 50 annual scenarios are higher in the case without price cap. Indeed since the market price can take higher values during scarcity periods, revenues obtained for difficult climatic scenarios are higher, which induces a greater dispersion of revenues. The same results are obtained for lifetime revenues, as is illustrated below in the following curves which present the distributions of lifetime revenues in EOM without price cap for coal fleet, and in EOM without price cap, EOM with price cap at 3k€/MWh and in the case of a CRM for peak fleets.

Looking at revenues dispersion in Figure 12, it is clear that coal fleet revenues are much more stable than peak fleet revenues (and DSM). Indeed, even though revenues expectations without price cap is exactly 100% of the fixed costs for both assets, peak fleets' revenues may vary by over 300% of their

[11] In this case semi-variance and variance are equal.

fixed costs depending on the climatic scenarios, since annual revenues of peak fleets can vary from 0 to 30 times their annual fixed costs. Coal fleet's revenue, on the other hand, have a global dispersion of about 120% of their fixed costs since the variation of their annual revenues is lower: even for difficult scenarios, annual revenues cover around 60% of their annual fixed costs. Overall results show that, in general, base fleets' risks are smaller than peak fleets' one.

These results stay true with a price cap, even if the revenues and risks are lower.

Finally, a CRM decreases significantly the revenue dispersion. Indeed, the CRM replaces an uncertain revenue from the EOM, depending on the climatic conditions, by a stable revenue. Another illustration of this phenomenon can be seen in the following table (Table 7) providing risk premiums for French fleets in the different market designs: energy market with and without price cap, with or without a CRM in France or Germany.

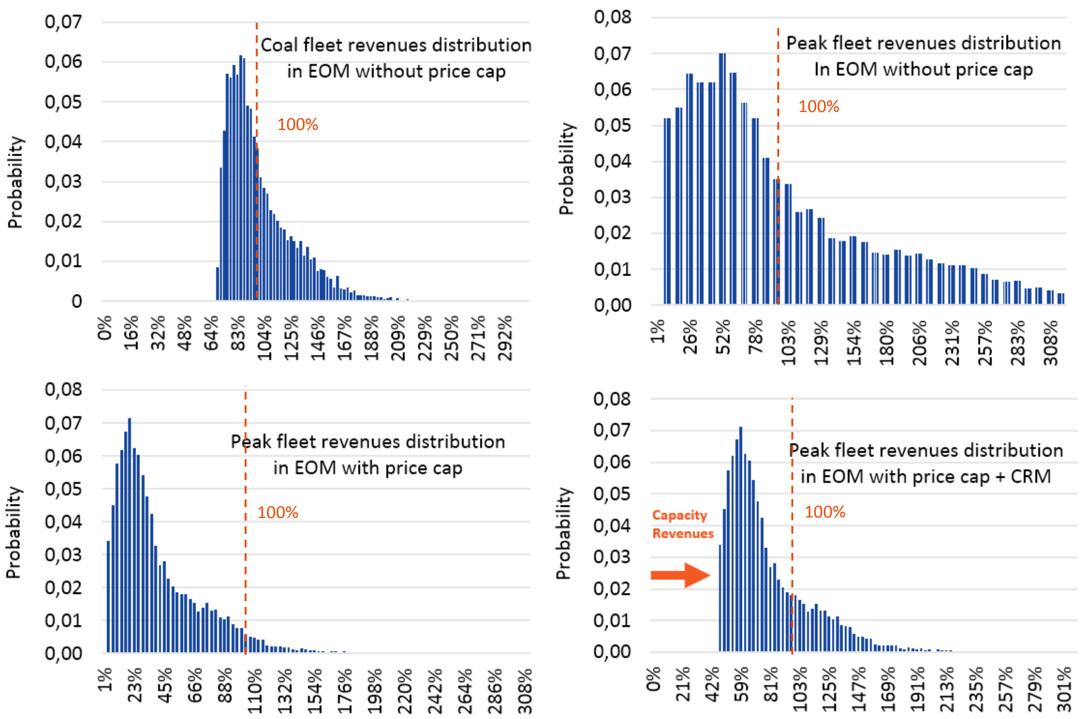

Figure 12: Impact of market design and technology type and lifetime revenues

Risk premiums (in % of lifetime fixed costs)		
	France CCGT fleet	**France peak fleet**
EOM without price cap	22.1%	50.7%
Energy market without price cap + CRM in France	12.6%	30.5%
Energy market without price cap + CRM in France and Germany	4.7%	14.0%
EOM with price cap at 3k€/MWh	5.5%	14.3%
Energy market with price cap at 3k€/MWh + CRM in France	2.9%	9.5%
Energy market with price cap at 3k€/MWh + CRM in France and Germany	0.9%	4.2%

Table 7: Impact of the market design on risk premium

As seen in Figure 12, the variability of revenues in an energy market without price cap is significant. The risk premiums are therefore very high. With a price cap, the variability is reduced, so the risk premium is lowered. With a CRM, the risk premiums decrease in both cases since the risk is lowered and more bearable.

Note that in this approach, risks related to long-term variations of the demand, variable costs and mix structure, such as a higher than planned rate of penetration of renewables, are not taken into account in the computation of the dispersion of revenues in the energy market nor in the computation of the capacity price[12].

[12] Capacity pricing methodology is given in section 4.1.3.

4 Investments and security of supply: the impacts of market designs

As seen in the previous section, market design has a high impact on risk levels pertaining to the lifetime revenues of assets. Since investors usually have to take into account risk to assess the economic feasibility of an investment, a market design generating a high level of risk for actors might lead to a global trend of underinvestment. Since the revenues of the different fleets are not impacted in the same way, risk is likely to modify the structure of the generation mix in the long run. This section aims at quantifying these structural changes.

4.1 Methodology

In order to compare the considered market designs, an iterative process allowing the conventional thermal fleets to adapt their installed capacities has been implemented. Starting from the virtual reference mix, the revenues of each actor, which depend on the market design, are computed for the 50 climatic scenarios. Depending on the assets' estimated revenues over their lifetime, the installed capacity is increased or decreased. After a number of iterations, the process leads to a new generation mix where every asset is at the financial equilibrium.

In this process, investors are assumed to be risk averse, meaning that in order to be at the financial balance, the total revenues need not only to cover the costs but also an additional risk premium related to the dispersion of the revenues. The value of an investment is therefore lowered by the risks on its revenues. For the same average revenue and investment cost, a risky investment might then be unprofitable while a non-risky investment will be profitable.

This process allows to take into account the volatility of the investments' performances due to climatic variability. Risks related to the long-term evolution of the demand, to national political decisions regarding the mix structure, to primary energy import prices, and to CO_2 costs, which impact both capacity and energy market prices, have not been considered in this study. Note that these additional risks would reinforce the risk dimension and thus the underinvestment trend in all cases.

In this part, for both types of energy markets, the following market designs were considered:

- **EOM** in both France and Germany - A coordinated Franco-German energy-only market (EOM) with a shared price cap,
- **Energy market + CRM** in France and **EOM** in Germany - The French capacity market is modelled according to the objective of the French capacity obligation: ensuring a LOLE of 3 hours (on average over the 50 climatic scenarios). Germany's market remains an energy-only market, both markets have the same price cap,
- **Energy market + coordinated CRM** in France and in Germany – In this case, system adequacy calculations are made in common in order to deliver the level of security of supply reached with the virtual reference mix. Both energy markets share the same price cap.

Note that only hard coal, gas and peak fleets were considered in the re-adaptation of the mix.

4.1.1 Risk criteria for investment evolution

The rules used to adjust the capacity of coal, CCGT and peak fleets are given below:

- **If**:
$$\mathrm{E[lifetimeRevenues]} > \mathrm{fixedCosts} + 2.5 \cdot \mathrm{riskPremium}$$
Then, the asset is considered as profitable and the installed capacity is increased.

- **If**:
$$\mathrm{fixedCosts} + 2 \cdot \mathrm{riskPremium} > \mathrm{E[lifetimeRevenues]}$$
Then, the asset is considered non-profitable and its installed capacity is decreased.

- Between these two limits, the asset is considered to be at financial equilibrium and its capacity remains unchanged. Its revenues are sufficient to cover the fixed cost of the investor while taking into account the risk.

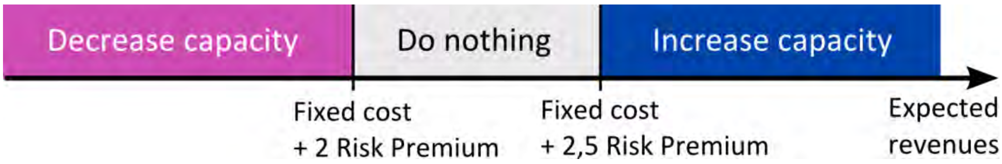

Figure 13: Capacity adjustment mechanism

Risk premium multiplicative coefficients (2 and 2.5) have been chosen to correspond to a moderately risk averse actor. A particularly risk averse actor may be modelled through larger coefficients while an actor less sensitive to risk may use lower coefficients. One may refer to *Holt and Laury, Risk aversion and Incentive Effects, American Economic Review, 2002*, for additional insight into these choices. Note that considering a more (respectively less) risk averse behavior of the actors will increase (decrease) the difference of risks between base and peak fleets, but the main tendencies in the evolution of mixes presented below will remain the same.

The capacity step by which fleets are increased or decreased is chosen so that the algorithm presented in the next section converges satisfactorily.

4.1.2 Simulation process for an energy-only market

Depending on the chosen market design, individual calculations of investors and the decision to increase, to keep or to decrease their installed capacity accumulate to a macro-economic result: a new generation mix. The following iterative process is used to adapt the generation according to the risk felt by investors. The algorithm presented below is valid for energy-only market designs with or without price cap.

1. Start from the virtual reference mix (see section 2.5)
2. Simulate the power system management over the 50 climatic scenarios
3. Compute actualized revenues' distribution using simulations' outputs (in particular production by fleet and the marginal costs of electricity)
4. Assess risk premiums and investors' decisions.
5. Update the mix in consequence, by increasing the capacity of profitable fleets and decreasing capacity of non-profitable fleets using previously described rules.
6. When every asset is at its financial balance, the process ends. Else, go to step 2.

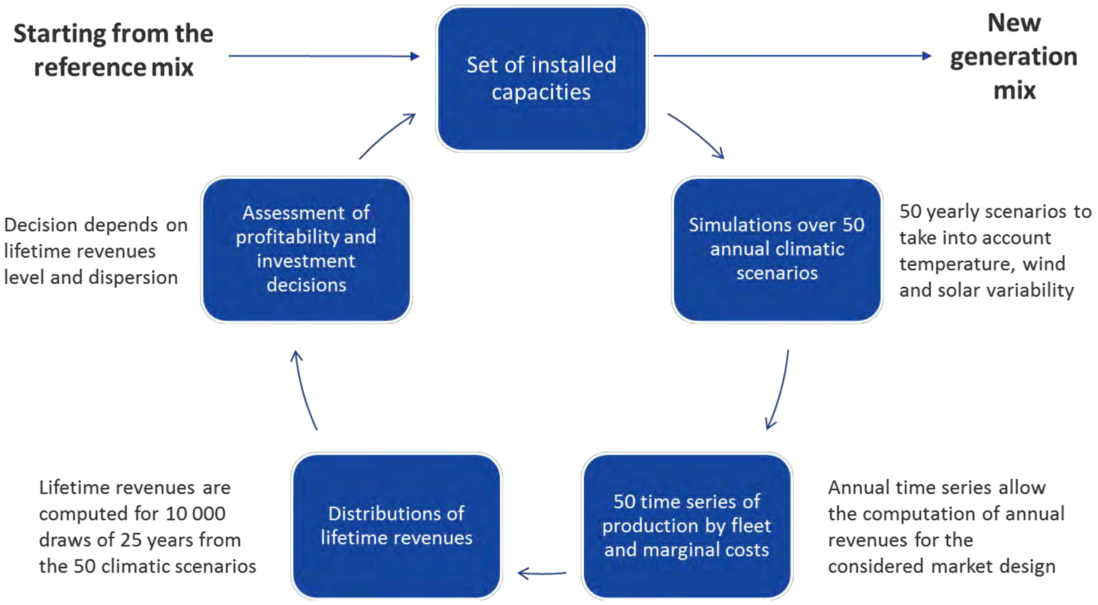

Figure 14: Generation mix adjustment with regard to investors' behavior

The result of this approach is a re-adapted generation mix, depending on the market design, where every asset is at its financial equilibrium.

4.1.3 Simulation process with a capacity reliability mechanism

The previously described process has been adapted to handle capacity mechanisms.

The capacity price is computed independently for France and Germany, for given criteria on the level of security of supply. In the case of the French capacity mechanism, as defined by the French authorities, the capacity price is set to ensure the average loss of load duration over the climatic scenarios is no more than 3 hours. In the case of coordinated capacity mechanisms, a target of minimal installed capacity, defined conjointly for France and Germany, is chosen instead[13].

In each case, the capacity price is common for all fleets within the country and is the minimum incentive to ensure the security of supply target is met.

Since an iterative process is used to adjust the mix, the capacity price evolves at each step of the process following the rules described below:

- If the security of supply is not sufficient, the price is set to the minimal level that would induce an increase of at least one asset's installed capacity.
- If the security of supply is more than required, the price is set to the minimal level that would induce a decrease of at least one asset's installed capacity.

The complete algorithm aiming at adapting the generation mix in the case a capacity mechanism is implemented is given below:

1. Start from the virtual reference mix (see section 2.5) and a capacity price of 0
2. Simulate the power system management over the 50 climatic scenarios
3. Compute actualized revenues' distributions using simulations' outputs (in particular production by fleet and marginal costs of electricity)
4. Assess risk premiums and investor decisions with the current capacity price.
5. If necessary, update the capacity price according to the targets so that capacity evolves in the right direction. Assess risk premiums and investor decisions.
6. Update the mix in consequence, by increasing the capacity of profitable fleets and decreasing capacity of non-profitable fleets using previously described rules.
7. If every asset is at its financial balance, the process ends. Else, go to step 2.

This methodology allows to reach a new generation mix where every asset participates to the CRM: offer of capacity is equal to the demand of capacity defined by the security of supply target (which is therefore met). Additionally, each asset is at its financial equilibrium: its remuneration in the energy market and in the CRM is just enough to cover its fixed costs and the risk premium.

4.2 A CRM in France to ensure security of supply

The simulation results demonstrate that the security of supply is greatly improved by the implementation of a CRM in France. Indeed, compared to a situation of a pure EOM, the CRM in France ensures structurally that loss of load will not go above 3 hours in average.

In a situation of an energy market with price cap at 3k€/MWh, the price of the French capacity market converges at 33600€/MW, which is sufficient to maintain enough capacity to ensure less than 3 hours of curtailment in France. In France, the average annual loss of load, measured in GWh, is reduced by a factor 4. Across the whole France-Germany zone, the reduction factor is 2.5.

---

[13] This capacity target is based on the capacity in both countries in the virtual and risk-free generation mix.

	EOM with price cap at 3k€/MWh	Energy market with price cap at 3k€/MWh + CRM in France
Loss of load volume in France (GWh)	46	11
Loss of load volume in Germany (GWh)	9	10

Table 8: Loss of load volumes in an energy market with price cap at 3k€/MWh, with or without CRM in France

The re-adapted generation mixes obtained in this case are presented below.

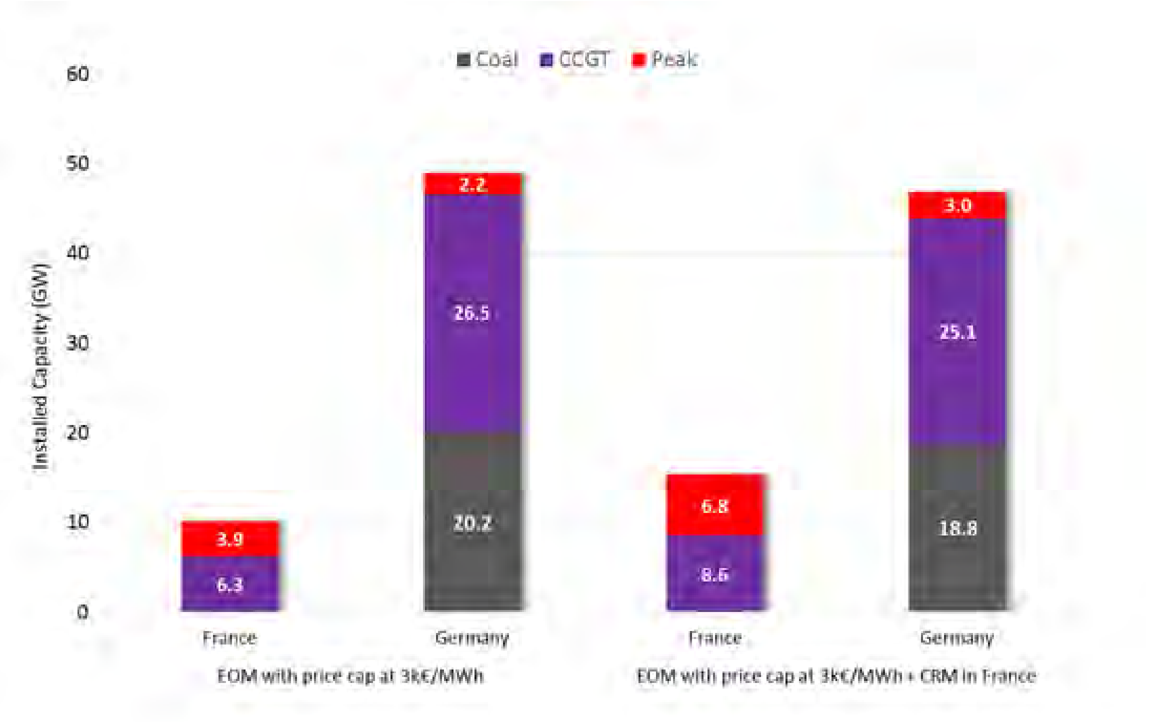

Figure 15: Coal, CGGT and Peak capacities for an energy market with price cap at 3k€/MWh, with or without a CRM in France

From this graph, one can see that the CRM in France has the following effects:

- **The total capacity increases to ensure security:** the global capacity increases (+3GW). The CRM ensures more stable revenues which decrease risks for investors.
- **The structure of the mix is changed because of the reduced risk:** New investments primarily concern peak capacity (+3.5 GW) and CCGT (+1GW). Coal capacity decreases by 1.5GW. As explained in Section 3.2, reducing investment risks with stable revenues first benefits peak capacities (and DSM, in an equivalent manner). Their capacity increases and comes closer to the reference risk-free mix.

- **Since capacity decreases in Germany, a new equilibrium has to be found to reach the required level of security of supply in France:** Investments are made in France (+5GW in France, versus -2GW in Germany in an energy market with price cap). Investments in France benefit from more stable revenues, while German capacity suffers from a high risk and insufficient remuneration as explained in section 3.1 due to the 3k€/MWh price cap. It should however be stressed that this phenomenon is likely be reduced if the interconnection capacity between France and Germany does not increase to the optimized level of 6,9GW[14].

Because of the improvement of the mix structure and of the reduction of loss of load duration, introducing CRM in France in addition to an energy market with price cap leads to a reduction of 370M€ of the annual total costs.

Costs difference w.r.t energy market with price cap at 3k€/MWh	Impact of a CRM in France
Operational Costs (M€/year)	70
Loss of load costs (M€/year)	-510
Fixed annual costs (M€/year)	70
Total Cost (M€/year)	**-370**

Table 9: Impact in terms of costs of a CRM in France in an energy market with price cap

Even if the global capacity increases by 3GW, the additional CAPEX costs remain limited as the generation mix is closer to the virtual reference mix (with more peak units and less coal). Operational costs slightly increase, as more energy is generated by peak units and CCGT (with higher variable costs). On the other hand, costs related to loss of load highly decrease.

When considering an energy market without price cap, one may notice that the capacity transfer from France to Germany is lower (less than 1GW). Moreover, the security of supply is in this case also improved by the introduction of a CRM in France and the global welfare is not decreased.

Note that in Germany, a strategic reserve is being implemented, complementing the electricity market. It is designed to exist on a stand-alone basis, separated from the electricity market. It is important to note that the strategic reserve therefore does not solve the risk issues for units in the energy market, as energy market revenues remain equally volatile and uncertain.

4.3 A coordinated CRM to improve the security of supply and secure investments in both France and Germany

As presented in section 4.1.3, the market design studied in this section assumes a CRM in both France and Germany with targets driven from the reference case (optimal supply mix without risk constraints).

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[14] In the study, the interconnection capacity between France and Germany has been optimized. Resulting capacity is 6,9 GW, a level which is higher than its current capacity.

In the case of an energy market with price cap at 3k€/MWh, the capacity market price converges at around 44300€/MW in Germany and 45300€/MW in France. It is not surprising that prices are very similar in French and German capacity markets even if they are not directly linked. Indeed, since France and Germany are very well interconnected (almost 7GW of interconnection), revenues per unit of installed capacity in the energy market are almost the same for thermal fleets in both countries. Therefore, the capacity prices needed to ensure that fleets stay/develop in the market are similar for the two countries. With this level of capacity price, around 80% of the fixed costs of peak power plants is covered by the capacity remuneration[15].

The obtained generation mixes with an energy market with price cap at 3k€/MWh are presented below.

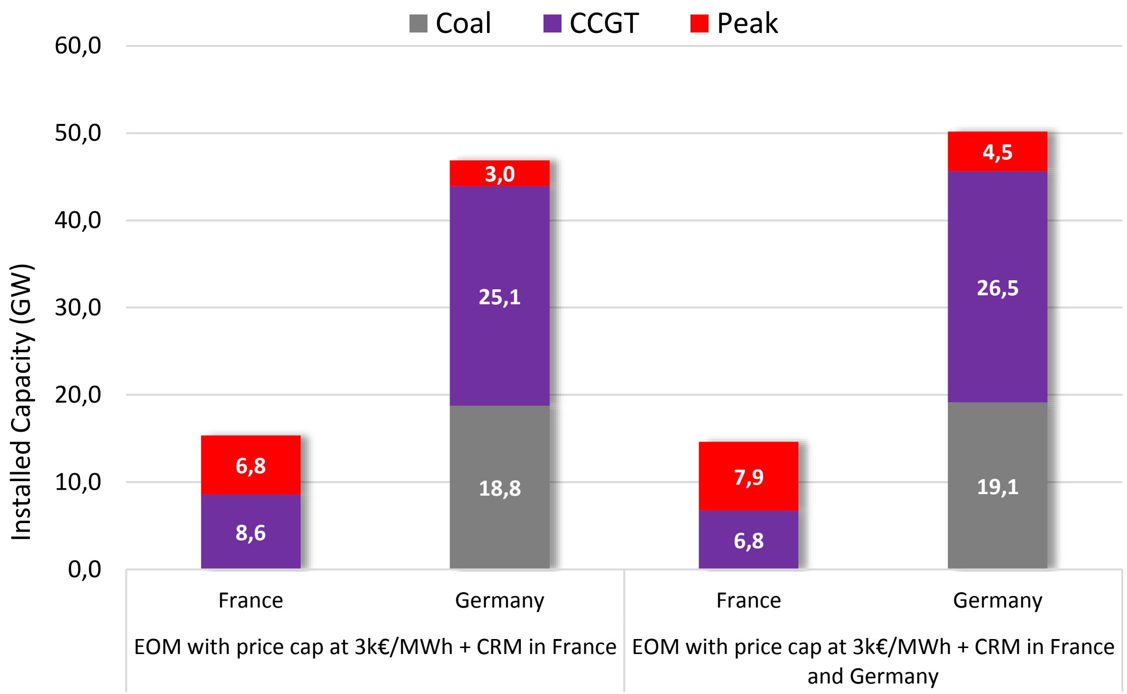
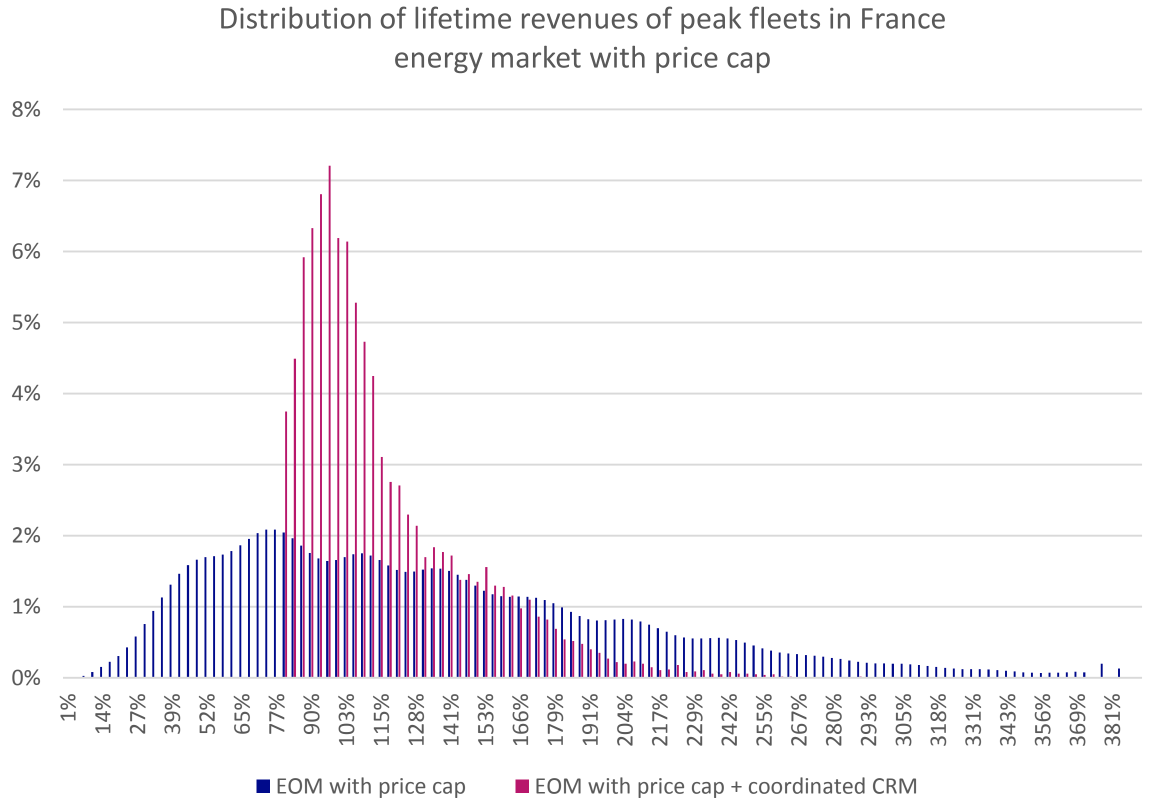


Figure 16: Generation mix for the market designs in an energy market with price cap

Note that in this case, the implementation of a coordinated CRM prevents a transfer of capacity from one country to another. Indeed, when a CRM is implemented in both countries, the risk levels for producers in both France and Germany are similar and cross-border effects on capacity investments are therefore limited.

[15] Indeed, since it is available at 90% of the time during peak hours, it will earn 40500€/MW for its capacity, which is roughly 80% of the fixed costs of 53k€/MW.

Moreover, with a coordinated CRM, the resulting supply mix is closer to the risk-free virtual reference mix[16]: revenues are more stable and the risk levels for producers are lowers, in particular for peak units as illustrated in the following lifetime revenue distribution curves.



Overall, due to the risk being reduced in France and Germany in a similar way, the global cost is lower for a coordinated CRM than for all the other studied cases (an EOM in France and Germany, or a CRM only in France).

Costs difference w.r.t energy market with price cap at 3k€/MWh	Energy market with price cap + CRM in France	Energy market with price cap + coordinated CRM in France and Germany
Operational Costs (M€/year)	70	< 5
Loss of load costs (M€/year)	- 510	- 700
Fixed annual costs (M€/year)	70	230
Total (M€/year)	**- 370**	**- 470**

Table 10: Difference of total costs with an energy market with price cap

[16] The difference in terms of annual costs is less than the numerical precision of the model.

Finally, a coordinated CRM allows to highly decrease the loss of load volume across the whole zone, as the notion of security of supply is inherent to this market design: as long as the target of capacity is chosen adequately, security of supply targets are met.

	EOM with price cap	Energy market with price cap + coordinated CRM
Loss of load volume in Germany (GWh)	9	1.9
Loss of load volume in France (GWh)	46	6.7

Table 11: Loss of load volumes in an energy market without price cap and with a coordinated CRM

In the case of an energy market without price cap, results of an implementation of a coordinated CRM are fairly similar. The obtained capacity market price is however lower since revenues in the energy market are higher than in the case with a price cap. The price converges at 26100€/MW in Germany and 24500€/MW in France. As a consequence, peak unit revenues are more volatile (since more than half the remuneration still comes from the energy market).

The obtained generation mixes are presented below.

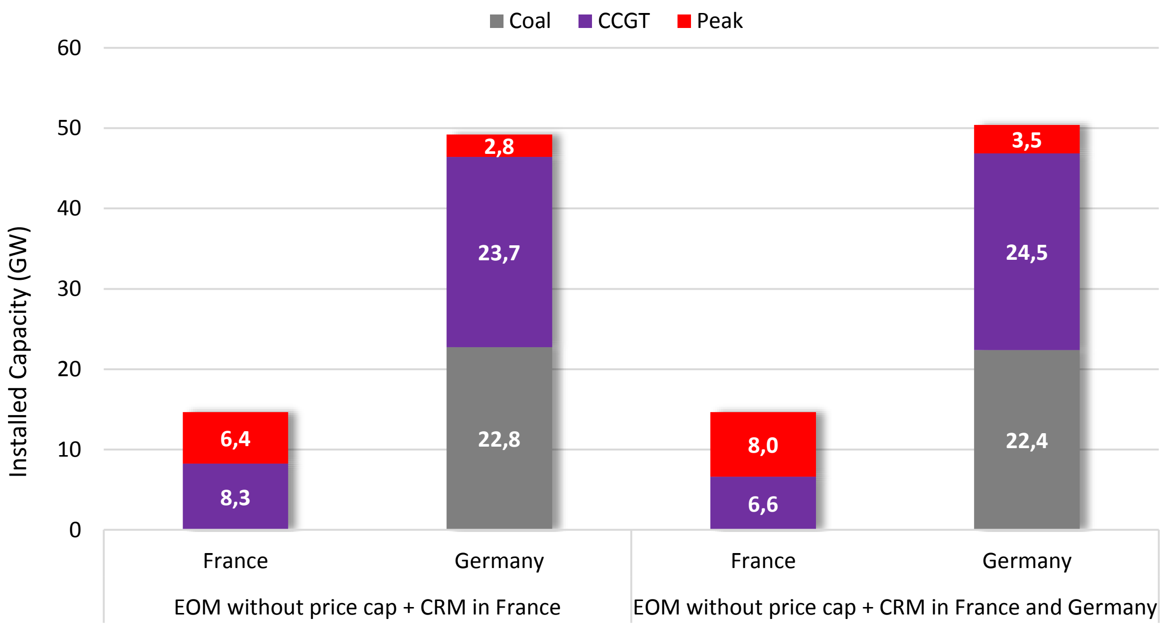
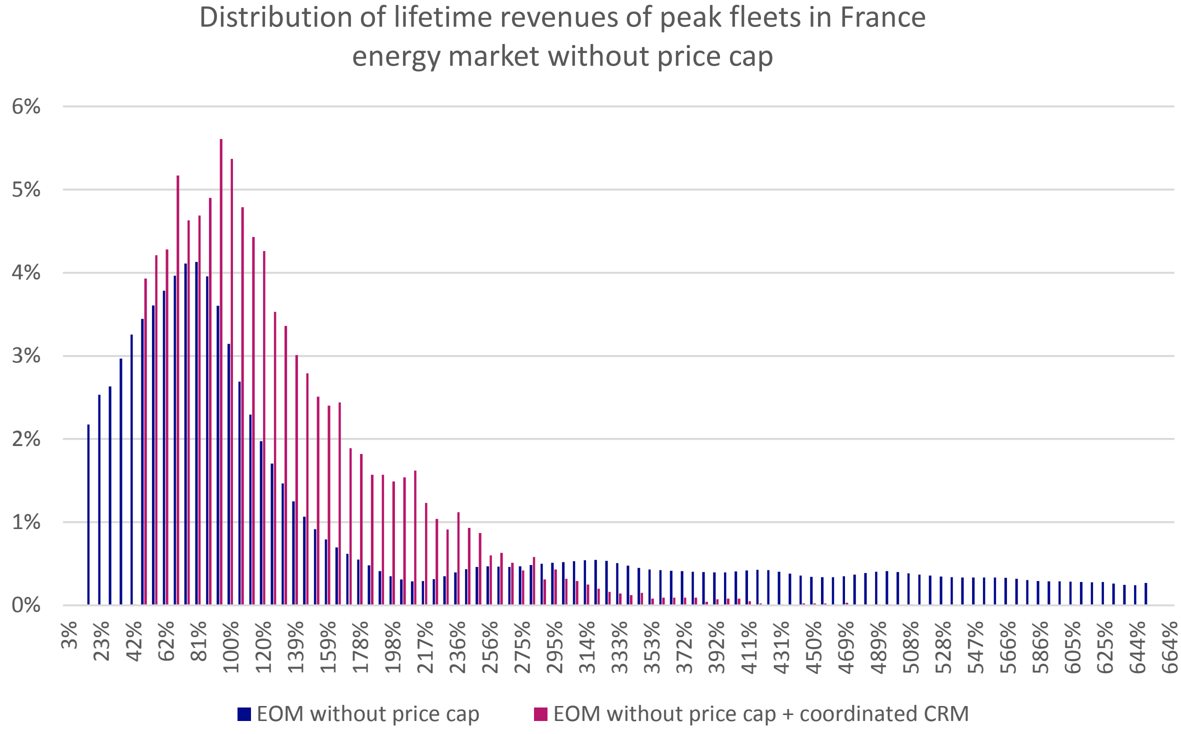


Figure 17: Generation mixes in an energy market without price cap with CRM and coordinated CRM

Note that in this case (energy market without price cap), the coordinated CRM also prevents the transfer of capacity from Germany to France. Indeed, as seen previously, this is due to the risk levels for production assets being lower and similar in France and Germany.

The obtained generation mix is therefore closer to the virtual risk-free mix due to the reduction of the risk. Lifetime revenues are indeed more stable, in particular for peak fleets, as can be seen in the following distribution curves.



The total annual costs are also reduced compared to a situation with no CRM, or with a CRM only in France, as one can see in the following table.

Costs difference w.r.t energy market without price cap	Energy market without price cap + CRM in France	Energy market without price cap + CRM in France and Germany
Operational Costs (M€/year)	-20	30
Loss of load costs (M€/year)	< 5	-70
Fixed annual costs (M€/year)	20	10
Total Cost (M€/year)	**< 5**	**-30**

Table 12: Difference of costs with the virtual reference mix in an energy market without price cap

One can note that the reduction of costs is mainly centered on the reduction of loss of load through an increase of capacity (and thus investment and operational costs). While the implementation of a coordinated CRM has a relatively modest impact on the annual costs of the power system, it allows a significant reduction of the loss of load volume across the whole zone, even with an energy market without price cap.

	EOM without price cap	Energy market without price cap + coordinated CRM
Loss of load volume in Germany (GWh)	3.5	1.9
Loss of load volume in France (GWh)	9.9	6.7

Table 13: Loss of load volumes in an energy market without price cap and with a coordinated CRM

5 Appendix A – Description of the Model and of Data Source

5.1 Description of the Model

5.1.1 Production Side

Section 2.4 contains the description of the assumptions related to the structure of the 2030 generation mixes in France and Germany. This section provides additional elements regarding the parameters characterizing each of the technologies entering these mixes.

Power plants have been clustered into so-called **fleets** according to the power plants' primary energy. As a result, the following fleets compose the generation mixes:

- non-renewable thermal fleets:
  - nuclear fleet,
  - lignite fleet,
  - coal fleet,
  - CCGT fleet,
  - peak fleet.
- intermittent renewable fleets:
  - wind fleet,
  - solar PV fleet,
  - renewable thermal fleet,
  - run-off-river hydro fleet,
  - hydro pondage fleet.
- hydro with storage fleets:
  - seasonal hydro storage fleet,
  - pumped hydro storage fleet.

NON-RENEWABLE THERMAL FLEETS

The non-renewable thermal fleets that enter the 2030 generation mixes are nuclear fleets (in France), lignite fleet (in Germany), coal fleet, CCGT fleet, peak fleets and other non-renewable thermal fleet.

Each thermal asset is characterized by:

- The installed capacity (in MW),
- The variable cost (in €/MWh), including both fuel and CO_2 emissions costs,
- The availability profile (in %) based on historical values.

For example, the France nuclear fleet average availability profile is presented below, along with some historical profiles.

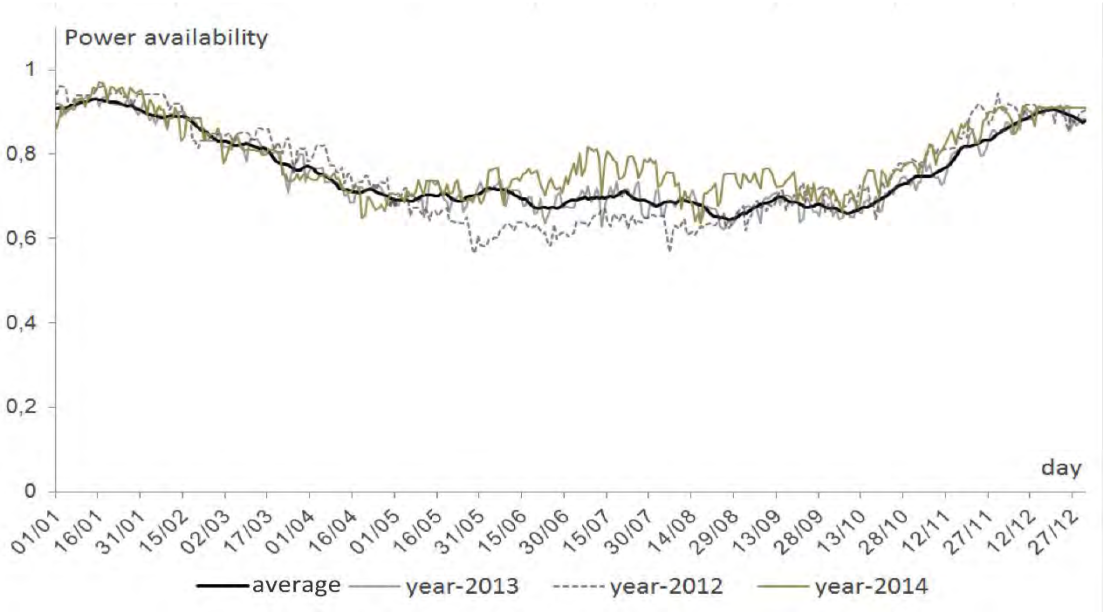


Figure 18: France nuclear fleet power availability average and historical profiles (data source: http://clients.rte-france.com/)

The previous figure clearly displays the seasonality of the French nuclear power availability. Indeed, to fulfill maintenance requirements while minimizing generation shortfalls risks, maintenance is mainly performed in summer, when less generation capacity is needed.

Parameters entering operational constraints such as minimum load (nuclear) and power gradients (coal, nuclear) constraints are also provided.

Additionally, since coal, CCGT and peak fleets capacities are optimized in our simulations (see section 2.4), these assets are also characterized by annual investment and fixed OPEX costs.

INTERMITTENT RENEWABLE ENERGY SOURCES

Intermittent renewable energy sources taken into account are wind fleet, solar PV fleet, renewable thermal fleet, run-off-river hydro fleet and hydro pondage fleet.

Since the production delivered by these assets is intrinsically intermittent, both their installed capacity and power generation profiles enter the model.

- Average profiles based on historical values are provided by RTE for hydro pondage, run-off-river and renewable thermal fleets,
- Generation profiles for wind and solar PV are generated based on 50 climatic scenarios, see Section 5.2.3.

HYDRO STORAGE TECHNOLOGIES

Two types of hydro storage facilities are taken into account in this study: a seasonal hydro storage fleet and a pumped hydro storage fleet.

By definition, pumped hydro storage facilities are assumed to control the amount of energy stored in their reservoirs. They are characterized by an installed capacity, a storage capacity and a storage efficiency of 80%.

Seasonal hydro storage facilities correspond to dams that are used to store energy from one season to another. They usually are equipped with large storage capacities, whose operations depend on water inflow. Seasonal hydro storage facilities are characterized by an installed capacity, a storage capacity, a minimum storage level and a water inflow profile, which are calibrated on historical data. The following figure shows the average France hydro seasonal storage level as well as historical profiles.

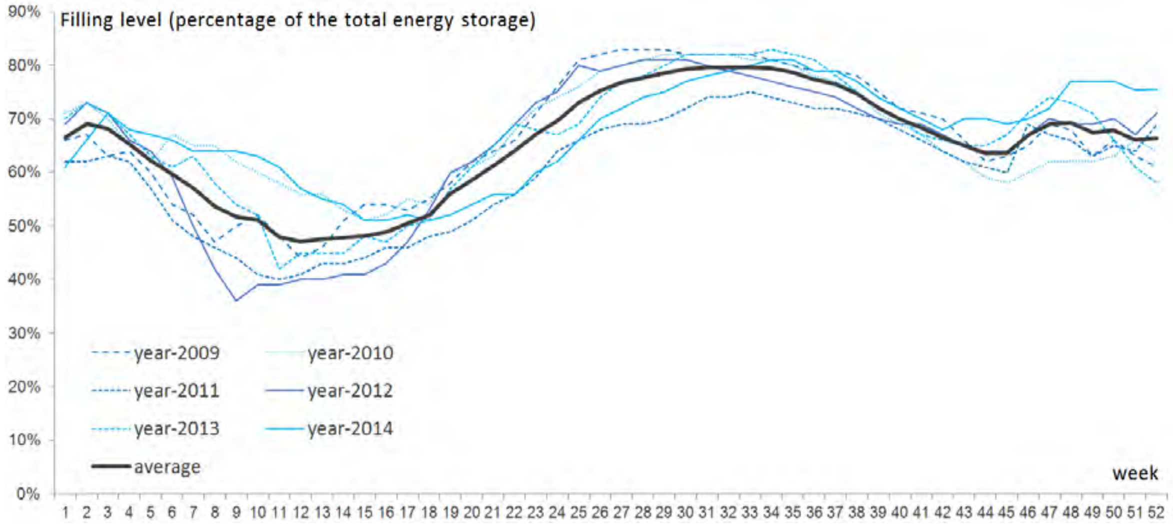


Figure 19: France hydro seasonal storage filling level average and historical profiles (data source: http://clients.rte-france.com/)

The following table provides the technical characteristics of the two types of hydro storage technologies considered in France and Germany.

Storage Capacities in 2030	Maximal Stock Volume (GWh)	Maximal Generating Power (MW)
France Hydro storage	3 700	9 300
France Pumped storage	160	4 300
German Pumped Storage	60	8 000

Table 14: Storage capacities in France and Germany

5.1.2 Demand Side

The overall demand has been divided into a thermo-sensitive part and a fixed part. The thermo-sensitive part corresponds to heating and air conditioning, whose profiles vary according to climatic conditions. All the other uses are aggregated into the fixed part of the demand except for the domestic hot water, whose significant contribution to the French demand called for a specific representation. Additional information regarding the construction of demand profiles is available in section 5.2.

The cumulative consumption in October 2030 for a particular climatic scenario is shown on the following figure for France:

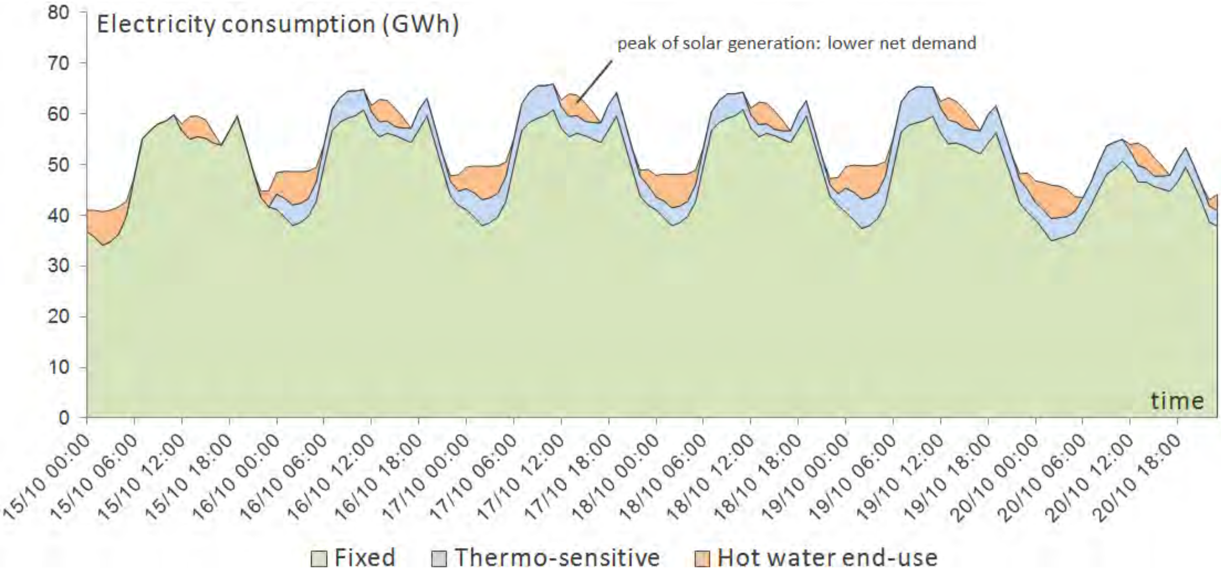


Figure 20: French cumulative consumptions in October 2030

5.1.3 Demand-side management capacities

Demand-side management is taken into account in the model. Two types of assets have been considered.

The first one represents distributed load shedding in the residential sector. It takes the form of an additional energy reserve with a limited power capacity. The energy reserve is supposed to be brought online for a maximum of 100 hours.

The second one represents the industrial demand-response program, and is only limited in power capacity for a cost of 400€ per MWh. The following table gives installed capacities in France and Germany in 2030.

	Demand-side management capacities (MW)	
	France	Germany
Distributed load shedding	7 000	2 500
Emergency load shedding (400€/MWh)	4 000	5 000

Table 15: Details on DSM installed capacities

5.1.4 Interconnection and exchanges with the rest of Europe

The interconnection between France and Germany is explicitly modeled. Its capacity is optimized during the construction of the energy mixes, see section 2.4 . The hourly power flow then results from the subsequent operations optimization.

Exchanges with the rest of Europe are modeled as import and export contracts. The import and export volumes are calibrated using a model based on considerations regarding the residual demand in both France and Germany.

5.2 Construction of the climatic scenarios

5.2.1 Climatic scenarios

The key parameters driving both the demand and intermittent power generation are related to climatic conditions. Due to the volatility of the latter, 50 climatic scenarios are constructed to handle the uncertainty pertaining to temperatures, and to wind and solar power availabilities. A climatic scenario consists of (i) hourly temperatures, (ii) hourly wind availability, and (iii) hourly solar radiation. A particular effort has been devoted to taking correlations between temperature, wind and solar irradiation into account.

Taking correlations into account may indeed be crucial. Indeed, whether or not residual demand peaks simultaneously in France and Germany may have a significant impact on optimal installed capacities, power management, and hence on investors' revenues and capacity prices.

First, the correlations between historical time series have been analyzed. For instance, the following graphs show that days that are both sunny and windy Germany are not frequent, and that windy days in Germany are neither very cold nor very warm in France. These empirical considerations prove to be useful to determine if a generated climatic scenario has to should better be rejected or not.

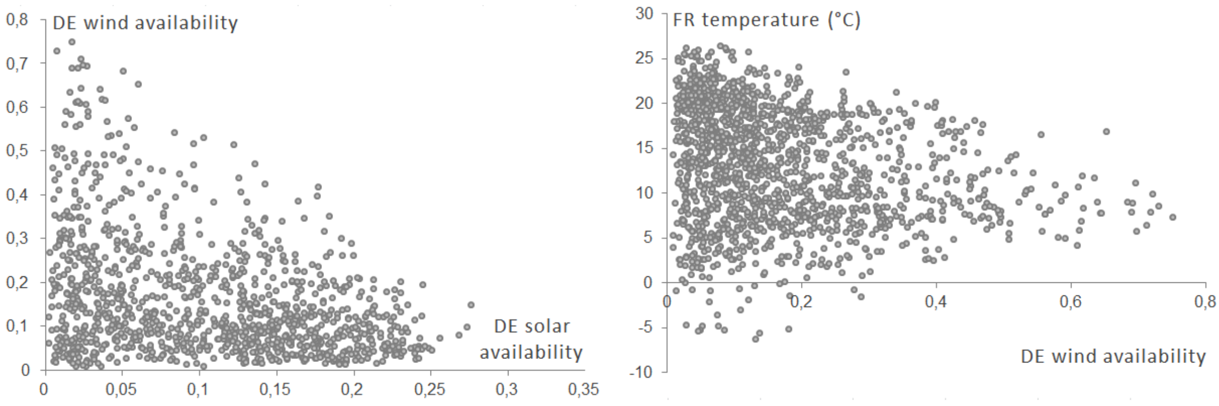


Figure 21: France temperature and Germany wind power availability and Germany wind and solar power availabilities correlations

Another important point when generating climatic scenarios, is to take into account the seasonality of temperatures, wind and solar time series. As shown in Figure 22, wind power availability profiles exhibits a short-term periodicity, which is not the case for solar profiles. Finally, mean solar and wind power plants' generating levels are related to seasons (see Figure 23).

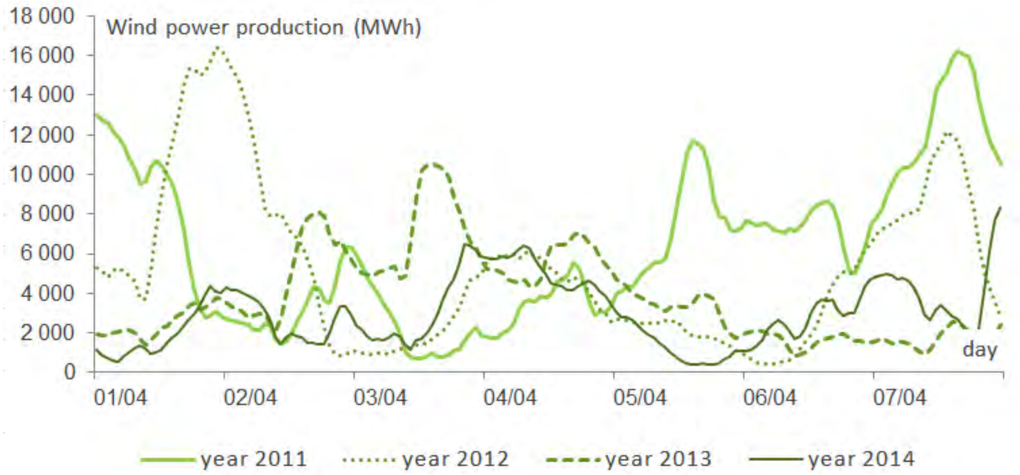


Figure 22: Wind power production in Germany during the first week of April for years 2011 to 2014

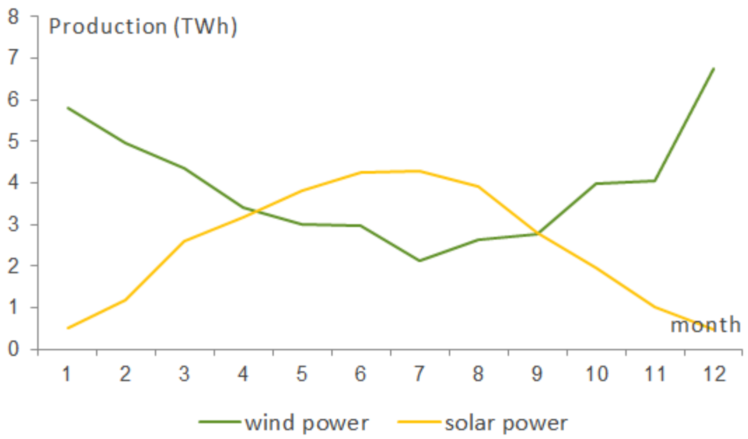


Figure 23: Germany wind and solar average monthly productions over 2012-2014

Finally, temperature also depends on seasons. Hourly temperature are generated using a statistical regression method over historical values. As a result, 50 scenarios of temperature have been obtained. These scenarios can be seen in the following figures.

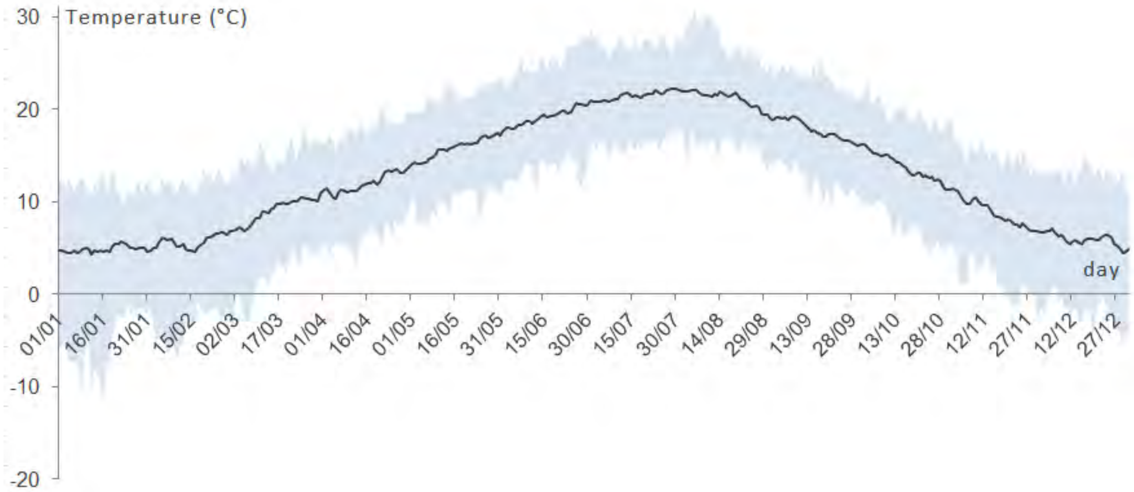


Figure 24: Overview of French year-2030 temperature forecasts

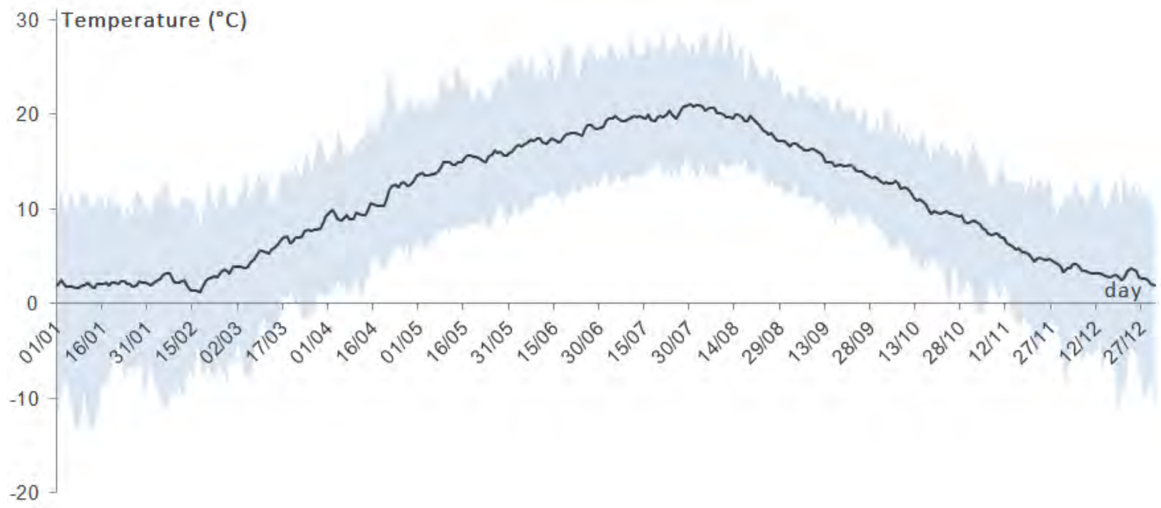


Figure 25: Overview of German year-2030 temperature forecasts

5.2.2 Demand Scenarios

As presented in 2.4, demand is divided in two parts for Germany (fixed non thermo-sensitive and thermo-sensitive parts) and in three parts for France (fixed non thermo-sensitive, thermo-sensitive and domestic hot water parts). The fixed non thermo-sensitive part of the load is generated by using forecasts that are based on historical values. The thermo-sensitive parts depend on the 50 previously generated climatic scenarios through the implementation of a thermal gradient method. For France, the hourly thermal gradient in winter is taken at -2040 MW per °C: a decrease of one degree results in an increase of the power demand by 2040 MW[17]. Air conditioning is also taken into account in France, with a gradient of 320MW per °C. In Germany, the average winter gradient is 460 MW per °C.

Finally, the French domestic hot water demand is distributed over the year by assuming the daily amount of hot water is produced when prices are at their lowest. The French and German 2030 daily demand are presented on Figure 26 to Figure 28. The colored area in figure 27 and figure 28 represents the area spanned by all 50 realizations and illustrates the scenarios' dispersion.

[17] Note that this gradient is lower than the current value of 2400MW. Main causes for this reduction are energy efficiency measures (including change of supply mix for domestic heating).

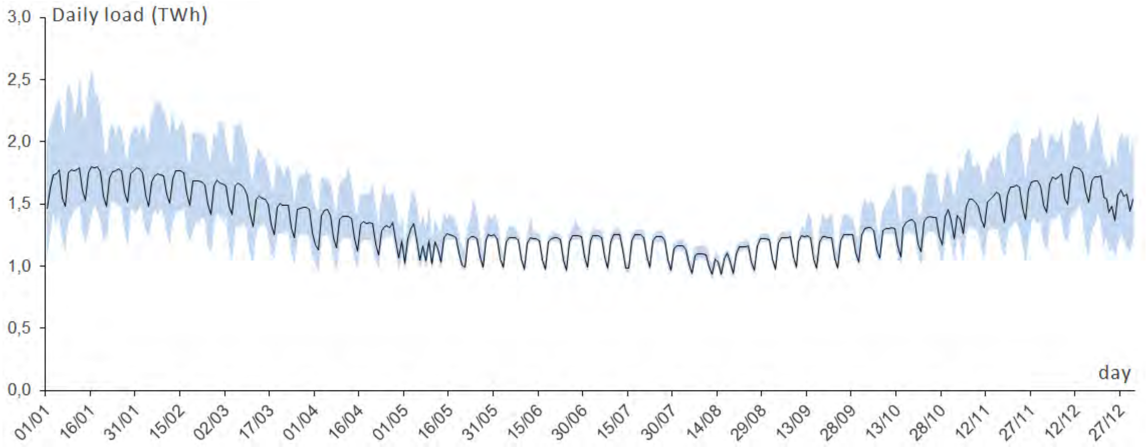


Figure 26: Overview of French 2030 daily load (blue area) and related average profile (black curve)

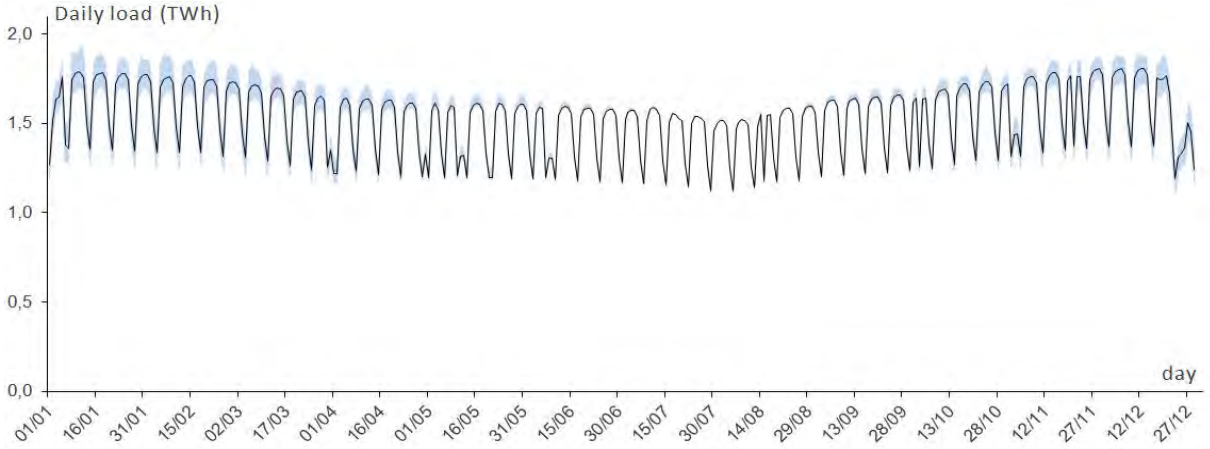


Figure 27: Overview of German year-2030 daily load (blue area) and related average profile (black curve)

As can be noticed, the demand scenarios comply with the main typical structures which have to be observed: seasonality, magnitude, holidays, thermo-sensitivity (Figure 26 and Figure 27) and the daily dispatch of the France hot water consumption (Figure 20).

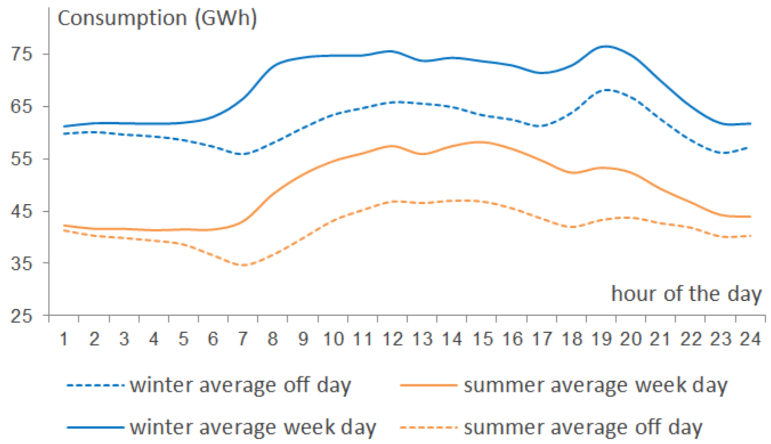


Figure 28: Average days of France consumption

5.2.3 Renewable Production

The construction of the renewables power scenarios is based on a monitored[18] crossover of the historical availabilities profiles and on a sample rejection mechanism based on correlation considerations (such as those which are described in Section 5.2.1). A sample of the generated scenarios are displayed in Figure 29, Figure 30 and Figure 31.

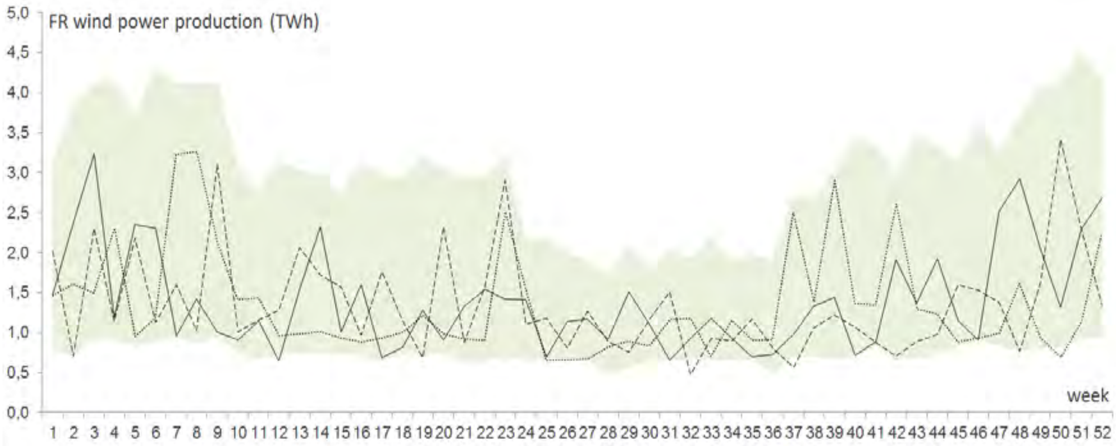


Figure 29: Overview of year-2030 wind power production in France

The 50 wind scenarios of wind power production in France span the colored area shown on Figure 30. In addition, three randomly picked curves are displayed to highlight the variability of wind production. The corresponding graph for Germany is shown in Figure 31.

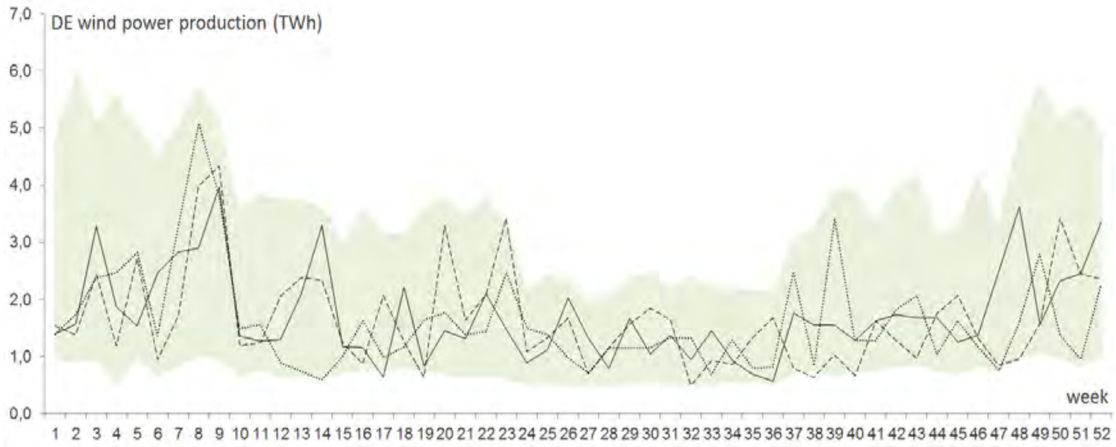


Figure 30: Overview of year-2030 wind power production in Germany

The areas spanned by solar winter and summer daily productions are represented in Figure 32 for France and Germany, along with their respective averages.

Thanks to the monitoring and rejection rules, the typical structures of renewable power production can be observed in the generated scenarios. Finally, it has successfully been checked that the

[18] Correlations and seasonality considerations which were made in section 5.2.1 are taken into account.

generated scenarios are compatible with the average frequency of windy days during winter and sunny during summer.

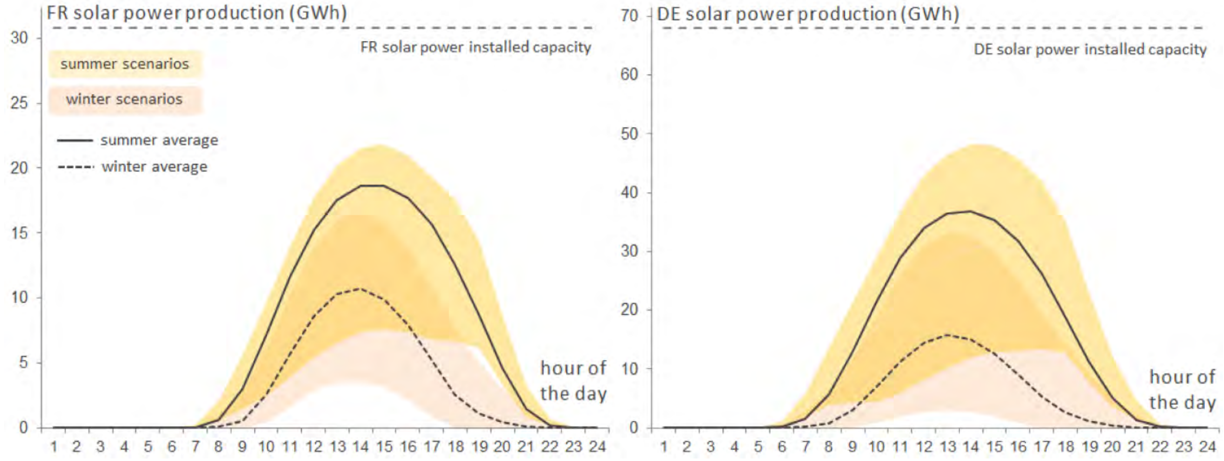


Figure 31: Overview of year-2030 solar power production in France and in Germany

6 Appendix B - France and Germany in 2030

The following graphs show the repartition of production during typical periods. Note that imports and exports with neighboring countries (other than France and Germany) do not appear in these graphs. When the demand curve (in black) is lower than the total production, it should be understood that power is being exported towards other countries and/or locally stored.

The different technologies are distinguished using the following color code:

- Nuclear
- Lignite
- Coal fleet
- CCGT fleet
- Peak fleet
- Other thermal
- Distributed load shedding
- Emergency load shedding
- Hydro RoR fleet
- Seasonal storage
- Pumped storage fleet
- Wind fleet
- Solar fleet
- Renewable thermal fleet
- Imports

6.1.1 Typical winter week: scenario 1 – January, 1st to January, 7th

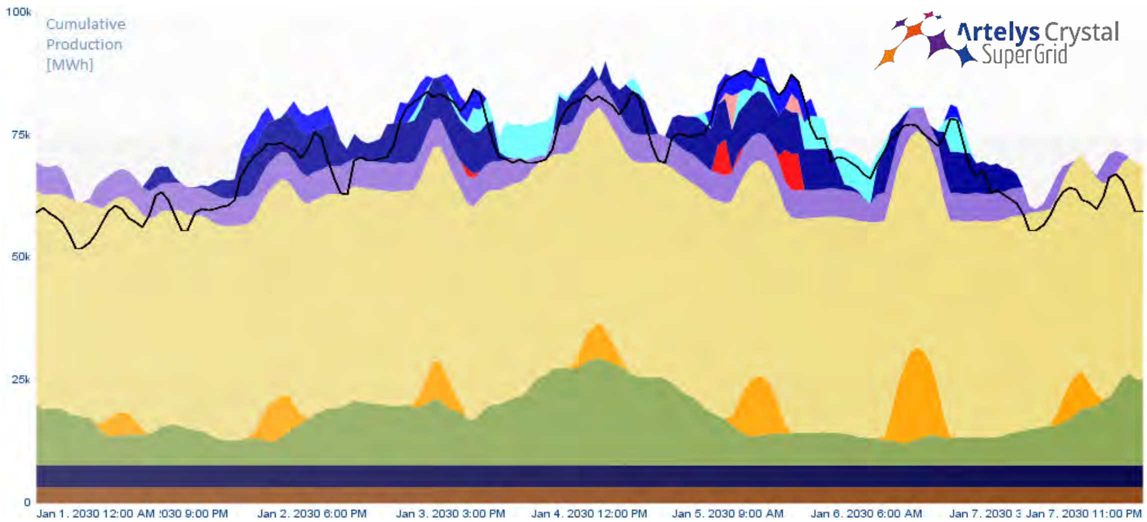


Figure 32: Cumulative production in France from January, 1st to January, 7th, for scenario 1

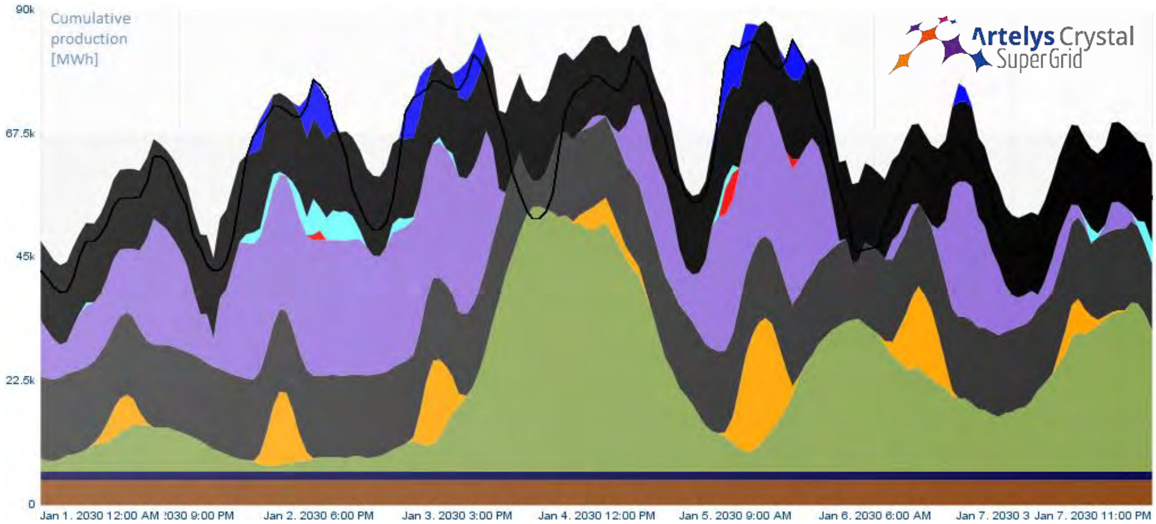


Figure 33: Cumulative production in Germany from January, 1st to January 7th, for scenario 1

6.1.2 Typical summer: Scenario 12 – June, 30th to July, 1st

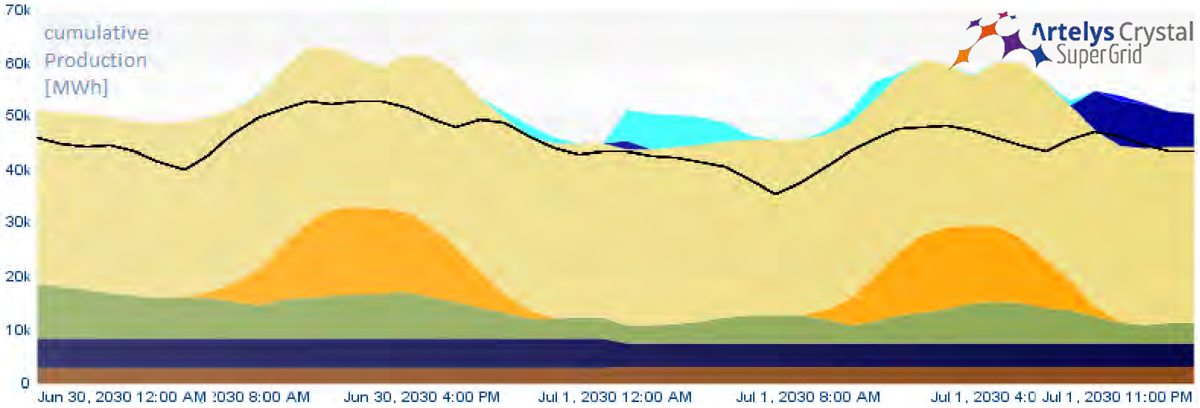


Figure 34: Cumulative production in France from June, 30th to July, 1st , for scenario 12

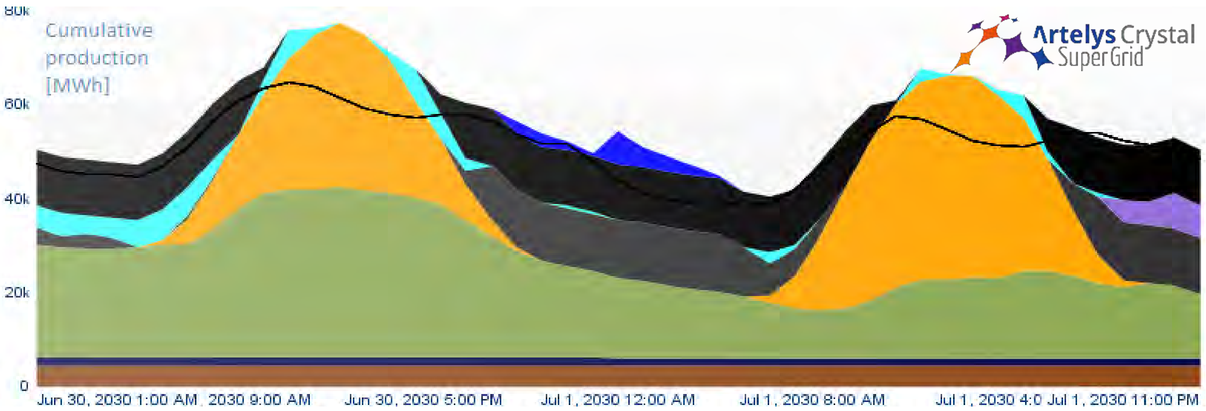


Figure 35: Cumulative production in Germany from June, 30th to July, 1st, for scenario 12

6.2 Production overview

This section gives an overview of the production dispatch in France and Germany over the 50 scenarios. The following charts provide an overview of the different technologies' average yearly production.

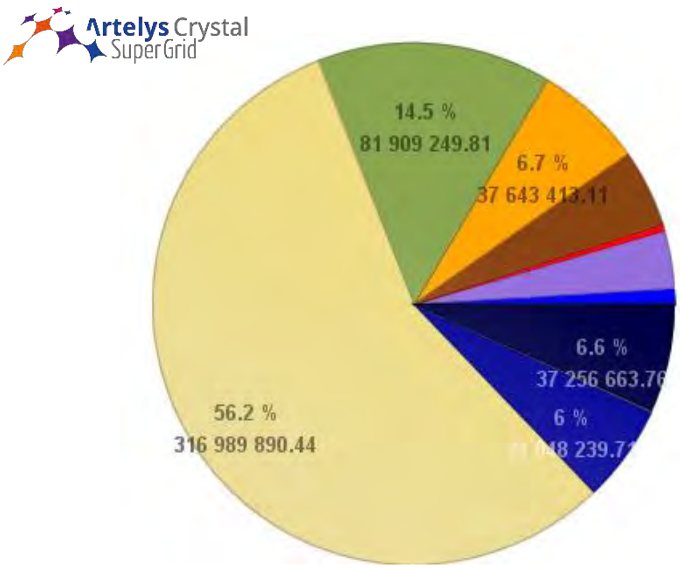


Figure 36: Production dispatch in France over 50 scenarios (in MWh)

	Average production dispatch in France	
Technology	Average production [TWh]	Contribution in the total production
Nuclear	317.0	56.2%
Coal	0.0	0.0%
Gas	20.1	3.6%
Peak fleet	2.6	0.5%
Other thermal	0.3	0.1%
Hydro seasonal storage	34.0	6.0%
Wind	81.9	14.5%
Solar	37.6	6.7%
Renewable thermal	26.9	4.8%
Hydro RoR	37.3	6.6%
Pumped storage	5.1	0.9%
Demand response	0.1	0.0%
Distributed load shedding	0.7	0.1%
Total	563.7	100%

Table 16: France average production dispatch over 50 scenarios

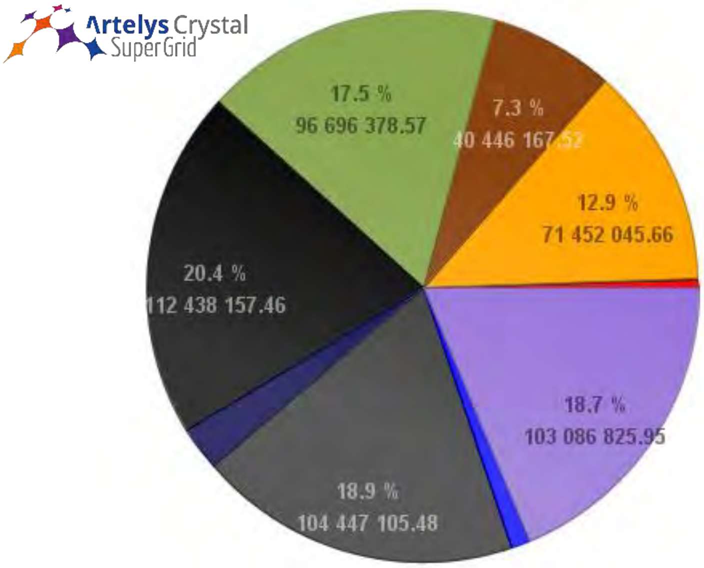


Figure 37: Production dispatch in Germany over 50 scenarios (in MWh)

	Average production dispatch in Germany	
Technology	**Average production [TWh]**	**Contribution in the total production**
Coal	104.4	18.9 %
Lignite	112.4	20.4 %
Gas	103.1	18.7 %
Peak fleet	2.5	0.5 %
Other thermal	0.4	0.1 %
Wind	96.7	17.5 %
Solar	71.5	12.9 %
Renewable thermal	40.4	7.3 %
Hydro RoR	14.3	2.6 %
Pumped storage	6.0	1.1 %
Demand response	0.1	0.0 %
Distributed load shedding	0.3	0.0 %
Total	552.1	100 %

Table 17: Germany average production dispatch over 50 scenarios

6.3 Interconnection utilisation

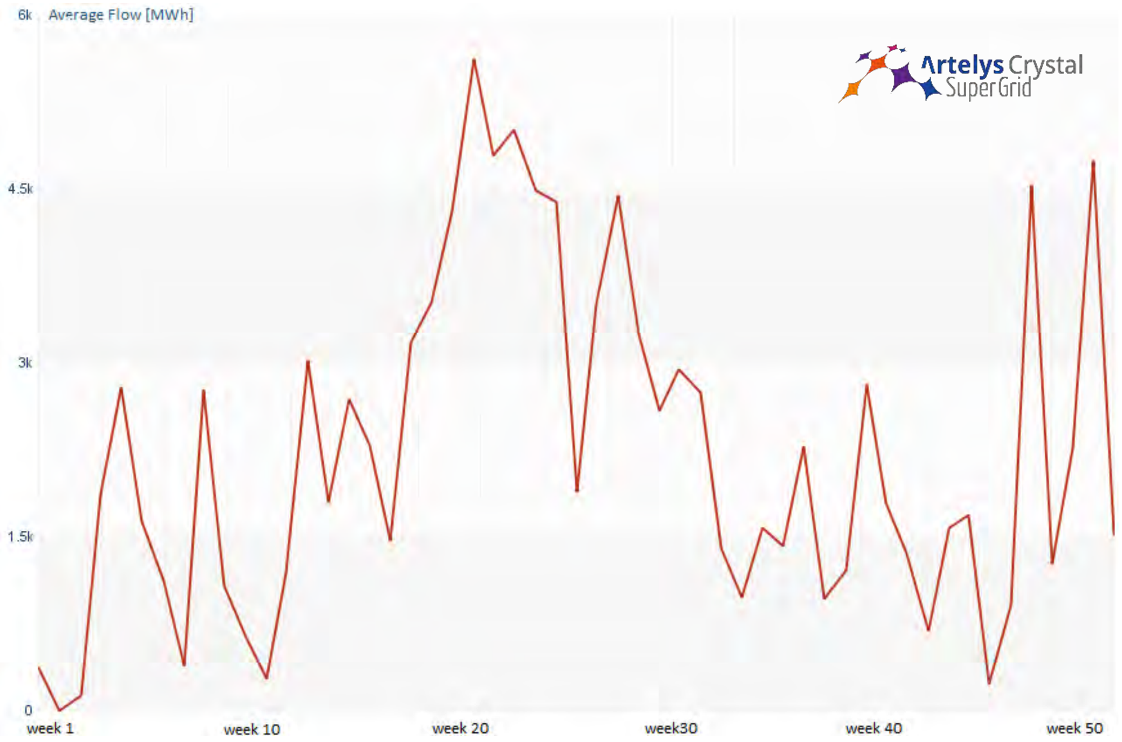


Figure 38: Weekly average flows from France to Germany in scenario 21

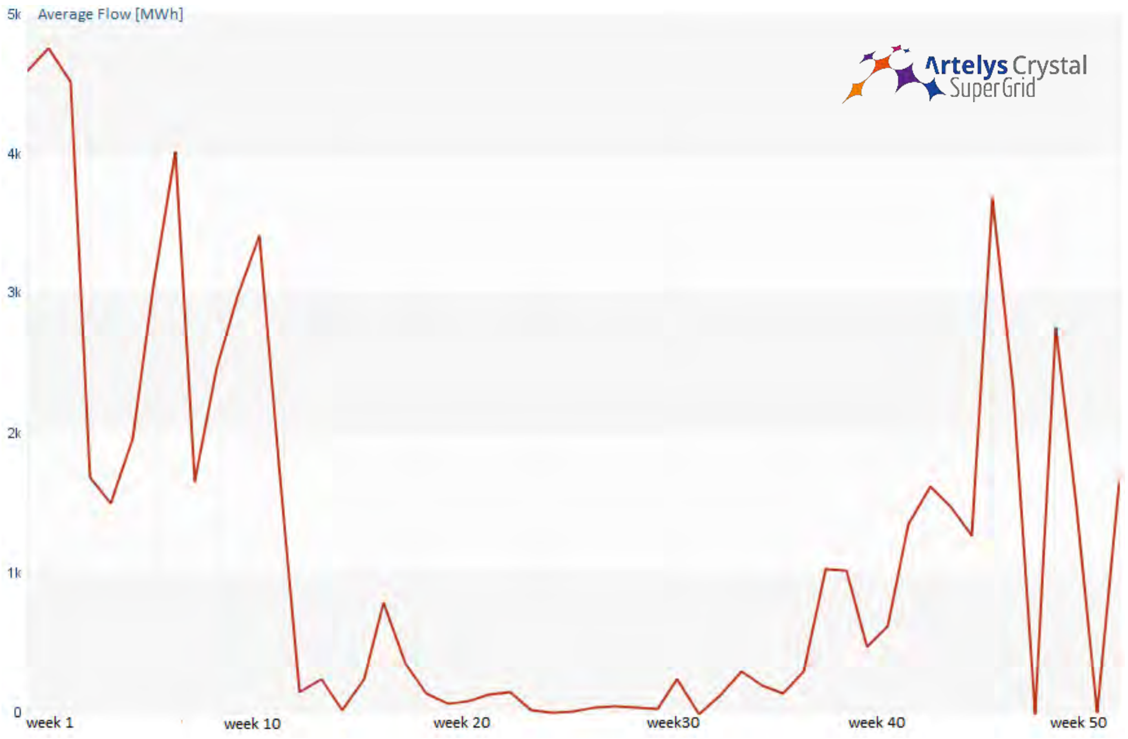


Figure 39: Weekly average flows from Germany to France in scenario 21

7 Appendix C - Market design and actors' revenues

This section provides graphics showing annual remuneration per fleet and per scenario, in EOM with and without price cap, for fleets of the virtual reference mix.

7.1 Annual remunerations

7.1.1 EOM without price cap

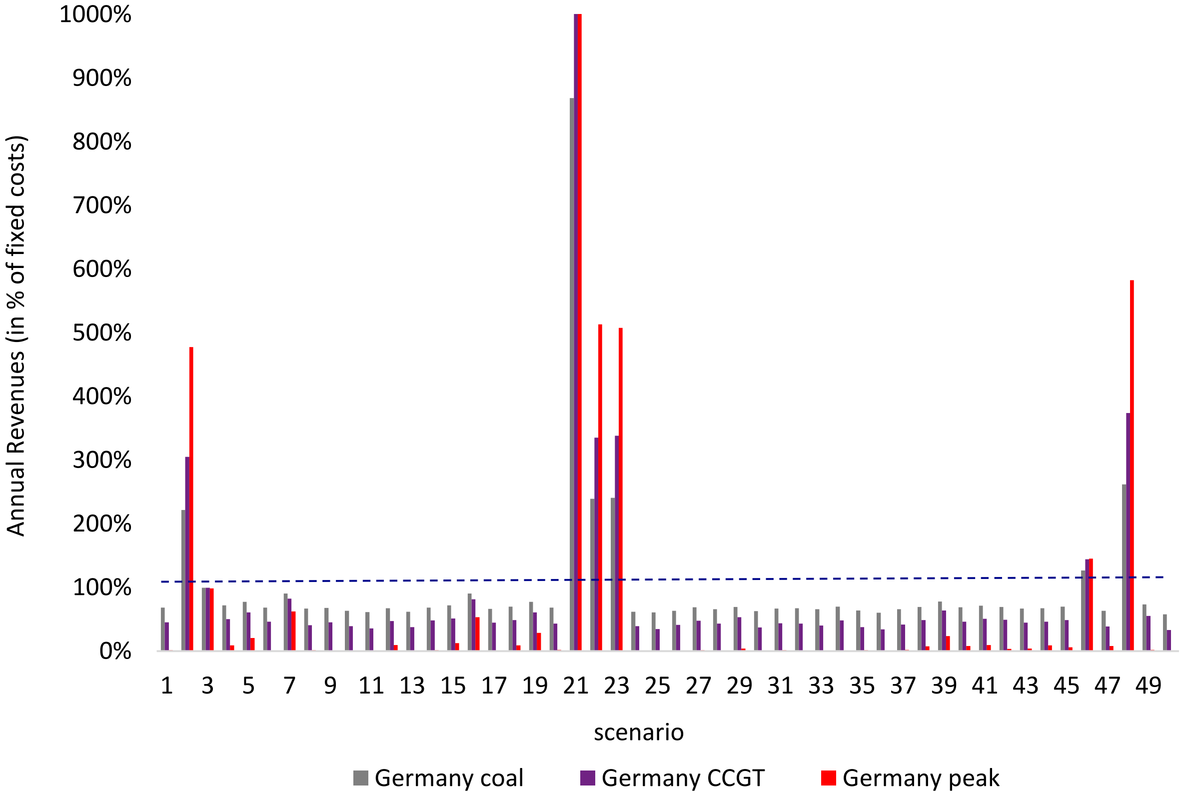


Figure 40: German assets' annual revenues without price cap

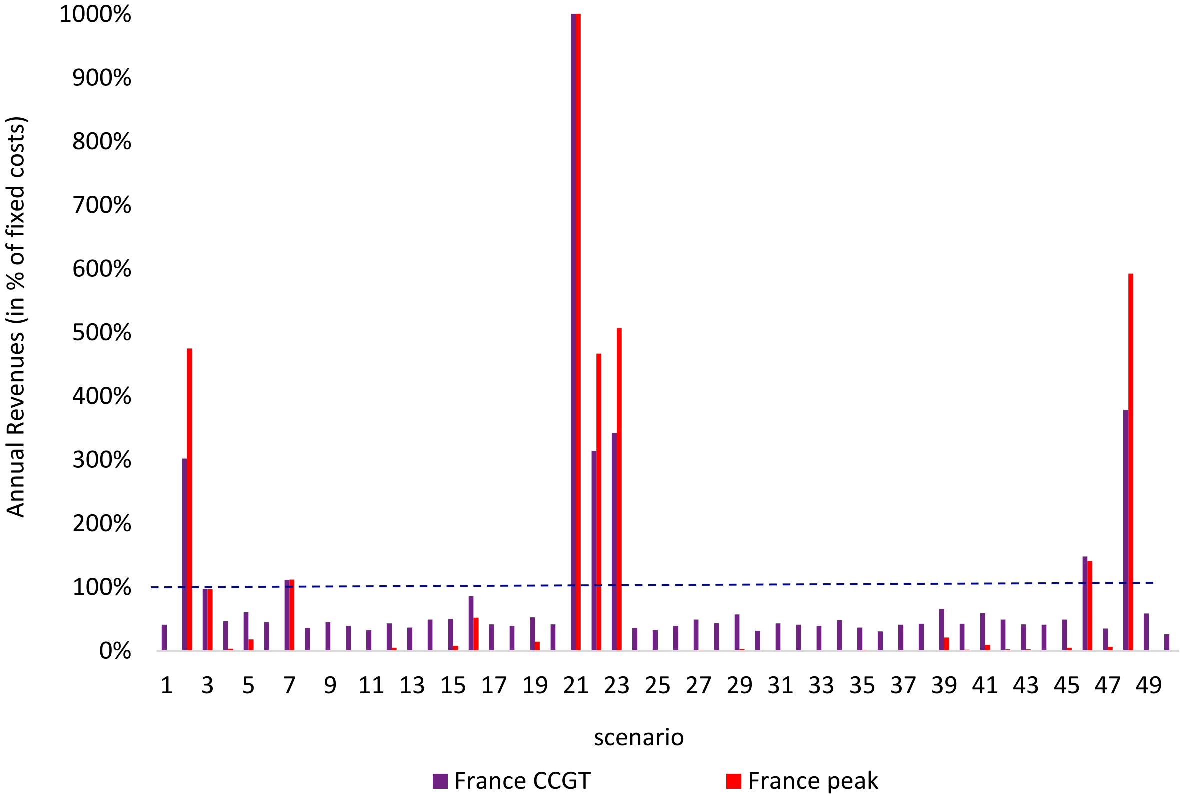


Figure 41: French assets' annual revenues without price cap

7.1.2 EOM with a price cap at 3 000 €/MWh

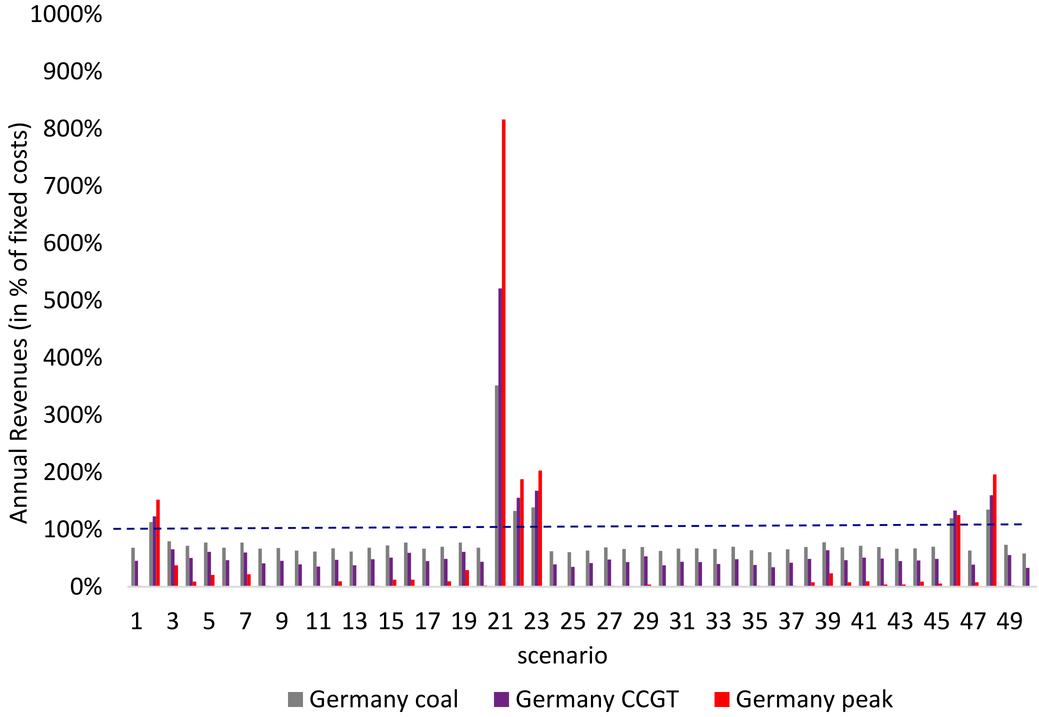


Figure 42: German assets' annual revenues with price capped at 3000€/MWh

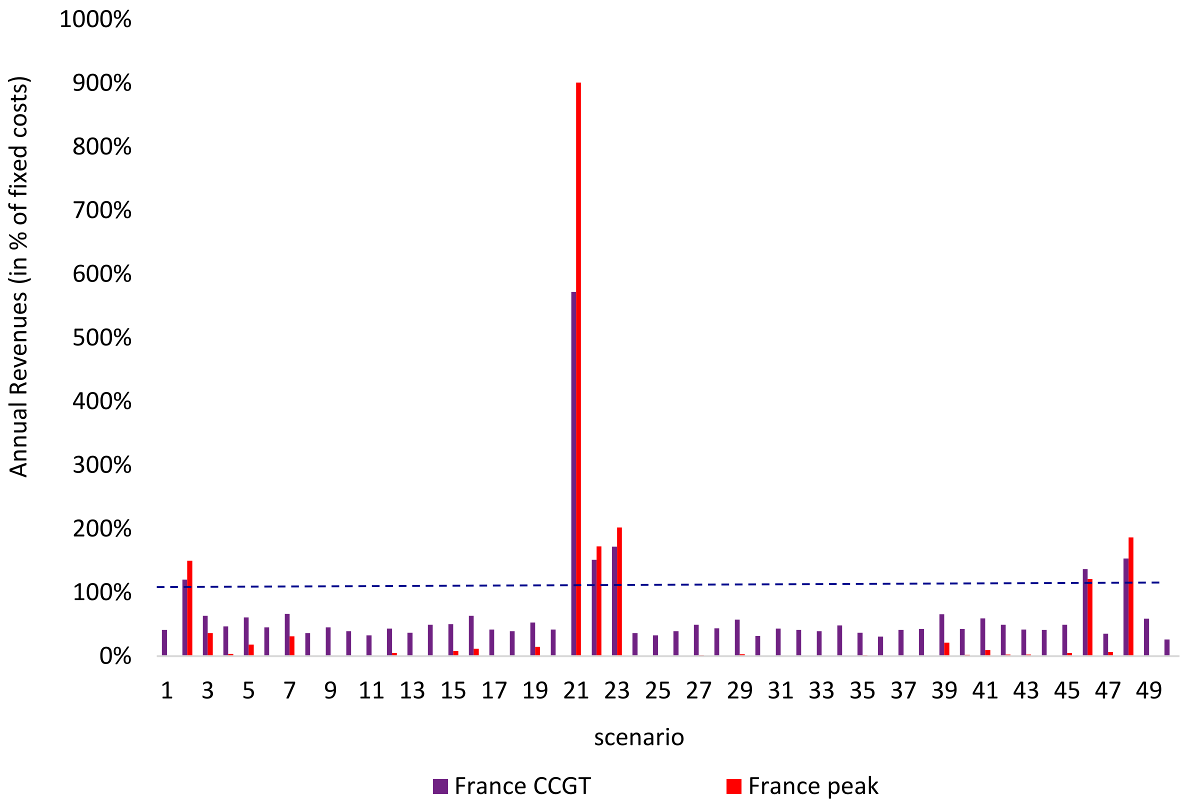


Figure 43: French assets' annual revenues with price capped at 3000€/MWh

7.1.3 Annual revenues' dispersion in EOM

The following tables provides the minimal and maximal revenues per asset over the scenarios, as percentages of the average remuneration, for the virtual reference mix.

Annual revenues dispersion over 50 scenarios					
	France CCGT	**France peak**	**Germany coal**	**Germany CCGT**	**Germany peak**
Minimal annual revenue (in % of investment cost)	26%	0%	58%	33%	0%
Average annual revenue (in % of investment cost)	100%	100%	100%	100%	100%
Maximal annual revenue (in % of investment cost)	1437%	2446%	869%	1387%	2363%

Table 18: Annual revenues' dispersion over scenarios without price cap

Annual revenues dispersion over 50 scenarios					
	France CCGT	France peak	Germany coal	Germany CCGT	Germany peak
Minimal annual revenue (in % of investment cost)	26%	0%	58%	33%	0%
Average annual revenue (in % of investment cost)	66%	38%	80%	66%	39%
Maximal annual revenue (in % of investment cost)	572%	901%	351%	521%	816%

Table 19: Annual revenues' dispersion over scenarios with a price cap at 3k€/MWh

7.2 Actualized revenues over assets' lifetimes

Lifetime revenues dispersion for assets of the virtual reference mix are given here in an EOM with price cap and without price cap.

7.2.1 EOM without price cap

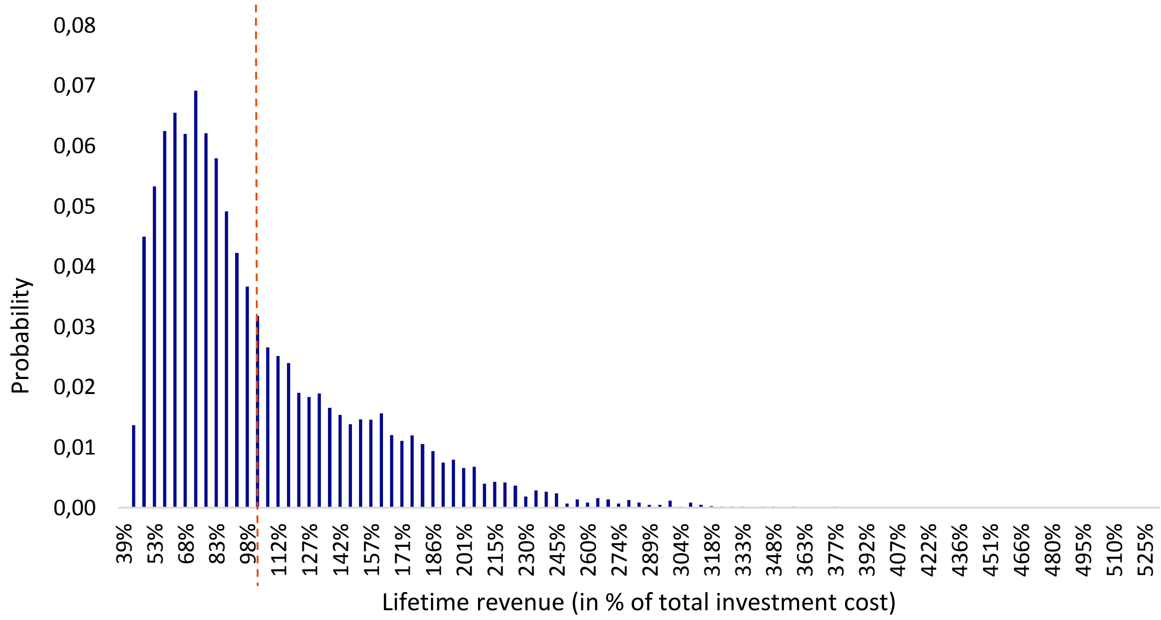


Figure 44: French CCGT fleet's revenue distribution without price cap

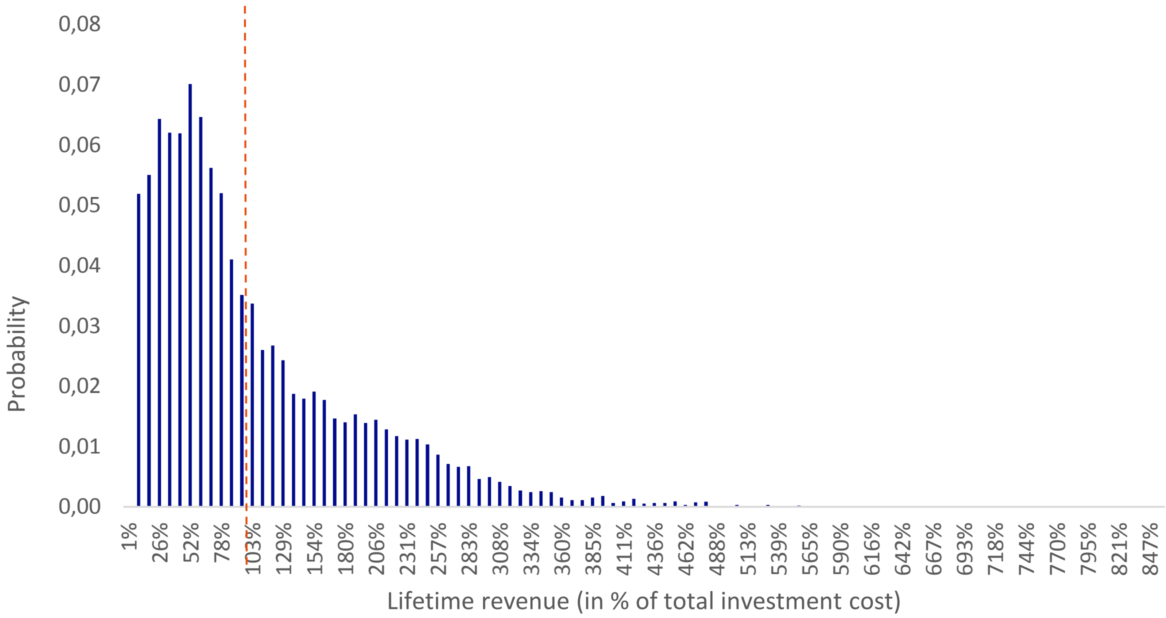


Figure 45: French peak fleet's revenue distribution without price cap

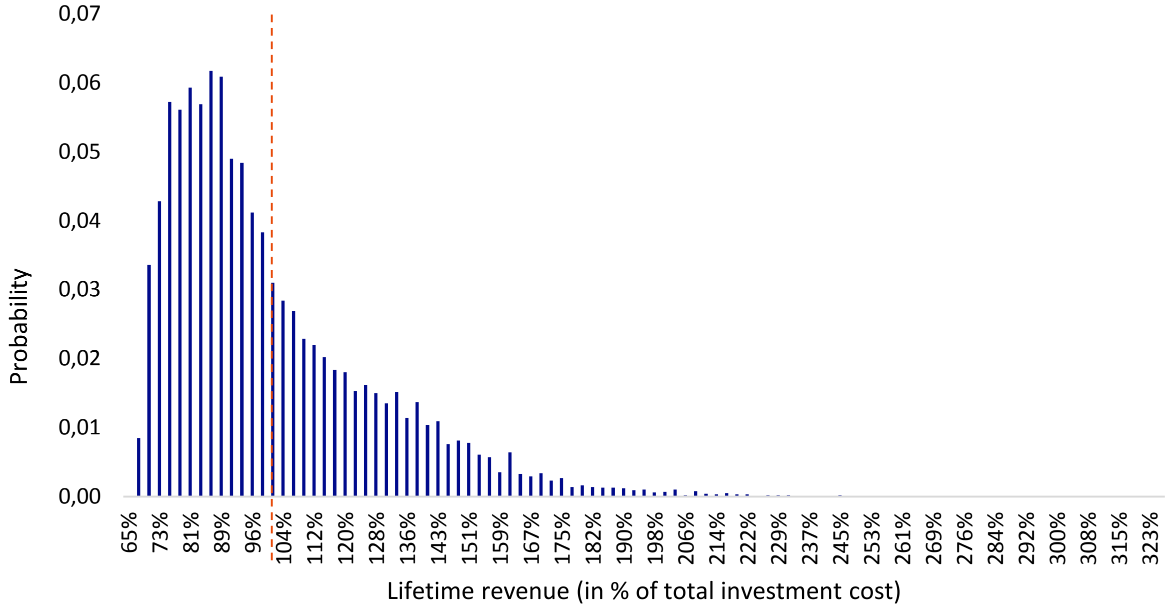


Figure 46: German coal fleet's revenue distribution without price cap

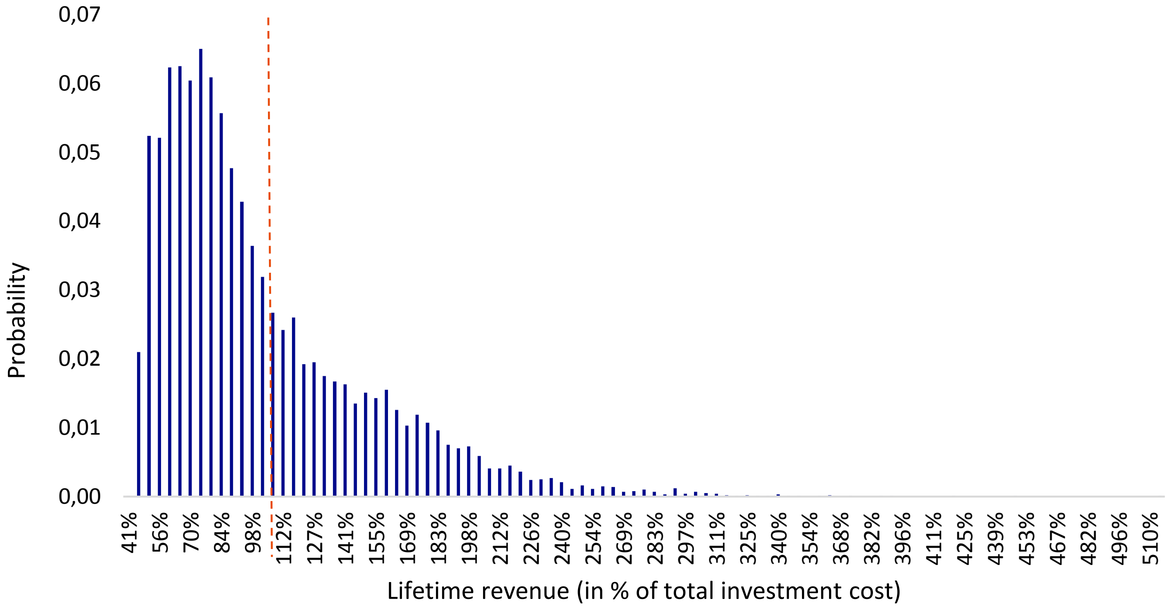


Figure 47: German CCGT fleet's revenue distribution without price cap

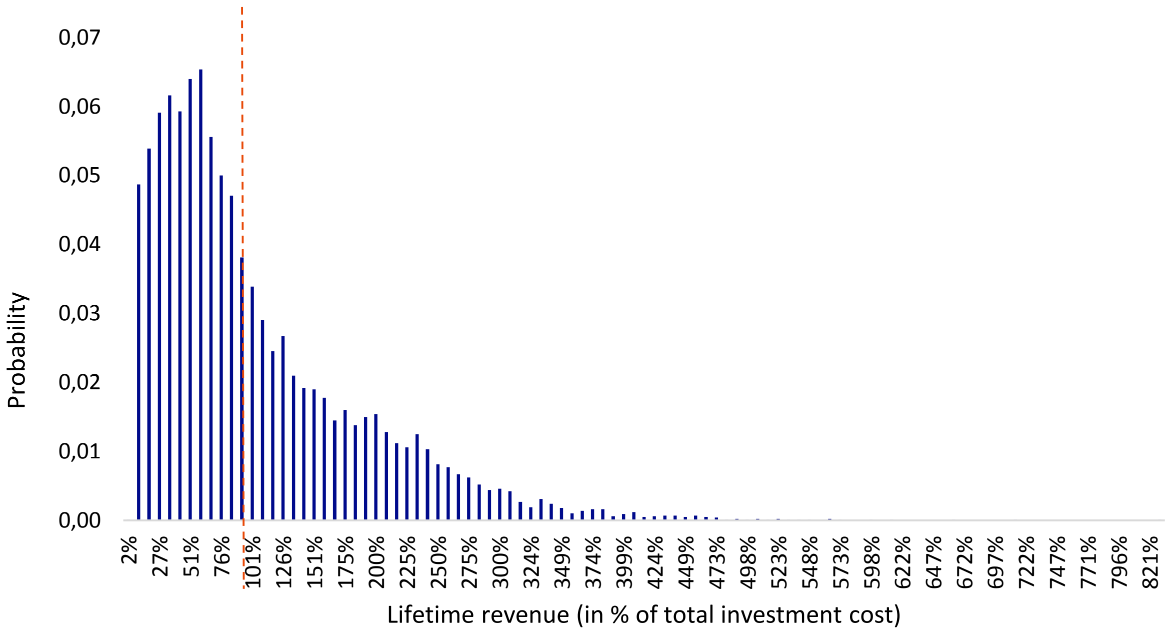


Figure 48: German peak fleet's revenue distribution without price cap

7.2.2 EOM with price cap at 3000€/MWh

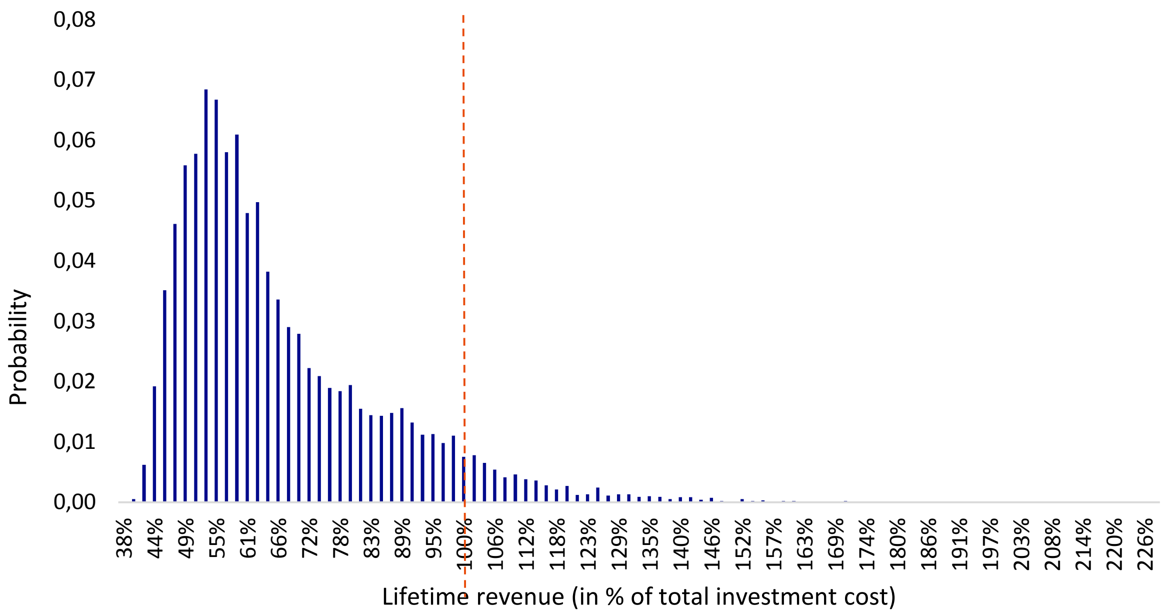


Figure 49: French CCGT fleet's revenue distribution with a price cap at 3k€/MWh

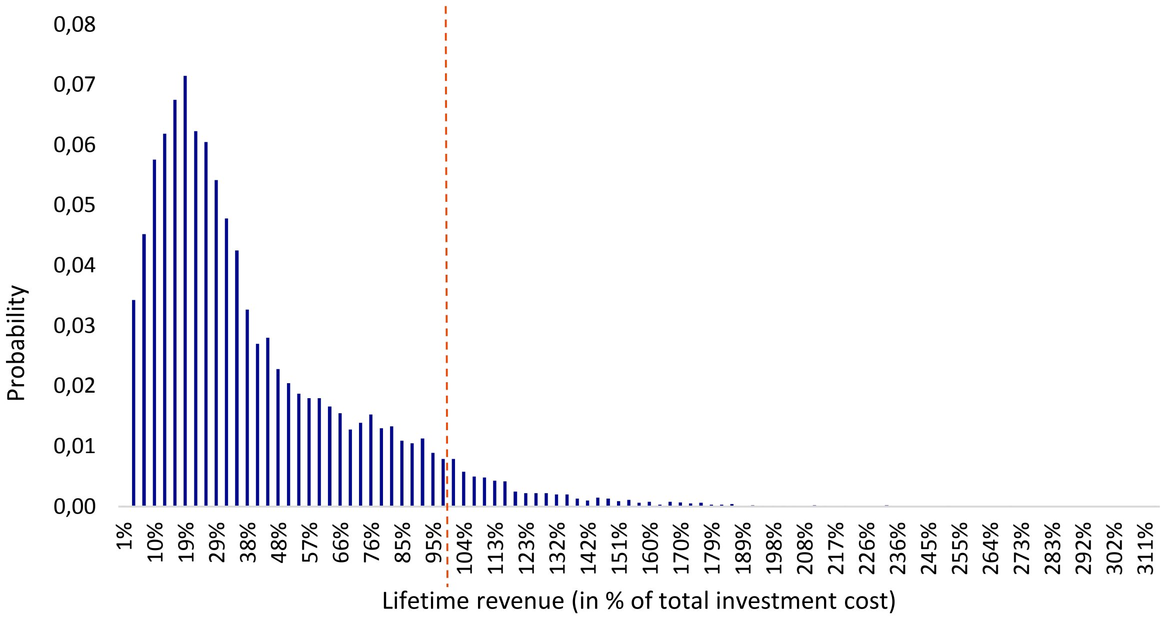


Figure 50: French peak fleet's revenue distribution with a price cap at 3k€/MWh

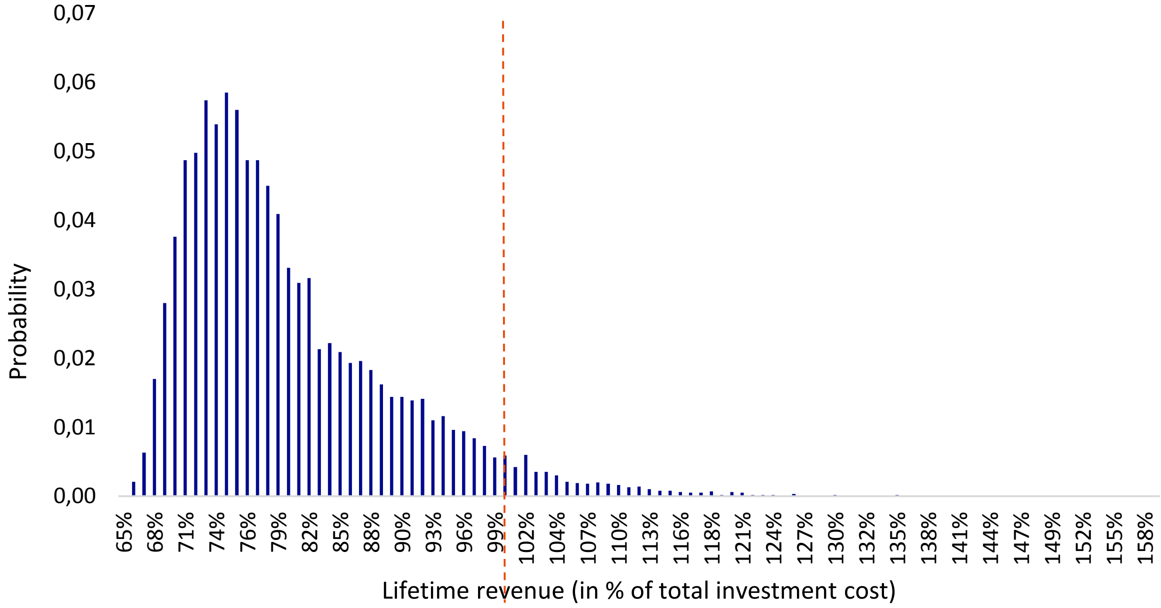


Figure 51: German coal fleet's revenue distribution with a price cap at 3k€/MWh

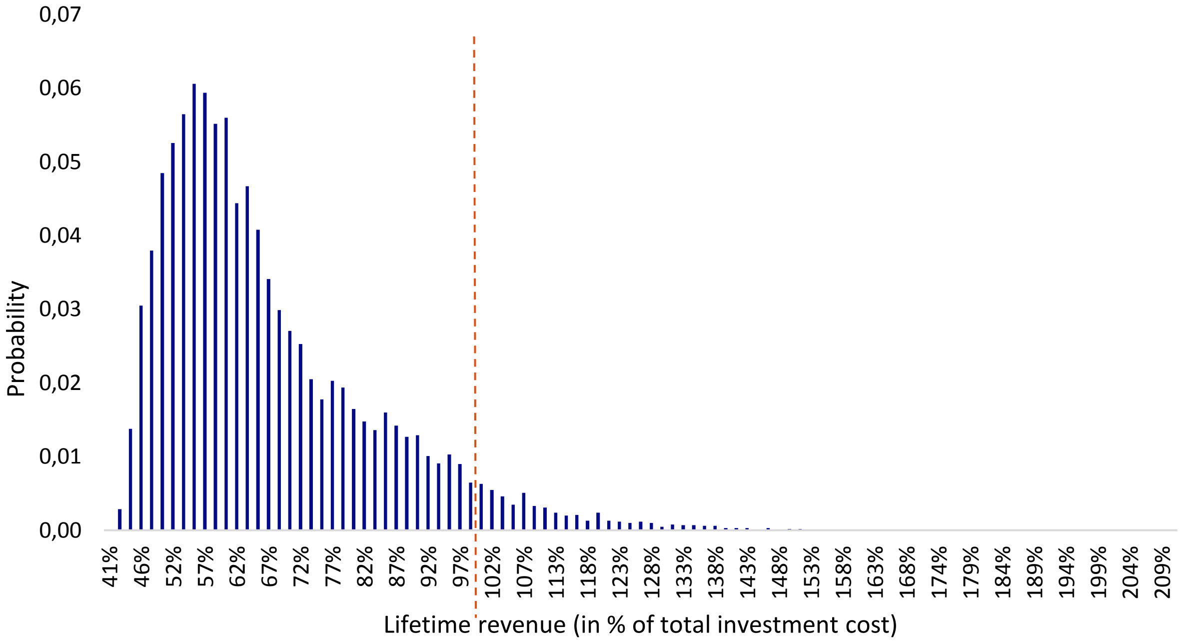


Figure 52: German CCGT fleet's revenue distribution with a price cap at 3k€/MWh

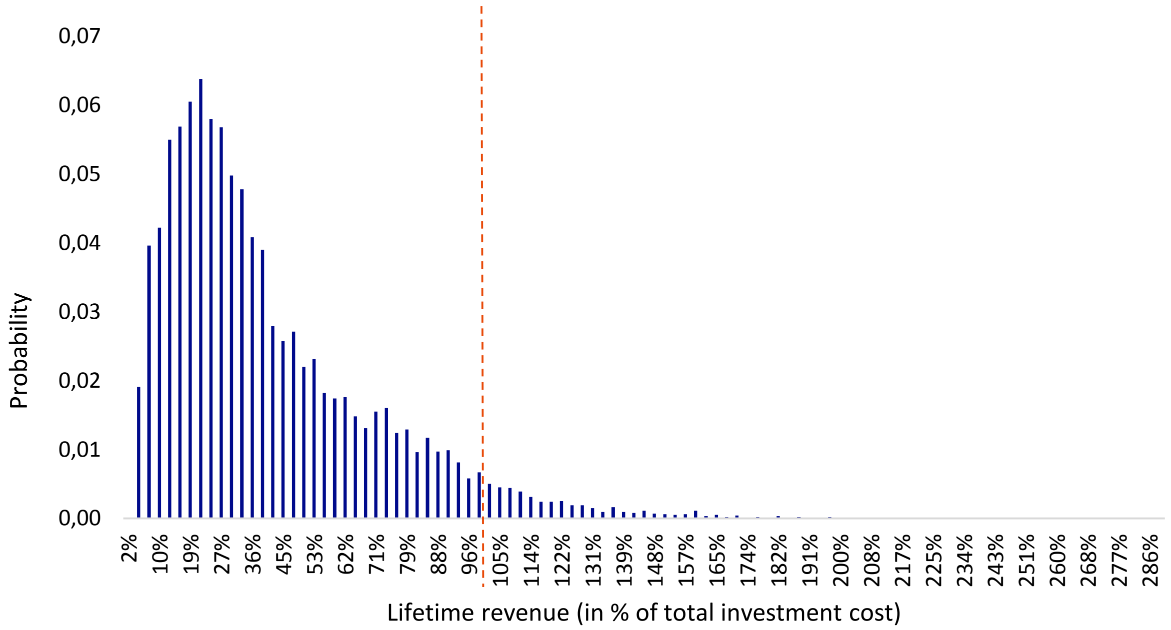


Figure 53: German peak fleet's revenue distribution with a price cap at 3k€/MWh