METIS Studies

Study S16

Weather-driven revenue uncertainty for power producers and ways to mitigate it

METIS Studies
November 2016

Prepared by

Jean-Christophe Alais (Artelys)
Christopher Andrey (Artelys)
Régis Bardet (Artelys)
Laurent Fournié (Artelys)

Contact: metis.studies@artelys.com

This study was ordered and paid for by the European Commission, Directorate-General for Energy, Contract no. ENER/C2/2014-639. The information and views set out in this study are those of the author(s) and do not necessarily reflect the official opinion of the Commission. The Commission does not guarantee the accuracy of the data included in this study. Neither the Commission nor any person acting on the Commission's behalf may be held responsible for the use which may be made of the information contained therein.

ISBN: 978-92-76-03427-8 doi: 10.2833/015124 MJ-03-19-328-EN-N

EUROPEAN COMMISSION

Directorate-General for Energy

Directorate A — Energy Policy
Unit A4 — Economic analysis and Financial instruments

Directorate C — Renewables, Research and Innovation, Energy Efficiency
Unit C2 — New energy technologies, innovation and clean coal

E-mail: ENER-METIS@ec.europa.eu

European Commission
B-1049 Brussels

Table of Contents

Table of Figures

1 ABBREVIATIONS AND DEFINITIONS

1.1 ABBREVIATIONS

Abbreviation	Definition
CRM	Capacity Remuneration Mechanism
CCGT	Combined Cycle Gas Turbine
MS	Member State
OCGT	Open Cycle Gas Turbine
RES	Renewable Energy Systems
RO	Reliability Option
TSO	Transmission system operator
VoLL	Value of Lost Load

1.2 DEFINITIONS

Concept	Definition
Residual load	Obtained by subtracting variable RES generation (wind, PV and run-of-the-river) from the power demand.
Net demand	Same as above.
Scarcity price	Market price when demand has to be curtailed because of insufficient generation capacity. In this study, we assume that the scarcity price is equal to VoLL.
Value of Lost Load	Cost associated with loss of load situations, i.e. when the demand cannot be met.

1.3 MODELLING SETUP

The study has been performed with the use of METIS software using the configuration described below.

METIS Configuration	
Version	METIS v1.2.1
Modules	Power system and power market modules
Scenario	METIS EUCO27 2030
Time resolution	Hourly (8760 consecutive time-steps per year)
Asset modelling	Cluster level at country granularity
Uncertainty modelling	50 years of weather data
Bidding strategy	Marginal cost bidding

2 EXECUTIVE SUMMARY

Context

The 2030 climate and energy framework sets as EU-wide targets for 2030 a 40% cut in greenhouse gas emissions compared to the 1990 level, and at least a 27% share of renewable energy generation. For the power system, this translates into around 45% of electricity demand being met by electricity generated from renewable sources, compared to 27.5% in 2014. A significant part of this additional renewable energy is expected to be produced by wind and solar technologies, which bring new challenges in terms of security of supply and electricity price volatility.

This study focuses on flexibility needs emerging during peak situations. Since variable renewable energy generation is driven by weather conditions, further flexibility (flexible generation, storage or demand-response) is required to provide firm capacity during scarcity periods. Ensuring that flexibility assets can get sound revenues from the market (consistently with the value they provide to the system) is therefore key to guaranteeing an appropriate level of electricity supply.

Approach

The analysis drawn in this study is based on 50 years of historical records of temperature and 10 years of wind and irradiance hourly data, which influence the demand (through thermal gradients), as well as the PV and wind generation profiles. The optimal dispatch is computed for these 50 years with an hourly time resolution and a country-level spatial granularity, using the METIS model, which is developed for the European Commission by Artelys, with the support of IAEW (RWTH Aachen University), ConGas and Frontier Economics. The METIS model takes into account generation unit technical constraints (availability time series, start-up costs, min off-time, min stable generation, etc.) and adopts an NTC description of the cross-border network constraints.

The installed generation capacities, transmission capacities (NTCs), fuel costs, CO_2 price and annual demands of the PRIMES EUCO27 scenario have been adopted. This scenario satisfies all EU targets cost-efficiently: at least 40% GHG reduction (including the split of reductions between the ETS and non-ETS sectors), 27% RES and 27% energy efficiency target.

Finally, the analysis of the benefits of regional cooperation have been performed using Artelys Crystal Super Grid, which provides advanced capacity optimisation services *via* a High Performance Computation Cluster.

Findings

Temperature will remain the main driver for generation adequacy in Europe by 2030

While the introduction of variable RES can generate local scarcity situations during periods of low wind and solar irradiance, the peaks of the European net demand are mostly driven by temperature effects[1]. On a country level, the amplitude of these peaks depends on the share and the efficiency of electrical heating equipment, and on the occurrence of very cold temperature events.

Even if the heating gradient varies a lot between countries, high prices during temperature extrema propagate across borders, which allow MSs, thanks to market coupling, to help each other during challenging periods. Yet, the propagation of price signals does not mean that loss of load is exported, since countries can favour their national supply-demand balance before assisting neighbours.

[1] In some countries, such as Spain and Portugal, the need for peak flexibility capacity is not only driven by demand peaks, but also by the year to year variability of hydro inflows.

Peak flexibility assets experience high uncertainties on their annual revenues

In contrast to periods without wind, which occur on a regular basis, periods of stress due to extremely cold temperatures are much rarer events. They cause a need for peak flexibility assets, whose revenues can be very volatile. Indeed, the number of hours during which these capacities are running and, even more crucially, earn revenues, can vary a lot from one year to the other.

This constitutes a risk for demand response and peak generators which rely on scarcity prices to generate revenues. In contrast to base-load producers which have more stable revenues from one year to the other, peak flexibility provider revenues can vary significantly (from 0 to 12 times their average annual value), and fixed costs can exceed market revenues more than 3 years out of 4.

While several Member States have already implemented Capacity Remuneration Mechanisms for adequacy, flexibility or risk mitigation purposes, other mechanisms (such as ERCOT Real Time Reserve Price Adder or New Zealand FTRs) are also possible: the main objective is to remunerate peak flexibility providers on a more regular basis (rather than only during scarcity periods) to secure their revenues and ensure the right level of capacity is available.

Whichever the risk mitigation mechanism chosen, cooperation is key to avoid massive overinvestments

The analysis shows that cooperation between MSs for generation adequacy can provide significant savings. In comparison with a system where each country would cover its own demand independently, a cooperative system can save up to 80 GW of generation capacity, which would represent around 5 billion euros per year in investment costs only[2]. Part of these savings are already captured by some MSs which take into account the contribution of neighbouring countries for their generation adequacy assessment.

To access these savings, a national CRM has not only to take into account the interconnection capacity with neighbouring countries, but also the probability that these countries can actually deliver capacity during scarcity periods (which means that they do not need it to balance their national systems). Hence, the results exhibited in this study support the introduction of a regional approach to generation adequacy with a common set of data and a common methodology.

[2] This figure does not include savings on production dispatch thanks to market coupling, which could lead to much higher savings.

Limitations

The estimates reported in this study are based on modelling which relies on a number of assumptions in terms of inputs. Changes to the input dataset may materially change the outputs.

Weather-driven uncertainties are based on historical records of temperature, wind and irradiance. The uncertainties on hydro inflows and demand variability between years outside of temperature-driven variations are not modelled.

While peak flexibility resources could correspond to demand-response or flexible generation, OCGTs' technical constraints and costs were used. Energy storage can also provide capacity services, which are not studied specifically herein, and is the focus of the METIS Study S7.

The analysis assumes a marginal cost bidding strategy, which may underestimate peak asset revenues during periods with low remaining capacity[3]. Moreover, the profitability of each peaking unit is addressed separately, as if in a project finance basis, while in reality peaking plants are usually part of a portfolio of power plants. Finally, flexibility providers may get additional revenues from reserve procurement, intraday and balancing markets, which is not studied here.

[3] This assumption does not change the main results of this report: the METIS Study S18, which focuses on the impact of bidding strategies on asset revenues, shows that a strategic bidding strategy does not remove the investment risks for peak assets.

3 INTRODUCTION

3.1 FOREWORD

The present document has been prepared by Artelys in response to the Terms of Reference included under ENER/C2/2014-639[4]. Readers should note that the report presents the views of the Consultant, which do not necessarily coincide with those of the Commission.

3.2 CONTEXT AND STRUCTURE OF THE REPORT

The flexibilisation of the European power system has to accompany the ongoing massive deployment of variable renewable energy sources in order to integrate them cost-efficiently. Flexibility can be provided by a number of technologies, ranging from demand-response to thermal power plants. However, recent years have witnessed depressed levels of power prices, resulting in the mothballing and decommissioning of a number of flexible power plants.

It has been argued that current market arrangements do not lead to appropriate price signals to encourage investments in an adequate level of flexible generation capacity, which is critical for the reliability of the power system especially during peak hours. Indeed, the ability of peak flexibility providers (demand-response or flexible generation) to collect sufficient revenues and to be profitable strongly depends on the occurrence of scarcity situations. This report aims at quantifying the impact of temperature variability on peak demand levels and price signals propagation on the revenues and associated risks taken on by peak flexibility providers. A number of solutions to support further investments are then considered, and the role of a cooperative approach is illustrated.

The first part of the study concentrates on the structure of the revenues of peak flexibility providers. It focuses on the weather-related risks arising from the unpredictability of the number of hours during which these units can expect to run in the future. To do so, the METIS EUCO27 scenario has been simulated in 50 different weather scenarios, each of them built from a particular climatic year between 1964 and 2013. Section 4 presents the scenario and the underlying assumptions, and describes the challenges faced by the European system in 2030 in terms of generation adequacy. Then, Section 5 focuses on the propagation of scarcity prices in periods of stress and on the risks faced by flexibility providers.

The second part of the study examines a number of measures which could mitigate the risks faced by investors. In particular, Section 6 describes a number of capacity remuneration mechanisms, which can be implemented to reduce risks and incentivise further investments, as well as some other schemes implemented outside Europe. Section 7 demonstrates the importance of coordination among European countries when dimensioning their energy systems, and when setting the capacity remuneration mechanisms’ targets. Substantial savings will be shown to emerge thanks to the development of solidarity and mutual assistance between Member States.

[4] http://ec.europa.eu/dgs/energy/tenders/doc/2014/2014s_152_272370_specifications.pdf

4 WEATHER SCENARIOS AND ADEQUACY ISSUES

This section aims at describing the METIS EUCO27 2030 scenario that is used throughout this study, and at presenting the adequacy challenges that the European power system would face in 2030 in such a scenario.

4.1 METIS EUCO27 2030 SCENARIO

The METIS EUCO27 2030 scenario, which is based on the PRIMES EUCO27 2030 scenario[5], is used throughout this study. The demand, installed capacities, fuel and CO_2 costs, and NTCs are adopted from the PRIMES scenario, while ENTSO-E datasets[6] have been used for non-EU countries (Switzerland, Norway, Bosnia-Herzegovina, Montenegro, Republic of Serbia and the Former Yugoslav Republic of Macedonia).

Fifty weather scenarios are simulated in order to evaluate the impact of weather-related uncertainty on market prices and producers' revenues. The following paragraphs describe some of the key aspects of the METIS EUCO27 scenario used in this study.

- **Demand** – A statistical analysis of the country-level hourly demand profiles has been performed to evaluate how the demand evolves when temperature changes. The result of this analysis[7] are presented on Figure 1, which shows the two thermal gradients, measured in MW/°C, which have been computed: the heating gradient and the cooling one. The thermal gradients are shown as a proportion of the average demand in order to facilitate the comparison between Member States.

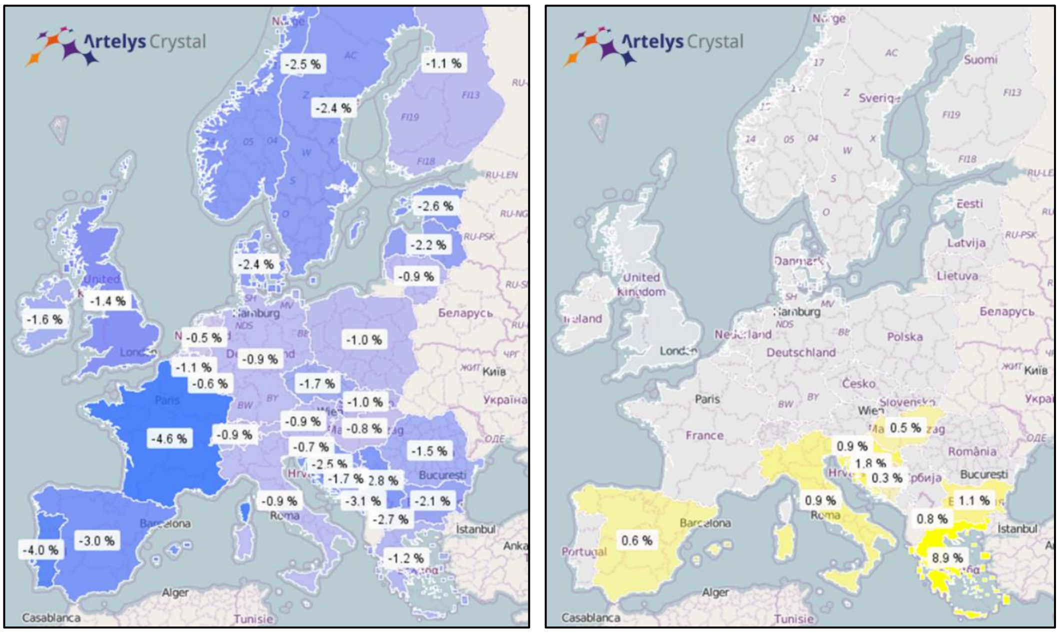

Figure 1: Heating (left) and cooling (right) gradient in % of mean demand per °C

Since the thermal gradients measure the variation of the electricity demand when the temperature changes, countries with high shares of electrical heating (e.g. France, Baltic and Nordic countries) are found to have higher heating gradients than countries using other energy vectors to satisfy their heating demand. Besides, during periods of high temperatures, the electricity demand is expected to rise in

---

[5] See *METIS Technical Note T1 - Methodology for the integration of PRIMES scenarios into METIS.*

[6] "Vision 1" 2030 scenario provided by ENTSO-E in the 2014 TYNDP.

[7] The computation of the thermal gradients is based on a statistical analysis of the load profiles of the "Vision 1" 2030 scenario provided by ENTSO-E in the 2014 TYNDP, which includes assumptions regarding the deployment of electrical heating at the MS level.

Greece and, to a lesser extent, in other Southern countries due to air conditioning, while the impact is relatively small for other countries.

The thermal gradients and the recorded temperature profiles of the 50 years between 1964 and 2013 are then used to build the demand of the 50 weather scenarios. The temperature impacts the demand through the previously computed thermal gradients. Figure 2 illustrates the results of the analysis for France.

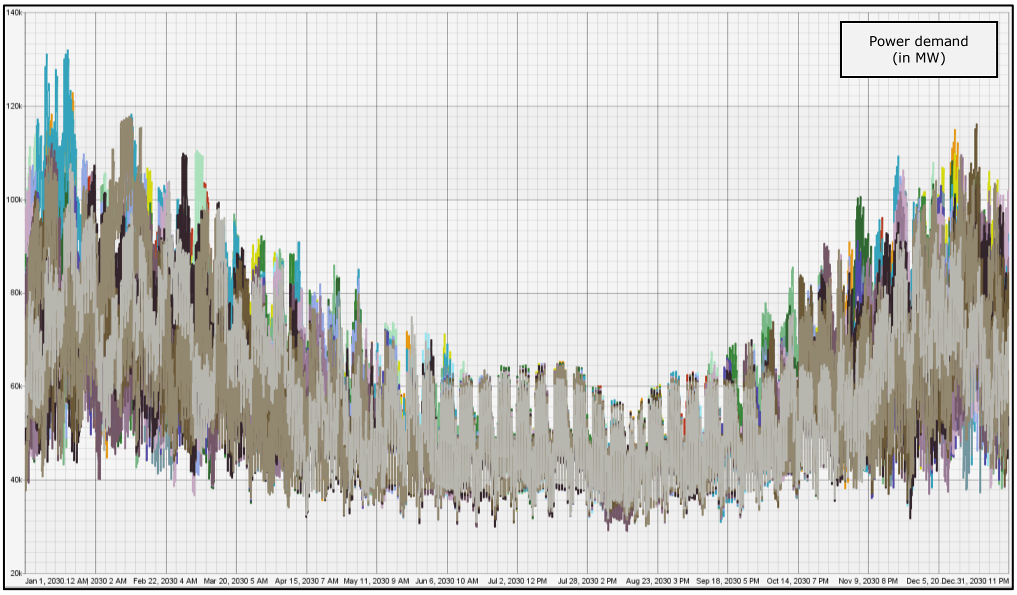

Figure 2: Impact of weather on the demand in France (50 variants)

The average annual electricity demand is shown on Figure 3. The demand load profiles have been rescaled so that the average over weather scenarios of the annual demand corresponds to the PRIMES EUCO27 scenario demand.

Figure 3: Average annual demand per country

- **RES profiles** - Ten years of measured datasets of wind speed and irradiance (2001-2010) have been used to compute hourly generation profiles for PV and wind power. Importantly, since all the weather datasets are based on historical values, power demand, PV and wind energy generation conserve the measured correlation between Member States. For hydropower, a single year of water inflow data is used (with weekly granularity). The sensitivity of revenues to water inflow variations is therefore not captured in this study.

As for the demand, the average PV and wind generation volumes are provided by the PRIMES EUCO27 scenario. The hourly profiles have been calibrated so that the mean value of the production matches the PRIMES scenario data. Figure 4 shows the share ratio between the variable renewable electricity production and the national demand. At the European level, the production of variable RES represents around 31% of the demand. This share reaches around 49% when including biomass and hydropower.

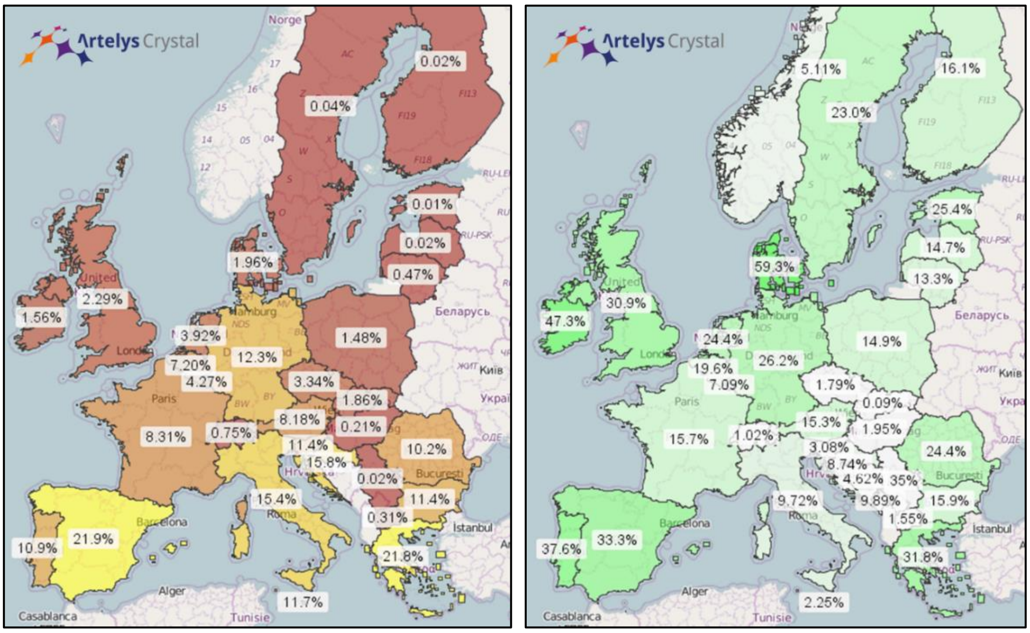

Figure 4: Share of solar (left) and wind (right) generation in the national demand

- **Peak flexibility** – As mentioned above, the installed capacities of the thermal units (nuclear, lignite, coal and CCGT) are provided by the PRIMES EUCO27 scenario data, with the exception of OCGTs. Indeed, since this study focuses on the economics of security of supply, one should make sure that installed capacities are consistent with the demand and RES generation profiles. Since METIS represents the demand-supply equilibrium with a high level of detail (METIS uses 50 years of hourly weather data whereas a certain number of typical days are used by PRIMES), it was necessary to optimise the capacity of peak flexibility assets (for a given security of supply criteria) so that the generation capacities remain consistent with the load and RES generation profiles.

  In practice, the capacities of the OCGTs that are included in the PRIMES EUCO27 scenario have been optimised. The 2030 OCGT residual capacities have been set as the minimum capacity that has to be adopted by the model. The model was then given the option to increase this capacity by investing in further peak flexibility options. The following cost assumptions have been used:

  - Annualised CAPEX: 45.7 k€/MW/year[8]
  - Annual fixed operating costs: 15.2 k€/MW/year[9]

[8] A CAPEX of 550k€/MW is assumed (Source: *ETRI 2014, Energy Technology Reference Indicator projections for 2010-2050*, JRC Science and Policy reports). The PRIMES discount rate for power utilities (8.5%) has been assumed.

[9] PRIMES EUCO27

One should note that a number of technologies can provide peak flexibility services: flexible thermal assets, demand-response, storage, etc. The analysis presented in this study, although based on state of the art OCGT cost assumptions for practical reasons, does not depend on the composition of the peak flexibility portfolio.

The cost assumptions presented above imply that the model favours the installation of an additional MW of peak flexibility capacity when it expects it to be producing energy for more than 4 hours remunerated at scarcity price levels[10]. The peak flexibility capacities of each Member States have been jointly optimised, taking into account the interconnection capacities between countries. The calculations have been performed with the Artelys Crystal platform capacity expansion features[11]. More details are given in *METIS Technical Note T1 - Methodology for the integration of PRIMES scenarios into METIS*.

Figure 5 shows the average over the 50 weather scenarios of the annual number of hours of scarcity prices when the optimised capacities are adopted. The value of loss of load is set at 15 k€/MWh in the capacity expansion algorithm computing the required OCGT capacity, meaning that the model invests in OCGTs on the basis of countries facing around 4 hours of scarcity prices per year on average over the 50 weather scenarios (when there are less than four hours of scarcity prices, OCGTs are no longer profitable). In some Southern countries, high baseload and mid-merit generation capacity projections, based on current capacities and PRIMES EUCO27 investment assumptions, lead to fewer hours of scarcity prices. No peak flexibility capacities have been added in these countries. For instance, in Italy, even with no additional peak flexibility units, there is an average available generation capacity of 64 GW12 while the maximum peak demand over the 50 weather scenarios barely reaches 58 GW, leading to a very low number of scarcity price hours.

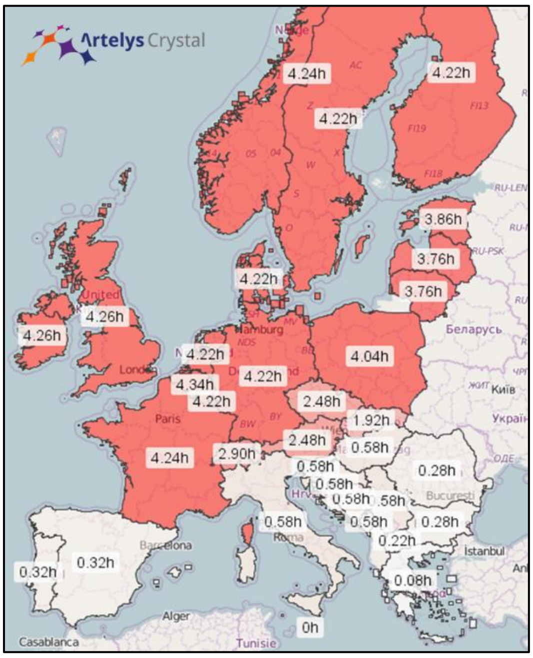

Figure 5: Average annual number of hours of scarcity prices with optimised capacities

[10] The annual fixed costs for 1 MW of peak capacity is 60.9 k€, which are inferior to the revenues this capacity would obtain if it runs during around 4 hours of scarcity prices (on average over the 50 weather scenarios).

[11] Such a computation requires a High-Performance Computation cluster since the capacity expansion algorithm uses the same time resolution as METIS (hourly resolution, 8760 consecutive time-steps per weather scenario).

[12] The 64GW value includes average variable RES generation and therefore does not guarantee that supply and demand can be balanced every hour of the 50 simulated weather years. In practice, results show that there are a few hours of loss of load in Italy even with this high level of available capacity.

4.2 IMPACTS OF WEATHER EVENTS ON GENERATION ADEQUACY

As previously described, the way the electricity demand varies from one weather scenario to another depend on two parameters: thermal gradients and temperature scenarios. Temperature extrema are found to significantly vary from one year to another. Figure 6 shows the average minimum temperature over the 50 weather scenarios and the lowest temperature among them. For example, in Poland, the coldest day over the 50 weather scenarios occurred in January 1987 with a temperature of -21°C, while, on average over the 50 weather scenarios, the temperature during the coldest day of the year is -12°C. This means that there is a 9°C difference in Poland between the coldest day over the 50 weather scenarios compared to a standard year.

The temperature variance significantly depends on the country: in Portugal, there are less than 3°C between the coldest day over the 50 years and the average of the annual coldest days, while this difference reaches 15°C in Estonia. This means that the coldest days of each year look alike in Portugal, while they can reach various levels of severity in Estonia.

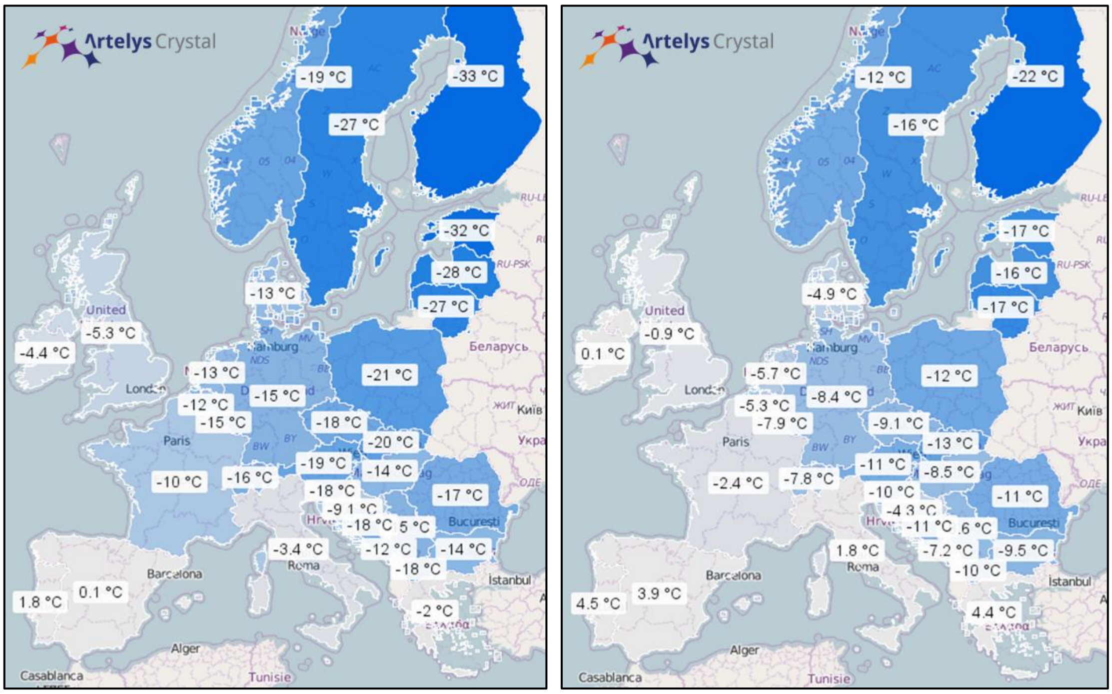

Figure 6: Temperature of the coldest day in 50 years (left) and of the coldest day per year on average (right)

As a result, countries which are subject to strong variations of their local temperature and are characterised by a high heating gradient can face very high demand peaks compared to their average peak. For such countries, one could expect that the peak flexibility options would only be used during exceptional years. However, it will be shown in that the interconnectivity of the EU power system results in a harmonisation of the level of risk faced by peak flexibility providers in all European countries.

Figure 7 shows the average annual peak demand and the relative difference with the maximum peak demand over the 50 weather scenarios. For example, in Italy, where there is a low heating gradient (see Figure 1) and a moderate temperature difference between years (see Figure 6), the average annual peak demand is 57.3 GW, while the maximum peak demand only reaches 58.4 GW (2% higher than the average) during the coldest year[13]. In contrast, in Estonia, as the difference of temperature between the coldest day in 50 years and the average coldest day per year is important, the difference between the maximal peak demand and the average peak demand reaches 15%. In France, this

[13] In this study, peak demand variability between years is only based on temperature variations. Other events which could generate exceptional peak demand are not studied.

difference is even more substantial because of its high heating gradient, which induces a difference of 23% between the maximum and average annual peak demand over the 50 weather scenarios.

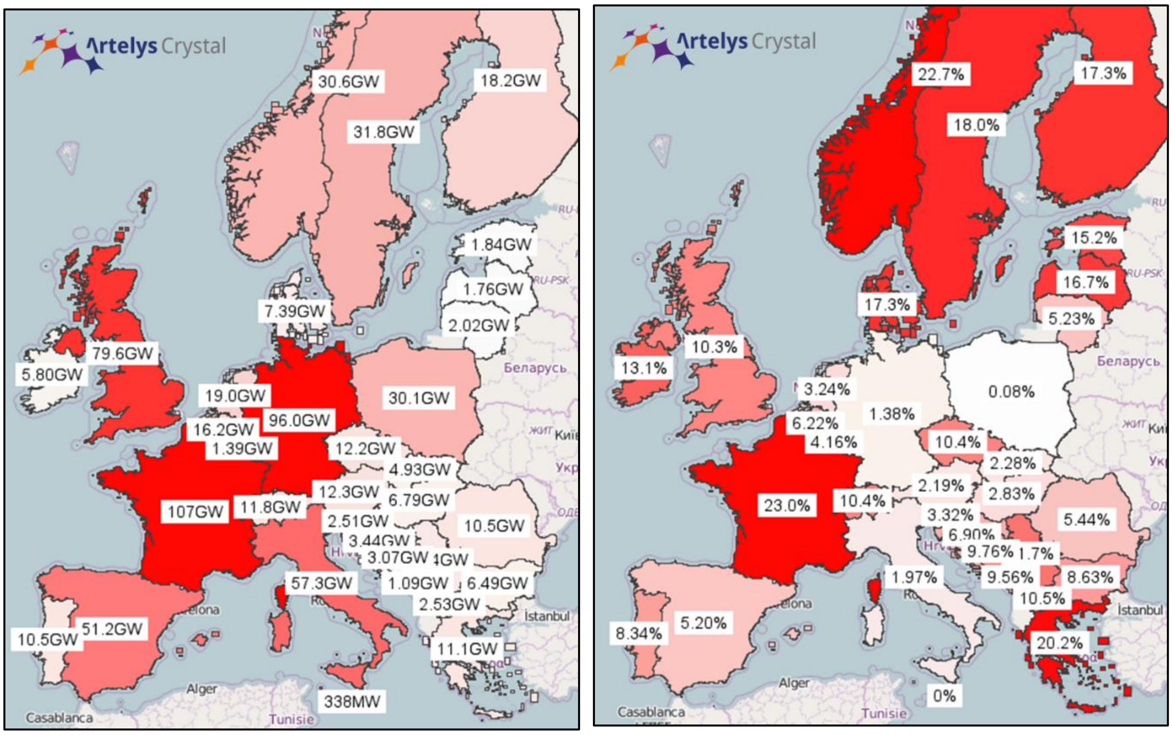

Figure 7: Average annual peak demand (left) and the relative difference with the maximal peak demand

The 20% figure in Greece is due to a high cooling gradient during summertime, and has a limited impact on the European generation adequacy issues.

Other categories of weather events, such as periods with very little wind generation, can cause generation adequacy issues. It is therefore crucial not to limit the analysis to demand and to explore the same indicators for residual load, which is obtained by subtracting the variable RES production from the demand. The dynamics of the residual demand is a better indicator for peak flexibility capacity requirements than demand itself. Indeed, high demand peaks that are accompanied by high variable RES production induce fewer risks than demand peaks that occur during low RES production periods. However, we observe similar results when using residual demand rather than demand itself: the average residual demand peak in Italy is around 50 GW while its maximum residual demand peak over 50 weather scenarios is 52 GW (i.e. a difference of 4%) while France and Northern European countries net face very high maximum residual demand peaks compared to their average residual demand peaks, the largest difference reaching almost 28% in France. A comparison between Figure 7 and Figure 8 shows that the impact of variable renewable generation on net demand peaks is limited compared to the impact of temperature variations.

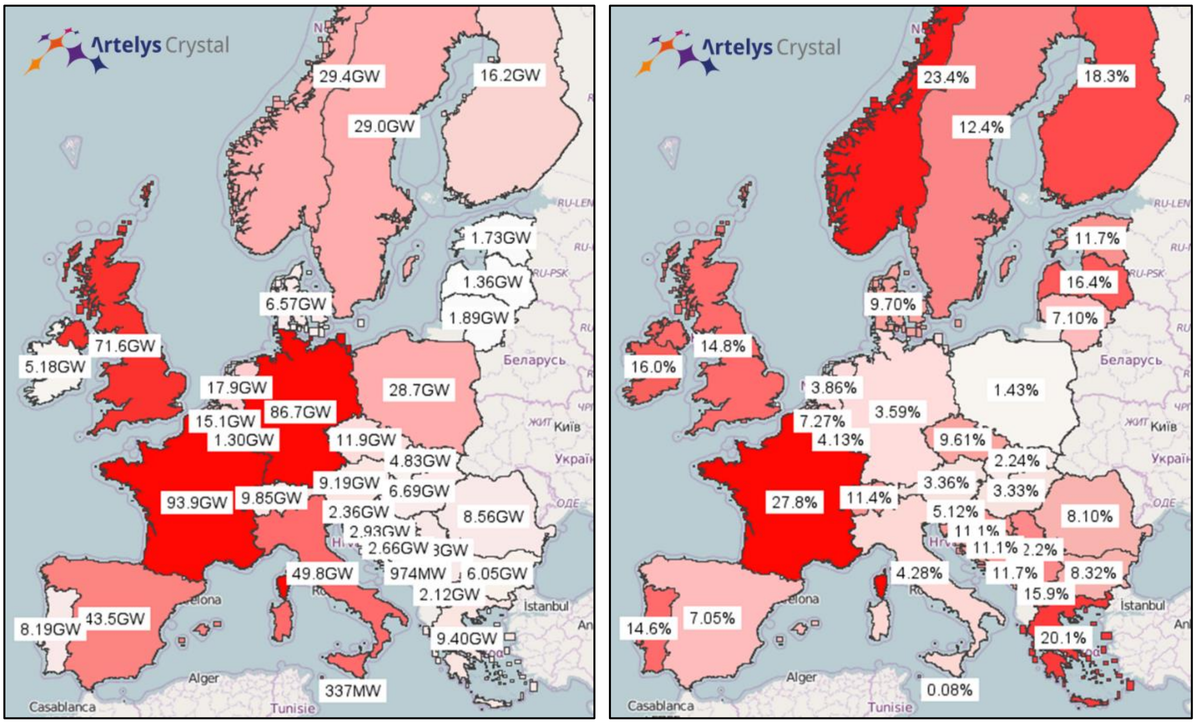

Figure 8: Average annual net demand peak (left) and the relative difference with the maximal net demand peak

The rather limited impact of variable RES generation on net demand peak variations is mainly due to the fact that events with low wind load factors occur on a regular basis, while events with very low temperatures occur much more rarely.

Figure 9 presents an illustration of this phenomenon. In Germany, during one percent of the time (i.e. 88 hours per year on average), the load factor of wind generators is less than 2.5%, with a minimal load factor of 1% over the 50 weather scenarios. As a result, there is only a small difference between the worst hour over 50 years and the worst 88 hours per year on average when looking at wind generation. In contrast, there can be a large difference in temperatures between the coldest day over 50 years and the 88th coldest hour per year on average. In France, this difference is found to reach around 9°C.

Temperature is therefore found to be the main driver of net demand peaks, while renewable production variations are almost negligible in the context of this study.

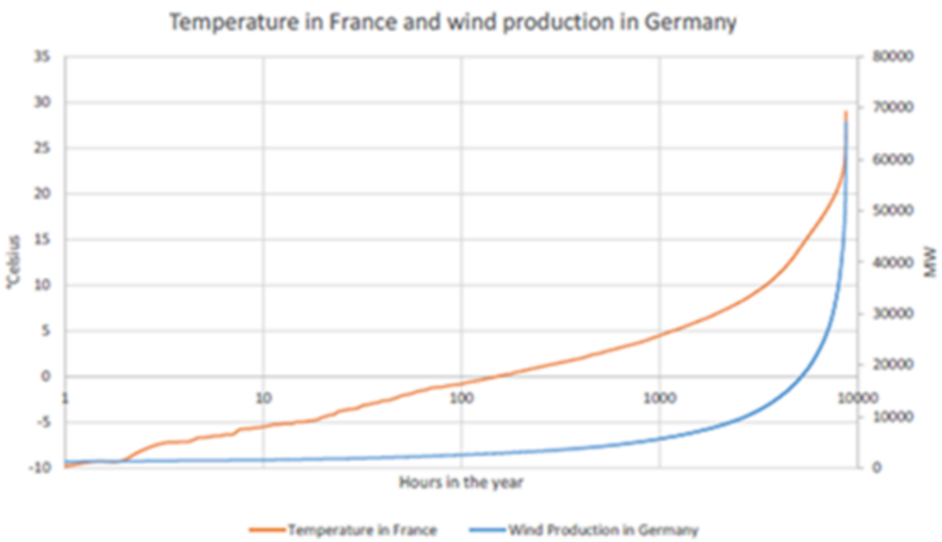

Figure 9: Temperature and wind generation distributions in Germany for the 50 weather scenarios

In conclusion, countries face very different needs and risks as they are subject to different thermal gradients and temperature variations. In particular, Northern European countries and France are found to have very occasional needs for high peak flexibility capacities, due to a combination of high thermal gradients and extreme temperature variations. In the next section, we will see how these events impact market prices throughout Europe and induce risks for producers' revenues.

5 PROPAGATION OF PRICE SIGNALS AND REVENUES RISKS

This section aims at describing how an interconnected EU power system can tackle generation adequacy issues thanks to the propagation of appropriate price signals, without however having to propagate risks of unserved demand across borders. The geographic pattern of risks for producers' revenues will be shown to be significantly impacted by the mutual assistance between Member States.

5.1 REGIONAL COOPERATION AND PROPAGATION OF SCARCITY PRICES

As described in Section 4.1, the capacity of the peak flexibility units are calculated by finding the optimal balance between additional investments (annualised CAPEX of 61 k€/MW) and revenues (15 k€/MWh during hours of scarcity prices). An additional MW of peak flexibility is therefore profitable as long as the average number of hours of scarcity price is above four.

Figure 10 shows the occurrence of hours of scarcity price per country per weather scenario[14]. For example, in Germany, in weather scenario 17 (which adopts the temperature profile of 1981[15]) there are 32 hours out of 8760 during which the market price reaches the value of lost load. On average over the 50 weather scenarios, the number of hours during which scarcity prices appear is found to be around four, as was already presented in Figure 5.

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
AT		5		26																		7								5																13	36		17	
BA				8																																													6	
BE		28		26				5		5					6			29				25								6																13	36		17	
BG																																																		
CH		7		26						5					6							11								6																13	36		17	
CZ		5		26																		7								5																13	36		17	
DE		29		26				5		5					6			32				12								6																13	36		17	
DK		29		26						5					6			32				12								6																13	36		17	
EE		29		26											6			32				7		5						5																13	36		15	
ES				5																		7																												
FI		29		26											6			32				7		19						5																13	36		15	
FR		7		26						5					6							62		13						6																13	36		17	
GR																																																		
HR				8																																													6	
HU				8																																													6	
IE		29		8						6				5	6			33				12								6																	74		14	
IT				8																																													6	
LT		29		26											6			32				7								5																13	36		15	
LU		29		26				5		5					6			32				12								6																13	36		17	
LV		29		26											6			32				7								5																13	36		15	
ME				8																																													6	
MK																																																		
MT																																																		
NL		29		26				5		5					6			32				12								6																13	36		17	
NO		29		26											6			32				7		19						5																13	36		15	
PL		29		26				5							6			32				11								5																13	36		17	
PT				5																		7																												
RO																																																		
RS				8																																													6	
SE		29		26											6			32				7		19						5																13	36		15	
SI				8																																													6	
SK				22																																										13	30		17	
UK		29		10						6				5	6			33				12								6																	72		14	

Figure 10: Scarcity price hours per country per weather scenario

[14] To enhance readability, Figure 10 does only display the number of scarcity hours if greater than 5.

[15] Weather scenario 0 adopts the temperature profile of 1964, weather scenario 1 the one of 1965, etc.

Figure 11 shows the number of hours of loss of load per country per weather scenario. For example, in Germany, in weather scenario 17, there are 5 hours during which the demand cannot be served. In fact, there is less than one hour with loss of load on average per country[16] (the maximum being 2.3 hours in average in Ireland and France).

One can observe that there is a high variability on the number of hours with unserved energy over the 50 cases. In particular, when the national demand is very thermosensitive, as is the case in France (see Figure 1), loss of load situations can be concentrated in a specific year. For example, in France, there are 52 hours of loss of load in a single weather scenario (1985), which represent almost 50% of the total number of loss of load situations over the 50 years.

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
AT																																																		
BA																																																		
BE				7						3					4							4								4																4	11		5	
BG																																																		
CH																																																		
CZ																																																		
DE		7		13						4							3	5				3																								6	12		7	
DK		6		5														7				4																									3			
EE																		5																																
ES																																																		
FI																		8				3		17		3														4										
FR			4	8											4							52		12						4																6	7		7	
GR																																																		
HR																																																		
HU																																																		
IE		8		3				4		6				3	4			14	3			10								5																	47		5	
IT																																																		
LT																																																		
LU				3																																										4	5		4	
LV																																																		
ME																																																		
MK																																																		
NL		7		10				3		3					3			7				8								3																	11		3	
NO		5																9						5																										
PL		8		3														5																												4	4		6	
PT				3																		4																												
RO																																																		
RS																																																		
SE		6		3														4				3		7																										
SI																																																		
SK																																																		
UK		5						3		5				4	3			14				7								5																	32		5	

Figure 11: Hours of loss of load per country per weather scenario

The following example illustrate why the number of hours with scarcity price propagate to countries which do not experience adequacy issues, i.e. why Figure 10 and Figure 11 are found to be so different.

Let us imagine the following fictitious situation occurs during a given hour:

- Country A has an available capacity of 11 GW and a demand of 14 GW
- Country B has an available capacity of 5 GW and a demand of 4 GW
- Countries A and B are interconnected and can exchange up to 2 GW

In such a situation, all the entire capacity would be running in both countries. However, this would not be sufficient to avoid unserved demand in Country A (11 GW of local generation + 1 GW provided by Country B *vs* 14 GW of demand). Country A therefore experiences loss of load, while Country B does not. The price in Country A is the scarcity price since reducing the demand by 1 MW would reduce the unserved energy by 1 MWh. Since the interconnection is not saturated, the price propagates to Country B, which has no generation adequacy problems: if the demand were to be decreased by 1 MW in Country B, it could export it to Country A and reduce the unserved energy by 1 MWh. In

[16] To enhance readability, Figure 11 only displays the number of hours of loss of load if greater than 3.

such a situation, the scarcity price propagate from Country A to Country B, but, crucially, the risks do not (Country B has no generation adequacy issues).

	Country A	Country B
Generation adequacy situation	Unserved energy	No issues
Price	Scarcity price	Scarcity price

Let us now go back to the analysis of Figure 10, which shows the number of hours of scarcity price per weather scenario. We can observe that neighbouring countries tend to share the same number of scarcity price hours per weather scenario, even if the number of hours where they cannot serve their local demand varies substantially (Figure 11). For example, in weather scenario 3, 16 countries have 26 hours when the price reaches the scarcity price, while only two have more than 10 hours of loss of load. This illustrates the propagation of scarcity prices and the corresponding incentives sent to other countries to assist those which experience loss of load situations.

The propagation of scarcity price signals also results in a synchronisation of the years during which scarcity prices are experienced. As illustrated by Figure 7, the annual peak demand does not vary much in Germany. As a result, Germany should be facing similar adequacy issues almost every year, leading to a balanced distribution of scarcity price hours over the years. However, Figure 10 shows that its scarcity price hours are not equally distributed over the years and are instead synchronised with the scarcity price hours of its neighbours (e.g. France and Denmark). This is due to the fact that, when facing adequacy issues, Germany can usually rely on the capacities and cooperation of its neighbours, thanks to its important import capacities. Scarcity prices therefore only appear in Germany when its neighbours cannot provide the Germany power system with a sufficient level of assistance (i.e. when they also experience scarcity prices).

It is important to stress that the propagation of scarcity price signals does not result in any spread of loss of load. When the generation units in one MS assist another MS experiencing generation adequacy issues, they can be led to generate power at their maximum capacity. As a result scarcity prices appear in the exporting country too, but the demand of that country does not need to be curtailed[17]. For example, in weather scenario 21, France faces 52 hours of loss of load which do not propagate to its neighbours: for example, Belgium experiences 25 hours of scarcity price that year but only 4 hours of loss of load. This is due to cooperation and exchanges between France and Belgium, which gives rise to a harmonisation of market prices, which reach the value of lost load in Belgium when there are adequacy issues in France.

The propagation of scarcity prices is illustrated by Figure 12. In the weather scenario 29, there are adequacy issues in Western Europe. While the loss of load remains contained in these countries, they benefit from the assistance of generation units located in other Member States, which thus share the same market price (scarcity price).

[17] The model assumes a single value of loss of load, but favours the use of local capacities for solving local generation adequacy issues before assisting neighbours to meet their demand.

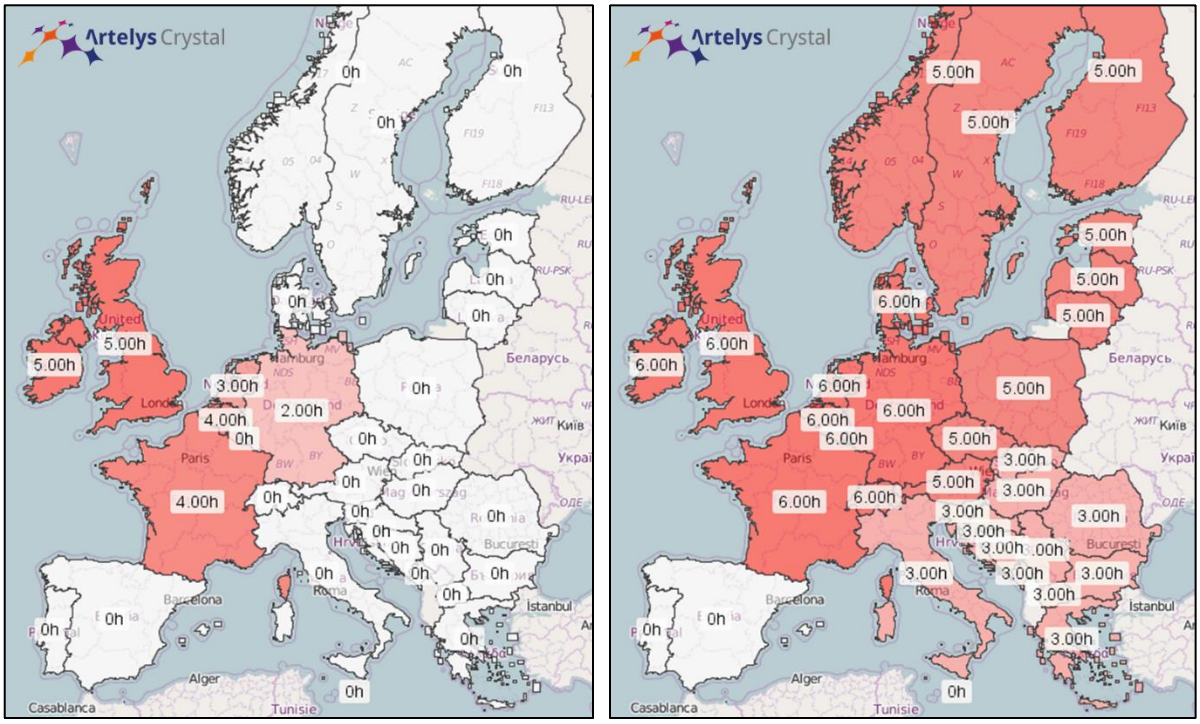

Figure 12: Loss of load (left) and scarcity price hours (right) in weather scenario 29

In summary, the propagation of price signals from one country to another has been found to incentivise mutual assistance between Member States and participates in the minimisation of unserved energy at the EU level. The next section is devoted to the analysis of the impact of price propagation on the revenues for peak flexibility capacities.

5.2 REVENUE RISKS FOR PEAK FLEXIBILITY CAPACITIES

The analysis of Figure 7 shows that the electricity demand varies much more in some countries, due to a combination of high thermal gradients and extreme temperatures. One could expect that the risks faced by peak flexibility units follow the same pattern: low level of risk for the countries where the peaks have roughly the same magnitude each and every year, and high level of risk for the countries where the peaks have very different magnitudes over the years. However, this line of reasoning does not take into account the mutual assistance between MSs, which is triggered by the propagation of scarcity price signals. This section explores how the risks for peak flexibility capacities harmonises in time and over regions.

The revenues presented in this section are calculated for the day-ahead market, assuming that generators bid at their marginal variable cost. Therefore, peak generators only generate revenues during scarcity price hours[18], when the price is higher than the variable production costs.

In order to understand the structure of the revenues of peak flexibility units, it is not the occurrence of peak demand that should be investigated, but the occurrence of scarcity price hours, and in particular the number of years with more than 4 hours of scarcity prices, which is found to be the breakeven point for peak generators.

[18] These are the only hours during which the inframarginal rent is strictly positive. This study does not take into account other bidding strategies which would also allow peak flexibility units to partly recover their fixed costs during other periods. Yet, in *METIS Study S18 - Impact of bidding behaviours on market revenues*, it is shown that a strategic bidding strategy, even if it increases revenues, has a limited impact on the investment risks for peak flexibility assets.

Figure 13 shows the percentage of years with more than 4 hours of scarcity prices. It therefore reveals the percentage of years during which peak producer can recover their fixed annual costs. For example, this happens in Sweden in 13 out of the 50 weather scenarios (26%), which means that peak flexibility units can recover their fixed annual costs only once every four years.

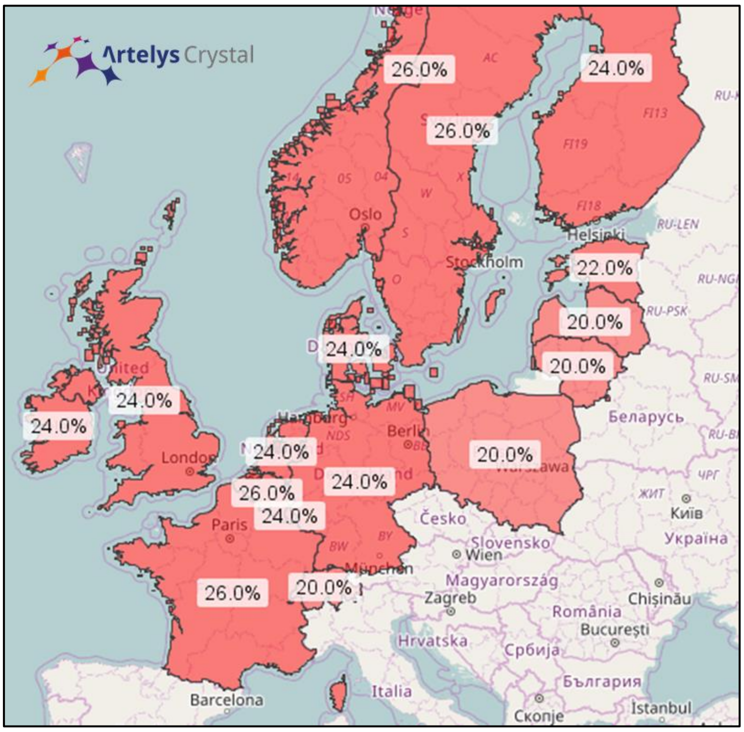

Figure 13: Percentage of year with 4 hours (or more) of scarcity price[19]

It can be observed that producers from neighbouring MSs share almost the same weather-related risks on their revenues: with only 10 to 13 of the 50 weather scenarios with 4 hours or more of scarcity prices, peak flexibility providers are only able to their fixed annual costs every 4 to 5 years. In Section 5.1, and in particular through Figure 10, we have seen that scarcity prices tend to propagate and synchronise, meaning that peak flexibility providers capture revenues simultaneously as long as interconnection capacities are not congested.

As a result of the propagation and synchronisation of price signals, European peak flexibility providers share similar weather-related risks on their revenues, instead of facing risks that are specific to the weather events of their own country.

5.3 RISK METRICS FOR BASE-LOAD, MID-MERIT AND PEAK UNITS

To better understand the revenue risks faced by base-load, mid-merit and peak flexibility providers, we can compute the revenues for every weather scenario, using the following formula for each producer:

$$\mathrm{AnnualRevenues} = \sum_{t} (\mathrm{MarginalCost}_{t} - \mathrm{VariableCost}) * \mathrm{Production}_{t}$$

MarginalCost is the cost of producing an additional MWh of electricity in the system.
VariableCost is the cost of 1 MWh of electricity produced by the producer.

---

[19] As mentioned in Section 4.1, in some countries, the projected high baseload and mid-merit generation capacity leads to very few hours of scarcity prices, independently from propagation effects. These countries are therefore not shown here.

Under a marginal cost bidding assumption, a producer generates revenues only if the marginal cost is higher than its variable production cost (fuel costs, CO_2 cost, operational and start-up costs), i.e. when a more expensive unit is called:

- Baseload producers generate revenues whenever they are online and mid-merit or peak flexibility producers are dispatched (including during scarcity price periods). When such units are called, baseload producers generate a revenue equal to the difference between their variable production costs and the market clearing price (variable cost of the most expensive unit that is dispatched or scarcity price)[20].

- Mid-merit producers generate revenues whenever they are online and peak flexibility producers are dispatched (including during scarcity price periods).

- Peak flexibility producers only generate revenues when they are online and the market price reaches the value of lost load.

In order to determine when producers can make profits, one should compare the revenues with the annual fixed costs. In Figure 14, we can identify the 12 weather scenarios (24% of the cases as indicated by Figure 13) in which the Dutch peak flexibility providers can recover their fixed costs. Similarly, we observe that the weather scenarios during which Belgian and Dutch peak flexibility units recover their fixed costs are almost totally synchronised.

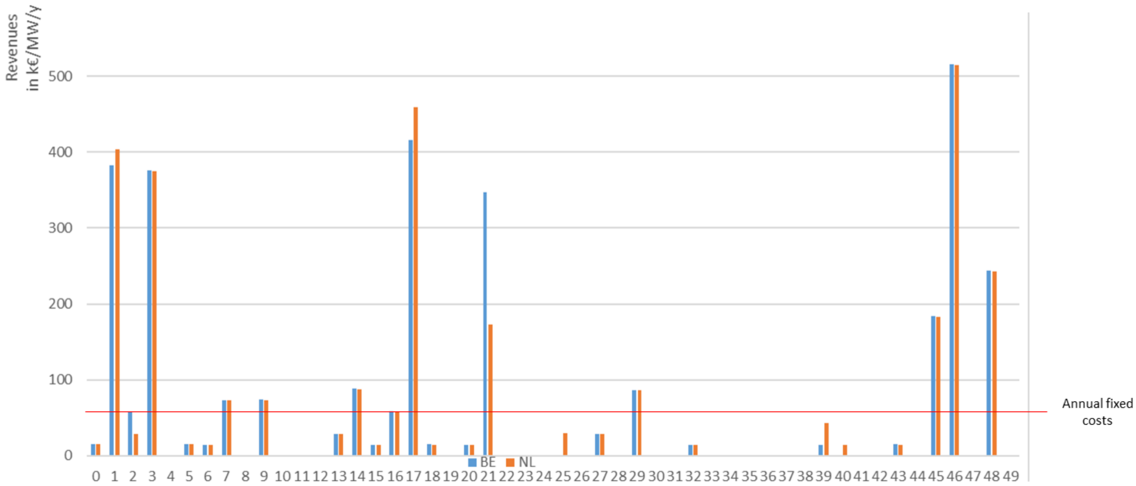

Figure 14: Peak flexibility units' annual revenues in Belgium (blue) and the Netherlands (orange) per weather scenario, and comparison with annual fixed costs

We can also observe that, although peak flexibility can recover their fixed costs every 4 to 5 years on average, there is a high volatility in the amount they can capture, varying in a range from 0 to more than 500 k€/MW/year in the Netherlands and Belgium. The average revenues are of the order of 60 k€/MW/year (equal to the fixed annual cost value by construction). This shows that there are always high uncertainties on revenues for peak flexibility providers from one year to another, due to the dependence on the occurrence of extreme weather events. In contrast, base-load producers generate revenues all year long due to their position in the merit order: since their variable production cost is low, high market prices, driven by extreme weather events, are not strictly necessary to generate sufficient revenues to recover their fixed costs. As a result, revenues for base-load units only marginally depend on extreme weather events, and exhibit a low level of dispersion. The structure of mid-merit units' revenues can be expected to be less regular than the one of base-loads units, but not as volatile as the one of peak-flexibility units.

[20] Start-up costs are also taken into account, but not included in the discussion to increase readability.

This phenomenon appears clearly on Figure 15, which shows the distribution of revenues in Europe for nuclear fleets, CCGTs and OCGTs, respectively representing base-load, mid-merit and peak flexibility producers.

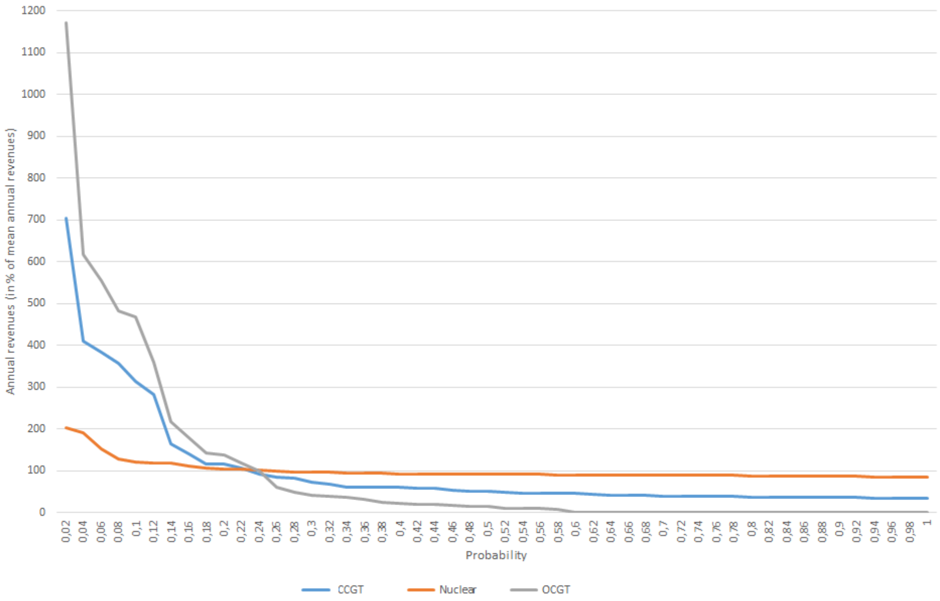

Figure 15: Distribution of revenues for base, mid-merit and peak producers in Europe

The risks faced by producers, as measured by the dispersion of their revenues, are found to substantially vary according to their position in the merit order:

- Base-load revenues are found to fluctuate from 80% to 200% of the mean annual revenues. Since base-load units generate revenues all over the year, and every year, risks are limited for investors.
- Peak-load producer revenues are found to be extremely volatile and can change from 0% to almost 1200% of their average value over the 50 weather scenarios. Peak-load producer revenues almost entirely rely on extreme weather conditions, as producers have to wait for scarcity price hours to generate revenues.
- Mid-merit load producer revenues insert themselves in between base-load and peak-load revenues, which vary from 30% to 700% of the average value.

The following table shows a number of metrics characterising the revenue distribution of the three categories of power plants:

(% of the average annual revenues)	Baseload	Mid-merit	Peak flexibility
Mean	100%	100%	100%
Median	92%	51%	15%
9th decile	120%	310%	470%
Standard deviation	23%	127%	215%
Risk premium[21]	0.4%	11%	30%

[21] Risk premium is defined here by the formula: $\text{Risk Premium} = \frac{\text{SemiVariance(AnnualRevenues)}}{2 \cdot \text{E[AnnualRevenues]}}$.

The analysis presented in this section shows that the revenues of peak flexibility assets have a strong dependence on extreme weather events. The level of risk having to be taken on by investors is therefore found to be important, and to be very similar in all the countries facing generation adequacy issues due to the propagation of scarcity price signals. This could discourage investments and lead to security of supply risks, since peak flexibility producers are needed to cover demand during difficult weather conditions.

This phenomenon is further enhanced in countries with low price caps, where peak flexibility units are not able to receive adequate remuneration, even during periods of scarcity[22]. This observation has led to the introduction of new mechanisms, including capacity remuneration mechanisms, to mitigate risks on revenues and encourage investments.

[22] The so-called "missing money" problem is not studied in this report.

6 RISK MITIGATION TECHNIQUES

This section aims at describing techniques to mitigate revenue risks. In particular, capacity remuneration mechanisms (CRMs) are described, since several such schemes have already been implemented, and that they are considered by several other Member States to tackle issues related to system adequacy, flexibility and risk mitigation.

6.1 CAPACITY REMUNERATION MECHANISMS

6.1.1 *TYPES OF CAPACITY REMUNERATION MECHANISMS*

Member States have recently been taking measures to ensure supply adequacy in the medium and long-term. These measures, called capacity remuneration mechanisms, are designed to support investments in order to ensure that there is no gap between demand and available capacity, even during extreme weather events. These mechanisms reward capacity in return for maintaining or investing in capacity needed to ensure the national security of supply.

There are several types of capacity mechanisms, either volume-based or price-based, each of them pursuing slightly different goals.

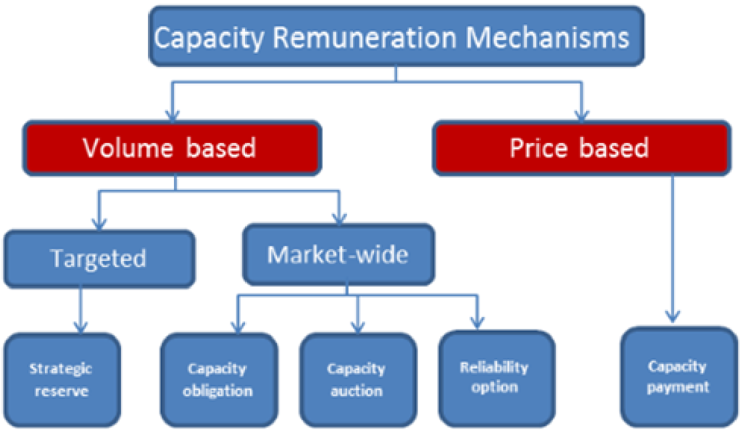

Figure 16: Taxonomy of CRMs (Source: Capacity remuneration mechanisms and the internal market for electricity, ACER, 2013)

- In a **Strategic Reserve** scheme, some generation capacity is set aside (out of the market) to ensure security of supply in exceptional circumstances, which can be signalled by market prices above a certain threshold. The amount of capacity to be set aside is determined and dispatched by an independent body, for example the TSO. Costs are borne by the network users.

- In a **Capacity Obligation** scheme, large consumers and suppliers have to contract a certain level of capacity linked to their self-assessed future consumption and supply. Contracted generators and consumers are required to make the contracted capacity available to the market in periods of shortages.

- In a **Capacity Auctions** scheme, the total required capacity is set several years in advance through an auction by an independent body. Costs are charged to the suppliers who charge end consumers.

- In a **Reliability Options** (ROs) scheme, holders of ROs are given a fixed fee and are required to pay the difference between the wholesale market price and a preset reference price (the "strike" price). Thus holders of ROs cap their electricity sale price at the level of the strike price since excess has to be reimbursed. An obligation is usually imposed on large consumers and suppliers to acquire a certain amount of ROs linked to their future consumption and supply.

- In a **Capacity Payment** scheme, generators and flexible consumers are paid a fixed price for available capacity. The price is determined by an independent body and the quantity supplied is determined by the actions of market participants.

6.1.2 *CRMs IN EUROPE*

Several Member States have implemented capacity remuneration mechanisms. The following map presents the operational and considered CRMs in Europe:

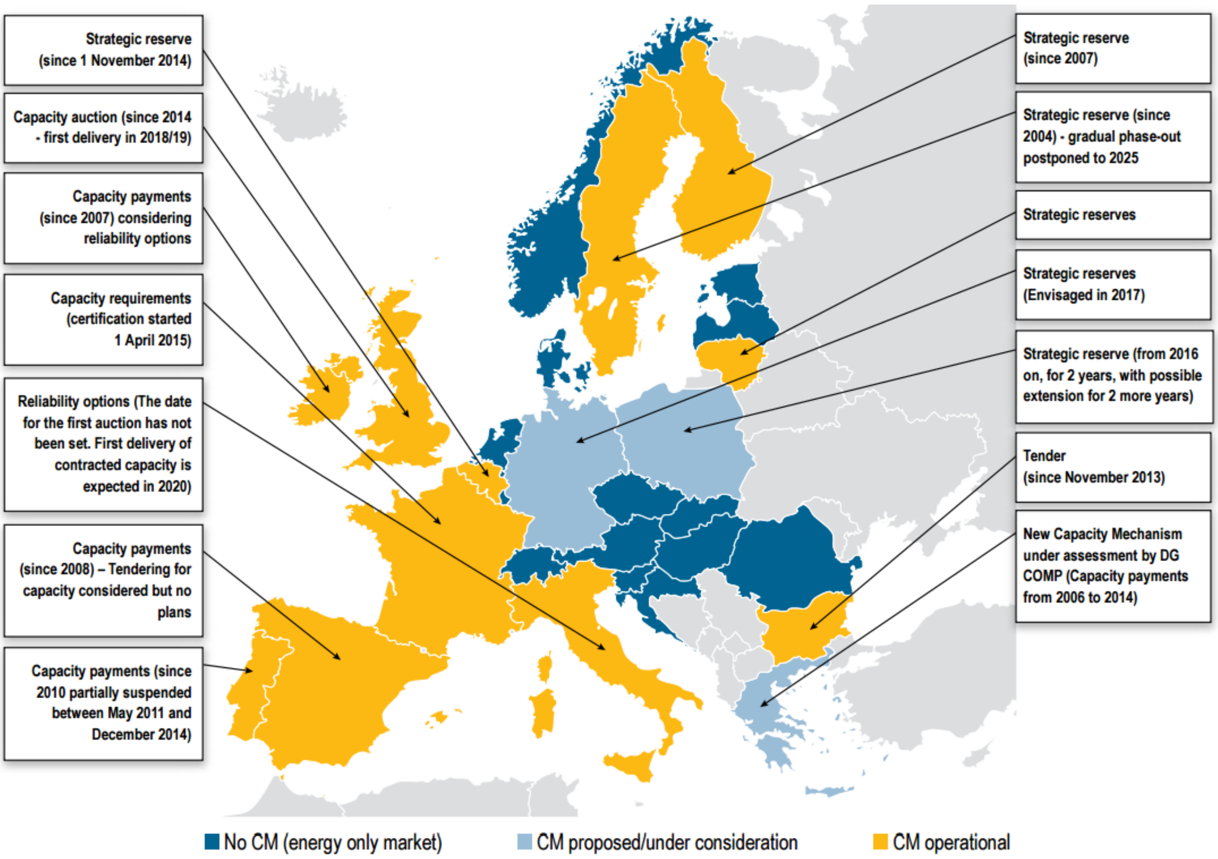

Figure 17: Map of CRMs in Europe (Source: ACER/CEER, Annual Report on the Results of Monitoring the Internal Electricity Markets in 2015)

A number of potentially complementary reasons can motivate the introduction of CRMs:

- **Adequacy**, which refers to the ability to ensure sufficient generation capacity in the electricity system to meet demand at all times, including at peak load periods,
- **Flexibility**, which refers to the ability to maintain sufficient system flexibility to balance the electricity system notably in response to demand variations or unexpected outages,
- **Reduced risk and price volatility**, which refers to the will to decrease risks for new investors and avoid price volatility associated with generators that run only periodically recovering their fixed costs over a short period of time.

The following table presents the CRMs that are implemented in Europe, and the reason leading to the introduction of such mechanisms.

Member State	Existing CRMs	Considered CRMs	Considerations
Belgium	Strategic reserve	Capacity payment	Adequacy
Denmark	-	Under consideration	Adequacy
Finland	Strategic reserve	-	Adequacy
France	Capacity obligations	-	Adequacy
Germany	Strategic reserve	Under consideration	Adequacy
Greece	Capacity payments	Capacity obligations	Adequacy
Hungary	-	Under consideration	Adequacy
Italy	Capacity payments	Reliability options	Adequacy
Ireland[23]	Capacity payments	Reliability options	Adequacy, Reduce risk and price volatility
Poland	Strategic reserve	Under consideration	Adequacy
Portugal	Capacity payments[24]	-	Adequacy, Flexibility Reduce risk and price volatility
Romania	Capacity payments	-	Adequacy
Spain	Capacity payments	Capacity auctions	Adequacy, flexibility Reduce risk and price volatility
Sweden	Strategic reserve[25]	-	Adequacy
United Kingdom[26]	Capacity auctions	-	Adequacy

[23] Ireland and Northern Ireland
[24] Suspended since 2012
[25] To be phased-out in 2020
[26] Excluding Northern Ireland

6.2 ALTERNATIVE RISK MITIGATION SOLUTIONS

As previously mentioned, CRMs constitute one of the available approaches to incentivise investments and to mitigate risks. However, other approaches exist and have been implemented in countries outside of Europe such as the Operation Demand Reserve Curve, the Reliability and Emergency Reserve Trader and Financial Transmission Rights.

6.2.1 *OPERATION DEMAND RESERVE CURVE*

The Operating Demand Reserve Curve (ORDC) was implemented by the TSO of the state of Texas, ERCOT, on June 1, 2014.

The aim of this mechanism is to improve scarcity pricing, i.e. to increase prices at times where the resource adequacy margin is tight. Indeed, a study commissioned by ERCOT[27] found that with the previous market design, reserve margins would need to fall below 8% for prices to exceed the marginal cost of new power generation plants. This lack of revenues for new capacities resulting from this price curve has been recognised as a threat for Texas' long term electricity supply, and has encouraged the introduction of the ORDC mechanism.

The ORDC introduces a new price component, the Real Time Reserve Price Adder (RTRPA) whose aim is to raise market prices and thus incentivise new infrastructure investments by allowing market participants to more easily recover their fixed costs. The RTRPA is calculated based on the real time market price, the Value of Lost Load (VOLL) and the Loss Of Load Probability (LOLP). Figure 18 provides a description of a fictional ORDC.

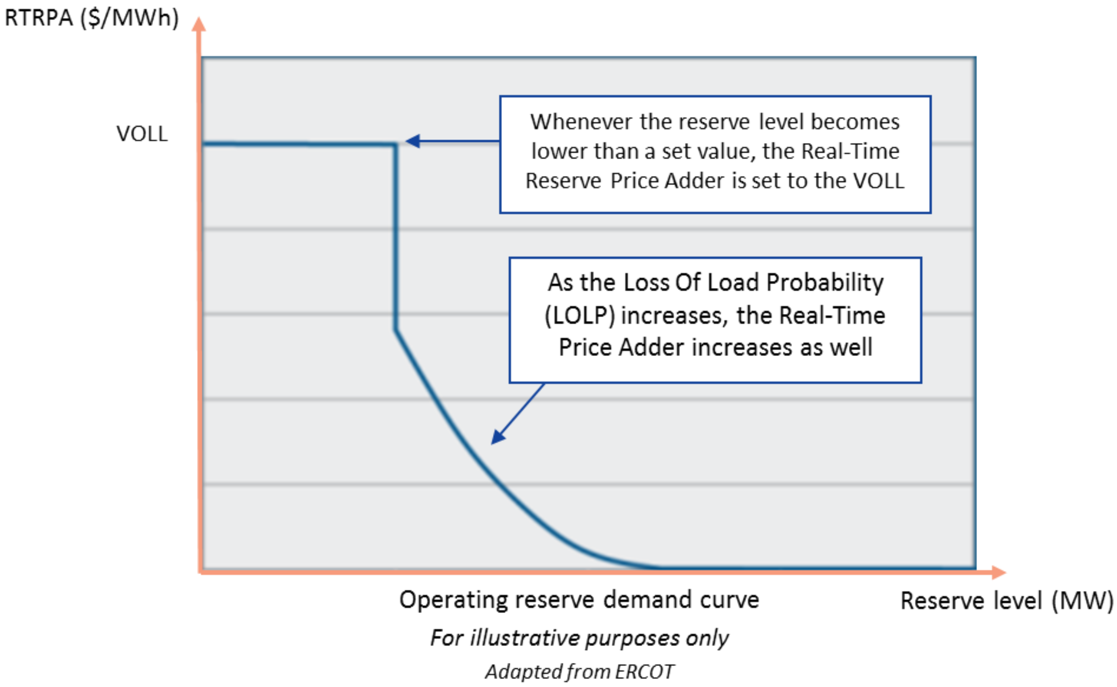

Figure 18: Illustration of the Operation Demand Reserve Curve

One can see that whenever the reserve margin decreases, the RTRPA value increases, which thus improves the scarcity price. If the reserve level becomes lower than a set value (currently set at 2000 MW in Texas), then the RTRPA is automatically set equal to the VoLL.

The sum of the Electricity Market Price and of the RTRPA is the price paid to all market participants, regardless of whether they provide electricity or online-reserve to ERCOT.

[27] « ERCOT Investment Incentives and Resource Adequacy », The Brattle Group

This treats real-time energy market and reserve market participation as equivalent and ensures that producers are indifferent between offering either of the two services.

The implementation of ORCD by ERCOT is too recent (2014) for its impact on resource adequacy to be fully understood. The main design characteristic to be followed is the level at which the RTRPA has been set, and whether it is high enough to allow fixed costs to be recovered.

The Reliability and Emergency Reserve Trader is an example of strategic reserves scheme.

6.2.2 *RELIABILITY AND EMERGENCY RESERVE TRADE*

The Reliability and Emergency Reserve Trader (RERT) is a mechanism currently being used by the entity managing the electricity and gas markets in Australia, the Australian Energy Market Operator (AEMO). The RERT lets the AEMO contract for reserves for up to nine months in advance for times where it thinks there will be a lack of reserve. The contracted reserves should normally not be available on the market otherwise.

The RERT was originally seen as a short-term measure to accompany the evolution of the Australian market with the creation of the New Electricity Market (NEM). Nonetheless, RERT has since then been extended several times. It was to expire by June 30, 2016 but should be extended until June 2019.

So far, AEMO has used the RERT mechanism only three times, and the contracted reserve was not called upon.

Some Australian stakeholders consider that the RERT can create possible market distortions, encouraging power producers to withdraw investments or plants openings in order to receive more revenues from existing power plants through the RERT. This is the reason why in the new version of RERT proposed by AEMO, reserves could be contracted only ten weeks in advance, and not nine months as of now, in order to make sure the RERT does not create a parallel market for reserves.

6.2.3 *FINANCIAL TRANSMISSION RIGHTS*

Financial Transmission Rights (FTRs) are a way for power producers to secure revenues in markets with Locational Marginal Prices (LMPs; such markets can be found in the US, - PJM, NYISO for instance -, or in New Zealand). Indeed, in such markets, prices can vary between two nodes whenever the transmission line between those two nodes becomes congested. When this situation occurs, a power producer in market A which has entered into a long-term contract with a buyer in market B may have to sell its production in market A and buy the amount in energy it is supposed to supply in market B, thus losing an amount of money equal to the price difference between the two areas. This is illustrated by Figure 19:

The transmission line between nodes A and B is saturated: prices diverge between the two markets.

Figure 19: Illustration of price divergence between markets

A power producer in market A would sell its production at 30€/MWh in market A, but would have to buy it at 50€/MWh in market B in order to supply its customers in market B. Market revenues in such a situation are thus uncertain, and in the case of resource adequacy, could deter power producers from investing in new capacities.

A way to fix this issue has been found with FTRs; FTRs are a financial product providing hedging against the situation described above. For a fixed fee, power producers can buy FTRs from the market operator (or the TSO depending on the market design). In return, if the line is saturated and prices diverge between the two markets, the producer is compensated with the difference between the two market prices.

In the previous example, a power producer buying a FTR between nodes A and B would receive 20€/MWh from the market operator thanks to its FTR, which is exactly the difference in price between area A and area B. FTRs are purely financial products and do not actually provide the right to use the transmission line (such products are Physical Transmission Lines).

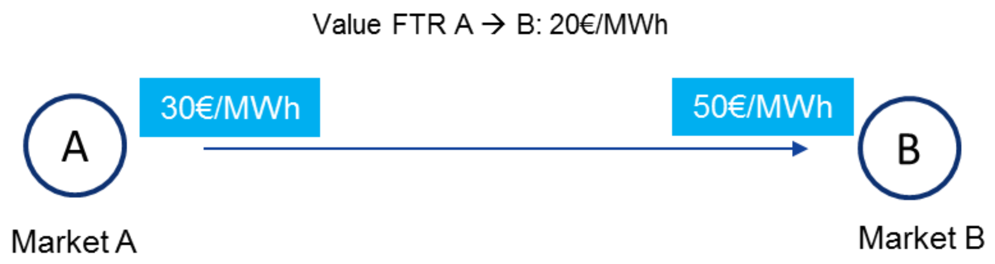

Figure 20: Illustration of a Financial Transmission Rights scheme

From an investor's point of view, FTRs are thus a means to reduce revenue volatility linked with the saturation of transmission lines.

7 BENEFITS OF EUROPEAN COOPERATION

This section aims at assessing the benefits of a coordinated approach to the dimensioning of power systems. We first explore the required investments when dimensioning the system with or without considering that MSs can assist each other when facing difficult periods. We then show that, if CRMs are to be introduced, setting the capacity objectives in a coordinated way leads to an optimal balance between investment costs and security of supply.

7.1 CAPACITY SAVINGS DUE TO SYSTEM COOPERATION

As explored in Section 4, MSs are characterised by very different thermal gradients and temperature profiles. Some countries face peaks that have the same magnitude almost every year, while others face high demands more rarely. In the absence of cooperation, the peak flexibility units of the latter countries would only be used very rarely. Thus, a cooperative approach to energy system dimensioning can induce considerable investment savings, provided that the demand peaks are not simultaneous.

To estimate the benefits of cooperation, the analysis is based on the METIS 2030 EUCO27 scenario, and uses 50 weather scenarios and an hourly time resolution (8760 consecutive time-steps per weather scenario). In order to assess, from a systems point of view, the capacity savings that can be generated thanks to regional cooperation, the capacities of peak flexibility options (which could be CCGTs, OCGTs, DSR, etc.) are optimised while the capacity of nuclear, coal, lignite, hydropower are fixed to the corresponding PRIMES EUCO27 scenario values[28]. The optimisation has been performed in two cases:

- **Without cooperation** – The capacities are optimised for each country separately, assuming no possibility to benefit from the capacities of neighbouring countries during peak hours,

- **With cooperation** – The capacities are jointly optimised for all countries, taking into account interconnection capacities and the fact that MSs may or may not be able to provide each other assistance during peak hours, depending on their local situation.

The difference of installed capacity between these two cases reveals how much capacity savings could be generated if all MSs were to take mutual assistance into account when dimensioning their power systems. However, one should note that a part of these savings is already captured by the current practices adopted by some MSs when performing their generation adequacy assessment[29].

The optimisation problems have been performed with the Artelys Crystal platform capacity expansion features[30].

[28] In contrast with the procedure adopted in Section 4.1, the residual capacities are not taken into account in Section 7.1. In such a way, we are able to identify the savings generated by cooperation, without being influenced by the current overcapacity situation. A sensitivity analysis reveals that the methodology only marginally impacts the results: the avoided investments at the European level (ENTSO-E perimeter) are found to be around 80 GW when taking residual capacities into account, while they would reach 90 GW if one were not to take residual capacities into account.

[29] For instance, the French TSO RTE assumes that 7% of French peak demand can be covered by neighbouring countries and French utilities only have to provide capacity credit for 93% of the peak demand. In the UK, interconnectors can participate in the capacity market (via de-rated capacities).

[30] Such a computation requires a High-Performance Computation cluster since the capacity expansion algorithm uses the same time resolution as METIS (hourly resolution, 8760 consecutive time-steps for each of the weather

The following cost assumptions have been used:

- Annualised CAPEX: 45.7 k€/MW/year[31]
- Annual fixed operating costs: 15.2 k€/MW/year[32]

The capacity expansion algorithm finds the optimal trade-off between additional investments in peak flexibility options and paying the cost associated with unserved energy (the cost of loss of load is set to 15 000 €/MWh). The system will keep investing until the average of weather scenarios of the number of hours with scarcity prices reaches a value of around 4 hours.

Results based on the EUCO27 projections show that almost 80 GW of generation capacity can be avoided at the EU28 level thanks to a cooperative approach to system dimensioning. This represents more than 30% of the installed gas capacities in 2030 for the case without cooperation. Given the assumptions on investment costs (which is assumed to be identical for all peak flexibility options), this represents savings of the order of 5 billion euros per year. Moreover, this figure does not include savings on production dispatch, which could lead to even higher savings.

Country	Optimal capacities (GW)		Investment costs (B€)	
	Without cooperation	With cooperation	Without cooperation	With cooperation
AT	2.8	-	0.2	-
BA	-	-	-	-
BE	13.9	11.6	0.8	0.7
BG	-	-	-	-
CH	4.8	-	0.3	-
CY	1.1	1.1	0.1	0.1
CZ	-	-	-	-
DE	40.8	26.6	2.5	1.6
DK	4.2	2.4	0.3	0.1
EE	0.4	-	0.0	-
ES	22.0	19.5	1.3	1.2
FI	9.6	6.8	0.6	0.4
FR	30.4	20.2	1.9	1.2
GR	5.2	2.5	0.3	0.2
HR	1.5	0.2	0.1	0.0
HU	2.3	0.1	0.1	0.0
IE	4.0	3.1	0.2	0.2
IT	29.0	23.0	1.8	1.4
LT	0.5	0.3	0.0	0.0

scenarios). As METIS typically runs on a desktop computer, the capacity optimisation was performed using Artelys Crystal Super Grid, then exported to METIS for the rest of the study.

[31] A CAPEX of 550k€/MW is assumed (Source: *ETRI 2014, Energy Technology Reference Indicator projections for 2010-2050*, JRC Science and Policy reports). The PRIMES discount rate for power utilities (8.5%) has been assumed.

[32] PRIMES EUCO27

Country	Optimal capacities (GW)		Investment costs (B€)	
	Without cooperation	With cooperation	Without cooperation	With cooperation
LU	1.1	0.6	0.1	0.0
LV	1.3	0.7	0.1	0.0
ME	0.0	-	0.0	-
MK	1.1	-	0.1	-
MT	0.3	0.3	0.0	0.0
NL	11.2	4.4	0.7	0.3
NO	9.3	5.3	0.6	0.3
PL	6.9	1.1	0.4	0.1
PT	5.0	3.0	0.3	0.2
RO	2.5	-	0.2	-
RS	2.7	-	0.2	-
SE	10.8	5.2	0.7	0.3
SI	0.6	0.2	0.0	0.0
SK	-	-	-	-
UK	43.2	38.9	2.6	2.4
EU28	**251**	**172**	**15.3**	**10.4**

The above table shows the optimal gas capacities and the corresponding investments in both cases (with and without cooperation) at the country level. In absolute terms, the capacity savings are largest in Germany and France (respectively 14 GW and 10 GW), i.e. in large and well interconnected power systems.

In particular, the table shows that a number of countries do not need any additional peak flexibility units when taking cooperation with neighbouring countries into account. For example, Austria and Romania, which respectively require 2.5 GW and 2.8 GW of peak flexibility capacity in the option without cooperation, are found not to need to install any peak flexibility units when taking cooperation into account.

Furthermore, no gas capacities are needed in the Czech Republic, Bulgaria and Slovakia in both cases (with and without cooperation). This is due to their important baseload and mid-merit capacities (mainly nuclear and coal capacities[33]), which, along with imports, are sufficient to balance supply and demand.

Figure 21 presents the capacity savings measured in terms of percentage of the mean demand at the country level. Although Germany and France benefit from the largest absolute savings, smaller countries are found to benefit much more from cooperation in relative terms. For example, the capacity savings represent 64% of the mean demand in Estonia while it only represents around 20% in Germany. The figure is even lower for Spain with savings reaching only 8% of mean demand, while Portugal is found to substantially benefit from the cooperation with Spain.

[33] Nuclear and coal generation capacities are based on the PRIMES EUCO27 scenario, which includes current capacity still operational in 2030, along with estimated investments in the 2015-2030 period.

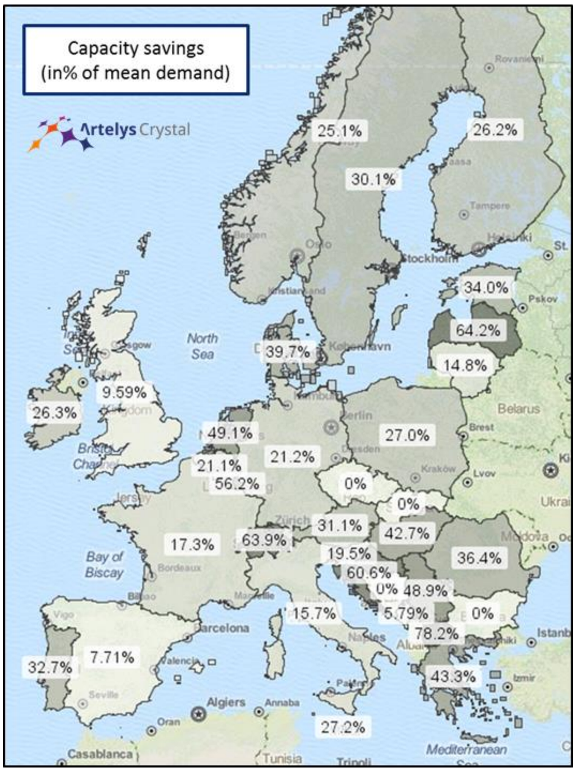

Figure 21: Capacity savings due to cooperation in investments

The two main drivers explaining the level of capacity savings are the variability of peak demand across Europe, and the variability of weather conditions (and consequently of RES generation profiles). The aggregated European demand peak is therefore lower than the sum of all national demand peaks. As a result, a single additional peak power plant can help several countries balancing their energy systems, since demand peaks are not totally synchronised across countries[34].

In addition, despite geographical correlations at the regional scale, different weather regimes produce different weather conditions across Europe, which can compensate one another. Aggregating the RES generation profiles at the European level leads to higher capacity credit for RES compared to national values, and decreases the need for additional peak flexibility options.

In conclusion, this section has demonstrated that a European power system in which MSs consider mutual assistance when performing their generation adequacy assessment would generate substantial capacity savings compared to a set of isolated national power systems.

[34] For instance, extreme temperature conditions are often not synchronised between Western Europe and Northern Europe (Norway, Sweden, Finland and Estonia).

7.2 BENEFITS OF COOPERATION AND COORDINATION

The previous section has highlighted the benefits of a cooperative approach when estimating the generation capacity requirements at the European level. In this section, we explore how to optimally set the objectives, in terms of capacity, a CRM should target.

7.2.1 *OBJECTIVES AND METHODOLOGY*

Currently, a number of MSs have implemented CRMs. Interestingly, some of the implemented schemes do take neighbouring countries into account when setting the objectives of the CRM (e.g. the capacity that should be auctioned). This section aims at illustrating the benefits of such approaches, and to identify the optimal trade-off between the level of security of supply and the corresponding investments.

The evaluation of several options that could be used to set the CRM objectives is illustrated on two countries: the United Kingdom and Ireland.

Five options are considered in the following:

- **Option 1 – Uncoordinated and uncooperative CRMs**
  Each country dimensions its CRM capacity objectives in order to be able to face its demand peaks without assistance.

- **Option 2 - Uncoordinated CRMs, with full transmission capacity**
  Each country dimensions its CRM capacity objectives in order to be able to face its demand peaks, by taking into account the import capacity, assuming that it will be fully available to provide assistance during scarcity periods.

- **Option 3 - Coordinated CRMs without network constraints**
  The two countries jointly dimension their CRM capacity objectives, but ignore the network constraints between the UK and Ireland. In an auction scheme, this would correspond to an auction in which UK and Irish capacities could participate, without any geographical allocation targets.

- **Option 4 – Coordinated CRMs**
  The two countries jointly dimension their CRM capacity objectives, and take the network constraints into account. In an auction scheme, this will be shown to correspond to auctioning the same amount of capacity as in Option 3, but with national targets.

- **Option 5 - Partially coordinated CRMs with strategic reserves**
  The two countries jointly dimension their CRM capacity objectives, and take the network constraints into account (i.e. same as in Option 4). Ireland then adds a strategic reserve so that it total peak flexibility capacity is the same as in Option 1. The strategic reserve is assumed to be available only to help Ireland face challenging situations, and have the same variable cost as other peak plants.

For each of the options listed above, the following two steps are performed:

- **Step 1 - Investment phase**
  The peak flexibility capacities (the 2030 residual OCGT capacities are taken into account) are optimised over 50 weather scenarios[35], by taking the characteristics of the options presented above into consideration (e.g. by ignoring network constraints between the UK and Ireland in Option 3). The results of Step 1 are the installed capacities in the UK and Ireland, and the corresponding investment costs.

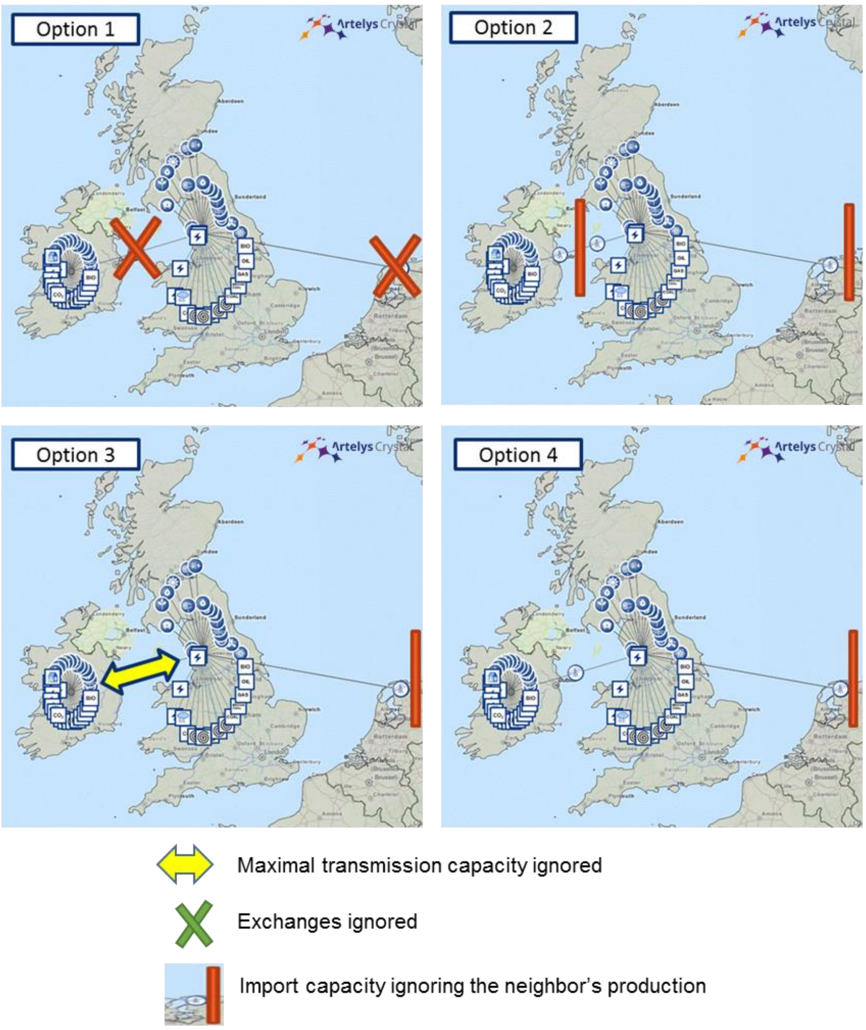

Figure 22: Illustration of the options for cooperation in CRM

- **Step 2 - Simulation phase**
  The installed capacities obtained in Step 1 are used during the simulation of the optimal dispatch performed with METIS. All the European countries are assumed to cooperate during the simulation phase. The results of Step 2 include production costs, exchanges between countries, hours of loss of load, etc.

[35] The methodology and parameters used to dimension peak flexibility means are identical to the methodology and parameters used to calibrate the METIS EUCO27 scenario, see Section 4.1.

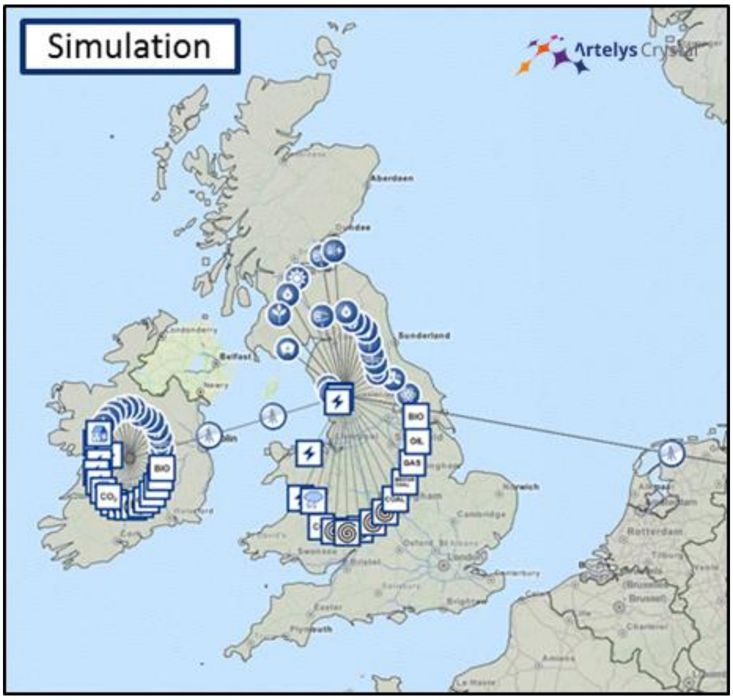

Figure 23: Illustration of the simulation model

For simplicity, the UK and Ireland are modelled explicitly while the rest of Europe is aggregated into a single zone.

For example, for Option 1, the process unfolds as follows:

- **Step 1 – Investment phase**
  The UK and Ireland independently assess the required peak flexibility capacity they need to face their demand peaks without assistance. It is found that they respectively need 18.9 GW and 1.7 GW of peak flexibility capacity.

- **Step 2 – Simulation phase**
  During the simulation phase, interconnectors are taken into account when simulating the optimal dispatch. The peak flexibility capacities of the UK and Ireland obtained in Step 1 are used as inputs (18.9 GW and 1.7 GW respectively). Indicators measuring the operational performance of the power system are computed (e.g. production costs, CO_2 emissions, loss of load hours, producers' revenues, etc.)

7.2.2 *RESULTS*

We present our results in this section, in terms of investments (Step 1), loss of load and costs (Steps 1 and 2). The operational results presented below correspond to the average over the 50 weather scenarios (the investments are independent of the weather scenario).

Investments

The following table shows the results of the investment phase (Step 1). They correspond to the capacities of peak flexibility options that would need to be installed in both MSs to satisfy the criteria set by each of the options.

Investments (GW)	Ireland	United Kingdom	Total
Option 1	1.7	18.9	20.6
Option 2	0.5	10.1	10.6
Option 3	4.3	8.3	12.6
Option 4	0.9	11.7	12.6
Option 5	1.7	11.7	13.4

In Option 1, each country has to be able to face its demand peaks without assistance. The required level of peak flexibility capacity is therefore the highest among all options. In total, more than 20 GW are required to satisfy this security of supply condition.

In Option 2, each country assumes that the full capacity of the UK-IE interconnector is available to help them balance their energy system. The overestimation of the ability of the neighbours to provide assistance during peak hours leads to a very low level of investments compared with Option 1 (10.6 GW *vs* 20.6 GW). In particular, the additional capacity installed in Ireland corresponds to less than 30% of the capacity required to be self-sufficient (Option 1). This situation will be shown to lead to a large volume of loss of load.

In Option 3, the joint optimisation of the capacities of peak flexibility units leads to peak flexibility requirements of 12.6 GW. However, since the interconnection capacity is not taken into account, the allocation of capacity between Ireland and UK will be shown to be insufficient for the UK to be able to cover its peak demand.

In Option 4, the joint optimisation of the peak flexibility capacities takes the UK-IE network constraint into account. As argued in Section 7.1, this procedure can lead to substantial savings when compared to Option 1. Indeed, we find that Option 1 overestimates the required capacity by around 8 GW (20.6 GW *vs* 12.6 GW)[36].

Finally, in Option 5, the same investments as in Option 4 are required in the UK. Higher investments are made in Ireland, which sets up strategic reserves so that the local installed capacity is the same as in Option 1 (1.7 GW).

[36] The fact that the total installed capacity in Options 3 and 4 are the same is due to the capacity of the UK-IE interconnectors (assumed to be 1.4 GW). If the interconnectors were to have a lower total capacity, the investments required in Option 4 would be higher than those of Option 3.

The investment costs are assumed to be proportional to the installed capacities (60.9k€/MW/year). The same conclusion as above can therefore be drawn for investment costs.

Loss of load

In Option 4, the investments are jointly optimised using an accurate description of the exchange capacities. Given the parameters used to dimension peak flexibility means, the number of hours during which the demand cannot be entirely served is found to be below 4 hours in both countries on average over the 50 weather scenarios. The total volume of loss of load is around 14 GWh on average.

In Option 2, the ability of both countries to cooperate is overestimated: each country assumes that the full import capacity would be available when required. However, since both countries are likely to experience some similar weather events at the same time, this uncoordinated approach leads to underestimated investments which induce loss of load during peak hours (24 GWh in total, and more than 4 hours of loss of load in both countries).

In Option 3, it is found that a similar volume of loss of load would result from the suboptimal allocation of investments (21 GWh of loss of load in the UK, and more than 4 hours of loss of load on average). The total investment capacity is the same as in Option 4, but the geographical allocation is found to be different. In a capacity auction setting this situation would correspond to a joint calculation of the required capacity and a joint auction, whereas Option 4 would correspond to a joint calculation of the required capacity, and two separate auctions in the UK and in Ireland, so as to ensure the geographical distribution of investments is optimal.

In Options 1 and 5, since the investments are more important than in Option 4, the volume of loss of load are found to be rather low (almost zero in Option 1). In Option 5, loss of load in Ireland also decreases from 2.6 GWh (in Option 4) to 0.6 GWh, as Ireland can activate strategic reserves during peak hours. However, the analysis of the corresponding costs (see below) confirms that the reduced loss of load does not compensate for the additional investments compared to Option 4.

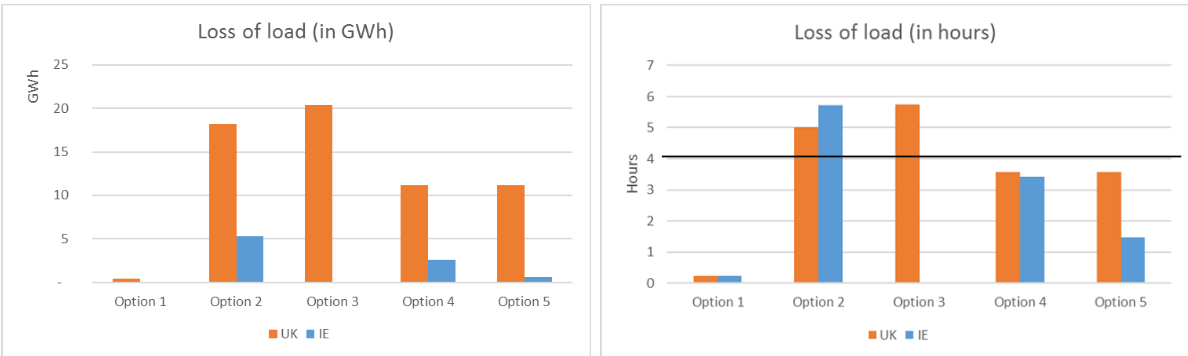

Figure 24: Loss of load per country per option

Costs

The production costs discussed in this paragraph include fuel costs, CO_2 costs, operational and start-up costs. The production costs are found to be very similar in all options (around 11 B€) since almost same amount of electricity is generated in all options (the options without loss of load are characterised by a slightly higher production volume). The main impacts on the total system costs are therefore the loss of load costs and investment costs.

In Option 4 is found to be the cheapest option with an optimal balance of investment and loss of load costs. Total costs reach 12 B€ per year, among which 200 M€ are due to loss of load and 760 M€ are dedicated to investments. The costs of all the other options will be compared to those of Option 4.

In Option 1, since the loss of load volume falls almost to zero, the corresponding loss of load costs are found to be of the order of 7 M€. However investments costs increase substantially and are found to reach 1.3 B€. Therefore, compared to Option 4, the loss of load savings do not compensate for the extra investment costs: Option 1 is around 300 M€ more expensive than Option 4.

In Option 2, the reduced level of investments does not compensate for the extra cost of loss of load: investments costs are lower by 120 M€ than in Option 4 while loss of load costs are higher by 150 M€, leading to Option 2 being around 30 M€ more expensive than Option 4.

In Option 3, the same investment costs are the same as in Option 4, but due to the suboptimal allocation of capacity, additional loss of load costs are induced. Option 3 is therefore found to be more expensive than Option 4 by around 100 M€.

Finally, in option 5, the strategic reserves introduced in Ireland cause a 1 M€ rise of production costs and induce savings of around 30 M€ thanks to the reduced level of loss of load. However, the additional investment costs are found to be more important than the savings, leading to a total additional costs of 20 M€ compared to Option 4. If the strategic reserve scheme were to be adopted by the UK instead Ireland (using the same methodology as in Option 5), the additional investment costs would be even higher, as more than 7 GW of additional capacity would be required.

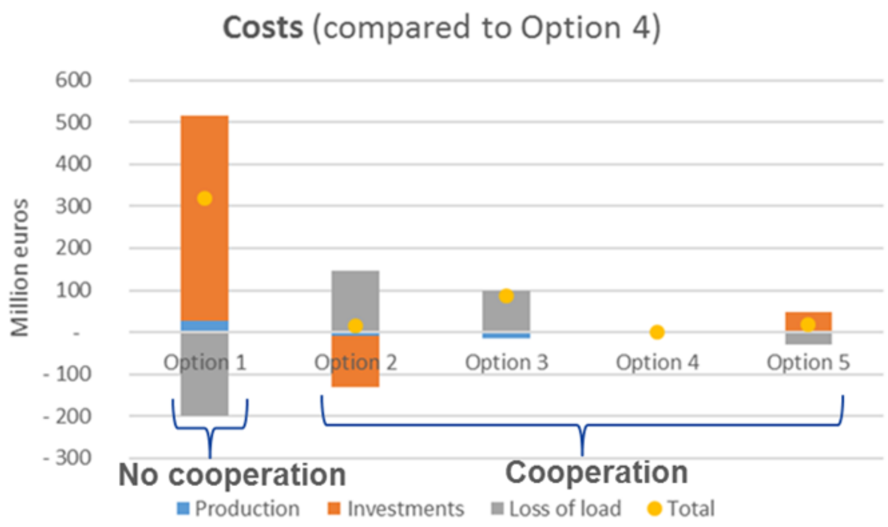

Figure 25: Costs per option compared to Option 4

In conclusion, it appears that large savings can be obtained when countries cooperate when setting their CRM capacity objectives. Ignoring cooperation can lead to substantial overinvestments or to more frequent loss of load situations.

8 CONCLUSION

In this report, we have explored the structure and drivers of the market revenues and profits peak flexibility providers can expect to generate in the METIS 2030 EUCO27 scenario. Such assets, which are necessary to face irregular but potentially important variations of the demand and to ensure Europe has access to a secure source of energy, face important revenue uncertainties.

In contrast to baseload producers, which have a very stable revenue stream from one year to the other, peak flexibility providers generate revenues which can vary between 0 and 12 times the average annual value, and make profits once every four years at best. Thanks to the propagation of price signals, the mutual assistance between Member States is shown to harmonise the risk levels across Europe.

However, such risks may discourage investments, and pose a threat to security of supply since peak flexibility providers are one way to ensure the demand is met, especially during stressful events. Therefore, MSs are exploring or implementing new techniques to ensure that the demand can be covered adequately. Among these techniques, capacity remuneration mechanisms have already been put into practice by several MSs. Such schemes provide an additional revenues stream to producers (and sometimes demand-response providers) in exchange for the provision of capacity, whether used or not. This study has highlighted the importance of cooperation when setting the CRM capacity target (e.g. the amount of capacity that has to be auctioned).

More generally, cooperation, mutual assistance and solidarity are found to be key to tackle generation adequacy issues. In comparison to a system where each country would dimension its own power system so as to be able to cover its demand independently, a cooperative approach would generate saving of up to 80 GW of generation capacity, which would represent around 5 billion euros per year in investment costs only.

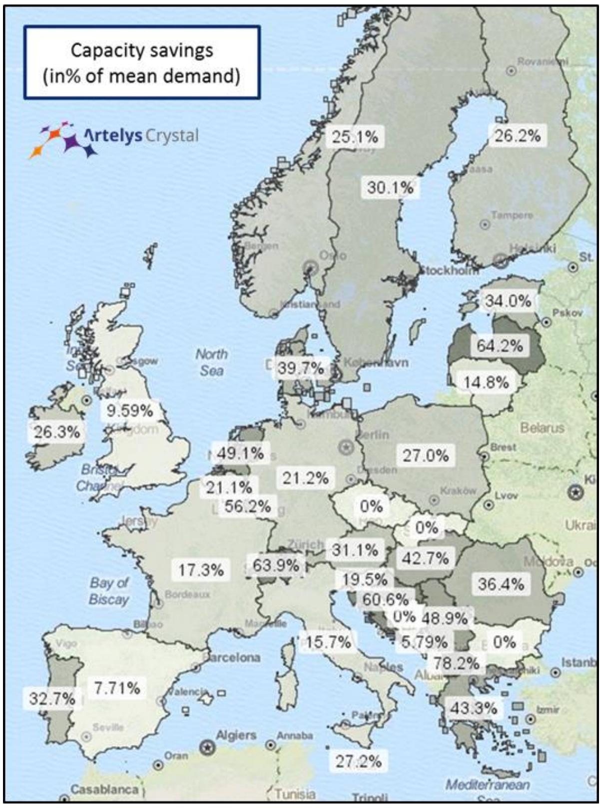

Figure 26: Capacity savings due to cooperation

9 REFERENCES

EU Energy, Transport and GHG emissions | Trend to 2050 - Reference scenario 2013, *European Commission, 2013*

Scenario outlook and adequacy forecast 2014-2020, *ENTSO-E, 2014*
https://www.entsoe.eu/publications/system-development-reports/adequacy-forecasts/Pages/default.aspx

10-Year Network Development Plan 2014, *ENTSO-E, 2014*
https://www.entsoe.eu/news-events/announcements/announcements-archive/Pages/News/Ten-Year-Network-Development-Plan-2014-for-Public-Consultation.aspx
https://www.entsoe.eu/Documents/TYNDP%20documents/TYNDP%202014/141031%20TYNDP%202014%20Report_.pdf

World Energy Outlook 2011, International Energy Agency, 2011

ERCOT Investment Incentives and Resource Adequacy, *The Brattle Group, 2012*
http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/Brattle_ERCOT_Resource_Adequacy_Review_2012-06-01.pdf

Review of the Reliability and Emergency Reserve Trader, *Reliability Panel AEMC, 2011*
http://www.aemc.gov.au/getattachment/3b955d3e-93bf-4666-a27f-25662f407d74/Final-Report.aspx

Financial Transmission Rights of New Zealand website
https://www.ftr.co.nz/

Electricity Authority of New Zealand website
http://www.ea.govt.nz/operations/wholesale/hedges/ftr-market/

Capacity remuneration mechanisms and the internal market for electricity, *ACER, 2013*
http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/CRMs%20and%20the%20IEM%20Report%20130730.pdf

Capacity mechanisms, Reigniting Europe's energy markets, *Linklaters, 2013*
http://www.linklaters.com/Insights/Thought-Leadership/Energy-generation-adequacy-capacity-mechanisms/Pages/Capacity-mechanisms-Reigniting-Europes-energy-markets.aspx

Capacity Mechanisms in EU Energy Markets: Law, Policy and Economics, *Leigh Hancher, Adrien de Hauteclocque and Malgorzata Sadowska, 2015*

Capacity mechanisms in the EU: Nationalizing energy security?, *Jekaterina Grigorjeva, 2015*
http://www.delorsinstitut.de/2015/wp-content/uploads/2015/05/20150518_CapacityMarkets-Grigorjeva-JDIB.pdf

Market model 2.0, Final report, *Energinet, 2015*
https://www.energinet.dk/SiteCollectionDocuments/Engelske%20dokumenter/El/Final%20report%20-%20Market%20Model%202.0.pdf

Capacity mechanisms for power system reliability, Sarah Keay-Bright, *RAP, 2013*
http://www.raponline.org/document/download/id/6805-Bright&ie=utf-8&oe=utf-8&gws_rd=cr&ei=lyICV7_BKMS0aZ6du_AE

Capacity mechanisms in Europe, *IHS ENERGY, 2015*
http://www.ceem-dauphine.org/assets/dropbox/IHS-_Christian_Winzer.pdf

The Rise of Capacity Mechanisms: are they inevitable in the European Union ?, *T. Zgajewski, EGMONT, 2015*
http://www.egmontinstitute.be/wp-content/uploads/2015/10/ep80.pdf

Survey of Capacity Support Mechanisms in the Energy Community, *CEER, 2006*
http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/2006/CEER_SEE-CapacitySupportMechanism_2006-06-06_V2.pdf

Capacity mechanisms: revived interest in capacity mechanisms throughout Europe in the face of high volumes of intermittent generation, *NEPP, 2011*
http://www.nepp.se/pdf/capacity_mechanisms.pdf

Capacity remuneration mechanisms*, CREG, 2013*
http://ec.europa.eu/competition/state_aid/modernisation/tirez_en.pdf

A reference model for European capacity markets, *Eurelectric, 2015*
http://www.eurelectric.org/media/169068/a_reference_model_for_european_capacity_markets-2015-030-0145-01-e.pdf

Italian Capacity Market, *Terna, 2015*
http://ec.europa.eu/competition/sectors/energy/capacity_mechanisms_working_group_12.pdf

French capacity market, *RTE, 2014*
http://www.rte-france.com/sites/default/files/2014_04_09_french_capacity_market.pdf

Reform of the Capacity Remuneration Mechanism in Greece, *Prof. P. Capros, E3-Modelling, 2014*
http://www.rae.gr/site/file/system/docs/misc1/20102011/29071402

Annual Report on the Results of Monitoring the Internal Electricity Markets in 2015, *CEER/ACER, 2016*
http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National_Reporting_2016

Other websites:
http://www.sqconsult.com/content/newsletter_html/sqconsult_mailing_04-09-2013.html
http://www.energyworldmag.com/20/03/2015/greece-the-reform-of-the-capacity-remuneration-mechanism-crm/
https://www.cleanenergywire.org/factsheets/capacity-markets-around-world
http://www.nortonrosefulbright.com/knowledge/publications/134879/the-capacity-market-in-great-britain-results-and-reform
http://www.icis.com/resources/news/2015/09/18/9925037/italy-s-2017-electricity-capacity-market-early-start-delayed-sources/

Publications Office