Modelling study contributing to the Impact Assessment of the European Commission of the Electricity Market Design Initiative

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Abbreviations

ATC	Available transfer capacity
CHP	Cogenerated Heat and Power
CM	Capacity mechanisms/ Capacity markets
DA	Day-Ahead
DAM	Day-Ahead market
EOM	Energy-only market
ID	Intraday
IDM	Intraday market
IEM	Internal Electricity Market
MDI	Market Design Initiative
NTC	Net transfer capacity
RES	Renewable Energy Sources
UC	Unit Commitment

EXECUTIVE SUMMARY

The Market Design Initiative of the EU Commission aims at addressing the challenges and opportunities posed by the transition towards a decarbonised energy system for the internal market of electricity. Various policy options targeted to tackle these issues and at the same time remove current market distortion are the subject of economic evaluation within the Impact Assessment of the Market Design Initiative. The study described in this note used modelling techniques based on the PRIMES model and newly developed sub-models for the electricity markets to contribute to the impact assessment. The study consists of two parts:

The first part focuses on electricity market operation assuming the sequential operation of organised markets at Day-Ahead, intraday and real time timeframes. A newly developed model of the PRIMES suite simulates the operation of these markets for the entire EU with high resolution over time and by country. The purpose is to simulate the markets in future years assuming implementation of the low-carbon strategy to evaluate the impacts of various policy options. The options regard market design issues which aim at removing distortions, unify the internal market and address the challenges of a system with high penetration of low-carbon resources effectively, notably due to the variable renewables. The evaluation of the policy options regards the impacts on the market operation, the costs and prices borne by the consumers, and the degree of recovery of costs of generators.

The second part focuses on the behaviour of investors and assesses the ability of markets to sustain adequate levels of investments in future years amid considerable uncertainties related to the transition. The purpose is to simulate dynamic projections of the EU electricity markets with and without the implementation of capacity mechanisms and place particular focus on the role of cross-border participation in national capacity mechanisms. The ambition of this analysis is not to argue whether a pure energy-only market or a market with capacity mechanisms is more appropriate, as it was difficult to quantify subjective behaviours of investors taking a decision under uncertainty. The modelling approach simulates some stylised cases and evaluates the system costs, in an aim to show the superiority of harmonisation and cross-border market integration compared to national or asymmetric market design approaches.

PART I: IMPACTS OF REMOVING CURRENT DISTORTIONS IN THE EU ELECTRICITY MARKETS

The model-based analysis of the policy options regarding the operation of the electricity market uses as a basis the PRIMES-based projection of the EU energy system that is designed to meet the 2030 emissions, renewables and energy efficiency targets, as mentioned in the October 2014 European Council. This projection, named as the “EUCO27” scenario, is essentially a low carbon emission scenario. It defines a pathway and an effort-sharing to meet 27% RES share, 27% energy efficiency, 40% GHG (domestic) emissions reduction in 2030 (relative to 1990), 30% GHG emissions decrease in the non-ETS sectors from 2005 and 43% CO2 emission reduction in the EU ETS sectors from 2005. The PRIMES-based projection simulates a well-functioning electricity market, which delivers optimal (least cost) capacity expansion based on perfect foresight in the absence of uncertainties and recovers all system costs. The PRIMES projection does not consider any particular market design, as it simulates the ideal outcome of markets directly. In this sense, the EUCO27 projection is a benchmark of what a well-functioning market would deliver in the context of a low carbon emission scenario meeting the above targets. Given the EUCO27 benchmark scenario, the study configures a series of cases, which explicitly consider market design options.

The starting market description reflects the present situation, which involves market distortions. A parallel study (with partners COWI, THEMA, E3MLab and KUL and others) identified the current market distortions and collected data about the distortions and other market features as needed to feed the electricity market simulator. E3MLab designed and used a new electricity market simulator for the EU electricity market (named as PRIMES-IEM, standing for internal electricity market) which has high granularity, mimics the sequence of markets from Day-Ahead up to real time, includes the interconnections and models distortions as well as policy options aiming at removing the distortions. The data projecting power capacities and demand into the future come from the main PRIMES model and the EUCO27 scenario in particular. The simulator goes into the hourly operation of the electricity markets and applies a methodology which explicitly represents the distortions as well as their removal. The first simulation is for the recent situation with distortions, as identified by the COWI study. Subsequently, the simulator includes the following policy options:

- **Case 0**: Baseline case, reflecting current market arrangements, e.g. price caps, must-run obligations, limited ATC (available transfer capacity) of interconnectors, illiquid and uncoordinated short-term markets.
- **Case 1**: a market with improved efficiency, through limited must-run obligations, extended trade possibilities and no price caps.
- **Case 2**: fully integrated EU market, with the improvements introduced in Case 1 and also with harmonised and liquid intraday and balancing markets.
- **Case 3**: a market with the improvements of Cases 1 and 2 and also adequate incentives to pull all generating resources, demand and storage into the market, and fully unlock the potential of demand response.
- **Sensitivity cases**: further cases based on Case 1 and Case 2 assuming different assumptions regarding NTC (net transfer capacity) values and a change in the merit order.

The PRIMES-IEM model simulates on an hourly basis the sequence of operation of the European electricity markets, namely the Day-Ahead market, the intraday and balancing markets and finally the Reserve and Ancillary Services market or procurement, at the level of the entire EU with full details by country and the interconnections. The model includes a random generator to represent unexpected events, regarding the load, plant outages, renewable resources and weather, occurring after the completion of the Day-Ahead market. The random events influence the intraday and balancing markets. Also, the model includes simulation of economic bidding behaviour of the generators, taking into account scarcity factors and competition. The market coupling across countries is part of the modelling which applies the full detail of the real-world market arrangements, such as the EUPHEMIA software, with the possibility of using the coupling also in intraday and balancing markets.

KEY FINDINGS OF PART I

The benefits of making available the entire capacity of the interconnectors in the coupled electricity markets, both in Day-Ahead and in the intraday, are very significant. The benefits are due to the increase in competition, liquidity and the sharing of balancing resources, enabled by the higher use of the interconnection capacities. To this end, the options evaluated provide for abolishing the setting of restrictions to the availability of interconnectors from a national perspective and instead apply a coordinated management of the interconnectors which a priori would be available at full capacity in the markets. The analysis confirms the benefits in the modelling of Case 1, which assumes an increase of NTC values, and the higher benefits of Case 2, which considers that the NTC limitations do not apply at all.

Increasing liquidity in the organised markets by broadening the participation of generators, demand response and other resources bring considerable cost savings. The Case 2 describes a context where all markets are liquid and harmonised, and out-of-the-market actions for balancing and reserve procurement are as minimum as possible. Moreover, trade flows are not restricted by NTC values. In such a context, generators would be able to bid in the Day-Ahead markets anticipating system requirements and minimising their exposure to the balancing markets. The Day-Ahead market, based on decentralised bidding behaviours of the participants, could in these circumstances deliver co-optimisation of energy costs and ancillary services while respecting technical, operational constraints of the various plant types. The de facto co-optimisation increases cost-efficiency and reduces the costs also in the intraday and balancing markets.

The analysis did not find adverse effects from removing priority dispatch of variable renewable generation. As part of the broadening of participation, the inclusion of variable RES in the Day-Ahead and the intraday can help reducing plant scheduling discrepancies between the day ahead and the real-time operation. However, the analysis found positive but small benefits from the participation of variable RES. The reason is that the analysis considered the removal of priority dispatch of variable renewables in a context where trade possibilities are very high (Case 2) allowing an efficient sharing of balancing resources and a minimum recourse to curtailment of RES generation.

Removing priority dispatch of biomass is detrimental to biomass-based generation and incurs changes in the generation mix which however better reflect the economic merit order. The use of biomass for cogeneration serving district heating could be at stake in this case.

Abolishing price caps in the day ahead markets does not bring considerable benefits, according to the simulations. The reason is that the price caps in the baseline case are in most countries at high levels (as current practices, with one or two exceptions, having defined the price caps close to the value of loss-of-load, which is high). It is also because the scarcity bidding of units assumed in the simulation does not lead to very high price levels.

Unlocking the full potential of demand response improves the resilience of the system and decreases the costs of flexibility resources in the system, thus bringing significant cost savings.

Increasing competition, as a result of market integration, the broadening of participation and the high use of interconnectors, implies a decrease in the revenues of power plants, compared to cases with weak market coupling. However, the analysis finds that in the context of Case 2, i.e. of an integrated EU market where distortions and limitations to its efficient operation do not exist anymore, a scarcity bidding behaviour of the generators in the markets can ensure sufficient revenues for generators. They can cover a large part of their fixed and capital costs from the markets provided that they evaluate the costs for the fleet of plants considered as a portfolio. On an individual plant basis, the analysis finds that some plant types, e.g. (mainly old) solid fuel plants would see reduced operating time and incur financial losses in the market.

PART II: IMPACTS OF INTRODUCING CAPACITY MECHANISMS IN THE EU ELECTRICITY MARKETS

The analysis of Part I applied a static view of the electricity markets. Part II uses a dynamic view to assessing the impacts of the markets on capacity adequacy. The standard PRIMES model used to prepare the EUCO27 projection assumed perfect foresight free of uncertainties and portfolio financing of the fleet of plants. Thus, the model determined the least cost intertemporal capacity mix in the system, which the analysis in Part II considers as a benchmark.

Taking the EUCO27 projection as a starting point, a new model developed by E3MLab, named as PRIMES-OM – oligopoly model, simulated the wholesale electricity markets in the future assuming scarcity bidding by the generators to compute the revenues of the plants. Then, the model determined the expected value of each plant, by considering a spectrum of probable futures regarding the ETS prices, demand, renewables and gas prices, as all these factors influence plant's revenues in the wholesale markets. The model evaluates the expected value of each plant considered individually and may suggest premature retirement for old plants or a cancelling of investment for new plants by mimicking a behaviour of risk-avert generators. The plants that are a candidate for the evaluation are those which the EUCO27 projection found economically appropriate in the context of the least cost of the system considered as a portfolio of plants. Apparently, the evaluation of the financial viability of the individual plants aims at identifying the most vulnerable plant types, from an economic perspective, and thus assessing capacity adequacy risks in an uncertain market context while the system performs transition towards a low carbon future.

The study used the PRIMES-OM model to simulate different stylised cases, such as a "pure" energy market and market varieties with a stylised capacity remuneration mechanism. The varieties have regarded different assumptions regarding harmonisation and integration across the EU, cross-border participation in the capacity mechanisms and asymmetric developments in the EU countries. The stylised capacity mechanism is a standard design of centralised auction for capacity availability remuneration in exchange for reliability options. A particular model, built by E3MLab, has simulated explicit cross-border participation of plants in the hypothetical auctions as a result of consideration of the deliverability of the capacity service through the interconnected system and the profitability in the auctions which depends on the degree of participation.

The Cases developed and examined in this part of the study are:

- **Case B:** a non-distorted energy-only market, where market participants exercise scarcity bidding.
- **Case C:** asymmetric implementation of capacity mechanisms only in four Member States (United Kingdom, Ireland, France and Italy).
- **Case D:** implementation of capacity mechanisms in all Member States, in a harmonised manner.
- **Case E:** similar to Case D, but with cross-border participation in the capacity auctions of all Member States.
- **Case F:** similar to Case C, but with cross-border participation in the capacity auctions of the four Member States.
- **Cases of unilateral capacity mechanisms:** two cases, one where the capacity mechanism applies only in France, and one where it applies only to Germany.

The model simulated the above cases dynamically until 2030 and 2050. The model computed wholesale market prices and the auction clearing prices of the capacity mechanisms if applicable, the probability of early retirement or investment cancelling of power plants in the context of risk avert behaviour in an uncertain environment and the impacts on system costs, revenues and capacity adequacy.

For the study of Cases that consider the explicit participation of cross-border flows in capacity mechanisms, the analysis examined the possibilities of transferring capacity between the Member States at stress times of the system thoroughly. The study considered the capacity requirements of every country and evaluated the ability that the particular availability services are sufficiently secure given the network limitations and congestions.

The investments and the power plant capacities which are the object of the evaluation are those included in the EUCO27 projection. If investors perceive that revenues from the market are not sufficient beyond a threshold of cost recovery, they decide to cancel these investments, or, in case the decision regards old capacities, they retire them early. Thus, the model results constitute an adjusted capacity expansion projection. Overall, the simulation results give us two main pieces of information: a) how many investments cancel and how many old plants retiring early (compared to the EUCO27 context), and b) how the remaining plants perform.

KEY FINDINGS OF PART II

In the framework of the energy-only market (without distortions and with scarcity bidding of generators), the uncertainty surrounding future revenues of the plants was found to imply that 63GW of plants are financially vulnerable in the period 2021-2030. The old solid-firing plants represent more than half of this capacity at stake. The other half includes old plants based on steam turbines using oil or gas and some peak units. The market is successful in sustaining investments in CCGT capacities. The same applies to nuclear capacities.

The capacity mechanisms improve the certainty of revenues compared to the wholesale markets. But at the same time, the reliability options reduce the scarcity bidding and have negative implications on income in the wholesale markets. The capacity auctions entail additional costs compared to a pure market solution, as in addition to agency costs the mechanism remunerates all plant types some of which may not deserve remuneration from the perspective of least costs. The simulations confirm the cost inefficiency of the capacity mechanisms, but at the same time show, they show benefits regarding capacity adequacy.

The EUCO27 scenario shows lack of profitability for new investment in coal or lignite plants, beyond projects presently under construction or in the process of financial closure. Regarding existing plants the PRIMES-OM projections demonstrate that capacity mechanisms can result in old vulnerable coal plants remaining operational, resulting in the delay of retirement at the expense of higher system costs.

For those thermal plants with sufficient flexibility to be essential for the system in the presence of large amounts of variable RES, such as the CCGT, the energy-only market appears to provide sufficient revenues for cost recovery, except for peak load units to some extent. This result depends on the degree of scarcity bidding; higher bidding improves the financial viability of peak devices. However, under the PRIMES-OM assumptions, old steam turbines using oil and gas are financially vulnerable, and without a capacity mechanism support, they are likely to retire early. The analysis has excluded industrial CHP plants and other cases of plants which serve special purposes, such as district heating (as the primary activity of a plant) or islands.

The analysis estimated that total cost (as payments by consumers) in the cases including capacity mechanisms is higher than in the energy-only market, mainly because of remuneration, in excess of costs, in the capacity auctions. The cost savings achieved in the wholesale energy markets, due to the strike prices of the reliability options of plants supported by the capacity mechanism, do not offset the additional costs of capacity auctions compared to pure energy markets with scarcity bidding.

The implementation of capacity mechanisms unilaterally in one country (or a few of them) causes incentives for investing in the particular country asymmetrically at a higher degree compared to the incentives in other countries. The investment in the given region increases asymmetrically, which induces free-riding practices in the neighbouring countries. Overall, the total costs in the asymmetric cases are higher than in the symmetric implementations of the capacity mechanisms.

Capacity mechanisms with cross-border participation attract considerable amounts of plants located abroad, especially in countries which have high capacity requirements (and are therefore perceived as more profitable for generators) and sufficient interconnections. Congestions from trade flows that occur regardless of the implementation of the capacity mechanisms become a limiting factor to cross-border participation in some cases.

The model found the Cases with capacity mechanisms and with cross-border participation as less costly than those excluding cross-border participation. The foreign participation implies a reduction of total payments to capacity markets by 6% (in the cases where capacity mechanisms are implemented only in four countries) and 12% (in the cases where capacity mechanisms are in all countries).

INTRODUCTION

The EU energy system and in particular the electricity system will undergo a significant transition towards a structure with low carbon emissions. Climate change mitigation justifies the transformation. In the power sector of the EU, the main policy measure is the ETS with market stability reserve, expected to drive increases of carbon prices in the future. Policies promoting renewables, and in some countries, policies facilitating nuclear investment or retrofitting, are additional drivers of the transition. It is conventional wisdom that a system with a high share of variable RES requires considerable attention regarding the adequacy of flexibility and backup resources. Sharing such resources in a broad market interconnecting many countries is more cost-efficient than using only national balancing resources. The completion of the Internal Electricity Market in the EU has, therefore, the duty to support the transition efficiently, in addition to the aim of enhancing competition and reducing costs.

The internal market of electricity is not yet fully completed in the EU. Distortions persist, and despite the progress in the cross-country coupling of Day-Ahead markets, the coupling is weak for the intraday markets and the balancing. National perspectives still prevail regarding the setting of constraints, expressed as Net or Available Transfer Capacities, on the use of interconnections. The RES, as well as other cases of plants, have the "privilege" of being dispatched with must-take or must-run priority and do not face exposure to risks of balancing costs. Historically, the priorities served specific policies, such as the facilitation of investments in RES and others. The recent projection of energy systems, undertaken in the present context by the PRIMES model for the EUCO scenarios, assume that the expected reduction in costs, occurring as "learning", will allow RES investment to be market-based except for some technologies which still have a significantly high untapped learning potential.

Cost-efficiency in the electricity markets increases with market liquidity and the broadening of the size of the market. Obviously, competition and economies of scale are the economic drivers of efficiency improvement. Some of the currently observed distortions limit market liquidity which could increase if the participation of generators and other resources participated in the markets. Other distortions limit the broadening of the markets, in particular regarding the full market coupling cross-border. Efficiency gains and economies of scale are possible when broader markets share resources, including for balancing and flexibility. A regional perspective on the management of the system could lead to the setting of more efficient reliability and reserve requirements and the unobstructed use of the entire physical capacity of interconnections, in comparison to management based on a superposition of national perspectives.

The EUCO scenario, quantified using the PRIMES model, includes a detailed projection of power plant investments, retrofitting and decommissioning, as well as projection of demand, for each Member-State of the EU. The scenario projection is compatible with the targets set in the European Commission's proposal regarding the GHG emissions, the ETS, the non-ETS, the RES and energy efficiency, for the year 2030. The scenario projection goes until 2050 and foresees achievement of the GHG emissions reduction target for that year. The structure of electricity generation in the context of the EUCO scenario undergoes considerable changes to reach an almost carbon-free generation mix in the long term, and thus facilitate ambitious emissions reduction in other sectors such as transport and heating by expanding the use of electricity. The decarbonisation of power generation uses as a major pillar the significant penetration of variable RES in the power generation mix. The strategy foresees maintaining or slightly expanding the capacity of nuclear energy where possible, as well as the moderate development of carbon capture and storage in the long term in some countries, but the major growth is for the RES. The remarkable features of the transformed electricity generation mix are mainly the full decline of solid fuel firing capacities and the major use of gas plants for flexibility, balancing and backup purposes, in particular in the medium term. In the long-term, new techniques of electricity storage complement the role of gas. The projection finds that new investment in coal or lignite plant is not economically appropriate, except in the case of plants that are today known projects under construction or in the process of financial closure. However, the projection finds economically appropriate the extension of the lifetime of some of the old coal or lignite plants after spending for retrofitting and in general excludes premature decommissioning of the old solid fuel plants, which remain until 2035 and 2040 but with increasingly low utilisation rates.

The PRIMES-based projection assumes a well-functioning market with a fully integrated multi-country structure, achievable a little after 2020. Integration implies full exploitation of interconnections, according to a power flow use of physical capacities, full market coupling and the full sharing of resources, for ancillary services, reserve, balancing and flexibility. The model projects least cost expansion of the system in a world with perfect foresight free of uncertainties and full cost recovery of the plants considered in total as a portfolio. The PRIMES model answers the question which generation mix is economically appropriate in this context and which consumer prices by sector and countries will allow for full recovery of costs plus normal profit. The model does not answer the question which market design options have the ability to deliver a well-functioning market in a cost-efficient manner. In this sense, the EUCO scenario projection is a “normative” benchmark, focusing on the optimality rather than the way of achieving the optimality.

Of course, in reality, an ideal market does not exist. And the relevant question is which market design options are the more appropriate for delivering the perfect market described by the benchmark and how the market operates explicitly in a system with low carbon emissions and high shares of variables RES. The aim of the present study is to develop and apply appropriate modelling tools to answer this last question.

The starting point of the market design analysis is the characterization of the current situation and the identification of market distortions. A study coordinated by COWI and THEMA, with the participation of KUL, E3MLab and several experts, provided the analysis of current market distortions. The next step has been to identify the alternative policy options, mainly the alternative market design options, which aim at improving the current situation and ideally will lead to a well-functioning and integrated market in the EU. The European Commission defined the list of policy options.

The market design questions group in two main categories, depending on their scope: (a) operation of organised markets ranging from the Day-Ahead up to real time system operation; (b) facilitation of power generation investment and capacity adequacy. Naturally, the former group focus on a snapshot view of the markets, in the sense of looking at market operation with given plant sizes; whereas the latter group has a dynamic view, in the sense of looking at the market conditions as enablers of investment in plants. The models developed by E3MLab apply these two views separately. The PRIMES-IEM (internal electricity market) is a high granularity simulator of the operation of organised market ranging from the Day-Ahead until the real-time operation of the system. The PRIMES-OM (oligopoly model) simulates generators’ revenues from wholesale markets and capacity remuneration mechanisms, where applicable, as well as the implications of individual plant-related decisions in an uncertain business environment. Both models take from the standard PRIMES model the full details of a scenario-projection, which in the case of the present study is the EUCO scenario.

Assessing market design options using a simulation model is difficult because the assessment requires an evaluation of the design choices in an uncertain world. Standard system optimisation is not sufficient as in reality unexpected or random events cause deviations from optimisation. The robustness of the market design depends precisely on whether the market will handle such stochastic variations in a cost-efficient manner. The modelling is hard also because the evaluation of a market design depends on the way the model represents behaviours, such as economic bidding by market participants. The PRIMES-IEM model simulates a sequence of organised markets, including the markets of Day-Ahead and intra-day, as well as the balancing and reserve markets. Between the Day-Ahead and the intraday markets, the simulator generates random events regarding the magnitude of the load, plant outages, availability of renewable resources, the weather and others. Thus, the model produces deviations from the schedule derived from the Day-Ahead energy market. For the intraday market, the model simulates a market for deviations, up and down, as well as a market for balancing and ancillary services. Finally, a unit commitment algorithm, which includes the technical restrictions of plant operation and the system services, simulates the real-time operation of the power system. The simulation operates on an hourly basis and for the entire European system of interconnected countries. The fleet of plants and the load come from the PRIMES scenario. The simulator uses behavioural modelling of bidding depending on scarcity of resources and the degree of competition. Regarding the bidding, the model can optionally represent perfect competition, Cournot oligopoly or supply function equilibrium, or simply a bidding conditional on fixed (and variable) cost recovery by plants. By varying the assumptions regarding the use of interconnections, the participation in the markets, price caps, harmonisation across countries and others, one can simulate cases of stylised market design. The simulator computes equilibrium prices and thus payments by the load, as well as revenues by plants.

The simulation of the market operations takes as given the capacities of the plants. The question addressed by the PRIMES-OM model is the impact of the market on investment decisions regarding the building of new plants and the possible premature retirement of old plants. The simulation of the organised markets provides a computation of the revenues for each plant, depending on market design options and the assumptions about competition.

From a modelling perspective, we characterise a market as a pure energy one if the wholesale market is the only source of revenues for generators. In reality, an energy-only market can combine a wholesale market and exchanges based on bilateral contracts. In a perfect market, the wholesale market and the bilateral contracts would converge to the same clearing prices. Thus, the model simulates a wholesale market with full participation of generators as a representation of an energy-only market. In such a market, the generators seek to recover all costs, including fixed O&M costs and capital costs.

A capacity remuneration mechanism (CM) defines a particular procedure or a market for pricing the availability of power plants, independently of their energy production. Naturally, a CM seeks to provide revenues to the generators for recovering part of fixed O&M costs and capital costs in addition to the possible cost recovery in the wholesale market. There exist different designs[1] of the CMs. Recently a significant part of the literature considers the centralised auctions with reliability options as an efficient layout. For this reason, the PRIMES-OM model has included in the simulation this type of CM design as a stylised example of a CM. The CM submodel simulates competition and price clearing in the capacity

[1]Neuhoff and De Vries 2004; Joskow 2006; Finon 2006; De Vries 2007; Meulman and Méray 2012; Leautier 2012 are some of the numerous examples of CM discussions in the literature

auctions organised at national level, with or without cross-border participation in an explicit or implicit manner. When including CMs in the market design, the model computes the capacity revenues resulting from the estimated auction clearing prices. The generators remunerated by a CM, lowers the bidding in the wholesale market, to reflect reliability options, which include a strike price determined in the simulation of the capacity auctions. The model assigns different degrees of risk to the wholesale market and the CMs regarding the revenues, assuming that the generators perceive higher security in the CMs than in the wholesale markets.

The next step of the PRIMES-OM model is the computation of the expected future value of a plant, which is considered individually from a financial perspective and is either an old or a new unit that is a candidate for investment. The valuation uses a probabilistic space quantified using a Monte-Carlo technique, which considers as random the future ETS prices, gas prices, demand growth, development of renewables and others. On this basis, the model quantifies a probabilistic subjective decision function which depends on the value of the plant, which also depends on the idiosyncrasy of investors based on a probability distribution of risk preferences (this is an analogy to the discrete choice theory). The final step is to re-simulate the wholesale markets and, depending on the options, the CM markets after the possible retirement of old plants or the cancelling of investment for new plants. The possible reduction of capacities refers to the fleet of plants projected using the standard PRIMES model.

Thus, the PRIMES-OM evaluates for several years the payments, revenues and capacities, as well as indicators relevant for capacity adequacy analysis and the influence of various market design options. Such options can be an energy-only market, CMs in few but not all countries, harmonised CMs in all countries, and cases with or without cross-border participation in the CMs. The model can combine the analysis of revenues and investment with market design options regarding the interconnections and the operation of the organised markets.

Despite the sophisticated approach of the PRIMES-OM model, we take a clear position that the model is not able to answer the question whether an energy-only market is a better design than a market with a capacity mechanism. The modelling difficulties and the impossibility of verifying the modelling assumptions lead us to this statement. The evaluation critically depends on the modelling of behaviours notably on the decisions under uncertainty as there is poor econometric evidence to verify the validity of the related modelling assumptions. The modelling involves calculation of endogenous bidding in the wholesale markets in the various stages of the market, as well as behaviours of bidding in the capacity auctions. The most difficult parameters to verify is those regarding the perception of risk and how risk aversion influences investment decisions or decisions to retire old plants. Also, the investment decisions in the electricity sector do not depend only on uncertainty factors related to the sector, but also on risks related to general economy factors (currency, capital markets, etc.), the accidents, the liability, regulatory interventions and others. It is, therefore, difficult to isolate the influence of electricity market design options on investment decisions. Due to this complexity, the model necessarily represents stylised designs of the markets and the CMs, as well as stylised behaviours of representative actors.

The vast literature on electricity market design and the CMs supports that an energy-only market implies a higher risk of cost recovery by generators and that a CM facilitates risk hedging for investors. But, at the same time, the literature recognises that a CM being an out-of-the-market intervention necessarily is less cost-efficient than an energy-only market and also entails non-zero agency costs. Another argument is that a market with a CM is likely to induce smoother business cycles (boom and bust investment cycles[2]) than an energy-only market. However, there is no empirical evidence supporting this statement, because, in reality, a market-based capacity remuneration price can also be subject to substantial volatility as the wholesale market does during the boom and bust phases of a cycle. There is no empirical evidence of the cost-efficiency superiority of one of the design options. If a CM succeeds reducing the volatility of prices because of the smoothening the business cycle, at the same time consumers pay an agency cost which inevitably implies lower cost-efficiency performance compared to a purely free market. But if investment comes in the context of a purely free market at the expense of a high return on capital then the pure free market approach does not necessarily imply the best cost-efficiency. Therefore, the discussion, also in the literature, is inconclusive regarding the comparison of energy only markets and markets with a CM. For this reason, the literature often states that the choice is political, in the sense that it depends on the political preference of the risks of security of supply versus the additional costs of the out-of-the-market intervention.

The use of the PRIMES-OM model in the simulation of stylised market design cases had three main purposes. Firstly, to estimate the magnitude and the type of generation capacities which are at risk in an uncertain world amid transition. Secondly to verify whether broadening the markets, by ensuring cross-border participation in the EU energy markets but also in the national capacity auctions, where applicable, will bring benefits due to competition, economies of scale and the sharing of resources. And thirdly, to assess the adverse impacts of asymmetric CMs compared to harmonisation. The model can study these questions but not to provide a general assessment of energy only markets versus the CMs.

According to the theory of electricity economics, an energy-only market with perfectly optimal structure of generation resources does not present a problem of "missing money" (in other words, it successfully recover the total costs of production) as long as the peak units can recover their fixed (and variable) costs. The peak units have much lower capital costs than other units placed below peaking units in the merit order. However, in reality, the structure of generation is never optimal, as some types of resources are in scarcity (lower levels than in the optimum) and some other resources are in excess (higher levels than in the optimum). Therefore, missing money symptoms can occur in reality in situations of overcapacity in a market even if the market has a perfect design. The fact that some plant types experience non-recovery of total costs can be because these plants are in excess in the market, i.e. they should not be in the mix if the structure was optimal. Such a situation does not necessarily imply that it is appropriate to establish capacity mechanisms for allowing non-optimal plants to recover total costs.

The PRIMES-based EUCO scenario has a clear interpretation: the generation structure is intertemporally optimal; old capacities which are not currently optimal may remain in the system until the end of their

[2] During the boom phase, capacity scarcity induces high prices and returns on capital which incentivise investment in new plants. During the bust phase, excess capacity implies low prices and diminish returns on capital, thus discourage investment. Large volatility of prices between the boom and bust phases implies that investors need to add high risk premiums to normal hurdle rates (hurdle rate is the minimum rate that a company expects to earn when investing in a project); in contrast, a smooth variation of prices between the boom and bust phases implies a stable time profile of capital earnings. A CM, at the expense of direct payments per unit of capacity, which may probably exceed market-based remuneration of capacity, expects as a return low energy prices in the wholesale markets, as a result of no scarcity. A reliability option, which may accompany the CM remuneration, reflects this expectation.

lifetimes just because it is more costly to replace them prematurely. However, this does not necessarily justify supporting them through a CM.

The discussion regarding CMs in few countries versus harmonised CMs in all countries is held for quite some time now in the EU[3]. Some Member-States have already implemented or plan to implement a capacity mechanism, in most cases in an un-coordinated manner with their neighbours. Therefore the question of assessing asymmetric versus harmonised CMs is pertinent.

The study presented in this document aims to cover a vast spectrum of the issues discussed above. It consists of two parts; the first focuses on the energy-only market. It looks at the energy system of 2030, identifies distortions and builds scenarios (Cases) in which these distortions are assumed to vanish thanks to relevant policy measures. It supports that improving the EOM has significant benefits regarding efficiency and ultimately for consumer costs. The second Part of the study takes as a basis an "improved" energy-only market and assesses various cases with or without capacity mechanisms with regard to investment and the retirement of old plants. The simulation considers a single stylised capacity mechanism, but it assumes variations regarding harmonisation of practices among countries. It supports that non-harmonised solutions are less efficient than harmonising, while it helps argue that opening capacity mechanisms to cross-border participation enhances competition and thus saves costs for the consumers.

The modelling study presented in this document supported the Impact Assessment of various policy options developed under the Market Design Initiative of the EU Commission. E3MLab is grateful for the funding of this study by the European Commission and the excellent and fruitful discussions with the European Commission officers. Needless to say that the entire responsibility remains at the E3MLab and that the results or conclusions do not engage the European Commission.

After the completion of the modelling studies reported in the main part of this document, the PRIMES model undertook a quantification of an additional scenario which refers to the Commission proposal (Art. 23 par. 4) that new generation capacity is not allowed to participate in a capacity mechanism if CO2 emissions are above 550 gr/kWh. The modelling analysis so far has not included this provision. The additional scenario aimed at quantifying impacts of building additional coal or lignite plants based on a support mechanism, in comparison to the main EUCO scenario. Appendix I reports the results.

[3] NERA 2002; CEER 2006; European Commission 2012; Tennbakk and Capros 2013

Part I IMPACTS OF REMOVING CURRENT DISTORTIONS OF THE EU ELECTRICITY MARKETS

I - 1 Overview of the analysed Cases

The purpose of the Market Design Initiative of the EU Commission is to define the inefficiencies of current market designs and propose relevant policy measures to address them. The identification of the market distortions and the appropriate policy measures has been conducted by a parallel study (Tennbakk et al. 2016) with partners COWI, THEMA, E3MLab, KUL and several experts. The present analysis defines four "Cases" of market conditions[4] starting from a "business as usual" context that reflects current practices, and gradually assuming the removal of identified market distortions and the introduction of policy measures that improve market efficiency. A short description of the four Cases considered is the following:

- **Case 0:** Baseline case, reflecting current market arrangements (e.g. price caps, must-run obligations, limited ATC of interconnectors, illiquid and uncoordinated short term markets).
- **Case 1**: a market with improved efficiency, through limited must-run obligations, extended trade possibilities and no price caps.
- **Case 2**: fully integrated EU market, with the improvements introduced in Case 1 and also with harmonised and liquid intraday and balancing markets.
- **Case 3**: a market with the improvements of Cases 1 and 2 and where proper incentives exist to pull all generating resources, demand and storage into the market, and unlocking the potential of demand response fully.

Each Case uses specific assumptions for every market (Day-Ahead market, intraday and balancing markets, and reserve and ancillary services market or procurement) which are discussed in detail in the following section (I - 1.1). The main issues that differentiate the cases are the following:

- **Practices that do not allow for a level playing field among generation technologies**
  These practices refer to the existence of "must-run" generation, which implies that resources are not used on the merit-order basis and enhance the inefficiency of the system[5]. We may identify three types of such practices:
  - Priority dispatch rules: across cases, we assume the gradual removal of existing priority dispatch rules (must-run or must-take) and the introduction of curtailment possibilities.
  - Non-participation[6] of certain power technologies in the markets: we assume that participation of power plants in the markets expands across the Cases. In Case 3 the participation expands to

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[4] These cases are closely aligned to the policy options of Problem Area I of the Market Design Impact Assessment. For a presentation of their correspondence please see Section 1.3.

[5] See Oggioni (2014) and Chaves-Ávila (2015).

[6] We do not consider in the analysis the method which makes possible the participation of plants in the market. We do not examine whether enforcement is required or if incentives can be sufficient.

(mostly) all power generating technologies, including highly distributed technologies (small-scale RES), owing to the assumption of aggregators. This way, balancing responsibility can be allocated more efficiently[7]. More specifically, regarding intraday and balancing markets, we assume that participation is extended to all resources except RES and small CHP capacities in Case 2. RES (except small-scale) participate in the intraday market in Case 3. Regarding the Reserve and ancillary services market, we assume that across Cases 1 to 3, RES (except small –scale) participate, while participation is also enabled for CHP, albeit solely in Case 3.

- Nominations[8] of capacity. We assume that already in Case 1 the market conditions (increased NTC[9] values, extension of participation to more resources in the markets) are able to provide incentives to generators to participate in the markets rather than engaging their capacity to nominations. In contrast the Case 0 does not reduce the nominations notably for solids and nuclear power plants as practiced today. The conditions are such that all generators participating in the markets have an interest in bidding at their variable cost at a minimum[10].

- **Practices that render short-term markets inefficient**
  The cases assume an increase in the liquidity of intraday and balancing markets, going from illiquid markets in Cases 0 and 1 to liquid and coordinated markets in Cases 2 and 3. Already in Case 1, we assume the establishment of standard rules for financial settlement of imbalances, common rules for SMP of imbalances and other common market rules. Moreover, making available the entire capacity of the interconnectors in the coupled markets (in Cases 2 and 3) imply an increase in cross-border participation, which allows for better allocation of resources among the control areas and yields considerable efficiency improvement of the markets.
- **The level of market coupling**
  In Case 0, the available transfer capacity (ATC) is limited by NTC values, nominations and the capacity engaged for reserve purposes. In Case 1 the assumed increases in NTC values, along with the reduction of nominations, relax the ATC restrictions and the system gains regarding competition, liquidity and sharing of balancing resources due to the broadening of the markets. In Cases 2 and 3, we assume that the entire physical capacity of interconnectors is available (no NTC restrictions).
- **The ability of generators to anticipate their exposure in balancing markets**

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[7] For an assessment of the efficacy of imbalance reduction strategies through employing highly distributed sources see Zapata (2014)

[8] Nominations is a practice of declaring to the TSO power capacity of certain plants and a specific load, usually defined regarding the time profile and the magnitude, as a package which is taken out of the merit order scheduling performed by the TSO. Often a nomination may also involve part of the capacity of an interconnector, in which case the transfer capacity of the interconnector available for other operations is reduced.

[9] The NTC values are unilaterally defined by the TSOs on the basis of reliability considerations (such as N-1 rules) which reflect a national perspective. The NTC restrict transfers compared to the physical possibilities of interconnectors. Such restrictions never apply within a control area, where the interconnectors can be used up to their thermal capacity. Abolishing the NTC restrictions between control areas is as if they are managed as a single control area.

[10] This is not a restriction of the generality for the modelling, as there is no need of submitting bids below marginal costs or negative bids when curtailment of RES is possible and there are no (or only few) must take obligations. Also, in a market with sufficient liquidity and competition there is no reason why a plant would bid below marginal costs when serving a bilateral contract outside the wholesale market (bidding below marginal cost may kick-out a plant with lower marginal cost, which is not economic for the supplier holding the bilateral contract, while the plant risks not recovering the fuel cost in the wholesale market).

The elimination of must-run or must-take priorities and the increased participation of generators in the markets, along with the harmonisation of EU markets and the broad market coupling assumed in Case 2, create a context where generators would be able to act optimally. In this context, the generating companies and the aggregators have incentives and possibilities to employ sophisticated bidding strategies, by for example bidding in the Day-Ahead markets appropriate block orders, so as to minimise their exposure in the balancing markets and optimise overall earnings. The induced optimal behaviour of generators allows for significantly increasing the efficiency[11] as it leads to the optimal scheduling of units. The optimality regards taking into account the technical restrictions of plant operation already in the day ahead markets, as well as reserve part of capacities[12] as needed to meet ancillary services. The optimality in Day-Ahead significantly reduces the demand for imbalances and re-dispatching. In the modelling, this de facto co-optimisation of the offering of energy and ancillary services operates through introducing, together with the energy-only market formulation, the technical constraints of power plant operation and the demands for ancillary services in the optimisation of the Day-Ahead market scheduling.

- **The reserve requirements**
  The demand for reserves is exogenous in the modelling, in all Cases. In Cases 0, reserve quantities are set according to estimations for the future[13], by projecting data of 2015. We assume that the increase in the liquidity of the short-term markets, the elimination of the merit-order distortions (induced by priority dispatch of capacities and nominations of energy), and the higher participation of cross-border flows in the markets will lower reserve requirements. Thus, in Case 1 we slightly reduce the reserve requirements compared to the Case 0. In Cases 2 and 3, we assume that reserve requirements reduce further, due to the highly efficient Day-Ahead Scheduling (owing to the optimal behaviour of generators for offering energy and reserves).
- **Introduction of demand response as an active participant in the markets**
  In the Cases, we assume that gradually the markets take advantage of the potential of demand response, initially only of industry and ultimately (in Case 3) of the full potential[14].
- **Existence of price caps**
  The baseline Case includes price caps, as applied today[15]. Already in Case 1, we assume that no price caps apply. This assumption allows to reflect scarcity in biddings by plants, and thus to provide improved market signals regarding the necessity of investments on particular types of capacity and services.

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[11] See Liu et al. (2015) and Pablo González et al. (2014)

[12] A relevant example is the bidding of CCGT capacity in the day ahead market together with a baseload plant. When taking into account the ancillary services and the technical operation limitations of the plants, the generator would bid in such a way so as to make sure that the CCGT closes when the baseload plant needs to operate at the level of minimum stable operation power, and that the CCGT does not exhaust its capacity in the day ahead merit order to be able to offer ancillary services. A non-optimal bidding would ignore the constraints and the ancillary services and so the intra-day and balancing markets should treat large deviations from the scheduling of the day ahead market in order to accommodate the technical operation of the plants and the ancillary services. An ideal day ahead market should be able to make the participants bidding while pre-empting deviations due to technical plant-operation constraints and the ancillary services.

[13] See Artelys and THEMA Consulting (2016)

[14] Demand response potential has been provided by COWI (2016)

[15] See Tennbakk, Von Schemde and Six (2016)

I - 1.1 Assumptions of Cases

Table 1: Assumptions across Cases for the simulation of the Day-Ahead market

ASSUMPTIONS FOR THE DAY-AHEAD MARKET

	Case 0	Case 1	Case 2	Case 3
DAM load coverage – nominations	DAM covers part of the load. Bilateral contracts nominated.	DAM covers the vast majority of load, no nominations	DAM includes the whole load and no nominations	DAM includes the whole load and no nominations
Priority dispatch	Priority dispatch of must-take CHP, RES, biomass and small-scale RES (rooftop). Solar thermal is excluded and includes 8-hours storage.	Priority dispatch of must-take CHP, RES and small-scale RES, except for biomass. Solar thermal is excluded and includes 8-hours to storage.	Priority dispatch of must-take CHP and small-scale RES, but curtailment possible.	Priority dispatch of must-take CHP, but curtailment possible. No priority of small-scale RES thanks to aggregators.
Bidding	Bidding per plant. Scarcity bidding except for nominations. Hydro lakes apply economic offers only for the non-mandatory part. The prices are above marginal costs.	Bidding per plant. Scarcity bidding. Hydro lakes apply economic offers only for the non-mandatory part. Biomass offer at marginal costs minus FIT. The prices are above marginal costs.	Bidding per generation portfolio. Scarcity bidding. Hydro lakes apply economic offers only for the non-mandatory part. Biomass bids at marginal costs minus FIT. The prices are above marginal costs.	Bidding per generation portfolio. Scarcity bidding. Hydro lakes apply economic offers only for the non-mandatory part. All RES (except for small-scale) and biomass offer at marginal costs minus FIT. The prices are above marginal costs.
Consideration of balancing and ancillary services	no	no	Co-optimisation of energy and reserves in the DAM (as a result of behaviours of participants)	Co-optimisation of energy and reserves in the DAM (as a result of actions of participants)
Demand response	Demand response only in countries where currently practised	Demand response limited to large entities	Demand response limited to large entities	Demand response close to potential estimated by recent studies
Price caps	Price caps apply as today	Price caps equal to VOLL (4000 EUR/MWh), same for all MS	Price caps up to the VOLL, same for all MS	Price caps up to the VOLL, same for all MS
NTC	Restrictive ATC (NTC minus bilateral contracts minus TSO reserves), defined by country.	ATC constraint (NTC minus bilateral contracts minus TSO reserves), as defined per country, but less restrictive than in Case 0, due to	Flow-based allocation of the entire physical capacity of interconnectors	Flow-based allocation of the entire physical capacity of interconnectors

ASSUMPTIONS FOR THE DAY-AHEAD MARKET

	Case 0	Case 1	Case 2	Case 3
		the reduction in nominations.	All countries coupled in all the stages of the markets	All countries coupled in all the stages of the markets
Bidding zones	National Bidding Zones (NTC values at an existing border basis).	National Bidding Zones (NTC values at an existing border basis).		
Market coupling	All countries coupled in DAM.	All countries coupled in DAM.		

Table 2: Assumptions across Cases for the simulation of the intraday market

ASSUMPTIONS FOR THE INTRADAY AND BALANCING MARKETS

	Case 0	Case 1	Case 2	Case 3
Market liquidity	The illiquid market in certain countries, thus settlement of deviations using the DAM bids or administrative prices. In illiquid markets (or no markets) TSO calls must-run plants administratively defined (based on reserves or TSO contracts).	The illiquid market in certain countries, thus settlement of deviations using the DAM bids or administrative prices. In illiquid markets (or no markets) TSO calls must-run plants administratively defined (based on reserves or TSO contracts).	All markets are considered liquid and harmonised - coordinated. Bidding addresses IDM independently of bidding in DAM.	All markets are considered liquid and harmonised - coordinated. Bidding addresses IDM regardless of bidding in DAM.
Participation of resources	Limited participation of resources in IDM, as nominations, must take RES and CHP plants with priority dispatch do not have balancing responsibility	Extended participation of resources in IDM and balancing responsibility, i.e. no participation: must-take CHP and RES. Solar thermal is an exception and assumed to participate in the ID market, due to storage capability.	Extended participation of resources in IDM and balancing responsibility, i.e. no participation: must take CHP and RES. Solar thermal is an exception and assumed to participate in the ID market, due to storage capability.	Participation of all resources in IDM (no exclusion thanks to aggregators)
Demand response	Demand response only in countries	Demand response limited to large	Demand response restricted to	Demand response as potential

ASSUMPTIONS FOR THE INTRADAY AND BALANCING MARKETS

	Case 0	Case 1	Case 2	Case 3
	where currently practised.	entities.	large entities	from studies
Price caps	Price caps in some countries	Price caps equal to VOLL same for all MS.	Price caps up to the VOLL same for all MS.	Price caps up to the VOLL same for all MS.
EU Market's harmonisation	Fragmented country markets	Standard rules for financial settlement of imbalances, common rules for SMP of imbalances and common market rules.	Standard rules for financial settlement of imbalances, common rules for SMP of imbalances and common market rules.	Standard rules for financial settlement of imbalances, common rules for SMP of imbalances and common market rules.
Market coupling	Country-specific IDM	Country-specific IDM	Market coupled IDM	Market coupled IDM
Participation of cross-border flows	Limited participation of flows over interconnectors (as the available capacity for intraday is restricted to the minimum –defined by country).	Limited participation of flows over interconnectors (as the available capacity for intraday is restricted to the minimum – defined by country).	The entire physical capacity of interconnectors allocated to IDM and flow-based allocation of capacities, after taking into account remaining capacity of interconnectors after unit commitment coupled with DAM.	The entire physical capacity of interconnectors allocated to IDM and flow-based allocation of capacities, after taking into account remaining capacity of interconnectors after unit commitment coupled with DAM.

Table 3: Assumptions across Cases for the simulation of the Reserve and Ancillary services market or procurement

ASSUMPTIONS FOR THE RESERVE AND ANCILLARY SERVICES MARKET OR PROCUREMENT

	Case 0	Case 1	Case 2	Case 3
Reserve requirements	High reserve requirements (set from a national perspective).	High reserve requirements (set from a national perspective) but slightly reduced than in Case 0.	EU-wide reserve requirements (nonetheless taking into account areas systematically congested),	EU-wide reserve requirements (nonetheless taking into account areas systematically congested),

ASSUMPTIONS FOR THE RESERVE AND ANCILLARY SERVICES MARKET OR PROCUREMENT

	Case 0	Case 1	Case 2	Case 3
			lower amounts compared to Cases 0 and 1[16]. Reserve requirements lower than in other Cases because of co-optimization in Day-Ahead and the intraday market.	smaller amounts compared to Cases 0 and 1. Reserve requirements lower than in other Cases because of co-optimization in Day-Ahead and the intraday market.
Reserve procurement	Country specific purchase. In some countries, non-efficient markets for reserve imply administratively defined actions by TSO (curtailment, call of reserves) and administratively set payments for ancillary services (based on procurement and contracts).	Country-specific procurement. In some countries, non-efficient markets for reserves imply administratively defined actions by TSO (curtailment, call of reserves) and administratively set payments for ancillary services (based on procurement and contracts).	EU-wide procurement. Only market-based purchase of reserves and ancillary services, through the liquid and harmonised balancing/reserve markets.	EU-wide procurement. Only market-based purchase of reserves and ancillary services, through the liquid and harmonised balancing/reserve markets.
Demand response	Demand response practices as applied today	Demand response limited to large entities.	Demand response restricted to large entities.	Demand response close to potential estimated by recent studies
Price caps	Price caps and restrictions on resource participation in balancing and for ancillary services (excludes CHP, RES, and other plants if applied today).	Price caps up to the VOLL same for all MS.	Price caps up to the VOLL same for all MS.	Price caps up to the VOLL same for all MS.
Participation of resources	Based on current practices	No restrictions on resource participation (except must take CHP and small-scale RES).	No restrictions on resource participation (except must take CHP and small-scale RES).	No restrictions on resource participation (no exclusion thanks to aggregators).
Participation of cross-	Limited participation of flows over	Limited participation of flows over	The entire physical capacity of in-	The entire physical capacity of in-

[16] For the assumed reduction of reserve requirements, we have followed a conservative approach. Total reduction of reserve requirements between Case 0 and Case 2 amounts to 3%, being 2% for spinning reserves and 4% for non-spinning reserves.

ASSUMPTIONS FOR THE RESERVE AND ANCILLARY SERVICES MARKET OR PROCUREMENT

	Case 0	Case 1	Case 2	Case 3
border flows	interconnectors (as observed to-day) for balancing and ancillary services.	interconnectors (as found today) for balancing and ancillary services.	terconnectors allocated to IDM and flow-based allocation of capacities after, taking into ac-count remaining capacity of inter-connectors after unit commitment coupled with DAM and modifica-tions from IDM.	terconnectors allocated to IDM and flow-based allocation of capacities after, taking into ac-count remaining capacity of inter-connectors after unit commitment coupled with DAM and modifica-tions from IDM.

I - 1.2 Sensitivity Cases

In addition to the Cases above, we have further analysed with PRIMES-IEM four additional sensitivity cases. The sensitivities build on Cases 1 and 2:

- **Case 1_NTC:** This sensitivity relies on Case 1. It includes the same assumptions as Case 1 except that NTC values are assumed to be at the same level as in Case 0. The examination of this case allows isolating the impact of removing nominations and priority dispatch from the impact of NTC increase.
- **Case 2_Merit_Order**: This sensitivity builds on Case 2. It includes the same assumptions as Case 2, however it assumes that EU ETS prices are higher by 50% in 2030, all else being kept the same. This stylised scenario (since the modelling does not close the loop using the entire PRIMES model and therefore it ignores that higher carbon prices would logically entail endogenous changes in investment hence in the power generation mix) is presented to study the impact of a change in merit-order of plants, with CCGT and other gas units moving to a lower rank in the merit-order at the expense of old coal or lignite plants.

I - 1.3 Association of the analysed Cases with the Policy Options of the European Commissions' Impact Assessment

In Table 4, we summarise the correspondence of the analysed Cases to the Policy Options that are discussed in the EU Commissions' Impact Assessment, focusing on the main measures. The Table shows the correspondence of Cases 1 to 3 and sensitivity Case 1_NTC[17] to the Policy Options.

It is worth noting, at this point that Case 1 and Case 1_NTC differ regarding the assumed value of NTCs (higher NTC values in Case 1). As a result, the sensitivity Case 1_NTC and not Case 1 is the closest to Options 1(a) to 1(c) of the Impact Assessment.

Regarding the baseline Case 0 and the baseline Policy Option 0 of the Impact Assessment, they both reflect current practices of today. The difference between the two regards the consideration of nominations of energy in the Day-Ahead market. Baseline Option 0 of the Impact Assessment assumes that only units with priority dispatch disrupt the economic merit order in the Day-Ahead market. The baseline Case 0 analysed with PRIMES-IEM considers that, in addition to priority dispatch of some units, a part of energy (by solids and nuclear plants) is being nominated, and thus is not part of the Day-Ahead scheduling. In subsequent Cases (Case 1 to 3), the analysis with PRIMES-IEM assumes that the market conditions are such that provide with sufficient incentives to generators to participate in the Day-Ahead market. Thus, nominations of energy eliminate, while all generators that participate in the Day-Ahead market offer prices at a minimum reflecting variable costs.

[17] Sensitivity Case 2_Merit_order is excluded, as it does not correspond to any of the options of the Impact Assessment.

Table 4: Correspondence of Cases and policy options

Specific measures	Cases as in the present study	Policy options as in the EU Impact Assessment study
Priority Dispatch	Case 1 and Case 1_NTC: Removal of priority dispatch of biomass plants	Partly Options 1(a) to 1(c), which assume removal of priority dispatch for all RES, except for small-scale RES and CHP
	Case 2: Removal of priority dispatch of all power plants except for small-scale RES and CHP	Options 1(a)-(c)
	Case 3: Removal of priority dispatch of all power plants except small-scale CHP	Partly Option 2, which assumes full abolishment of priority dispatch
Balancing responsibility	Case 1 and Case 1_NTC: no balancing responsibility for nominated plants, must take RES and CHP and plants with priority dispatch	Partly Options 1(a)-(c): exemption of small-scale RES and CHP
	Case 2: no balancing responsibility for small-scale RES and CHP	Options 1(a)-(c)
	Case 3: no exemptions	Option 2
RES providing non-frequency ancillary services	Case 1 and Case 1_NTC: RES can provide non-frequency ancillary services, except for small-scale RES	Partly Options 1(a)-(c): Market-based non-discriminatory framework for provision of such services
	Case 2: RES can provide non-frequency ancillary services, except for small-scale RES	Partly Options 1(a)-(c): Market-based non-discriminatory framework for provision of such services
	Case 3: All RES can provide non-frequency ancillary services	Option 2
Reserves sizing and procurement	Case 1 and Option 1_NTC: Country-specific procurement	Options 1(b)-(c)
	Case 2: EU-wide procurement	Option 2: EU-wide procurement
	Case 3: EU-wide procurement	Option 2: EU-wide procurement
Remove distortions for short-term liquid markets	Case 1 and Case 1_NTC: Illiquid market in some countries	Options 1(b)-(c)
	Case 2: Liquid markets in all EU	Option 2
	Case 3: Liquid markets in all EU	Option 2
Demand response	Case 1 and Case 1_NTC: Demand response limited to large entities	Options 1(c): Consumers have access to enabling technologies, but full potential is not unlocked
	Case 2: Demand response limited to large entities	Options 1(c): Consumers have access to enabling technologies, but full potential is not unlocked
	Case 3: Full potential of demand response unlocked	Option 2

I - 2 Overview of modelling work

I - 2.1 The PRIMES-IEM

The modelling analysis with the PRIMES-IEM aims to simulate in detail the sequence of operation of the European electricity markets, namely the Day-Ahead market, the intraday and balancing markets and finally the Reserve and Ancillary Services market or procurement. The PRIMES-IEM modelling suite consists of four main models:

- A Day-Ahead Market simulator (DAM_Simul), which simulates the operation of the Day-Ahead market and builds on the EUPHEMIA algorithm[18] which has been coded in GAMS language and adapted to the modelling of the electricity systems of the European countries according to the logic of PRIMES. The model simulates the bidding by generators using various stylised competition regime assumptions, and possible rules for the bidding.
- A Unit Commitment simulator (UC_Simul), which simulates the scheduling of plants occurring real-time, considering the technical limitations of power plants sufficiently. The simulator is a standard code used by TSOs (and proposed by the FERC in the USA) for the hourly simulation of real-time dispatching and plant operation. The simulator includes all technical constraints of plant operation, demand constraints for energy and ancillary services, as well as curtailment options. The simulator finds the dispatching schedule by maximising social welfare by considering economic functions which are ascending for plants and descending for demand and ancillary services, under technical constraints which involve binary variables.
- An intraday and Balancing market simulator (IDB_Simul), which simulates the operation of the market for balancing services and the settlement of deviations which occur between the real-time scheduling of units (output of UC_Simul) from the Day-Ahead (output of DAM_Simul). The markets solve separately for upward and downward deviations and take into account the scheduling resulted from the day ahead market, after applying the randomly generated events (for the load, renewables, outages, etc.), and after engaging capacities required to meet the ancillary services. The market solution takes into account the technical or commercial possibilities of plant types to provide downward or upward resources to meet the deviations. The model simulates the economic offering of generators assuming scarcity bidding behaviours separately for the downward and upward markets for deviations.
- A Reserve and Ancillary Services market simulator (RAS_Simul), which simulates the reserves and ancillary services market procurement. The model simulates the bidding of capacities by the generators, based on scarcity pricing. In non-market design options, the model simulates least-cost acquisition of capacities based on long-term contracts with the TSO, assuming capacity cost recovery through the contract prices.

The PRIMES-IEM covers all EU 28 Member States individually, in detail. It also represents Norway, Switzerland and the Western Balkan countries, to account for exchanges of energy between EU and these countries. PRIMES-IEM disaggregates the interconnection network and considers more than

[18] EUPHEMIA (Pan-European Hybrid Electricity Market Integration Algorithm) is the single price coupling algorithm used by the coupled European PXs. The public documentation of EUPHEMIA is available in: https://www.nordpoolspot.com/globalassets/download-center/pcr/euphemia-public-documentation.pdf.

one node for each country[19], to represent in-country grid congestions. The assumptions about the interconnections within each country and across the countries change over time, reflecting an exogenously assumed grid investment plan. Existing power capacity of lines and new constructions reflect the ENTSOE data and the TYNDP[20]. Technical characteristics of transmission lines (thermal limits and admittance factors) take values as collected from TSOs.

The power market simulators of the PRIMES-IEM use data and calibration from projections of the standard PRIMES model[21] for a scenario and run for any year of the projection (usually 2015 to 2050 by 5-year periods). For this analysis, the PRIMES-IEM calibrates to the 2030 projections of the EU-CO27 scenario[22], which is a decarbonisation scenario prepared for the European Commission. Inputs from the EUCO27 scenario include:

- Load demand (hourly), power plant capacities, net imports with countries outside of EU28, the capacity of the transmission lines and NTC values.
- Fuel prices, EU ETS carbon prices, taxes, etc.
- RES generation (the simulators of PRIMES-IEM determine curtailment endogenously).
- Potential of hydro production (for hydro reservoirs).
- Heat or steam-serving obligations of the CHP units whose primary product is heat or steam rather than electricity (industrial CHP and small CHP units exclusively used for steam and heat).
- Other restrictions derived from specific policies, e.g. operation restrictions on old plants, renewable production obligations, and, if applicable, support schemes of renewables, biomass and CHP.

Constraints on water availability of hydro with a reservoir apply on a daily basis in PRIMES-IEM. The model distinguishes mandatory hydro-lakes production (due to excess water and other uses of water) from hydro-lakes production at peak load times. The distinction applies to the bidding behaviour of lakes (discussed in I - 2.2). The data on hydro pumping are directly those of the EUCO27 scenario, and the PRIMES-IEM model uses them exogenously.

The PRIMES-IEM incorporates a detailed database per plant (a complete list as in the standard version of PRIMES), with disaggregated technical and economic data for each unit to be able to represent the cyclical operation of plants, possible shut-downs and start-ups. The database also includes detailed data on the technical possibilities of plants to provide ancillary services. The ancillary services represented in PRIMES-IEM include Frequency Containment Reserve (primary reserve), Automatic Frequency Restoration Reserve (secondary reserve – Automation Generation Control or AGC), Manual Frequency Restoration Reserve (spinning tertiary reserve) and Replacement Reserve (non-spinning tertiary reserve). Relevant data have been collected from the national TSOs.

Finally, the PRIMES-IEM represents typical 24-hour days, which are distinguished by season, and by working days or holidays (and weekends). For example, a typical day could be a working day in winter.

[19] The analysis with the Unit Commitment model in particular (described in detail in I - 2.2.3), considers five nodes for France and Germany, and two nodes for Poland, Austria and Italy. The split of these countries is conducted in a way to capture the most important in-country congestions, after consulting relevant literature, as in Supponen (2012).
[20] As available in https://www.entsoe.eu/major-projects/ten-year-network-development-plan/ten%20year%20network%20development%20plan%202016/Pages/default.aspx
[21] A detailed description of the standard PRIMES model can be found in "PRIMES Model Version 6 2016-2017" (E3Mlab/NTUA, 2016)
[22] See Appendix A.

I - 2.2 Modelling procedure

The simulations with the PRIMES-IEM models are conducted for 2030, assuming load and power plant capacities as projected with the standard PRIMES model for the EUCO27 scenario[22].

Table 5 summarises the steps of the modelling framework. The following paragraphs describe in more detail each modelling tool of the PRIMES-IEM and the methodology followed in the simulations.

Table 5: Steps of modelling work performed with the PRIMES-IEM modelling suite

Steps of the PRIMES-IEM simulations	Process	Output
Step 1: Running of the Day-Ahead Market Simulator	Simulation of the DAM simultaneously for all EU countries. The basis is the EUCO27 scenario (capacity, demand, must-take generation, etc.).	Plant and interconnectors operation schedule (DAM schedule), and its financial settlement
Step 2: Generation of experiments with the Random Events Generator	Generation of experiments (random events), with deviations from EUCO27 projections on wind and solar generation, demand, availability of plants and interconnections	52 cases (random events), and respective frequencies
Step 3: Running of the Unit Commitment simulator	For each random event, UC simulation considering all technical constraints of plants and the ancillary services	Revised plant and interconnectors operation schedule (UC), deviations from the DAM schedule
Step 4: Running of the intraday and Balancing Market Simulator	Set-up of the market to settle down and up deviations from DAM defined with the UC simulator. Eligibility per plant to bid in the IDB is determined hourly, based on the output of UC.	Financial settlement of deviations and revised schedule for operation of units and interconnectors
Step 5: Running of the Reserves and Ancillary Services market or procurement simulator	Settlement of exogenously set reserve requirements, considering residual capacity after the settlement of the IDB.	The remuneration of the resources for providing reserves
Step 6: Final cost-accounting	Calculation of financial balances (revenues and costs) for each generator, load payments (payments by consumers) and payments by the TSOs. Calculation of unit cost indicators (e.g. for reserves, etc.). Calculation of expected values of the outcomes, as the average of results by case (random event), weighted by the frequency of each Case.	

First, the Day-Ahead Market simulator runs (DAM_Simul), and determines a unit-commitment schedule of power plants, including demand response and a schedule of flows over interconnectors.

After the simulation of the Day-Ahead market, we use a “Random Events Generator” tool (developed as part of the PRIMES-IEM specifically for this analysis) to generate a set of random events (experiments). The goal of this step is to artificially introduce a deviation between the Day-Ahead forecasts (on load, RES generation, availability of plants, etc.) and what is occurring in real-time operation of the system.

Considering these deviations, we run a unit commitment simulation with the UC_Simul, which uses the bidding as in the Day-Ahead market simulation, with the difference that it includes constraints on the technical operation capabilities of plants and the ancillary services. The outcome is a simulation of the real-time functioning of the system, and it compares to the Day-Ahead simulation result. The difference represents the best forecast of deviations by the market participants.

The next step is the financial settlement of the deviations between the Day-Ahead schedule and the UC_Simul schedule and is a result of the intraday and Balancing Market simulator (IDB_Simul). The IDB_Simul runs and generates the bids for meeting the deviations, separately for down and up deviations.

Afterwards comes the simulation of the market or procurement of reserve and ancillary services, which is conducted using the RAS_Simul tool. It takes into account the commitments in the previous stages and determines the offerings and then the remuneration for the provision of reserve and ancillary services, given the reserve requirements set exogenously. The model can simulate either a market-based clearing or a contract-based remuneration of plants offering for the ancillary services.

I - 2.2.1 Day-Ahead market simulator (DAM_Simul)

The DAM_Simul algorithm consists of a set of constraints which builds on the EUPHEMIA[18] algorithm. The core parts of the algorithm of the DAM_Simul use balancing equations, which regulate the inflows and outflows in each node. The objective function maximises the social surplus (i.e. the sum of consumer and producer surplus). The demand and supply functions at an aggregate level result from the individual bidding of price-quantity pairs, which form a descending locus for consumers and an ascending locus for generators). The balancing equations complemented by network constraints allow simulating a flow-based allocation of interconnection capacities (discussed in more detail in I - 2.2.1.1). The model also includes economic functions for possible curtailment (of load, RES, etc.) and constraints related to operational limitations, which guarantee that all plants should offer energy below their maximum capacity or above the over-the-counter arrangements (nominations of energy) (discussed in more detail in I - 2.2.1.3). The model formulates all bidding options of the EUPHEMIA, notably simple bidding, block orders, conditional bidding and others. The bidding behaviour regarding the prices of the bidding of generators is determined endogenously by the model by assuming a particular competition regime. The bidding by the load (demand response) is endogenous reflecting cost-supply potential curves, which are estimated by external studies. Appendix B describes in detail the elements of the DAM_Simul model.

The DAM_Simul runs for all the European countries simultaneously, with every country representing a node, and determines market clearing by node and interconnection flows. The DAM_Simul produces a full unit schedule, the use of interconnectors and the system marginal prices – SMPs, as well as curtailments if deemed appropriate. It also computes revenues and payments (also across the borders) as part of the financial settlement of the DAM.

The DAM_Simul draws techno-economic and other data from the standard PRIMES model database, including:

- Capacity data, fuel type and other technical data for each plant
- heat rates per plant,
- fuel prices,
- ETS carbon prices
- CO_2 emission coefficient per plant,
- cost parameters per plant (capital, fixed and variable), and
- power network topology and technical characteristics of interconnectors.

Moreover, it takes as given the projections of the standard PRIMES model for the EUCO27 scenario on the following:

- Hourly load demand, including losses and quantities of pumping injection/extraction.
- Must-take CHP generation
- RES generation by hour and type

Must-take CHP generation is considered for CHP plants whose operation is driven by heat supply, namely industrial CHP units and exclusively district heating plants. Other units producing heat as by-product (large CHP units) are treated in the simulations as any other power plant.

I - 2.2.1.1 Network representation in DAM

In the DAM_Simul, every country corresponds to one bus. The network includes all current AC and DC interconnections, as well as known investments according to the TYNDP[19]. The model simulates optimal flow-based allocation of capacities across interconnections. The flows are restricted by the first and second Kirchhoff laws and by administratively defined Net Transfer Capacity (NTC) limitations, applying to pairs of adjacent countries. Depending on the Case under analysis, flows may be further restricted by over-the-counter arrangements.

In particular, in the simulation of the baseline Case 0, the Available Transfer Capacity (ATC)[23] depends on the NTC values, and the capacity reservations for cross-border nominations. The Case 1 assumes that the NTC values increase, compared to the Case 0, and closer to the technical limits of interconnection lines. Moreover, the Case 1 assumes that the market conditions are such that generators participate in the markets rather than nominating their capacity and load, which means that the amount of capacity of interconnectors engaged for the nominations in Case 0 is free in Case 1. Hence, in Case 1 there are more possibilities for trade flows than in Case 0. Finally, in Cases 2 and 3, we no further incorporate NTC restrictions, assuming a fully integrated EU market. Thus, in these latter Cases, trade flows are only limited by the technical capacity of the grid.

I - 2.2.1.2 Bidding of power plants

The economic offers per plant in the DAM_Simul can be of various types, including hourly orders, flexible hourly orders, block orders and complex orders[24]. In the context of the MDI exercise, we have used hourly orders defined for individually per plant. For the cases 2 and 3, we have included technical constraints and ancillary services, and although the economic offers are specific to each plant, the scheduling of the plants is determined as if every generator holding a portfolio of plants was submitting complex bids to pre-empt on balancing and deviation settlement costs in the subsequent stages of the market.

We assume that plants bid in the markets (if bidding is allowed in the Case under analysis) at a level equal or higher than their marginal cost (which come from the PRIMES database). Scarcity bidding is equivalent to applying a cost markup to determine the bidding price. The markup depends on a scarcity bidding function (defined per plant), which takes into account hourly demand, plant technology and the fixed costs[25]. The employment of the scarcity bidding function serves as a means of mimicking the strategic bidding behaviour of plant owners in an oligopoly. Such behaviours are found to be representative of current EU markets[26].

Regarding hydro-reservoir power plants (lakes), in all Cases, we assume that part of the generation of lakes (mandatory generation) makes zero bids, simulating the energy that needs to be used to

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[23] For an overview of concepts related to the transmission transfer capacity the reader is referred to Dobson et al. (2001)

[24] Definition of the various types of block orders can be found in the description of the EUPHEMIA algorithm, available in https://www.nordpoolspot.com/globalassets/download-center/pcr/euphemia-public-documentation.pdf.

[25] A detailed overview of the implementation of scarcity bidding (which is used in the exercises with both PRIMES-IEM and PRIMES-OM) can be found in Appendix C.

[26] As supported by Willems (2009)

avoid overflow and for irrigation purposes (particularly relevant for southern EU countries). Only the non-mandatory part of lakes is bidding in the Day-Ahead market. The prices of the bids depend on a scarcity bidding function (similar to all other power plants), which applies a markup to the most expensive marginal cost of operating units, so as to reflect scarcity during peak hours and a possible shortage of water availability. It is worth noticing that the market conditions do not require negative bidding for any type of power plant, and thus the simulations have excluded negative bids.

Depending on the Case, we adopt different assumptions regarding the existence of bidding zones. Cases 0 and 1 assume national bidding zones with NTC restrictions applicable on existing borders. The Cases 2 and 3 consider the operation of fully integrated EU markets with a flow-based allocation of the entire capacity of interconnections as if there was a single bidding zone.

I - 2.2.1.3 Modelling of nominations

The baseline Case 0 takes into account that a part of the energy generated by power plants is being nominated instead of participating in the Day-Ahead market (see Section I - 1.1). In particular, it is the generation of nuclear and solids-fired power plants that usually correspond to nominations in the simulation of the Day-Ahead market in the Case 0. Therefore, the production of these power plants is scheduled and fixed. Part of the nominated energy is assumed to contribute to the fulfilment of cross-border trade contracts (cross-border nominations). The annual amount of electricity for cross-border nominations follows the 2015 pattern of bilateral transactions according to the EUCO27 scenario[27]. The distribution of the nominated electricity among the adjacent countries is proportional to the respective transfer capacities. The electricity nominated within a country does not participate in the DAM solution. The cross-border nominated electricity implies a reduction in the ATC.

I - 2.2.1.4 Modelling of priority dispatch

Depending on the Case under analysis, the DAM simulation assumes priority dispatch for certain power generation technologies. In particular, in the Baseline Case (Case 0) it is assumed that CHP generation of industrial CHP units and exclusively district heating plants and all RES generation (including biomass) dispatch with priority. In the subsequent Cases (Cases 1 to 3) priority dispatch in the DAM is gradually removed, except for must-take CHP generation. Must-take CHP generation is continuous to apply in all the Cases. The reason is that the simulators of the PRIMES-IEM do not represent the demand and supply of heat and steam explicitly. However, using the results of the standard PRIMES model, we infer about the interactions with the heat/steam demand so as to simulate the participation of CHP units in the markets appropriately.

To simulate priority dispatch, the model assumes zero prices for the bids for fixed hourly amounts of generation of the concerned capacities (taken from the results of the PRIMES EUCO27 scenario), However, depending on a high penalty, the model can consider curtailment economically, to accommodate scheduling of other plants, notably during periods threatened by overgeneration. As priority dispatch vanishes across the Cases, the penalty for curtailment also decreases.

I - 2.2.1.5 Modelling of demand response

The model represents demand response as an endogenous shifting of demand quantities among peak and valley load segments within the timeframe of dispatching. Thus, we do not consider load shedding as part of demand response, because the model represents load shedding as an effect of

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[27] The 2015 annual bilateral transactions of the EUCO27 scenario have been calibrated to the actual released transactions, according to ENTSOE (https://www.entsoe.eu/data/data-portal/Pages/default.aspx).

price-elasticity which is part of the demand-supply equilibrium projected by the standard PRIMES model. In the PRIMES-IEM model, we include shifting of the load as a result of demand response. It comes as a response to price signals on an hourly basis derived from the system marginal prices of the wholesale market in the Day-Ahead and depending on options also in the balancing markets. The shifting of demand from hours of peak prices to hours of low prices leads to a smoother demand curve. The curve follows the locus of an ascending cost-potential curve which expresses that the marginal cost increases with the volume of demand response, as in reality.

Modelling of demand response used data from a recent study coordinated by COWI[28] and other information from the literature. In particular, COWI provided estimations of the potentials and stepwise functions that associate the amount of demand response with marginal costs, exhibiting decreasing returns to scale. In the markets simulated by the model, the consumers can offer pairs of volumes and prices for demand response, with bidding quantities limited by the potential and bidding prices reflecting a stepwise marginal cost.

The potential of the demand response differs between the Cases analysed. The Case 2 limits demand response to large consumer entities, notably industry, and the Case 3 assumes unlocking of the entire potential (I - 1.1).

I - 2.2.1.6 Day-Ahead market simulator version with Unit Commitment (DAUC)

The DAM model includes as an option an extended variant of the energy market simulator described insofar, which allows for optimising energy and reserves simultaneously while respecting the technical constraints of cyclical operation of power plants. The co-optimization is applicable only to certain Cases of the analysis[29] to represent mature energy markets where generators submit complicated bidding of generation portfolios to pre-empt for future costs related to deviations and balancing during the intraday markets. When this option is activated, the DAM model algorithm includes additional constraints:

a. Technical restrictions of plant operation (e.g. technical minimum and maximum, ramping capabilities, minimum uptime, minimum downtime, etc.). The DAM simulator in these Cases includes the same set of constraints as the Unit Commitment simulator[30] (which is described in Section I - 2.2.3[31]).
b. The constraints of the Reserve and Ancillary Services Procurement model (which is described in Section I - 2.2.5[31]). In practice, when the co-optimisation option is activated, it is as if the two models run simultaneously.

The problem of co-optimising energy and reserves is a mixed integer problem, with binary variables reflecting plant operation status. To derive the SMP, we perform a second run, after fixing variables to the integer solution, and relaxing the integer constraints, allowing them to be linear. It is necessary to do so because the SMP has no sense as a shadow cost in the context of nonconvex programming (in this case integer programming.

[28] See study by COWI (2016).
[29] Case 2 and Case 3, see section I - 1.1.
[30] The fact that the DAM model becomes similar to the UC model, implies that deviations between the day-ahead market scheduling and the real-time scheduling simulated by the UC are the least possible, and attributed solely to random events occurring unexpectedly real-time. This has very considerable impacts in the comparison of results between the Cases and will be discussed in detail in chapter I - 3
[31] Detailed overview of the mathematical formulations of each model are given in Appendix B.

I - 2.2.2 Random Events Generator

Using a random events generator is a modelling method to represent the difference between "what is projected to happen" the Day-Ahead and "what is happening" in real-time operation of the system. The simulation of the Day-Ahead market, discussed in 0, builds on the projections for the EUCO27 scenario regarding hourly demand, renewables generation, and availability of plants, EU ETS prices and fuel costs. The outcome of the simulation is a scheduling of plants for operation in the next day, depending on the bids of generators and demanders in the Day-Ahead market, which operates simultaneously in the entire EU. The production in real time does not take place identically to the scheduling off the Day-Ahead because of deviations. The random event generator generates a set of scenarios for deviations and associates a probability to each one.

The generation of random events implies deviations for the following:

a. Demand on an hourly basis
b. Weather changes affecting the generation of variable RES, notably of wind and solar
c. Unexpected availability issues of large power plants (equivalent to forced outages)
d. Unplanned reduction in the net transfer capacities (NTC) of interconnectors (equivalent to a loss of transmission lines)

The generation of scenarios applies a sampling based on the Monte-Carlo technique assuming a normal probability distribution for each random event and a variance-covariance matrix. After applying a scenario reduction technique, to reduce as much as possible the number of scenarios to run because of computer time limitations, the random events generator builds 52 stylised scenarios[32], or experiments, and assigns a frequency of occurrence to each one of them. The parameters and ranges of the probability functions regarding the random events take values based on expert judgement. To further reduce computer time, the model groups the days of the year in clusters according to their characteristics (season, whether it is working day or holiday). The set-up of the experiments, (shown in Table 32 in Appendix C) is the same across all Cases analysed.

The simulations using the Unit Commitment simulator and the modelling of settlements for deviations between the Day-Ahead market and the intraday market (with the intraday and Balancing market simulator) run separately for each experiment, and the final results are the expected value calculated by weighting the results of each experiment using the assigned frequency.

I - 2.2.3 Unit Commitment simulator (UC_Simul)

The Unit Commitment simulator models the real-time dispatch of the system, after having resolved all the uncertainties regarding the random events and the forecasted deviations. The run of the unit commitment at this stage of the sequence of the markets represents a sort of best guess by the market participants (TSO, generators, demanders) about the real time system operation to make them able to guess the deviations to handle in the intraday and balancing markets. Naturally, the simulator runs for every experiment, and the "best" guess is an expected value based on the frequencies of the experiments. We assume that the estimate of deviations takes place in a single step, i.e. we do not perform repetitive steps of the UC_Simul, and thus we ignore a possible sequential

[32] We have limited the number of experiments to only 52 to avoid unreasonable computer times for the overall simulation. In fact, the sequence of market simulators take significant computer time to run for the entire Europe, and thus the total computer time is proportional to the number of random cases. From a software perspective the user can of course increase the number of experiments produced by the random events generator.

operation of the intraday and balancing markets in different points in time between the DAM closure and the real-time (as if continuous IDM were operating)[33].

In the UC_Simul, the generators compete for providing energy and reserves simultaneously[34]. The model takes as inputs exogenously defined reserve requirements[35], the outcomes of the Random Event Generator as deviations from forecasted (in the Day-Ahead simulation) demand, renewables generation, availability of power plants and NTC values, and the dispatch schedule and bidding according to the DAM simulator.

It runs for the pan-European electricity network, following the same modelling of power flows as in DAM_Simul (I - 2.2.1.1). However, network representation is more detailed in the UC_Simul than the DAM_Simul, as it includes more than one node for some countries[36]. In this way, the model captures the in-country network limitations, which are of high importance not only for the flow of power within the country but also for the international flows.

The UC model uses the DAM solution as an initial condition. The solution of the UC_Simul regarding dispatching of units differs from the solution of the DAM model due to:

a) The inclusion of technical constraints for the operation of power plants in the UC_Simul
b) The simultaneous optimisation of energy and ancillary services
c) The deviations regarding load, renewables generation, availability of plants and interconnections produced by the Random Events Simulator.

In particular, all technical constraints that generators encounter in real-time operation are represented in the UC_Simul, namely the maximum hours of operation above the technical minimum, ramping constraints, minimum up and down time constraints (Appendix B provides complete documentation of the formulations). Data on start-up and shut-down costs are specific to each plant type. Moreover, UC_Simul includes constraints that represent the technical limitations of each power plant for providing ancillary services.

The bidding by the generators for energy follows the same logic as in the DAM_Simul (see Chapter I - 2.2.1.2), i.e. generators bid strategically according to a scarcity bidding function[37]. Bidding for reserves varies across the Cases analysed (see Chapter I - 1). In particular, in Cases 0 and 1, the remuneration of reserves is assumed to be administratively defined, both regarding quantities and regarding payments for ancillary services (based on procurement and contracts). Therefore no bidding applies except in countries where markets for ancillary services exist today. In Cases 2 and 3, the bidding for reserves reflects the opportunity cost of generators, i.e. on the value that generators

[33] That would require that we make assumptions on the deviations introduced at each point in time between the DAM closure and the real-time, which would add unnecessary complexity in the modelling.
[34] At this point it is important to clarify what is considered as reserve in the modelling. Demand for reserves is predetermined and exogenous. The amount of capacity that is bound for reserve purposes according to the optimization with the UC model is not participating at all at the clearing of the intra-day and balancing markets that follows. Therefore, in the modelling reserve refers to the capacities that participate in the reserve markets or procurement after the clearing of the intra-day and balancing markets.
[35] Reserve requirements have been provided by Artelys and THEMA Consulting (2016).
[36] The UC_Simul considers five nodes for France and Germany, and two nodes for Poland, Austria and Italy. The split of these countries is conducted in a way to capture the most important in-country congestions, consulting relevant literature, as in Supponen (2012)
[37] A detailed overview of the scarcity bidding function employed is available in Appendix C.

lose by binding their capacity for reserves instead of bidding this amount of capacity in the energy markets[38]. A markup reflecting scarcity applies on top of opportunity costs.

The opportunity cost is calculated taking into account the hourly SMP price of the DAM solution. In particular, if we denote OC_n the opportunity cost of plant n, $GenDA_{n,h}$ the generation of plant n in hour h, $SMPDA\ (h)$ the SMP of the DAM in hour h, VC(n) the variable cost of plant n, $TotGenDA_n$ the total generation of power plant n in the DA market, then:

$$OC_{(n)} = \frac{\sum_h GenDA_{n,h} \cdot (SMPDA_{(h)} - VC_n)}{TotGenDA_n}$$

The model distinguishes the hydropower outflows corresponding to mandatory obligations to manage excess water and other uses of water and the peak load dispatching. In the UC_Simul model, both can operate in a load-following manner and can offer in the intraday market for balancing services as well as in the market for ancillary services. In both cases, the water availability, as specified per day after having applied a yearly plan of hydropower use, limits the offers. The annual program of hydropower use builds on the results of the standard PRIMES model, and it corresponds in essence to a maximisation of the value of water on a yearly basis, depending on the shape of the load curve and the anticipation of system marginal prices. Due to computer time limitations, we determine the annual plan of hydropower use only once in the beginning of the simulations, and we do not revise it once the simulator has produced results for the system marginal prices, the pumping and the demand-response. In this sense, our approach is only a proxy to the full optimum.

The UC Simulator models priority dispatching and demand response (if eligible to participate in the intraday and balancing markets in the Case under analysis) in the same way as the simulation of the Day-Ahead market, using the DAM_Simul (I - 2.2.1.4 and I - 2.2.1.5).

The UC_Simul optimisation of real-time unit commitment aims at limiting the deviations from the DAM solution as much as possible. For this reason, the model assumes penalty factors for the deviations from the DAM schedule (re-dispatching), which are part of the objective function of the optimisation. Hence, re-dispatching costs occur for units which operate according to the UC at a different level compared to the DAM schedule.

The financial settlement of deviations regarding the scheduling of units and the load are part of the simulators which handle the intraday and Balancing markets (see Section I - 2.2.4).

I - 2.2.4 Intraday and balancing simulator (IDB_Simul)

The intraday and Balancing Market Simulator (IDB_Simul) simulates a stylised hourly market for the deviations that occur between the DAM_Simul solution (0) and the UC_Simul solution (I - 2.2.3). The random events generated using the Random Events Generator (I - 2.2.2) regarding the load, RES generation, availability of plants, etc. are the causes of deviations. Another source of differences is the possible non-optimal merit order scheduling of plants resulting from the Day-Ahead energy-only market in case the bidding by generators ignore the cyclical operation constraints of dispatchable plants and the resources required to meet the ancillary services. The simulator performs a one-shot market clearing of the deviations, i.e. it does not simulate sequential intraday markets. It runs simul-

[38] The opportunity cost is calculated taking into account the hourly SMP price of the DAM solution. In particular, if we denote OC(n) the opportunity cost of plant n, GenDA(n,h) the generation of plant n in hour h, SMP-DA(h) the SMP of the DAM in hour h, VC(n) the variable cost of plant n, TotGenDA(n) the total generation of power plant n in the DA market, then $OC(n) = \sum_h GenDA(n,h) \cdot (SMPDA(h) - VC(n)) \big/ TotGenDA(n)$.

taneously for all hours in every typical day and determines an SMP price for deviations, which is different for upward and downward deviations, the financial settlement of deviations and a revised schedule for operation of units as well as interconnectors.

Before running the IDM_Simul, for every hour, the nodes (countries) are categorised into regions based on an ex-post coupling criterion which considers that adjacent nodes are de facto parts of a coupled market if they share the same SMP, which depends on the model results, not assumptions.

Comparing the DAM and the UC solutions, deviations occur due to the consideration of technical constraints of plants in the UC model and due to other variations in demand and renewables generation as included in the experiments produced using the Random Event Generator. Before settling these deviations financially, the IDB_Simul uses a set of rules to determine which resources are eligible to bid in the IDM to meet the deviations. The bids are different for upward and for downward deviations of power supplied by the eligible resources. The markets for down and up deviations clear at different prices, and the resources are different for meeting the down and up deviations.

Examples of rules used in the model to represent the possibilities of resources for meeting the deviations are as follows. All the dispatchable[39] power plants that have altered their generation from the DAM solution to the UC solution opposite to the direction of demand deviation (sum of the demand deviations of the countries in the coupled region) form a group which splits into two subgroups, one for every direction of the demand deviation. If demand in the Day-Ahead simulation is lower than the one in UC and the generation of the unit is higher in the Day-Ahead simulation than in UC, the unit cannot offer to meet upward deviations. If the reverse is true, the unit cannot offer to meet downward deviations.

The logic behind this is that these plants are not load-following in the UC solution due to technical reasons, and thus should not be able to contribute in covering intraday deviation. Hence, the rest of the dispatchable plants can submit offer to meet the deviations between DA and UC. The dispatchable power plants can offer their capacity in the IDM[40] (including demand response), except the capacities that are part of the schedule to meet the reserve and ancillary services market according to the UC solution. To meet upward deviations, the eligible capacities can offer the remaining unused capacity above the level committed following the scheduling issued by the DAM, minus commitments for upward reserve procurement.

Similarly, to meet downward deviations, the eligible capacities can offer to reduce the capacity below their level in the scheduling issued by the DAM up to the minimum stable generation level and after taking into account the capacity qualified for downward reserves. The hydro generators with a reservoir, in particular, can offer energy only up to the maximum difference between DAM and UC solution, either upwards or downwards.

Units not dispatched in the DAM solution can perform a start-up if suggested so by the results of the optimisation using the IDB_Simul. Along the same lines, the optimisation using the IDB_Simul can force units dispatched in the DAM solution to shut-down. Start-ups and shut-downs are possible only for flexible plants[41]. Power plants having operation constraints making them inflexible are not

[39] We define as dispatchable all the thermal power plants which are fired with conventional fuels plus the hydroelectric generators. From Case 1 onwards we add to conventional plants the (strictly) biomass and solar thermal plants.

[40] Note that RES and CHP plants do not participate in ID markets in all Cases except in Case 3.

[41] In particular, nuclear power plants are considered as inflexible in all Cases. Solids-fired are considered inflexible only in Cases 1 and 2.

eligible for shut-downs or start-ups. Also, none of the plants can offer energy which violates the ramping possibilities and the other restrictions, such as minimum uptime and minimum downtime.

Resources that are eligible to participate in the IDM are in competition with each other, depending on relative price offers for the deviations. For upward deviations, the offers use prices equal to the marginal cost of the unit plus a scarcity markup in case there is a shortage of resources.

For downward deviations, the prices of the offers reflect the variable cost of the plant but also the fixed operation and maintenance costs in case cyclical operation stresses the machinery including shut-down or start-up costs. The scarcity bidding methodology is similar to that applied in the DAM_Simul[42].

The bidding prices and the ensuing remuneration of resources depend on the assumed market liquidity, which varies in the Cases depending on assumptions about participation and market integration. When for some countries and Cases there is no liquid IDM market (see details in I - 1.1), the generators base their revenues on administratively set prices to meet the deviations. These costs derive from the bidding in the DAM market. But in liquid IDM markets, the bidding is independent of the DAM reflecting scarcity in the market for deviations[42]. The offers differ for upward and downward deviations, and the scarcity considerations differ in these two market segments.

The modelling of flows over the interconnections uses DC power flow in the context of the IDM market, as in the DAM_Simul (I - 2.2.1.1). Depending on the Case, it is possible by assumption not to have the participation of cross-border offers in the IDM. In the Cases which assume market coupling also in the intraday and balancing markets the models solve for a flow-based allocation under restrictions due to the NTS factors, where applicable. In the case of congestion, the prices clearing the deviations differ by country, as expected.

Appendix B includes a complete documentation of the constraints and other elements of the IDB_Simul model.

I - 2.2.5 Reserve and Ancillary Services market or procurement simulator (RAS_Simul)

The simulation using the UC_Simul (I - 2.2.3) assigns plant capacities to the provision of ancillary services so as to meet demand for reserves when co-optimising energy and reserves. The UC_Simul model runs after the application of the random generator of events and takes the output of the DAM as a desired scheduling of the plants. Therefore, the UC_Simul provides a best guess estimation of the deviations and the balancing as needed to perform the real-time operation of the system together with the meeting of reserve requirements. The capacities assigned to reserves do not participate in the IDM (I - 2.2.4).

However, as the IDM determines an updated scheduling of the unit commitment compared to the UC solution, resulting from the market clearing of deviations, it is probable that the assignment of some plant capacities changes relative to the UC. This implies further changes in the assignment of plant capacities to the provision of ancillary services. Therefore, the adjustments require running the UC model again, after taking into account the results of the IDM. However, to limit the computer time, we assume that only gas turbines, CCGTs and hydro are eligible for the adjustment due to their flexibility.

The RAS_Simul model runs to re-settle the reserve and ancillary services market financially taking into account the updated unit commitment schedule after having run the IDM. The RAS_Simul uses the same demand for reserves as the UC model. The demand for reserves distinguishes four types:

[42] Following the scarcity bidding methodology described in Appendix C.

1. Frequency Containment Reserve (primary reserve)
2. Automatic Frequency Restoration Reserve (secondary reserve – Automation Generation Control)
3. Manual Frequency Restoration Reserve (spinning tertiary reserve)
4. Replacement Reserve (non-spinning tertiary reserve)

We define the demand for reserves exogenously based on estimations for 2030 available in (Tennbakk et al. 2016). The estimations take into account current practices regarding the demand for reserves by country in combination with empirical methods used by ENTSOE to quantify reserve requirements if demand or RES change.

Regarding the procurement of ancillary services the model consider through optional parameters different types of market design:

1. Procurement based on TSO contracts with specific plants, at predetermined prices.
2. Plants bidding for the reserves with competition only on the volumes of capacity assigned by plant, knowing that the remuneration uses administratively set prices
3. A liquid market for reserves using economic offers (bids) for prices and quantities submitted by eligible plants.

The RAS_Simul applies scarcity-reflecting bidding for reserves using a methodology similar to the UC model (I - 2.2.3). The Cases 0 and 1 assume administratively set prices reflecting variable costs. The Cases 2 and 3 assume bidding for reserves using a markup applying on the opportunity cost of capacity reservation for ancillary services, i.e. the value that generators lose by binding part of the plant capacity for reserves instead of bidding the entire plant in the markets[38]. The resources that are eligible to participate in the market or the procurement of ancillary services differ in the Options. The plants that participate in the ID scheduling, and also demand response (see I - 1.1), are eligible. For the Options assuming fully liquid markets for ancillary services, the modelling assumes that RES participate in the ID market, allowed to bid for downward deviations, and thus they also participate in the market for reserves in the same manner.

The participation of demand response in the RAS market (in some of the Cases, depending on assumptions which differ by Case, see I - 1.1) is similar to the participation as modelled in the DAM_Simul (I - 2.2.1.5).

Cross-border resources are eligible to participate in the reserve markets in the Cases which assume complete market integration, as in Cases 2 and 3, and partly in the Case 1. Their contribution is subject to limitations arising from the availability of interconnection capacities, which are the remaining capacities after taking into account the scheduling of interconnection flows in the IDM. The resources from interconnections that are not part of the scheduling resulted from the IDM market are eligible to submit bids to the market for reserves, but only for tertiary reserves.

The four reserve markets or procurements are inter-related because of technical restrictions of the plants and therefore run simultaneously.

I - 3 PRIMES-IEM simulation results

I - 3.1 Simulation results of Cases 1 to 3

The analysis uses a comparison of simulation results of the Cases 1-3 between them and to the baseline Case 0.

The Case 0 assumes that the market situation in 2030 is very similar to what is today. The market functioning is imperfect, as barriers and market distortions exist implying cost inefficiencies. Moving towards Case 3, the analysis assumes the gradual elimination of the obstacles and distortions. Thus the market focusing among others on the aim of creating a level playing field among generators (and so priority dispatch of units, nominations, must-take and must-run privileges) and the establishment of liquid and coupled market for intraday balancing and reserves (thus removing administratively setting of prices, non-harmonised markets, limited participation of units, limitations in the use of interconnections and demand response). The analysis emphasises on removing any obstruction to the flow-based allocation of interconnection capacities as a means of broadening the markets allowing more intense competition and an efficient sharing of generation, balancing and reserve resources across the entire European electricity system. For this purpose, the analysis assumed measures towards removal of NTC restrictions, an optimal use of interconnections and coordinated TSO practices.

The results of the simulation of Cases show that total costs gradually decrease as we pass from Case 0 to Case 3 (Table 6). A large part of this reduction is due to the increased exploitation of interconnections and to the higher efficiency of the Day-Ahead scheduling, which comes into play entirely in Case 2. The results are also verified across regions (Table 8). The total load payment variable (shown below) corresponds to the entire electricity bills paid by consumers for consumption of energy, excluding any payment for the grids and public service obligations. In this logic, there is no other source of revenues for the generators. The turnover variable shown for the standard PRIMES model corresponds to the same complete electricity bills for energy consumption.

Table 6: Total load Payment and for each Case and comparisons, EU28 in 2030

	Total load payment in bn€'13	Difference from Primes turnover EUCO27 in bn€'13	Difference from Primes turnover EU-CO27 (%)	Difference from Case 0 in bn€'13
Case 0	356.04	30.76	9.5%	0
Case 1	345.62	20.34	6.3%	-10.42
Case 2	331.15	5.87	1.8%	-24.88
Case 3	305.38	-19.90	-6.1%	-50.65

Source: PRIMES-IEM model

Table 6 shows that the maximum amount gained from moving to the well-functioning market design represented by Case 2 is 25 bnEUR in 2030, which is quite significant. If the full demand response potential is exploited, the system could gain another 25 bnEUR in 2030 in addition.

It is remarkable (Table 6) that for the Case 2 the total load payment estimated using the PRIMES-IEM model is very close to the turnover estimated using the standard PRIMES model. It is a sort of coincidence and is a result of the computation. As mentioned in previous sections, the two models apply fundamentally different approaches to compute the total costs; the PRIMES-IEM simulates the stages of the markets with explicit consideration of the market design options, whereas the standard PRIMES model optimises total cost without considering market design options explicitly. The results for Case 2 makes us infer that the market design underlying the assumptions of Case 2 is close to the implicit market design assumptions of the optimisation performed by the standard PRIMES model which has assumed that a well-functioning integrated market operates in the EU by 2030. It is also remarkable that the Case 3 is cheaper compared both to Case 2 and to the result of the standard PRIMES model. The reduction in cost is mainly attributed to the maximum exploitation of demand response potentials in Case 3, knowing that the standard PRIMES model has not included the potential to a similar extent as in Case 3.

Table 7: Decomposition of total load payments between the market stages, EU28 in 2030

in bn€'13	Day-Ahead market	Intraday and Balancing market	Reserve and ancillary services	Total
Case 0	326.19	22.11	7.74	356.04
Case 1	322.48	16.30	6.84	345.64
Case 2	317.65	11.64	1.86	331.15
Case 3	300.36	4.01	1.01	305.38

Source: PRIMES-IEM model

Table 7 shows that the day ahead market is by far the largest component of total electricity generation costs, representing close to 95% of the total. The intraday and balancing market represents approximately 4%, and the ancillary service procurement has less than 2% of the total. It is, therefore, obvious that improving cost-efficiency in the day ahead market is of great importance for the consumer bills. The broadening of the Day-Ahead market by ensuring larger participation, greater regional coupling and flow-based use of the interconnections brings significant cost benefits, as shown in the first column of Table 7 by comparing Case1 and Case 2 to Case 0.

The market design improvements involved in the Case 1 have significant cost saving effects in all three stages of the market, and in particular in the Day-Ahead and balancing stages of the market. This is an important finding given that the options included in the Case 1 are quite realistic from an implementation perspective.

The efficient co-optimisation of energy and reserves as well as the inclusion of the plant technical operation constraints in the Day-Ahead market, which by assumption reflect the modelling of the Case 2, have very significant cost reduction effects in the intraday and the balancing and reserve markets. The co-optimisation implies additional expenses in the Day-Ahead market, and for this reason, the cost-efficiency gains of Case 2 are not very impressive compared to the Case 0 when looking only at the turnover of the Day-Ahead market alone. The additional cost implies by Case 2 for the day ahead market is far below the cost reduction achieved in case 2 in the intraday and the balancing and reserve markets.

This result confirms the importance of increasing the part of interconnection capacities which support the coupling of the market stages.

The full exploitation of demand response potential as in the Case 3 induces considerable cost savings in all the three stages of the market. Given the results for the Case 3, it is likely that the magnitude of the impacts corresponds to the top maximum of possibilities of demand response.

The cost savings effects of the policy options are different by region. The effects depend on the initial status of the market in the region; see for example that the Case 1 involves small gains in the North Eastern Europe region where market integration has been achieved already today. Regions that risk operating in isolation can benefit from market broadening more than other regions; see for example the effects of Case 2 in the British Isles, the Iberian Peninsula and South Eastern Europe. Another factor is whether the countries in the region have diversified generation portfolios in which case they may benefit from the sharing of resources more than in other regions with a more uniform generation mix. This factor probably explains the relatively small cost savings found in the South Eastern Europe compared to other regions.

Table 8: Load payments decomposition by region, in 2030

Total load payments by region in bn€'13							
	Case 0	Case 1	% change from Case 0	Case 2	% change from Case 0	Case 3	% change from Case 0

North Eastern Europe	28.06	28.01	-0.17%	27.03	-3.67%	24.29	-13.42%
British Isles	47.29	46.54	-1.60%	41.25	-12.78%	38.39	-18.83%
Central Western Europe	187.89	180.51	-3.93%	186.98	-0.48%	164.71	-12.33%
Iberian Peninsula	38.29	36.93	-3.55%	26.89	-29.77%	27.70	-27.65%
South Eastern Europe	54.51	53.63	-1.61%	49.00	-10.10%	50.29	-7.74%
EU28	356.04	345.62	-2.93%	331.15	-6.99%	305.38	-14.23%

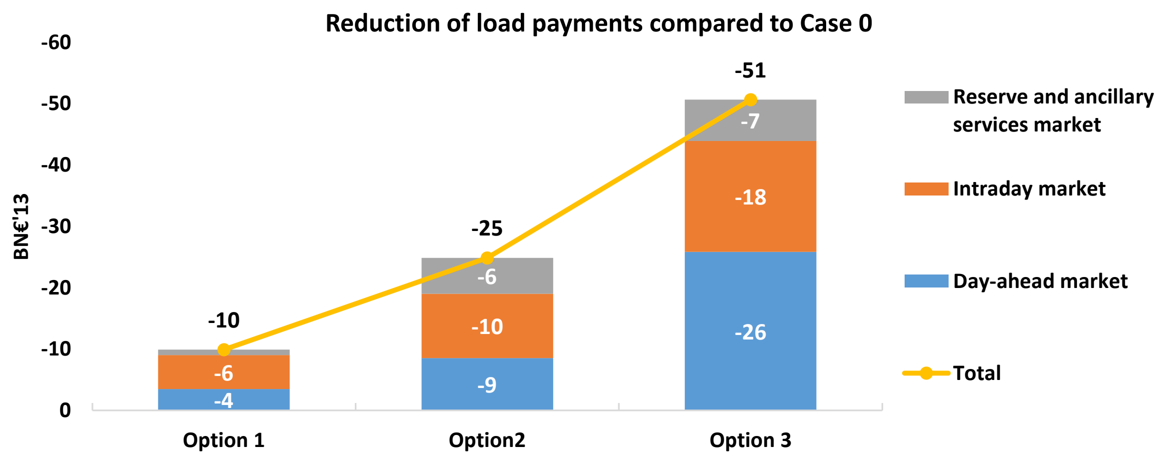
North Eastern Europe: Sweden, Finland, Latvia, Estonia, Lithuania
British Isles: Ireland, UK
Central Western Europe: Austria, Belgium, Luxembourg, Netherlands, Germany, France, Denmark, Slovenia, Czech, Slovakia, Poland, Hungary
Iberian Peninsula: Spain, Portugal
South Eastern Europe: Italy, Croatia, Romania, Bulgaria, Greece, Cyprus, Malta

Source: PRIMES-IEM model

The benefits of increasing the degree of use of interconnectors are very significant. Such effects are observed already in Case 1, which assumes an increase of NTC values. In Case 2, which assumes that NTC limitations do not apply, the effects of better utilisation of interconnectors in all markets become very considerable, as this allows for increasing competition, liquidity and the possibilities for sharing balancing resources among the Member States.

Equally significant are the benefits of actions that improve the efficiency of the Day-Ahead scheduling, and thus reduce the required intraday actions. The following options lead to a much better scheduling of generators, as the markets offer increased capability to the participants to plan, bid and balance the markets: 1) the harmonisation of short-term markets and the extension of balancing responsibility to more resources, 2) the elimination of distortions of must-run generation (nominations) and priority dispatch, and finally 3) the higher availability of interconnections owing to the removal of NTCs.

Figure 1: Contribution of each market stage to cost savings compared to Policy Option 0, EU28 in 2030



The modelling approach followed for the Cases 0 and 1 regarding the Day-Ahead scheduling does not include the technical constraints of generators and ignore the ancillary services. Therefore, the deviations in the intraday and balancing market stages are significant. In contrast, the co-optimisation of energy and reserves while taking into account the technical possibilities of the plants reduces the deviations. It is worth emphasising that the co-optimisation is a result of the bidding behaviour of generators endowed with diversified portfolios and operating in a broad market.

Thus, the largest effect of increasing market efficiency is possible under the assumptions of the Case 2. The Case 1 also implies benefits regarding the expenses which mainly come from the elimination of the distortions regarding must-run and must take privileges and the wider use of interconnections.

An indication of the improvement of efficiency across the Cases is the reduction in the curtailment of RES generation. In Case 1, the removal of priority dispatch of biomass capacities leads to a moderate increase in the curtailment of biomass-based generation (Table 9). However, owing to the increased possibilities of trade assumed in the Case 1 (less restrictive NTC values and elimination of nominations) the curtailment of other types of RES decreases compared to the Case 0 for all other RES, leading to an overall reduction in RES curtailment of 60%. The curtailment of RES reduces further in the Cases 2 and 3. It is worth noting that the RES curtailment is a small percentage of total RES generation (1.3%) and total production (0.6%) even in the worst Case 0.

Table 9: Curtailment of RES in the various Cases, EU28 in 2030

Curtailment of RES in GWh and as % of total generation*				
	Case 0	**Case 1**	**Case 2**	**Case 3**
Hydro (mostly run-of-river)	1326	979	520	413
Wind and large Solar PV	10806	1498	991	780
Biomass	2381	3650	988	473
Other RES	4535	1380	462	340
Curtailment as % of RES generation	0.57%	0.22%	0.09%	0.06%
Curtailment as % of total generation	1.32%	0.52%	0.21%	0.14%

**The figures in this Table regard the final scheduling of units*
Source: PRIMES-IEM model

Broadening the market regarding generation and other resources, the sharing of possibilities of balancing and the vast exploitation of interconnectors increase the versatility of the market, and in particular, they raise the variety of market configurations in the Day Ahead market.

Table 10: Distribution (number of hours) of the load-weighted system marginal price (SMP) in the various Cases, weighted average for the EU28 in 2030

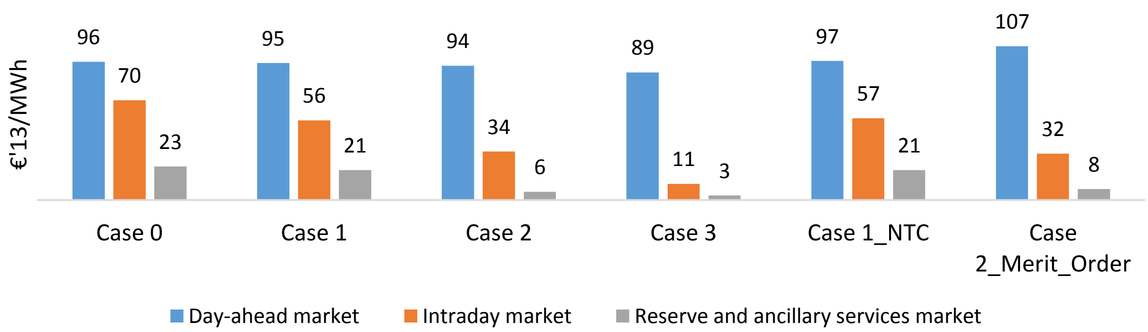
	Number of hours in a year			
SMP in €13/MWh	**Case 0**	**Case 1**	**Case 2**	**Case 3**
Below 60	0	0	84	0
Between 60 & 70	0	0	392	476
Between 70 & 80	0	0	763	1096
Between 80 & 90	2482	2642	2394	3169
Between 90 & 100	3254	3290	2870	3121
Between 100 & 110	2197	2013	1288	484
Between 110 & 120	372	555	528	0
Between 120 & 130	455	260	88	150
Between 130 & 140	0	0	0	0
Between 140 & 150	0	0	195	0
Between 150 & 200	0	0	158	264

Source: PRIMES-IEM model

Table 10 illustrates the growth of versatility of the market when moving towards Case 2 and 3, as it shows a widening of the distribution of system marginal price duration curve in the Cases 2 and 3. In the Cases 0 and 1, the technical constraints of plant operation are not sufficiently internalised through the bidding behaviour of the generators and thus the system marginal prices are depressed. In contrast, the increase in the variety of configurations of the scheduling in the Cases 2 and 3 allow system marginal prices remaining above zero. The removal of price caps and dispatching privileges in the Cases 2 and 3 allows the system marginal prices to increase at high levels when reflecting scarcity. The widening of the distribution of the SMPs provides a better price signal to potential investors than the narrow distribution in the cases 0 and 1.

Figure 2 illustrates the decrease in the clearing prices for the intraday and balancing markets as a result of the broadening of the market and the increase of efficiency of the scheduling in Day-Ahead.

Figure 2: System Marginal Price in each market stage, weighted average for the EU28 in 2030



The analysis does not find adverse effects from removing priority dispatch of variable RES capacities. As the marginal cost of variable RES is close to zero, so is their bidding. Thus they are ranked first in the merit order of the Day-Ahead market, except if their dispatch violates technical limitations of other power plants, in which case they may be subject to a curtailment. In such cases, some of the inflexible power plants would have incentives to bid negative prices, for example, to maintain a minimum level of operation. The modelling excludes negative prices for the bidding without loss of generality. The abolishment of priority dispatch of RES while the generators bid efficiently to pre-empt on exposure in the balancing stages, as in Cases 2 and 3, produces an optimal dispatching which takes fully into account the technical limitations of the plants and thus there is no reason to assume negative bidding. In other words, a negative bidding is a symptom of an inefficient scheduling of plants issued from a day ahead market.

The simulation finds that there is limited need to curtail RES generation by 2030 also because the system configuration projected using the standard PRIMES model is adapted to the penetration of variable RES and has projected investment mainly in units wich provide high flexibility instead of using inflexible ones. The analysis does show considerable adverse effects on biomass plants if their dispatching privileges terminate. The reason is, of course, the high marginal cost of most of the biomass plants. Similar findings hold true in general for the CHP units, notably for those producing heat as the primary output. To maintain unobstructed waste management, CHP and biomass policies, one should consider keeping dispatching privileges for these cases.

The removal of price caps and their replacement by the value of the loss of load (VOLL) in Cases 1 to 3 appears to have little implications in the Day-Ahead market, according to the simulation. This is because in Case 0, similarly to current practices, price caps are at high levels in most countries (i.e. defined close to the value of loss of load). It is also because the scarcity bidding assumed in the simulation does not lead to considerably high levels of prices even after the removal of price caps. Of course, the model cannot capture the psychological impact (as providing better assurance about revenues than otherwise) of abolishing price caps on investment behaviours.

The analysis finds substantial cost-reducing benefits from abandoning administratively defined prices and price caps in the intraday balancing markets and extending the balancing responsibility to more resources (Case 1). The benefits become even more considerable when we assume that intraday markets are coordinated and coupled, and interconnectors' capacity can be utilised to offer balancing services without restrictions (Case 2 and 3).

Overall, the analysis finds that the savings regarding load payments by moving from Case 0 to Case 3 are very considerable (Figure 1). The savings from the Day-Ahead market represent a significant share of total reductions in all Cases, and they become even more pronounced in the Case 3 where the full potential of demand response unlocks. In percentage terms, the load payments to the Day-Ahead market decrease by 1% in Case 1, 3% in Case 2 and 8% in Case 3 compared to the Case 0. The cost savings in the intraday markets are similar in absolute values to those of the Day-Ahead market, except for Case 3. In percentage terms though, they are quite remarkable; load payments for balancing and deviations are 26% lower in Case 1 than Case 0 and become 82% less in Case 3. The figures are similar for the balancing market taken alone, with load payments being lower by 12% in Case 1 than Case 0 and becoming 87% less in Case 3.

It was mentioned above that the total cost in the Case 2 is quite close to the total generation revenues projected for the EUCO27 scenario with the standard PRIMES model. The latter achieves full recovery of fixed and capital costs, not individually plant by plant, but as if all generation is part of a single portfolio (see Appendix A). This basically indicates that when the market is working "optimally", as in the Case 2 (i.e. optimal use of interconnections, high efficiency in the Day-Ahead market scheduling so as to limit deviations in the intraday market, scarcity pricing of generators), it is possible to generate the required revenues for capital cost recovery based on a portfolio financing, as in the EUCO27 modelling. However, it is possible that the revenues are not sufficient for ensuring the capital cost recovery when the financial analysis considers the plants individually. These dynamics will be discussed in detail in Part II of the study.

Table 11 confirms that the vast use of interconnections drives the broadening of the markets in the different Cases and notably in the intraday and balancing/reserve markets in particular in the Case 2.

Table 11: Indicators of cross-border trade in the various Cases

	Case 0	Case 1	Case 2	Case 3
Volume of cross-border exchanges in the Day-Ahead market (TWh)	212.83	313.78	312.37	321.27
Volume of cross-border exchanges as % of total electricity in the Day-Ahead market	9.6%	9.4%	9.4%	9.6%
Volume of cross-border exchanges in the intraday market (TWh)	75.64	64.36	182.07	176.26
Volume of cross-border exchanges as % of total electricity in the intraday market	14%	12%	39%	37%
Annual contribution of cross-border to reserves market in GW	313	1239	3433	2684

The volume of cross-border exchanges is the sum of imports and exports in absolute terms on a bilateral basis aggregated over the time segments simulated by the model
Source: PRIMES-IEM model

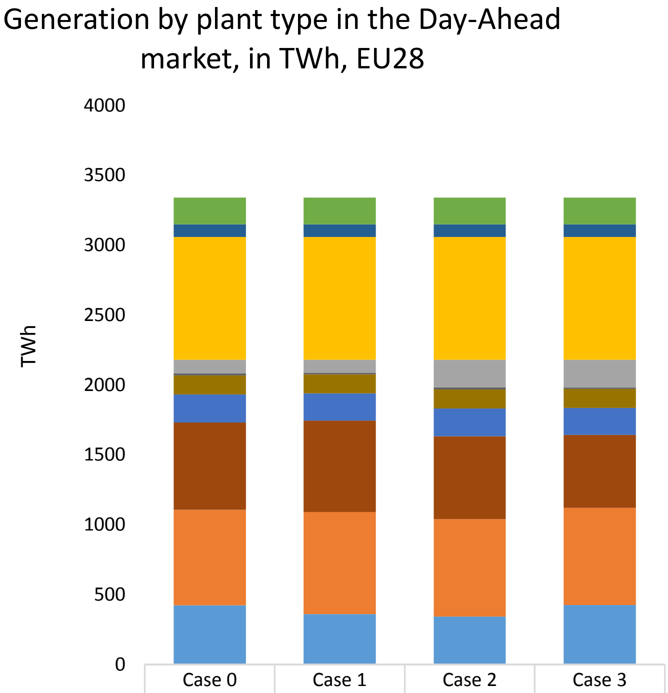
Table 12 provides details regarding the volume of deviations handled by intraday markets in the various cases. The co-optimisation practised in the Cases 2 and 3 implies lower amounts of deviations than in other Cases.

Table 12: Demand for deviations in the intraday market, across Cases, in TWh

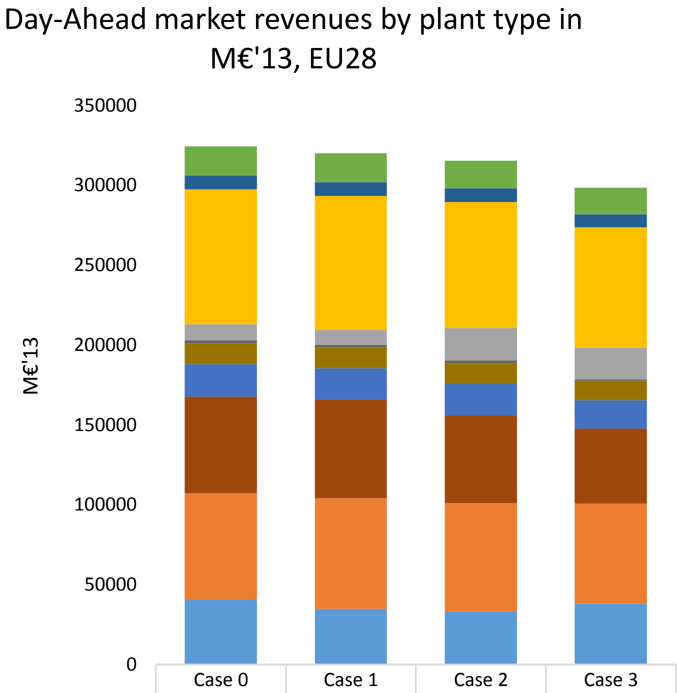
	Case 0	Case 1	Case 2	Case 3
Demand for deviations in the intraday market (upward)	314	293	292	299
Demand for deviations in the intraday market (downward)	229	230	181	182
Total demand for deviations in the intraday market	543	523	473	481

Source: PRIMES-IEM model

Figure 3: Generation and revenues by plant type in the Day-Ahead market in the various Cases, EU28 in 2030

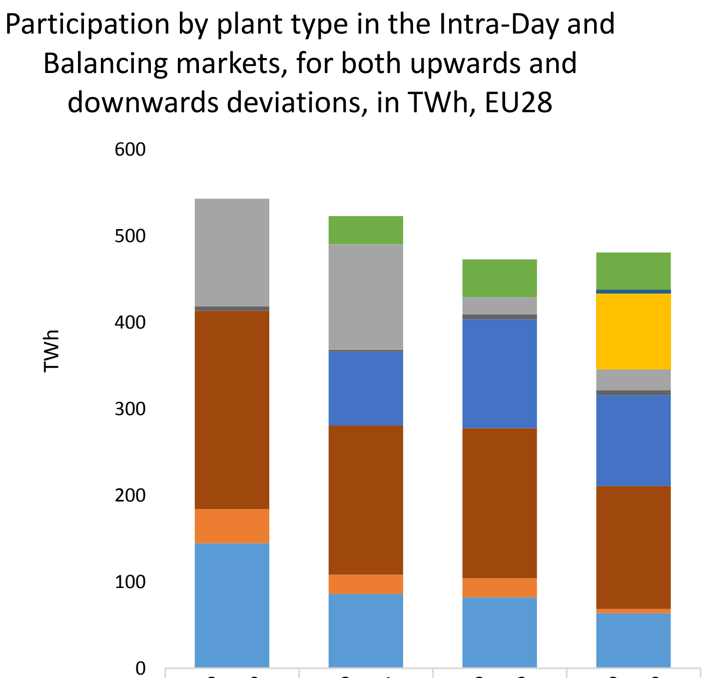


	Case 0	Case 1	Case 2	Case 3
Other RES	190.70	190.70	190.61	190.70
Small-scale RES	89.98	89.98	89.98	89.98
Wind and large Solar PV	879.55	879.57	879.32	879.54
Lakes	96.88	92.70	197.34	197.32
Peak units	14.69	10.68	14.59	10.25
CHP	136.16	136.58	136.64	136.50
Biomass	200.45	194.44	199.08	193.63
CCGT	625.52	654.71	592.23	522.12
Nuclear	682.09	729.86	697.52	695.16
Solids	423.76	360.54	342.29	424.40

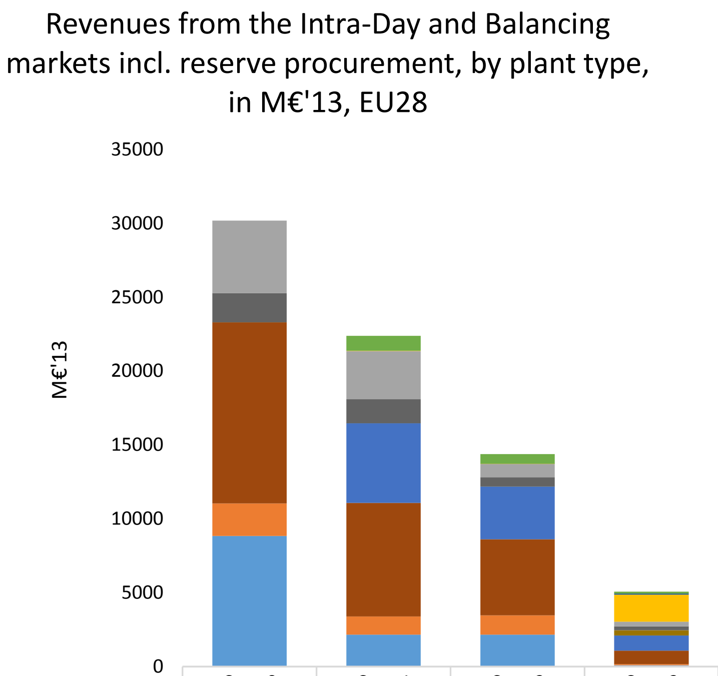


	Case 0	Case 1	Case 2	Case 3
Other RES	18197	18116	17247	16621
Small-scale RES	8643	8547	8666	8101
Wind and large Solar PV	84387	84049	78899	75613
Lakes	10028	9304	20392	19497
Peak units	1913	1421	1683	979
CHP	13181	13134	12900	12146
Biomass	20340	19588	19464	17858
CCGT	60487	61915	55272	46900
Nuclear	66527	69260	67623	62703
Solids	40574	34739	33282	38014

Figure 4: Participation and revenues (for both upwards and downwards deviations) by plant type in the intraday and balancing market across Cases, EU28 in 2030



	Case 0	Case 1	Case 2	Case 3
Other RES	0	33	44	43
Small-scale RES	0	0	0	4
Wind and large Solar PV	0	0	0	88
Lakes	125	122	20	24
Peak units	5	2	6	6
CHP	0	0	0	0
Biomass	0	85	126	105
CCGT	229	173	174	142
Nuclear	40	22	22	5
Solids	145	86	82	63



	Case 0	Case 1	Case 2	Case 3
Other RES	0	1016	656	136
Small-scale RES	0	0	0	77
Wind and large Solar PV	0	10	15	1830
Lakes	4899	3268	903	310
Peak units	1994	1636	612	254
CHP	0	0	0	362
Biomass	0	5380	3577	1025
CCGT	12242	7687	5148	916
Nuclear	2203	1227	1323	66
Solids	8843	2165	2149	93

I - 3.1.1 Case 1

Four main policy assumptions differentiate Case 1 from Case 0[43]:

a. The removal of priority dispatch for biomass in the Day-Ahead market, whereas RES and must take CHP generation remains in priority dispatch.
b. The abolishment of nomination practices by suppliers regarding packages of generation and load, which represent approximately 33% of the total energy of the Day-Ahead market in Case 0. Consequently the participation of plants bidding in the markets increases. We assume that all offers use the marginal plant's cost as a minimum. Also, the available transfer capacity of interconnections increase as nominations have reserved capacity, and thus the cross-border trade has larger interconnection capabilities to exploit.
c. Both changes in the previous items imply larger participation of balancing resources in the intraday markets.
d. Finally, Case 1 assumes better coordination of the TSOs allowing an increase in the NTC values, compared to the values considered for the Case 0, which are close to current practices. However, the NTC values considered for the Case 1 remain small compared to the thermal capacities of interconnections.

Electricity trading in wholesale markets can take place within a multilateral spot market (like a power exchange or a pool market), through over-the-counter bilateral contracts or implicit contracts within companies vertically integrating generation and supply, and in organised markets for future contracts. A market equilibrium in each segment of the market implies an agreement (bilateral or multilateral or unilateral within vertical companies) about an amount of generation and load which is nominated to the TSO in Day-Ahead for scheduling according to a proposed time profile. In reality, all market segments submit nominations, including the multilateral spot markets. However, the nominations resulting from implicit contracting within vertically integrated companies and the long-term fixed bilateral contracts have a different importance for the wholesale market, as in reality, these contracts are not exposed to competition or price variability in multilateral (organised) markets, either spot of futures.

In this sense, these nominations do not enter into competition in the day ahead wholesale market. It is, in fact, a common practice currently in the majority of wholesale markets in Europe, and as a result, the share of the market traded in multilateral markets is relatively small (below one-third in most countries, except in few countries where it may reach two-thirds maximum). The market conditions could push the participants to reduce implicit contracting within vertically integrated companies and long-term fixed bilateral contracts, and instead, prefer trading in multilateral markets. This is identified in our analysis as a potential source of efficiency both in the day ahead wholesale markets and in the intraday and balancing markets.

We mean by the abolishment of nominations a market situation where there is a reduction of the share of bilateral contracts handled outside the Day-Ahead multilateral markets as a result of a deliberate choice by the participants, not restrictive regulatory measures. In this way, we get an

[43] Demand response is also a differentiating factor between Case 0 and 1. However, as the impacts were not found to be crucial in this context, discussion on the impacts of unlocking demand response potential is conducted for Case 3, where they become considerably pronounced.

increase in the participation in the markets of a higher variety of generation resources. The same assumption applies to cross-border flows participating in the market.

The Case 1 models precisely the market broadening due to the reduction of nominations (related to bilateral contracts, implicit or long-term), the enlargement of the NTCs and, by assumption to a limited extent in Case 1, the removal of must-take or must-run privileges.

The broadening of market participation implies intense competition in the Day-Ahead market and availability of a high variety of resources in control areas and cross-border. Consequently, the bidding by the participants can be more cost-effective in anticipating not only profitability but also exposure to balancing costs in real time operation. The combined effect of competition and diversification drives an increase in market efficiency, hence a reduction of total costs. Despite an increase in the marginal system cost resulting from the merit-order of plants in the Day-Ahead, the cost-efficiency improves in the intraday markets. The increase in NTC values significantly contributes to this direction.

As a result, Case 1 has lower SMP prices in all three markets (Figure 2) and consumers incur lower total payments for electricity (Figure 1). A decomposition of the decrease in load payments by stage of the markets (Figure 1) reveals that the cost reductions primarily occur in the intraday market (saving 6 BN€'13) and secondarily in the Day-Ahead market (saving 4 BN€'13). The cost savings in the ancillary services market are less significant (amounting to approximately 900 M€'13), as by assumption the Case 1 does not include important measures to open this market to cross-border competition and maintains the national perspective in the definition of reserves requirements. By assumption, the Case 1 does not tap into the potential cost savings in the procurement of ancillary services.

Focusing on the Day-Ahead market, we observe a shift in the generation mix compared to Case 0 (Figure 3); generation from nuclear and gas power plants increases, while the opposite occurs for solid-fuels power plants. The assumption of reduction of nominations (implicit and long-term contracts) in Case 1 is essential for understanding this shift. We remind that according to current practice, the nominations assumed in Case 0 mainly regard the generation from nuclear and solid-fuels power plants, and by assumption, the amount of nominated energy considered for 2030 continuous in the Case 0 as observed in 2015 (I - 2.2.1.3). This implies that in the context of 2030, as EU ETS prices are expected to be at higher levels and also as gas plants with high efficiency (CCGT) have lower or comparable marginal cost than old solid-based plants, there is potentially more solids-based generation than justified in the merit-order of plants when current nomination practices continue in 2030. This is verified by the results of the simulation as when nominations are removed solids-based generation decreased (by 15%) and is replaced by lower-emitting and more cost-efficient gas generation (CCGT generation increases by 5%) and nuclear generation (increase by 7%), thus restoring better cost-optimality in the merit-order. It follows that the revenues of solids-fired power plants decrease by 14%, the revenues of CCGT plants increase by 2% and those of nuclear power plants increase by 4% in the Case 1 compared to the Case 0.

The elimination of nominations in parallel to the assumed increase in NTC values in Case 1 relative to Case 0, increases the ATC of interconnections and allows for better allocation of resources through increased cross-border trade (Table 11). An indication of the improvement of the utilisation of resources across the EU is a decrease in generation from peak units (around 27%) which is also beneficial for costs.

The cost-related benefits in the Day-Ahead market in the Case 1 also occur thanks to the removal of priority dispatch of biomass, as a step towards ensuring a level playing field among the various generating technologies. The cost-optimality of the merit order improves because biomass plants have high marginal costs due to expensive feedstock except in few cases where the plants use low-cost wastes within small niche markets. The removal of priority dispatch for biomass plants implies lower electricity generation from biomass. However, the reduction amounts to only 3% of the biomass generation of Case 0, while biomass holds in both Cases app. 6% of total generation. Curtailment of biomass increases from 2.3TWh in Case 0 to 3.6 TWh in Case 1, although both figures represent small percentages of total generation (1-2%). The revenues of biomass plants decrease by 4% in Case 1 compared to Case 0. As mentioned, the Biogas and waste plants retain their place in the merit-based dispatching[44]. It is noted at this point that the impact of removing priority dispatch of biomass is found to be more considerable in the context of Case 1_NTC, which is discussed in I - 3.2.1[45].

The increase in NTC values enhances the efficiency of the market through increased trade possibilities and contributes to lower generation requirements from peak units, adding considerable efficiency gains to the effect stemming from the reduction of nominations.

The benefits of cost reductions in the intraday market regarding the payments by consumers are more pronounced than for the Day-Ahead market due to the efficiency gains inherited in the intraday market from the broadening of participation in the Day-Ahead markets. The 26% decrease in load payments in Case 1 compared to Case 0 comes from a decrease in demand for deviations of approximately 4% and a decrease of the SMP (Figure 2) of approximately 20%. The extension of balancing responsibility to more resources, available at a higher variety than in Case 0, and the increase in the ATC of interconnections (due to removal of nominations and higher NTC values as assumed in the Case 1) allow for increasing competition in the intraday and the balancing markets and lead to lower clearing prices. In particular, the increased ATC of interconnections gives more flexibility to the optimisation of the scheduling for meeting deviations, allowing to make better use of the complementarity of resources between countries. Hence, the overall costs of balancing decrease in the Case 1 compared to Case 0.

The payments by consumers decrease by 12% in the reserve and ancillary services market compared to Case 0. By assumption, in the Case 1, the procurement of reserves and ancillary services is still undertaken by TSOs, assumed through contracts with generators, unless organised markets exist already today, as in some few countries. In contrast to the Case 0, the assumptions in Case 1 lead to an increase in the amounts and the variety of resources that are eligible for the procurement. Also, the Case 1 by assumption involves higher efficiency in the management of reserves cross-border which result in the procurement of lower amounts of the reserve by the TSOs compared to the Case 0, also owing to the increased ATC values of interconnections and the better functioning of the intraday markets. The combined effects of these assumptions lead to a decrease in the load payments in the reserve and ancillary services market in the Case 1 compared to the Case 0.

[44] This result is also consistent to the EUCO27 scenario, which projects priority on low cost biomass-feedstock investments in the long term together with a removal of support schemes for biomass around 2030.
[45] Case 1 _NTC is closer to the Policy Option 1 of the Impact Assessment than Case 1, because the former does not assume an increase in the values of NTCs relative to the baseline.

I - 3.1.2 Case 2

Case 2 continuous and enhances the logic of reforms assumed for the Case 1. The broadening of participation in the markets coupled with maximisation of cross-border participation drives significant efficiency improvements regarding the costs.

The broadening of the markets in the Case 2 leads to more intense competition, nationally and cross-border, related to the assumed harmonisation of regulations, practices and system management across the MS, to the point required for achieving coordination as if it was a single control area.

In this Case, all stages of the markets enjoy from liquidity, coupling and harmonisation, while out-of-the-market actions for balancing, and reserve procurement are inexistent. The TSOs are assumed to coordinate their practices, both at regional and at the EU levels, to integrate cross-border exchanges in all stages of the markets based on flow-based allocations of interconnection capacities.

In such a context, generators and aggregators would be able to offer in the day ahead market complex bidding of their portfolio of generation, to minimise their exposure in the balancing markets. Based on their diversified portfolio, nationally and cross-border, they are able to offer well-balanced packages in the form of block orders, which respect the technical constraints of cyclical operation of thermal plants, include flexibility providing resources and manage the scheduling of capacities, within the block orders, so as to include capacity margins coping with the supply of ancillary services. As all generators and aggregators behave in this way, the bids result into a system scheduling which is identical to the scheduling that a full optimal unit commitment program would produce. Such a program would include the technical operation constraints of the plants and would co-optimise the provision of energy and the ancillary services, and this simultaneously at the pan-European scale while fully exploiting the flow-based allocation of interconnection capacities. In this way, the scheduling produced from the day ahead market is extremely efficient for minimising the cost of supplying deviations in the intraday markets and providing the balancing and reserve services. We simulate the market development in the Day-Ahead towards an ideal cost-efficient operation by running a full scale (integer programming) unit commitment program using the offers and co-optimising energy and ancillary services already in the Day-Ahead. We emphasise again that we use the unit commitment program as a simulator of the outcome of the cost-efficient market functioning which does not mean that co-optimisation of energy and ancillary services is proposed as an obligation to achieve the cost-efficiency.

So, the optimal behaviour of generators is simulated through co-optimising energy and reserves in the DAM (see I - 2.2.1.6). For the modelling, this means that the technical limitations of the operation of power plants are taken into account in the optimisation of scheduling in the DAM. Thus, the DAM scheduling and the intraday scheduling[46] differ only because of the assumed occurrence of random events (deviations to forecasted load, RES generation, plant and transmission lines availability the Day-Ahead from the assumed realisation), and thus the deviations in intraday are strictly the minimum corresponding to the random events and not to the possible inefficient scheduling resulting from an energy-only market.

In summary, the key assumptions that differentiate Case 2 from Case 1 are:

[46] obtained with the Unit commitment simulator (I - 2.2.3)

a. Energy and reserves are co-optimised in the Day-Ahead scheduling, as a result of complex bidding behaviour of market participants.
b. The entire physical capacity of interconnectors is allocated to DAM and IDM, i.e. NTC restrictions are removed. This mimics a situation of absolute harmonisation and cooperation of TSOs. No NTC restrictions apply to the RAS market, which optimises the use of the remaining capacity of interconnectors (remaining after the scheduling of the IDM).
c. Reserve requirements are defined at EU level and not at country-specific level.
d. Priority dispatch is also removed for RES (in addition to biomass which is removed already in Case 1), except for small-scale RES (rooftop solar). Thus, priority dispatch remains only for must-take industrial CHP generation and small-scale RES.

The above assumptions allow Case 2 saving an additional 15 BN€'13 in load payments compared to Case 1, amounting to 25 BN€'13 in total savings from the baseline Case 0 (Figure 1). The decrease in load payments comes primarily from the intraday market and amounts to 42% (app. 10 BN€'13) and secondarily from the Day-Ahead market contributing 34% (app. 9 BN€'13), while savings in the RAS market contributes the remaining 24% (app 6 BN€'13).

The cost savings mainly stem from the assumption that generators offer their portfolio optimally in the Day-Ahead market, which is simulated through the co-optimisation of energy and reserves while respecting the operational constraints of the plants. The decrease in the demand for deviations drops by 50 TWh in the Case 2 compared to the Case 1. The SMP price in the intraday and balancing markets also drops by almost 40% compared to the Case 1, reflecting the low demand but also the increased availability of interconnection capacities resulting from the elimination of NTCs.

The results show that the contribution of trade in the intraday market is very considerable in Case 2, amounting to approximately 40% of the total turnover volume of the market (Table 11). The flow-based allocation of interconnections allows for cross-border sharing of flexible resources in all stages of the markets, which is crucial in a system with relatively high penetration of variable RES as in the EuCo scenarios.

Regarding the RAS markets, it is assumed that owing to the efficient scheduling in the Day-Ahead market, which takes into consideration the technical capabilities of plants to offer ancillary services, and the perfect coordination of the control areas, the total reserve requirements reduce further compared to Case 1. The idea is basically that TSO's would lower the required reserve margins given that the scheduling of units is becoming more efficient and that they follow regional approaches for the definition of reserves. Nonetheless, we qualify the assumptions about the reduction of reserve requirements as conservative. Nevertheless, the reduction in payments is considerable. This is owing to the opening and harmonisation of the RAS markets across the EU. Notably, the cross-border capacity (adding importing and exporting) for reserves amounts to 3433 GW (Table 11) and is almost double than the respective amount for Case 0. The elimination of the NTCs and the pan-EU consideration of reserve requirements, in this Case, result in considerable decreases in the clearing prices of the RAS market.

Regarding the cost-efficiency achievements in the Day-Ahead market, it is worth noting that the system marginal prices reduce maybe less than expected in Case 2 compared to Case 1. Mathematically, it is logical that the co-optimisation of energy and ancillary services, as well as the inclusion of the technical operation constraints of the plants, implies higher system marginal prices compared to an energy-only market. Therefore, the cost-efficiency improvements in the Day-Ahead market seem limited when considering the day ahead market alone. The cost-efficiency gains are very significant when also considering the intraday and the balancing and reserve markets, as already mentioned. We further justify this modelling result by referring to the relevant literature which argues that the introduction of energy and reserve co-optimization results in higher SMPs (Kirschen & Strbac 2004), as the more competitive generators tend to withhold capacity for reserve procurement; this means that more expensive generators will be dispatched and become SMP makers. In principle this argument is solid, but in this case, the counter effects of increased ATC values (due to the elimination of NTCs) prevails. Increased ATC values allow for more optimal exploitation of interconnectors, induce higher volumes of cross-border trade (6% as shown in Table 11) and have considerable effects on the price formation.

The effects of co-optimisation of energy and reserves on the generation mix are quite significant. The generation from thermal power plants decreases relative to Case 1, because some of these plants withhold capacity for reserve provision and some other plants are constrained by inflexibility in their cyclical operation. In particular, the generation from solids-based generation decreases by approximately 5%, generation of nuclear decreases by 4%, and generation from CCGT decreases by 10% (Figure 3). The generation using CCGT power plants is affected more than other plants, as their technical specification (i.e. rapid cycling operation, aFRR contribution) renders them more appropriate to meeting ramping requirements and thus more competitive in the reserves market than other thermal generation. In place of the thermal capacities that are being withheld from the reserves market, the system commits in the Day-Ahead hydro reservoirs (mentioned in the graphs as “Lakes”), hydro-pumping and peak units. At the same time, the co-optimisation fully exploits the interconnection flows.

The modelling results show small impacts of the removal of priority dispatch of variable RES on the generation mix and the costs. The benefit of removing priority dispatch is that it can help reduce the plant scheduling discrepancies between the day ahead and the real-time operation as the technical limitations of inflexible power plants cause over-generation problems at load valley times. But by assumption, in the context of the Case 2, the technical limitations of the inflexible plants are fully taken into account in the DAM solution, and thus either RES are curtailed or the cyclical operation scheduling of the thermal, hydro and pumping plants is appropriately optimised to remove the over-generation threads.

Therefore, in the context of such a market, as mimicked using the unit commitment algorithm, there is no reason for the inflexible units to submit negative bids to avoid shut-downs and the zero price bidding by the RES does not prevent them from curtailment if needed at the system level. A system that would equally curtail the RES even if they are exempted from bidding would, of course, result in the same scheduling. For this complex reason, our modelling does not find significant cost benefits from removing priority dispatching of variable RES provided that they are economically curtailed on the basis of the overall system cost optimisation. Obviously, the system cannot achieve this optimality if it does not curtail the variable RES when needed at over-generation times. If this is practised today in reality, then the removal of priority dispatch of variable RES has clear cost saving benefits as it allows achieving the same cost optimality as the simulated curtailment using our unit commitment program.

Another benefit of removing priority dispatch of RES comes from providing incentives to RES operators and aggregators to improve weather forecasting so as minimise their exposure to high balancing penalties. We have not studied this kind of benefit in our analysis as we have not included reduction of random disturbances in our random event generation program due to the removal of priority dispatch of variable RES.

I - 3.1.3 Case 3

The Case 3 describes a fully integrated EU market identical to the Case 2, but in addition, the flexibility resources enabled by demand response and storage are fully developed close to their potential. In addition, the Case 3 assumes the active participation of aggregators, who absorb the risks of certain technologies by optimising their operation in parallel to other resources, handling them as a portfolio. The main differentiating factors among Case 2 and Case 3 are:

- Demand response is participating in the market at full potential.
- Priority dispatch is also removed for small-scale RES. It remains only for industrial CHP units.
- RES are allowed to bid in the intraday market for downward deviations.
- CHP are allowed to participate in the reserve and ancillary services market.

Overall, the load payments of Case 3 are very significantly reduced. They become 26 BN€'13 lower compared to Case 2, with 17 BN€'13 savings coming from the Day-Ahead market (Figure 1). The harnessing of the full potential of demand response is the main contributor to load payment savings in this Case.

The demand response drives the very beneficial effect of smoothing the load curve, as it gives the possibility to consumers to decrease their consumption during peak hours and increase it during baseload hours, who are optimising this transfer of demand to their cost benefit. We have not considered load shedding in our definition of demand response, but only transferring of load between different time zones in the same day.

The flexibility requirements of the system are thus considerably lower, as the variability of the load curve introduced by variable RES generation reduces (to a certain extent) thanks to the demand response.

A direct effect of the smoothening of the load curve is a shift in the generation mix towards capacities which are economically better placed in the base load part of the merit order. Indeed, looking at generation by plant type in the Day-Ahead market (Figure 3) we see an increase of generation of solids-fired power plants by 24% from Case 2 and a decrease of generation of CCGT and peak units, by 17% and 30% respectively, while the participation of cross-border flows also reduces in this context given that flexibility requirements overall decrease. As a result, the revenues Day-Ahead market shrink by 42% for peak units and by 15% for CCGTs. The SMP also drops considerably, by 5%, which is the largest reduction incurred in the Cases analysed so far.

Focusing on the intraday and balancing markets, the participation of wind and solar PV capacities for downward deviations, which is considerable (Figure 4), implies that they can receive revenues for curtailing their generation. However, despite their introduction in the intraday market and the possibility of collecting additional revenues, the decrease in SMP in the Day-Ahead market implies a reduction of total revenues for RES compared to the Case 2.

I - 3.2 Simulation results of Sensitivity Cases

I - 3.2.1 Case 1_NTC

This Case 1_NTC is a sensitivity analysis of Case 1 in regard to the effects of not increasing the NTC values which remain at their levels as in Case 0, which are restrictive of cross-border flows. Compared to Case 0, the Case 1_NTC retains the reduction of nominations and the removal of priority dispatch for RES and biomass, except for small-scale RES.

The simulation results show that the assumptions for Case 1_NTC imply 5.8 BN€'13 higher load-payments compared to the results of the Case 1. The Case 1_NTC is, nonetheless, still less expensive than baseline Case 0, by approximately 5 BN€'13 (Table 13). The 5.8 BN€'13 losses should be attributed to the low NTC values, and the 5 BN€'13 gains should be attributed to the removal of nominations and priority dispatch. Keeping the restrictive effects of the NTC unchanged from present status is costly, as it can be seen by comparing the sensitivity case Case_1_NTC to Case_1. The additional costs represent 8% of the total. The restricting NTC values imply additional costs in all the three market stages. The cost of the Day-Ahead market is penalised in Case 1_NTC, being higher even than the Case 0, by 1.2 BN€'13. This implies that the enlargement of NTC assumed for the Case 1 is benefitting mainly the Day-Ahead market.

The generation from solids decrease in Case 1_NTC compared to the Case 0 due to the removal of nominations. However the decrease is not as pronounced as in the Case 1 (Figure 5). Nuclear generation is roughly at the same levels as in Case 1. The most significant differences regard the operation of biomass, peak units and CCGT.

The production of peak units in the Day-Ahead market is higher in the Case 1_NTC compared to the Case 1 (by 15%), owing to the more restrictive trade possibilities implied by the reduced NTC. Nonetheless, the production of peak units is still lower than Case 0.

The generation using biomass is lower in the Case 1_NTC compared to the Case 1, by 30%. The high marginal costs of biomass plants burning solid biomass feedstock and their relative inflexibility are the causes of the decrease in biomass plant production as the lower possibilities of sharing flexibility resources cross-border in the Case 1_NTC than in the Case_1 implies a need to use more the gas plants. For this reason, the removal of priority dispatch has stronger impacts on biomass production in the context of Case 1_NTC than in Case 1. The respective reduction in biomass plants' revenues amounts to 25%.

The restrictive NTC in the context of the Case 1_NTC implies a higher use of gas plants in the Case 1_NTC compared to the Case 1. The increased production of peak and CCGT units drives the wholesale market prices upwards in the Day-Ahead market of the Case 1_NTC and leads to SMP levels which on average are in Case 1_NTC higher than both the Cases 1 and 0.

Table 13: Load payments in the stages of the market in the Case 1_NTC sensitivity

Case 1_NTC	Day-Ahead market	intraday and Balancing market	Reserve and ancillary services	Total
Load Payments in M€'13	327484	17098	6837	351419
Difference from Case 1 in M€'13	5004	799	-3	5801
Difference from Case 1 in (%)	1.6	4.9	0.0	1.7

Source: PRIMES-IEM model

Table 14: Indicators of cross-border trade in Case 1_NTC

	Case 1_NTC	diff. from Case 1	% diff. from Case 1
Volume of cross-border exchanges in the Day-Ahead market (TWh)	311.85	-1.93	-0.62
Volume of cross-border exchanges as % of total electricity in the Day-Ahead market	9.30%	-0.10%	

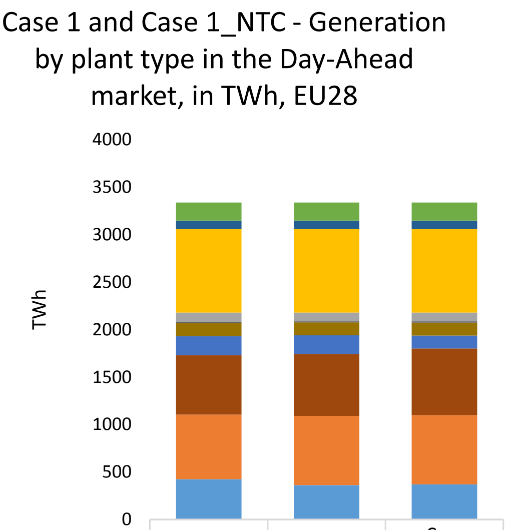
Volume of cross-border exchanges in the intraday market (TWh)	65.38	1.02	1.6
Volume of cross-border exchanges as % of total electricity in the intraday market	12%	0%	
Annual contribution of cross-border to reserves market in GW	1226	-13	-1.0

Source: PRIMES-IEM model

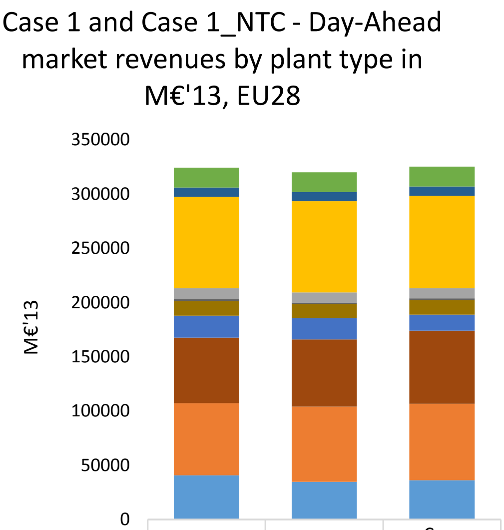
The restrictive NTC values assumed for the Case 1_NTC implies an increase in total demand for deviations, and some shifting in generation mix, notably lower biomass plant contributions in the Case 1_NTC than in Case 1, and higher contributions by the CCGTs. The cross-border contribution in the balancing is not eliminated, it is though deterred. There is thus some exchange of roles between CCGT, and cross-border trade flows for balancing purposes among Case 1 and Case 1_NTC. Consequently, the intraday market is more expensive in the Case 1_NTC than in Case 1, approximately by 800 M€'13 but is less expensive than Case 0 by 5 BN€'13. This hints that there are positive impacts from removing nominations and priority dispatch regarding cost savings in the intraday and balancing markets.

The model results find that the cross-border trade in the EU is lower in the Case 1_NTC compared to the Case 1, as expected (Figure 5). The sharing of reserve resources is also lower.

Figure 5: Generation and revenues by plant type in the Day-Ahead market for Cases 0, 1 and sensitivity Case 1_NTC, EU28



	Case 0	Case 1	Case 1_NTC
Other RES	190.70	190.70	190.70
Small-scale RES	89.98	89.98	89.98
Wind and large Solar PV	879.55	879.57	879.57
Lakes	96.88	92.70	92.80
Peak units	14.69	10.68	12.31
CHP	136.16	136.58	136.58
Biomass	200.45	194.44	137.10
CCGT	625.52	654.71	702.14
Nuclear	682.09	729.86	729.86
Solids	423.76	360.54	368.72



	Case 0	Case 1	Case 1_NTC
Other RES	18197	18116	18367
Small-scale RES	8643	8547	8655
Wind and large Solar PV	84387	84049	85182
Lakes	10028	9304	9439
Peak units	1913	1421	1635
CHP	13181	13134	13341
Biomass	20340	19588	14783
CCGT	60487	61915	67368
Nuclear	66527	69260	70516
Solids	40574	34739	36113

Source: PRIMES-IEM model

I - 3.2.2 Case 2_Merit_Order

The purpose of this sensitivity analysis case is to assess the impact on the market design options in a price context which implies that the CCGT plants are placed before the coal/lignite plants in the merit order. To assess this, the scenario uses the assumption of increased ETS prices. It is a stylised scenario, since the modelling does not close the loop using the entire PRIMES model and therefore it ignores that higher carbon prices would logically entail endogenous changes in investment hence in the power generation mix. The changes in power generation investment are not included in this sensitivity analysis.

The Case 2_Merit_order builds on the same assumptions as for the Case 2, with the difference that it assumes that ETS prices are 50% higher in 2030 than projected in the EUCO27 scenario, ceteris paribus. In such a case, the system uses the capacity of the CCGT plants mainly for energy production, as they are placed at a lower rank than solids, and thus the same capacities have less spare capacity to provide flexibility and reserve services. Because of inflexibility, the solid fuel plants are not able to perform a cyclical operation over short timeframes to eventually collect scarcity earnings during peak load times.

In the standard EUCO27 scenario, the relative prices are not sufficient to fully shift the full merit-order of dispatching, with still solids-based plants remaining in base load ranks. But the relative prices in the Case 2_Merit_Order move all solid fuel plants away from the base load and replace them by increased use of CCGT, as confirmed in the results of the models.

The relative scarcity of flexibility and reserve services in the Case 2_Merit_Order sensitivity case explain the significant increase (Table 15) of the costs of the balancing and reserve, compared to the Case 2 results.

Table 15: Load payments in the stages of the market in the Case 2_Merit_Order sensitivity

Case 2_Merit_Order	Day-Ahead market	intraday and Balancing market	Reserve and ancillary services	Total
Load Payments in M€'13	364449	14302	2427	381177
Difference from Case 2 in M€'13	46802	2658	566	50025
Difference from Case 2 in (%)	14.7	22.8	30.4	15.1

Source: PRIMES-IEM model

Table 16: Indicators of cross-border trade in the Case 2_Merit_Order sensitivity

	Case 2_Merit_Order	diff. from Case 2	% diff. from Case 2
Volume of cross-border exchanges in the Day-Ahead market (TWh)	323.67	11.3	3.62
Volume of cross-border exchanges as % of total electricity in the Day-Ahead market	9.70%	0.30%	
Volume of cross-border exchanges in the intraday market (TWh)	209.06	26.99	14.8
Volume of cross-border exchanges as % of total electricity in the intraday market	37%	-2%	

Annual contribution of cross-border to reserves market in GW	2538	-895	-26.1

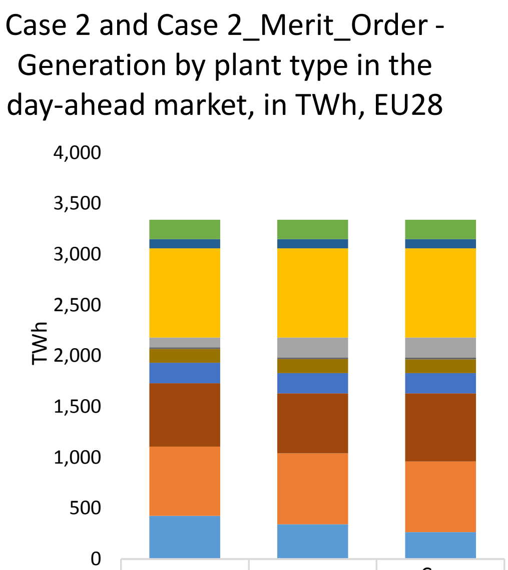
Source: PRIMES-IEM model

As expected, as generators pass through the emissions costs to the economic bids, load payments in the Day-Ahead market increase in the Case 2_Merit_Order compared to Case 2 (Table 15), but this increase is lower in percentage terms than in the rest of the market stages. This is because part of the impact of the stylised higher carbon price is offset by the reduced emissions as a result of the change in the merit order of dispatching. In the Day-Ahead market, this leads to a 23% reduction in the solids-based generation and an increase in CCGT generation by 13% (Table 15), with corresponding additional CO2 emission reductions.

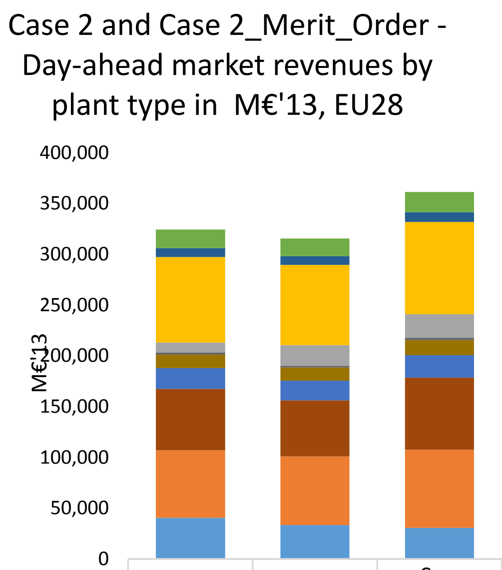
The relative scarcity of flexibility and reserve resources at a national level explains the increase in the contribution of cross-border trade to the balancing and reserve markets (Table 16) in the Case 2_Merit_Order sensitivity compared to the Case 2. The volume of trade cross-border in the Day-Ahead market is also found significantly increased in the Case 2_Merit_Order.

The net revenues (Figure 6) of the plants placed in the first ranks of the merit-order increase in this context (see revenues of CCGT and nuclear). The solids-based plants (mostly old plants in the context of the EUCO scenario projection) see decreased revenues and incur further economic losses in the Case 2_Merit_Order compared to the Case_2 because they move to a merit-order stage with low rate of use.

Figure 6: Generation and revenues by plant type in the Day-Ahead market for Cases 0, 2 and sensitivity Case 2_Merit_Order, EU28



	Case 0	Case 2	Case 2_Merit_Order
Other RES	190.70	190.61	190.69
Small-scale RES	89.98	89.98	89.98
Wind and large Solar PV	879.55	879.32	879.42
Lakes	96.88	197.34	197.35
Peak units	14.69	14.59	16.26
CHP	136.16	136.64	136.50
Biomass	200.45	199.08	199.22
CCGT	625.52	592.23	669.49
Nuclear	682.09	697.52	697.07
Solids	423.76	342.29	263.63



	Case 0	Case 2	Case 2_Merit_Order
Other RES	18,197	17,247	19,904
Small-scale RES	8,643	8,666	9,831
Wind and large Solar PV	84,387	78,899	90,619
Lakes	10,028	20,392	23,355
Peak units	1,913	1,683	2,123
CHP	13,181	12,900	14,855
Biomass	20,340	19,464	22,228
CCGT	60,487	55,272	70,812
Nuclear	66,527	67,623	77,130
Solids	40,574	33,282	30,595

Source: PRIMES-IEM model

I - 4 Concluding remarks

The analysis with the PRIMES-IEM modelling suite which simulates the consecutive stages of the wholesale EU markets, namely Day-Ahead, intraday, balancing and reserves, has successfully estimated the impacts of removing currently existing distortions in the EU electricity markets on market prices, the generation mix, the cross-border trade in all market stages, and ultimately the revenues of the various types of generation plants in these markets and costs that consumers incur.

The estimation and the simulations have looked at the energy system of 2030, assuming the context of the EUCO27 decarbonisation scenario (developed using the standard PRIMES model for the EU Commission and discussed in Appendix A) regarding the evolution of demand, the availability of the power plants, the interconnections and the fuel and EU ETS prices. The EUCO27 projection foresees a system with high shares of variable RES and significant EU ETS carbon prices, which poses challenges regarding flexibility, the balancing and the ancillary services.

The standard PRIMES model has assumed that a well-functioning and fully integrated pan-EU market delivers the least cost outcome for the system and the markets, without modelling the market design elements explicitly. In this sense, the projections of the standard PRIMES model for the EUCO27 scenario (regarding the costs, investment, the generation mix and the flows over the interconnections) are taken as a benchmark.

The PRIMES-IEM simulator takes as given certain elements of the standard PRIMES projection, but in addition, it assumes concrete market design and organisation options, which influence behaviours and the outcome of the wholesale market stages. In this sense, one set of concrete market design options can lead to different results than the standard PRIMES model, regarding costs, prices, the generation mix and the flows. By changing the design options, the results change as well.

Therefore, the PRIMES-IEM simulator serves to compare the various market design options and assess the impacts of the policy proposal within the market design initiative of the European Commission. For this purpose, the simulator mimics the detailed operation of the staged markets, depending on the design options, and also mimics the behaviours of the market participants, for example in the setting of prices of the bids.

The model produces individual results for each European country after solving the markets simultaneously at a pan-European level, with explicit modelling of interconnections and their use in the various stages of the markets. The model has a high resolution regarding the hourly operation of the system, the catalogue of power plants, the RES, the interconnections and the technical issues related to the technical restrictions of the cyclical operation of the plants and the ancillary services.

The simulation makes the simplification that the wholesale market, organised in consecutive stages, is the only source of revenues for the generators. The simulation does not ignore the part of the markets which in reality is economically based on bilateral contracts, but simply considers that the prices in the bilateral part and those in wholesale converge. Therefore simulating the wholesale market, assuming participation of the entire load and the entire generation fleet, is a sufficient proxy for the outcome of the more complex markets, in which spot, futures and bilateral markets coexist in reality.

The model simulates the bidding behaviour of market participants, assuming a bidding reflecting scarcity and competition. At present, the suppliers prefer not to bid large parts of generation in the wholesale markets, mainly concerning baseload units, and nominate them as part of bilateral contracts, implicit (within vertically integrated companies) or explicit.

The modelling assumes that the future market reforms and the generation conditions of the EUCO27 in 2030 (large deployment of variable RES) are likely to provide incentives to suppliers for bidding close to the entire generation in the wholesale markets. The abolition of the must-take and must-run privileges also broadens the participation in the wholesale markets, while the flow-based allocation of interconnection capacities increase the possibilities of using generation resources cross-border and allows for more frequent market coupling than under the restricting available transfer capacity limitations.

All these conditions imply broad participation and enlargement of the variety of resources in the wholesale markets. Both further imply that the suppliers have an interest in submitting complex bids (e.g. block orders) in the market which can better accommodate the technical constraints of plant operation, the over-generation pressures at low load times, and the system’s ancillary services.

By bidding block orders, the suppliers holding diversified portfolios of generation (in the same control area and cross-border) minimise the exposure to costly or large deviations in the intraday markets and the magnitude of re-dispatching, counter-trading, etc.

The model-based simulation confirms that broad participation, the flow-based allocation and the complex bidding can lead to a very significant reduction of costs in the wholesale markets in all stages and at the same time can approach a pan-EU market integration. Exploiting the demand response potential in this context can further decrease the total costs in the markets. In this context, the computation finds the CCGTs plants can approach a financial balance.

The model-based simulation explores scenarios where the market distortions gradually disappear through the hypothetical adoption of appropriate measures. It treats four main scenarios, each describing a context which is a step closer to an undistorted market design; Case 0, describes the “business-as-usual” context, whose problematic features include small participation in the wholesale markets, persisting priority dispatch privileges, low usage of cross-border possibilities and incomplete or inefficient intraday and balancing/reserve markets.

The Case 1 assumes the removal of a large part of the must-run and must take obligations and a significant part of limitations to cross-border trade. The Case 2 describes a context of a level playing field for all technologies, which are liquid and harmonised, and with no barriers to trade other than technical limitations of the network (no NTCs).

The context of Case 2 is a context with competitive Day-Ahead, and short-term markets provide generators with incentive and capability to optimise their offers already in the Day-Ahead market in both economic and technical grounds, so as to limit their exposure (and thus the exposure of the system) to intraday balancing requirements and re-dispatching.

Moreover, the Case 3 assumes full exploitation of the demand response potential, which considerably smoothes the load and reduces the balancing requirements of the system.

The simulations show that large cost-related benefits for consumers are possible when moving from Case 0 to Case 2 and furthermore the Case 3. In order of magnitude, the cost-reduction effects come from the unrestricted trade possibilities, the efficient operation of the Day-Ahead market which reduces the required intraday costs, and the removal of priority dispatch. The additional cost-reducing effect of demand response is also very significant.

In particular, the analysis indicates that owing mainly to measures that aim to create a level playing field among generators (elimination of nominations, removal of priority dispatch of biomass capacities) savings in load payments in 2030 amount to 4.6 BN€’13. The increase in the NTC values, on top of the previous measures, bring an additional amount of 5.8 BN€’13 cost savings. Measures like the removal of price caps and the activation of demand response potential of large entities also contribute to the reduction of load payments in Cases 1 and 1_NTC, but less prominently.

The results of the simulation of Case 2 indicate that a fully integrated EU market, with coordinated system operation and no NTC restrictions, extended balancing responsibilities to more resources and harmonised practices in the balancing markets across countries, bring additional savings of approximately 15 BN€’13.

The cost savings are the result of a very efficiently operating Day-Ahead market in which participants have the incentives and the capability to optimise their bidding in a way that limits their exposure to intraday deviations. Adding in this context the activation of the full potential of demand response, bring additional cost savings of 26 BN€’13, in 2030.

The removal of priority dispatch of variable renewables in a context where trade possibilities are very high as in the Case 2, does not affect the RES production as the system applies to a limited extent curtailment of RES. But removing the priority dispatch of biomass can be detrimental to biomass-based generation and induces changes in the generation mix, which however lead to an improvement of cost-efficiency in the merit order.

As the markets gradually become more competitive across the Cases, as a result of the removal of privileges, the broadening of participation and the high use of interconnectors, total cost reduce but also the revenues of generators reduce. However, it is of interest to note that the revenues obtained by generators in the context of Case 2 are almost high enough to allow for the recovery of total costs of production considered as a whole (i.e. when considering portfolio financing of capital costs).

As the results of the Case 2 are close to the results of the standard PRIMES model which optimises power generation in an “ideal” market, the approach of the PRIMES-IEM simulator based on revenues in the wholesale markets confirm the validity of the approach of the standard PRIMES model which assumed portfolio recovery of capital costs to determine investment, decommissioning and refurbishment of the plants. However, the portfolio financing approach is hardly followed in reality, and investment is surrounded by considerable uncertainties, instead of the perfect foresight assumption of the standard PRIMES model.

The result of the PRIMES-IEM model supports the statement that the integrated and free of distortions wholesale markets, as in Case 2, can lead to portfolio recovery of capital costs provided that generators apply reasonable scarcity bidding, without specific provisions for remunerating capacity. However, strong uncertainties and individual plant financial approaches can alter this result. This is the subject addressed by Part II of this document.

Part II IMPACTS OF INTRODUCING CAPACITY MECHANISMS IN EU ELECTRICITY MARKETS

II - 1 Overview of the modelling work

The PRIMES-OM modelling suite has been developed specifically for the requirements of the present study. To address the issue of studying the markets from the perspective of investment, the PRIMES-OM modelling framework has four distinct steps: a) the PRIMES Oligopoly Model used to simulate the wholesale markets and the bidding with or without capacity mechanisms, b) a model which simulates stylised capacity auctions regarding participation and clearing prices and c) a probabilistic Investment Evaluation Model. The PRIMES Oligopoly model runs first using the plant capacities as projected by the standard PRIMES model. The other models run sequence, and at the end, the PRIMES Oligopoly model runs again after modifying the capacities of the plants as suggested by the probabilistic investment evaluation model.

The main differences of the modelling of investment in the PRIMES-OM and in the standard PRIMES model is that the latter assumes perfect foresight, no risks and a financial evaluation of the portfolio of plants taken as a whole; in contrast the former assumes that investment decision is surrounded by large uncertainties and that the financial evaluation takes place for each individual plant. Apart the uncertainty and foresight issues, portfolio and individual plant financial evaluations lead to the same investment plan when the capacity expansion starts from no pre-existing capacities. But the two approaches can lead to different financial evaluations of plants if performed for a system which includes pre-existing capacities which are not optimal, together with distortions and constraints will make the system to deviate from the optimal generation mix.

In an optimal system, if the peak plants recover their capital costs, which per unit of capacity are small compared to other plants positioned in mid-merit or baseload ranks, then all dispatched plants recover their capital costs both individually and as a portfolio. But if the generation mix is not optimal, then the plants which are in excess (should have lower capacity in the optimal system configuration) cannot recover the capital costs and the plants which are in scarcity (should have higher capacity in the optimal system configuration) earn above recovery of capital costs. In this case, the portfolio can be financially balanced, but the financial evaluation of individual plants can be detrimental to the plants in excess. In this sense, the plants in excess can claim for "missing money" while the system as a whole has not a missing money problem. If a capacity mechanism is in place which remunerates all available capacities, then the plants in excess will also be remunerated although their capacity should be reduced to approach the optimal system configuration. If uncertainty about future revenues surrounds the investment decision also for the plants in scarcity (those which must increase the capacity to approach the optimal system configuration), then a capacity remuneration mechanism could provide higher certainty for investors in these plants, but at the same time the system will unnecessarily remunerate the plants which are in excess.

This discussion is the background of the modelling approach for the present study. The standard PRIMES model reaches the optimal system configuration only in the very long term. By 2030, the configuration projected by PRIMES does include plants in excess and plants in scarcity because of the inheritance of large pre-existing capacities. However, the PRIMES projection ensures financial balancing of the portfolio of the plants whole optimising total system costs. In contrast, the PRIMES-OM model assumes that uncertainty surrounds investment and that the actors evaluate the financial value of each plant on an individual basis. The evaluation may lead them either to retire an existing plant or to cancel an investment, although both are economically appropriate in the context of risk-free portfolio financing. Therefore, the PRIMES-OM model would suggest that part of the plant capacities projected by the PRIMES model for 2030 (pre-existing and new) are financially vulnerable when failing to pass the individual financial evaluation test which includes uncertainty and risks. This result of the PRIMES-OM model can be different if one considers that the plants get revenues only from wholesale markets and if a capacity remuneration mechanism co-exists. The system without the financially vulnerable plants would be less reliable regarding reserves, and therefore to achieve the standard reliability performance the removed capacities will have to be partly or totally replaced by new plants. Including this replacement, the system is more expensive that the one described in the results of the PRIMES model which has ensured a financial balance of the entire portfolio but has ignored the individual financial evaluations. A capacity remuneration mechanism could reduce the capacities which are financially vulnerable on an individual basis, and thus it will induce mitigation of the additional system costs, but at the same time, the mechanism may well entail unnecessary costs. The PRIMES-OM model attempts computing the costs in various cases with or without capacity mechanisms and also with or without cross-border participation in these mechanisms.

As mentioned, the PRIMES-OM model starts using the data of the projection for the EUCO27 scenario developed using the standard version of the PRIMES model, which provides with optimal projections of demand, capacity expansion, generation, cross-border trade, system costs and prices (see Appendix A).

The PRIMES Oligopoly Model is a special version of the standard PRIMES electricity sector model, which represents various assumptions about market power and the implied bidding behaviour of generators in wholesale markets in Europe. The markets are interconnected in the model, which includes interconnection flows endogenously depending on power flows restricted by grid capacities and the net transfer capacity restrictions.

The simulation of the wholesale markets is the first step of the modelling which serves to compute revenues by generation plant. Additional revenues from possible capacity remuneration mechanisms are considered in the model as an option. The model represents only the stylised reliability option capacity mechanisms which involve auctions for the determination of capacity remuneration prices and a strike price for the reliability options that the capacity remuneration beneficiaries have to concede, which limit their scarcity bidding behaviour in the wholesale markets. The model determines the participation of generators in the capacity auctions endogenously depending on profitability considerations and explicit cross-border participation is an option in the model depending on the deliverability of the capacity availability services across the grid and profitability. Implicit cross-border participation is included in the endogenous determination of the demand curve for capacities depending on capacities of interconnections. The model can handle various assumptions regarding the capacity mechanisms, as for example their establishment in a harmonised or an asymmetric manner in the EU Member-States, with or without cross-border participation (the cases analysed are discussed in section II - 4.1).

The next step of the model is the financial evaluation of the power plants projected using the standard PRIMES model which are either existing or refurbished or new. The financial evaluation uses the computation of future revenues in a large number of probabilistic scenarios which are randomly generated to represent uncertainties regarding the ETS carbon prices, the growth of demand for electricity, the gas prices in the future and the degree of deployment of variable RES. The value of each plant calculated as a present value of net profits per probabilistic scenario enter a risk-averse utility function which estimates the probability of considering either retirement or a cancelling of refurbishment or investment by the plant owner. The model takes into account the heterogeneity of idiosyncrasies of plant owners regarding risk avert utility functions to calculate the average value of the plans across the non-observed heterogeneous decision makers.

Some of the plants are eliminated, depending on the plant values, and the wholesale market simulation is repeated assuming that new (usually peak devices) plants replace partly or totally the missing capacities to re-establish desired system reliability. At this final stage, the model computes the total system cost which is borne by the consumers in the EU countries. The modelling is dynamic over the entire projection period.

Table 17 gathers the steps of the modelling work performed.

Table 17: Steps of modelling work performed with the PRIMES-OM modelling suite

Steps of the PRIMES-OM simulations	Process	Output
Step 1: Simulation of prices and capacities in CM auctions (optional step, which is not performed if CM are not included in the assumptions)	Model determining demand and supply for capacities in CM auctions with or without cross-border participation of plants	CM prices, strike prices of reliability options, volume and type of capacity remunerated
Step 2: Running of the PRIMES oligopoly model	Simulation of the operation of organised wholesale markets co-optimizing balancing and reserve procurement, under a pure EOM or EOM with CM	Bidding by generators (function of reliability options in CM and scarcity), wholesale market prices, revenues of plants and load payments
Step 3: Running of the Probabilistic investment decision model	Evaluation of capacity deviation from EUCO27 considering a probabilistic flow of revenues as projected by the PRIMES oligopoly model	Probability of mothballing of old plants and cancelling of investments (new or refurbishment)
Step 4: Running of the PRIMES oligopoly model with revised plant capacity assumptions	Revised simulation of wholesale markets with co-optimization of balancing and reserve procurement, after implementing the deviation of capacities and the possible CM based on the output of the investment decision model	Wholesale market prices, system reliability, modified cost of reserves, imports, exports, plant revenues and payments by the load. Calculation of total payments by load, for system and for CM and comparison of cases

The analysis with PRIMES-OM has been carried out for the period 2020-2050, with a resolution of 5-years periods.

II - 2 EUCO27 capacities and reduced capacities in the simulations

The basis of the modelling analysis is EUCO27, which represents the least-cost capacity expansion, in that it is the capacity expansion that could be delivered in a perfectly designed market, and under no uncertainty and perfect foresight[47]. Then, the whole modelling approach with the PRIMES-OM (simulations with the PRIMES Oligopoly model and the Investment Evaluation model) is basically dedicated to observe how this “perfect basis” (the capacities of EUCO27) would perform in several market contexts, and when evaluated from decision makers that face uncertainty and behave under risk aversion. In other words, the modelling approach will yield with the deviations (reductions) of capacity from “perfect” under several market contexts and when introducing uncertainty and heterogeneity in decision making. More specifically, the reductions are due to the following aspects of the modelling:

- Capacity expansion of EUCO27 is the product of a simulation that assumes perfect foresight and certainty, while deviated capacities occur from simulations where plant owners are surrounded by uncertainty regarding ETS, gas prices, demand, RES developments, etc.
- The economics of capacity expansion of the EUCO27 are evaluated with a WACC of 8.5%, common for all plants. In the Investment Evaluation model, however, the plant owners are heterogeneous and use different hurdle rates[48] for evaluating investments. Moreover, the hurdle rates are modified among the different market design cases simulated (EOM, CM, or CM with cross-border participation), to represent the influence of market conditions and competition on the rate or returns required by investors. In particular, the modelling assumes that plant owners consider that revenues from CMs are more certain than revenues from the wholesale markets, and hence apply lower hurdle rates in the cases with CM compared to the EOM case; moreover, it assumes that cross-border participation in CM would also lead to lower hurdle rates due to increased competition compared to the CM cases without cross-border participation.
- In the simulation of the EUCO27, the consumers’ prices are at levels to ensure full recovery of all costs at portfolio generation basis (i.e. as if all plants were part of a single portfolio). In the simulations with the PRIMES Oligopoly model and the Investment Evaluation Model, the plant owners evaluate investments by considering the revenues and profit/losses separately for each plant[49]. Portfolio evaluation and plant-specific evaluation yield different results, and in particular, we observe that recovery of all costs is not possible when looking at the economics of each individual plant, even in the EUCO27 context. This may appear to contradict the theory that in a perfectly designed market recovery of costs at portfolio basis is sufficient to ensure recovery of costs at individual plant basis[50]. However, the EUCO27 context, even though it is designed as closely as possible to a perfect market context, it still cannot exclude some distortions, in particular:
    - In the period 2015-2030, the power plant fleet cannot be entirely renewed. Hence the optimal configuration of the plant mix cannot (yet) be accomplished as it carries along

[47] A detailed description of the methodological issues on deriving the EUCO27 scenario is given in Appendix A.
[48] The hurdle rate is the minimum rate of return that a plant owner is willing to accept in order to undertake an investment project.
[49] As we move towards the completion of the IEM in the EU, it is realistic to adopt in the modelling a project-financing approach in evaluating new investments rather than portfolio-based. The latter is more characteristic of past market situations, organised nationally and bearing features of monopolies or oligopolies.
[50] See Schweppe et al. (1988), Chapter 10.

inefficiencies and non-optimality inherited from the past. However, as we move closer to the end of the projection period (2050) these inefficiencies diminish.

- The capacity expansion of the EUCO27 is subject to policy restrictions (e.g. phase-out of nuclear)
- At the same time, some plants receive revenues out-of-the-market (e.g. RES and CHP) and enjoy dispatching privileges.
- Due to these distortions, portfolio economics are not the same with individual plant economics.

In the EUCO27 no specific market design is assumed, but total costs pass on to the consumer prices in order to (as already mentioned) ensure full cost recovery. In the simulations with the PRIMES Oligopoly model market design is treated explicitly and revenues are collected from the wholesale, balancing and reserve markets, as well as from CMs if applicable.

It is important to note that the fact that the PRIMES Oligopoly model suggests a retirement of the financially vulnerable plants does not imply that the EUCO27 scenario projects excess (non-optimal) capacity. The reduction in capacity from the EUCO27 context potentially implies that generation adequacy is not ensured for all countries (albeit the modelling handles this issue as described in the following paragraph). The EUCO27 capacity expansion is determined considering strict reliability criteria, MS specific. The reduced capacities of the cases simulated potentially violate these criteria if they are not specifically taken into account in the simulations.

The PRIMES Oligopoly model handles this in a way to ensure that equal reliability standards apply thus avoiding load curtailments as in the modelling of the EUCO scenario. To do so the reduced capacities compared to the EUCO scenario are assumed to be replaced by the TSO renting peak devices at high costs. The remuneration of these rented capacities is set at the level of the annuity payment for the capital cost of a gas turbine unit using a high unit cost of capital, and the costs are passed through to consumer payments for the system services. With this approach, the level of reliability across all scenarios is similar. If not, any comparison among the scenarios would be infertile. However, the above methodology does not fully cover the replacement reserve requirements which by definition are provided by non-spinning capacities.

The standard PRIMES model run (the model that yields the capacity expansion of the EUCO27) has included replacement reserve which in the model can be met by plant capacities which are not operating for energy purposes at all (if found not economically appropriate according to optimisation of dispatching). Old plants which are not economical to operate may remain idle and not decommissioned in order to meet the replacement reserve requirement. However, some of these non-operating old plants may be decommissioned according to the oligopoly model simulations and may not be fully replaced by the rented peak devices. Therefore, if one would like to maintain full comparability between the oligopoly model runs and the standard model it would have been necessary to add a remuneration to old plants remaining idle. This remuneration would essentially cover maintenance costs and a small fraction of capital costs. These costs should be lower than the costs of the rented peak devices per unit of capacity. The oligopoly model report includes the hypothetical cost of replacement reserve, as needed to reach the same levels as in the standard model scenario.

II - 3 Simulation of CM auctions

The objective of the simulation of national CM auctions is to estimate the price of stylised CM auctions for reliability options, the participation of power plants and the volume of capacities to be remunerated. Optionally, a national CM auction can accept the participation of power plants located in other countries, irrespectively if the countries have a border or not with the country organising the auction. The model also mimics the regulatory practice of defining a demand curve for available capacities so as to procure the desired total capacity at passible a minimum cost. The demand curve as determined in the model takes into account to some extent the capacities of interconnections and the regulatory preference regarding considering capacity assurance also using imported energy, or considering capacity assurance for exported energy.

The price and volume of equilibrium in the CM markets including the possible cross-border participation have to be estimated prior to the running of the PRIMES Oligopoly model, which takes the estimations as given, as well as the revenues of power plants from the CMs. The PRIMES Oligopoly model also modifies the bidding of power plants in the wholesale markets to reflect obligations under the reliability options.

The purpose of a capacity mechanism is to make sure that an adequate amount of power capacity is truly available when the system is stressed due to low margins between demand and supply. The product auctioned in CMs is the availability of capacity[51]. Therefore, it is important to consider the conditions that ensure a level playing field for national and cross-border capacities regarding the guaranteed availability of capacities. Deliverability of capacity availability cross-border using the interconnections at system stress times is a key concept for defining such conditions and rule cross-border participation.

In case explicit participation of plants is allowed cross-border, the model assumes that all plants in the entire EU have such a right and seek to find the optimal offering of their capacity to the national CM markets so as to maximise expected remuneration. When participating cross-border, a power plant is liable to truly deliver available capacity if needed therefore it considers a risk of non-deliverability, hence a risk of financial liability, in the case of interconnection congestion at system stress times. The model estimates the deliverability as a matrix of probabilities linking the locational origin of the plants to the destination of the available capacity service at system stress times.

The probabilities are estimated by running a power flow problem within the conditions of a system stress time. The estimation is performed regardless of its proximity to a plant to the country of destination and depends only on the interconnection grid and the possible congestions. In reality, the deliverability limitations stem not only from technical characteristics of the network but also from the need for coordination and negotiation between intermediate TSOs. The analysis here assumes that in the context of a well-integrated market the limitations due to TSO coordination will not exist by 2030.

Whether a plant's capacity can be offered to various national CMs is an important issue. Theoretically, there is no problem in doing so as long as the national systems do not encounter simultaneous system stress times. However, the degree of correlation of system stress times in the European system is not negligible, and in particular, it is relatively high in the system north of the Alps. Also, the financial liability[52] of plants in case of non-delivery of the service is a factor discouraging the offering

[51] For a discussion on the product of cross-border capacity the reader is referred to Finon (2012), Newbery and Grubb (2015).

[52] Let's take the case that a generator is considering the possibility of stress occurring at different times in two different systems, and thus consider offering one plant's capacity twice, to cover for both. There would always be a risk of stress occurring simultaneously in both systems and of the generator not being able to deliver and face applicable penalties. Therefore, assuming that such penalties would be high enough, and given the fact that peak load times in the EU are occurring close, it is expected that generators would not be willing to take

of the same capacity to many national CMs. In view of these factors, the modelling adopts the simplification assumption that one plant's capacity cannot be offered to more than one national CM auction. Moreover, the modelling assumes that the national CM auctions occur simultaneously and thus arbitrage[53] profits are not possible.

II - 3.1 Computation of upper bounds on cross-border transferred capacity

As the purpose of a CM is to make sure that power capacity is available at system stress times, it is necessary to define a methodology for computing upper bounds on cross-border participation in a national CM auction.

The main idea for this computation is similar to the concept of unforced available capacity, which is used in CMs for generation capacities to measure the eligible part of a plant's capacity. The unforced available capacity, or de-rated capacity according to other terminologies, is the amount of capacity which is available in a risk-free manner during system stress times. It is calculated by multiplying the available capacity of a plant by one minus the probability (or frequency) of outages during system stress times.

Using this concept for calculating unforced available capacity (or de-rated capacity) of interconnectors during system stress times is more complex because the probability of non-delivery is not due only to technical factors, but it is mainly due to congestion factors, which can considerably vary depending on power trade circumstances during system stress times.

The complexity arises from the fact that the product procured in CM auctions is capacity availability and not energy. When a country experiences a systemic stress, the energy prices normally increase, hence attracting energy flows cross-border from countries with lower marginal prices. There is no reason to remunerate availability of such cross-border flows, as the market forces alone have an interest in providing this capacity availability.

The purpose of remunerating foreign capacity is to ensure that the foreign capacity is available to produce in excess of normal market-driven flows[54], provided that the incremental capacity can be effectively delivered. The probability of non-delivery under such circumstances should be used precisely to calculate unforced available (de-rated) foreign capacity.

It is necessary to generate and analyse simulation results of the operation of the multi-country system of the EU to do this computation. Alternatively, the computation can be based on statistical data on system operation in past years. In any case, the analysis requires the estimation of power flows over the interconnection system.

We have applied tow ways for the computation of upper bounds on the cross-border participation of capacities in national CM auctions, namely the "Bilateral Transfer Limit" and "Capacity Import Limit"[55]. For both, we take the perspective of a country (say country A) implementing a CM auction. The

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that risk. The modelling follows this logic and does not consider the possibility of non-synchronous stress times and of offering the same capacity in more than one auctions.

[53] It can be easily shown that organising non-simultaneous national CM auctions is not a stable market and is contrary to achieving least costs of procurement by the regulators.

[54] By normal market-driven flows we refer to the flows that are projected in the EUCO27 scenario as part of the optimal capacity and generation mix of the system.

[55] The terminology used is borrowed from the latest PJM Capacity Market manual, available here https://www.pjm.com/~/media/documents/manuals/m18.ashx.

purpose is to calculate the maximum amount of capacity of plants located in each foreign country, which - if allowed - could participate in the national auction in country A.

The two computations differ in the consideration of how many countries are simultaneously offering capacities to country A. The Bilateral Transfer Limit is the maximum capacity (incremental to normal market-driven flows) that can be transferred from country B to country A under system stress conditions, considering network limitations and existing congestion of transmission lines, when all other countries maintain the same power balance. The Capacity Import Limit refers solely to the country A and is the maximum amount of capacity (incremental to normal market-driven flows) that can be transferred to country A simultaneously from all other countries under system stress conditions, considering network limitations and congestions of transmission lines. Hence each foreign country contributes to the Capacity Import Limit of country A with a certain amount of capacity.

The Bilateral Transfer Limit from country B to country A is always higher than the contribution of country B to the Capacity Import Limit of country A, since, in the latter computation, the country B faces competition on the transmission network, while country A maximises its total import of capacities from abroad.

The reason for applying two distinct measurements of the upper bounds is to gain sufficient insight into the possibilities of transferring capacity between two countries A and B. The absolute maximum of transferring capacity from B to A will always be the Bilateral Transfer Limit. However, this absolute maximum can only occur if B is the only country offering to A. On the other extreme, the contribution of B to the Capacity Import Limit of A is a "most constrained" maximum of transferring capacity from B to A, since all countries are simultaneously offering capacities to A. Thus, using both measurements provides us with a range of maximum transferable capacity from B to A. This is very useful in defining "deliverability" between each pair of countries (see II - 3.2.1).

In the following, we summarise the steps followed by the algorithms used for each computation:

A. Computation of Bilateral Transfer Limit

A1. We take a snapshot of system operation, including the flows over the multi-country network, at a system stress time (e.g. pan-EU peak load).

A2. Assume that in this snapshot country A experiences a disturbance implying a requirement for additional capacity of X MW (set X sufficiently high).

A3. We solve a power flow model iteratively assuming that only country B can offer capacity to meet the X MW requirement of country A. We solve the power flow model only for the stress period in question, searching to calculate the incremental flows over the network which allow transferring X MW from country B to country A. We assume that all other nodes of the system keep unchanged the power balance (positive or negative) as before the disturbance. Similarly, we assume that all power flows are kept unchanged as before the disturbance and that the modification of flows needed for the transfer of X MW is incremental to prior flow levels.

A4. If the transfer of X MW from country B to country A is infeasible, because of congestions, we decrease X until it becomes feasible.

A5. We repeat steps A1 to A4 for each country other than country A. We do not require that the countries are adjacent to A. The computation for each country is performed independently of other countries. This reduces complexity, but it neglects the impacts of simultaneous occurrence of system stress in more than one country.

The computed Bilateral Transfer Limits are shown in Table 37 and Table 38 of Appendix F.

B. Computation of Capacity Import Limit

B1. We take a snapshot of system operation, including the flows over the multi-country network, at a system stress time (e.g. pan-EU peak load).

B2. Assume that country A experiences a disturbance implying a requirement for additional capacity of X MW (set X sufficiently high).

B3. We solve a power flow model assuming that all countries can simultaneously offer capacity to meet the X MW requirement of country A. The unknown variables are the amounts to be offered by each country, given the network limitations, while maximizing the total capacity that can be imported to the country in question (e.g. country A). We solve the power flow model only for the stress period in question, searching to calculate the incremental flows over the network which allow transferring X MW from country B to country A. We assume that all other nodes of the system modify the power balance (positively or negatively) in an incremental fashion depending on the additional offer. We assume that all power flows are kept unchanged as before the disturbance and that the modification of flows needed for the transfer of X MW is incremental to prior flow levels.

B4. To determine offers by country, we formulate an objective function which sums the country offers and we solve an optimisation problem.

The computed Capacity Import Limits are shown in Table 39 and Table 40 of Appendix F.

II - 3.2 Methodology of the simulation of allocation choices

The suppliers of capacity are called upon to determine how to allocate their capacity among the domestic CM auction and the CM auctions cross-border if of course, these are allowed. To simplify the presentation (in the simulations we have studies various cases where not all countries apply a CM) we assume that all countries apply a CM auction at a national level, with harmonised rules, and that a given plant cannot offer its capacity twice. The capacity suppliers would then determine the allocation of capacity to the various CM auctions, including the national one, so as to maximise revenues, depending on the probability of effective delivery of the availability services through the network and the speculation of eventual “tightness” of foreign CM auctions regarding the degree of competition. The tightness shall depend on the actual reserve margin in each country and the capacities that are likely to be offered. We simulate this behaviour through two main functions:

A. **The deliverability function:** a probability that a given amount of capacity of origin in a country B offered to a country A of destination can be effectively delivered at system stress times.

B. **The revenue anticipation function:** a speculation of auction clearing price depending on the degree of tightness of the CM auction in country A from the perspective of the capacity suppliers, assuming that the lower the ratio between supply and demand the higher the auction clearing prices. This function basically constitutes the CM demand curve and is similar to the CM demand curves that are defined by regulators for determining CM auction prices[56].

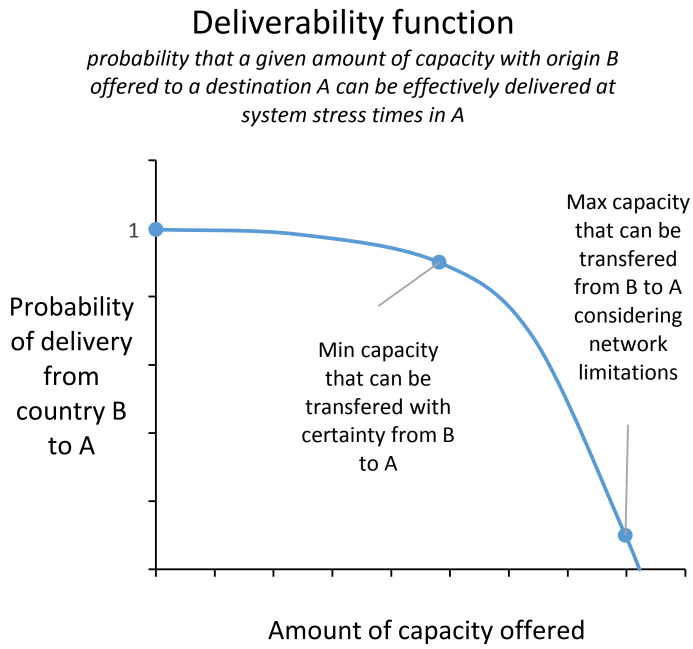
The following sections (II - 3.2.1 and II - 3.2.2) are dedicated to explaining the characteristics and the calibration of these functions.

[56] Example from the PJM capacity market is available in Bowring (2013).

II - 3.2.1 *Definition of the deliverability function*

The deliverability function is defined for every pair of countries A and B (a 28×28 matrix estimated for several system stress times). It is a probability function (taking values from 0 to 1), defining the probability that an amount of capacity can be effectively delivered from country B to country A. This probability always takes the value of 1 when considering transfer of capacity within the borders of a country (diagonal elements of the 28×28 matrix), as congestions within a control area are ignored in the modelling. For pairs of different countries, the function has a downward slope, implying that the larger the amount of capacity the less the probability that it can be delivered effectively (Figure 7).

Figure 7: Illustration of the deliverability function used in the simulation of capacity allocation in the CM auctions



The numerical estimation of the deliverability function is based on the calculated Bilateral Transfer Limits and Capacity Import Limits (see section II - 3.1). Hence, network limitations and congestion of transmission lines due to normal market-driven flows are fully taken into consideration.

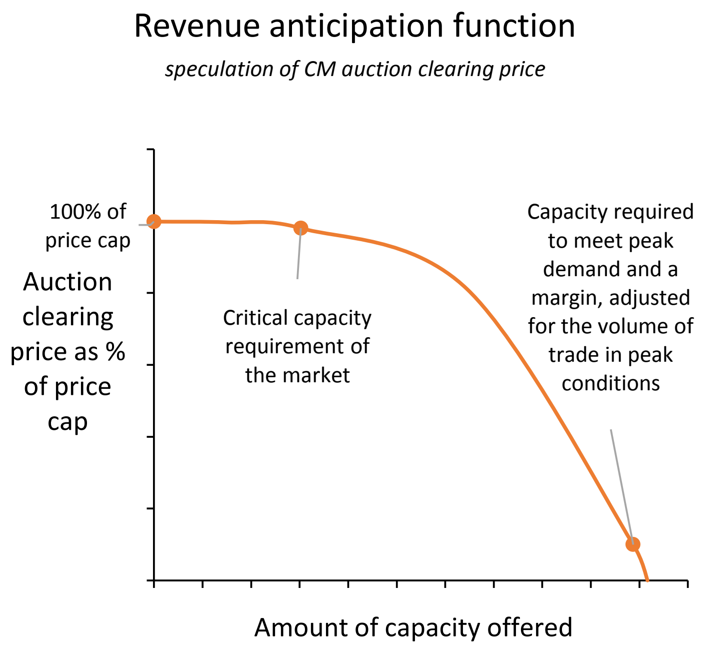
In particular, we consider that power transfer levels from country B to country A up to the amount of its contribution to the Capacity Import Limit of the latter (Table 39 and Table 40 of Appendix F) are considered almost certain, and high probability values are assigned to them (e.g. 0.9 at the level of contribution). On the other hand, the Bilateral Transfer Limit (Table 37 and Table 38 of Appendix F) is considered to be in all circumstances an upper limit to the power transfer from country B to country A, and thus, a low probability is assigned to it.

The probability of capacity being transferred is penalised by a factor depending on the electrical distance between the two countries, and in particular their “proximity” in terms of the electric network (see Table 41 of Appendix G). This allows accounting for issues other than purely technical network limitations that arise and/or augment as the electric distance between countries increases, such as complexities in coordination and negotiation between the TSOs of the countries involved. However, these factors have not been included in the present study.

II - 3.2.2 *Definition of the revenue anticipation function – CM demand curve*

The revenue anticipation function basically constitutes the capacity market demand curve, or what plant owners would anticipate that the CM auction demand curve would be. The CM demand curves are specific to each market (a country). They are negatively-sloped lines that depend upon a price cap and the linking of two capacity points: the minimum and maximum capacity requirements of a CM market (Figure 8)[57].

Figure 8: Illustration of the revenue anticipation function used in the simulation of capacity allocation in CM auctions



The price cap is the upper bound of auction clearing prices. It is a fixed number, uniform to all CM markets. It is determined considering the annuity of the capital cost of the units that are in the top of the merit order, i.e. of GT peak units. The annuity of the capital cost uses an interest rate which includes a risk premium, to reflect the risk associated with investing in a new power plant which would be at the top of the merit order. This is often referred to in the bibliography as the "cost of new entry". Given that the cost of new entry is the target price of the CM auctions, i.e. it is the price that should reflect the optimal level of capacity, the demand curves are numerically estimated so that the cost of new entry is paid for the amount of capacity which corresponds to the minimum critical capacity requirement. Thus, the price cap is set somewhat higher than the "cost of new entry".

Note that for the revenue anticipation function, the level of the price cap is not relevant. The generators anticipate the form of the CM demand curve and also anticipate how close or far to the price cap the auction clearing price will be.

In order to define the minimum and maximum capacity requirements, we set a desired level of reliability, or in other words a target reserve margin ratio (denoted TRM). The choice of the TRM may in

[57] The approach on defining the CM demand curves is based on literature (Cramton and Stoft 2005; Bowring 2013).

practice be replaced by results of probabilistic analysis of loss of energy probability, as usually followed in capacity adequacy studies performed by the TSOs, which determine a reserve margin above peak load in order to reduce the loss of energy (or loss of load) probability below an accepted threshold.

The minimum capacity requirement is defined for each market as the amount of additional capacity that is needed compared to available capacity in order to fulfil the defined TRM. The auction clearing price at this minimum point is (almost) equal to the price cap.

The amount of available capacity is equal to the capacity projected in the EUCO27 scenario, excluding the plants that individually are not recovering costs in the energy-only markets (according to the simulation of the EOM with the PRIMES Oligopoly model[58,59]). The exclusion reflects the view that these plants would not be available without a CM remuneration. The operating availability of plants[60] is also taken into account.

The maximum requirement (i.e. the size of the capacity market) is set equal to the total load requirement, i.e. it is equal to the peak demand plus the defined reserve margin and adjusted for the volume of cross-border trade in peak conditions, based on imports-exports as projected for the EUCO27 scenario. For this maximum requirement, the auction clearing price is by construction close to zero.

The peak load used for the demand function is adjusted to the volume of cross-border trade to reflect the implicit participation of flows over the interconnectors in the definition of the capacity auction. Depending on the country (whether it is mainly an importer or exporter according to the projections for the EUCO27 scenario), we take into account a portion of imports that can be viewed from the perspective of the regulator as “trusted” and we subtract them from peak load. Similarly, for mainly exporting countries, we consider a part of exports as “guaranteed” and we, therefore, increase peak load accordingly. Obviously taking out the trusted imports leads to lower auction clearing prices while the inclusion of guaranteed exports leads to higher auction clearing prices. The part of imports/exports that is considered is an assumption that attempts mimicking usual practices of the countries.

[58] The simulation of the EOM with the PRIMES Oligopoly model is discussed in detail in chapter II - 4.

[59] The simulation of the EOM with the PRIMES Oligopoly model that is presented in chapter II - 4, assumes that generators apply scarcity bidding in the wholesale market (see section Appendix C). In the course of the analysis we have also considered other bidding options, including marginal cost bidding. The capacity allocation procedure has been implemented for both scarcity bidding and marginal cost bidding cases. However, we present and discuss in this report only the findings that regard the scarcity bidding case. A general remark is that scarcity bidding appears to limit cross-border participation in their (hypothetical) CM markets compared to the marginal cost bidding case. The reason for this is that with scarcity bidding the amount of capacity not recovering costs and thus the critical capacity requirement of the CM markets is lower than under marginal cost bidding. This in turn implies faster declining revenue anticipation functions, or in other words, less attractive capacity markets for participants using the cross-border offering possibilities. Some countries, e.g. Greece, the Czech Republic and the Netherlands, attract no foreign participation in their (hypothetical) CM auctions in the scarcity bidding case, while they would attract foreign participation in the marginal cost bidding case.

[60] It should be noted at this point that all capacities are measured as unforced available capacities, which means that they have been de-rated according to the operating availability of plants, which also depends in their age and type.

II - 3.2.3 Definition of the capacity allocation model

In the following, we provide a description of the model that determines the optimal allocation of each plant's capacity to domestic and foreign CM auctions. Optimality is defined from the point of view of the capacity suppliers, who seek maximising profits (taking into account the revenue anticipation function) while maximising the probability of effective delivery through the network (hence taking into account the deliverability function).

Once the supply equilibrium (i.e. domestic and foreign offerings) is calculated, the model determines the amount offered in each CM auction and the auction clearing price can be determined using the CM demand functions specified by country. The resulting prices are used further by the PRIMES Oligopoly model to calculate the revenues of plants from CM auctions in the cases assuming application of the CMs. The capacity allocation model is specified as follows:

Given:

m: Countries with a capacity auction
p: Countries that participate in capacity auction of m, including country p
$Deliverability_{p,m}$: Deliverability function for the pair of countries p, m
$Profitability_m$: Auction clearing price as % of price cap of market m (revenue anticipation function)
Determine

$\boldsymbol{CM_{p,m}}$: Capacity offered from country p to market m,

By maximising *Total Revenue*

$$Total\ Revenue = \sum_{\mathrm{p,m}} Deliverability_{p,m} \cdot Profitability_m \cdot \mathbf{CM}_{\boldsymbol{p,m}}$$

Subject to

$$InstalledAvailableCapacity_p = \sum_{\mathrm{m}} \mathbf{CM}_{\boldsymbol{p,m}}$$

$$CapacityImportLimit_m \geq \sum_{\mathrm{p}} \mathbf{CM}_{\boldsymbol{p,m}}$$

$$Deliverability_{p,m} = 1 - \mathrm{e}^{\mathbf{A}_{\boldsymbol{p,m}} \cdot [\mathbf{CM}_{\boldsymbol{p,m}} - \max \mathbf{CM}_{\boldsymbol{p,m}}]}$$

$$Profitability_m = 1 - \mathrm{e}^{\mathrm{B}_m * [\sum_p \mathbf{CM}_{\boldsymbol{p,m}} - CapacityRequested_m]}$$

Where

$InstalledAvailableCapacity_p$: The maximum capacity that country p can offer to capacity markets, equal to the unforced capacity installed in country p (excluding all renewables apart from hydro capacities, cogeneration capacities of high efficiency as auto-producers in industry, district heating plants, etc.)

$CapacityImportLimit_m$: The maximum incremental capacity that a market m can import in periods of system stress considering network limitations

$\mathbf{A}_{\boldsymbol{p,m}}$: Parameter of deliverability function calibrated to contribution to capacity import limit and bilateral transfer limit for every pair of countries

$\max\mathbf{CM}_{p,m}$: Maximum transfer capacity from country p to market m

B_m: Parameter of profitability function calibrated to the ratio between supply and demand in a market

$CapacityRequested_m$: The maximum capacity requested by market m, for which the price is zero

II - 3.3 Simulation results of CM auctions

II - 3.3.1 Cross-border participation

The results of the capacity allocation model (Table 18 and Table 19) show that the countries that meet reliability requirements in the context of the EUCO27 do not attract foreign participation. This holds across all years for the following Member States: Spain, Portugal, Denmark, Sweden, Austria, Slovenia, Slovakia, Croatia, Romania and Bulgaria. On the other hand, the Member States for which the critical capacity demand takes high values do attract foreign participation. This holds across all years and options for the following Member States: Ireland, United Kingdom, Belgium, Germany, France, Finland, Poland, Hungary, Latvia and Estonia. There are also some Member States that attract foreign participation for some but not all years. Such examples of Member States are the Netherlands, Italy, and Lithuania.

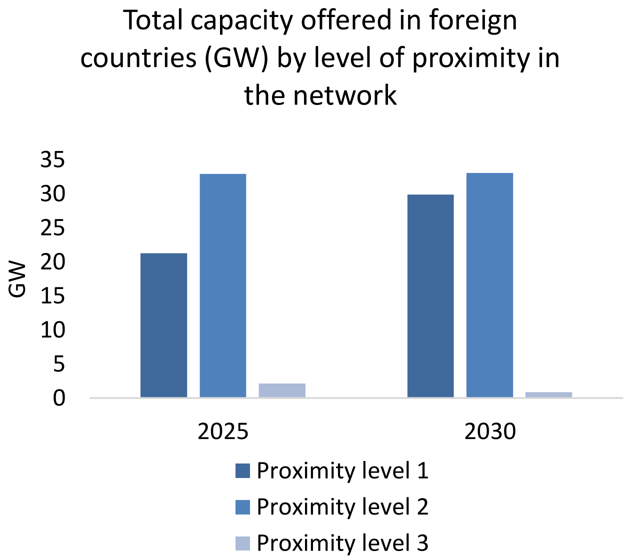
It is worth mentioning that the plants in all countries, regardless of whether they attract foreign participation or not, somehow participate in hypothetical capacity markets of foreign countries, with the exception of the plants in Denmark which is the only country that neither offers nor accepts cross-border capacity. Denmark appears to comfortably meet its reliability requirements and is not attractive for foreign participation, while it does not encompass significant amounts of capacity eligible to participate in hypothetical capacity markets due to the high share of renewables among its installed capacity.

The results of the capacity allocation model make apparent situations in which countries, e.g. Lithuania, prefer to offer their capacity to foreign markets through cross-border participation while satisfying their own demand for capacity also using eligible capacity brought from abroad. The main driver behind this is the fact that these countries have access to hypothetical capacity markets with profitability levels high enough to offset any losses due to deliverability inefficiencies. The capacity requirements of such countries are then met by capacity from countries that do not have access to the highly profitable markets due to network limitations.

We see a strong participation of foreign capacities in hypothetical capacity markets of countries that combine high profitability together with high deliverability from a large number of countries. Such an example is Germany, which, as it can be seen in Table 18 and Table 19, attracts capacity from a diverse pool of Member States.

On the other hand, countries that demonstrate high profitability function levels but experience poor deliverability from a large number of Member States, do not attract foreign capacity. Such examples are the UK and Italy which accommodate a relatively small percentage of their capacity needs from cross-border participation. These countries are not well interconnected compared to other countries, as for example the central European countries. Therefore the cross-border possibilities are relatively limited, as during system stress times the interconnectors are found often congested in these countries. So, the results show low values of the Capacity Import Limit in the UK and Italy, for example, compared to other countries of similar sizes, such as France and Germany (see Table 40 of Appendix F). As it can be seen in the bottom line of Table 19, the cross-border participation is limited

Figure 9: Total capacity offered in foreign countries of certain proximity in the network, in GW



The level of proximity indicates how many nodes apart the countries are in the network. Proximity level 1 implies that the countries are directly interconnected.

in 2030 due to the Capacity Import Limit of the country, implying that network limitations do not allow for further participation of foreign capacity in the hypothetical CM market.

The cross-border participation by proximity level in the network (i.e. by how many nodes apart the countries are in the network, with Proximity level 1 indicating that the countries are directly interconnected[61]) can be seen in Figure 9. As shown, the capacity participation is quite high for proximity level 1, even higher for level 2 in most cases, but it is quite small, albeit nonzero, for the proximity level 3, and equal to zero for the levels 4, 5 and 6. At first glance, it may seem counterintuitive that the cross-border participation of level 2 is higher than that of level 1, but this can be explained in the following manner: the pool of market participants of level 2 is much larger than that of distance 1, while deliverability is maintained, and therefore their total contribution is higher. Regarding the level 3, the pool of countries with quite large deliverability is very small and therefore total cross-border participation is quite low.

II - 3.3.2 Allocation to clusters

If cross-border participation is to be organised in clusters the results of the capacity allocation model could be quite useful. In any case, special attention should be given so that when defining clusters no Member States with a significant contribution to specific hypothetical capacity markets are left out since this would introduce inefficiency in the allocation of capacity. On the other hand, a more restrictive approach regarding the definition of clusters could ensure better coordination of the parties involved.

A very simple modelling approach to the definition of clusters that makes use of the results of the capacity allocation model, but neglects policy issues, is the following: start by identifying key Member States around each of which a cluster will be built. The number of key Member States also dictates the number of clusters. Subsequently, allocate all remaining Member States to the previously defined clusters, in a manner that maximises the cross-border capacity allocation as identified by the capacity allocation model, on the hypothesis that capacity allocated outside a cluster loses its value. In reality, selecting the key Member States that will set the basis for each cluster is a highly political decision that would have to be made by policy makers and is beyond the scope of this study. Nevertheless, we display two examples to showcase the applicability of the previously described method

[61] In Appendix G the reader may find a table with the network proximity level for all pairs of countries.

to the results of this study. One example in which three countries, namely Germany, Italy and France, are identified as cluster bases, and another one in which we add Poland to the list of the cluster, thereby increasing the number of clusters to four. The results can be seen in Table 20 for the year 2030.

Table 18: Results of the capacity allocation model - Capacity offering from participants to capacity markets in GW (EUCO27, 2025 context)

CAPACITY OFFERING FROM PARTICIPANTS TO CAPACITY MARKETS IN GW

2025		Capacity markets																								
		IE	**UK**	**BE**	**NL**	**DE**	**FR**	**ES**	**PT**	**DK**	**SE**	**FI**	**AU**	**IT**	**SI**	**CZ**	**SK**	**PL**	**HU**	**LV**	**EE**	**LT**	**HR**	**RO**	**BG**	**EL**
Participants	**IE**	4.10																								
	UK		39.79																							
	BE	0.21	0.15	6.91		0.69																				
	NL				13.9																					
	DE		0.03			60.86																				
	FR	0.48	1.61	0.44		1.82	81.53																			
	ES		1.75	2.50		2.79	5.04	43.87																		
	PT						3.25		9.19																	
	DK									2.88																
	SE		0.61			0.46					25.34															
	FI		0.10			0.29						11.38						0.06								
	AU			0.95		2.01	0.38						11.46					1.91								
	IT		0.45	1.00		6.16	3.03							54.78												
	SI			0.17		0.20	0.05								2.31											
	CZ					2.39										10.10										
	SK					0.72											4.44	0.62								
	PL					0.82												19.17								
	HU					1.20						0.49						0.82	2.92							
	LV											0.16						0.13	0.34	1.31	0.23	0.33				
	EE											0.37						0.20			0.71	0.21				
	LT					0.44						0.41						0.45	0.02		0.09	0.01				
	HR																		0.91				2.79			
	RO					0.59						0.81						0.97	0.63		0.51	1.31		10.70		
	BG																		0.42						6.96	
	EL						0.76												0.44							10.2
Total		4.8	44.5	12.0	13.9	81.4	94.0	43.9	9.2	2.9	25.3	13.6	11.5	54.8	2.3	10.1	4.4	24.3	5.7	1.3	1.5	1.9	2.8	10.7	7.0	10.2
% XB offer to total		14%	*11%*	*42%*	0%	25%	13%	0%	0%	0%	0%	16%	0%	0%	0%	0%	0%	21%	49%	0%	54%	99%	0%	0%	0%	0%

(00%): cross-border participation is equal to the Capacity Import Limit of the market, meaning that cross-border participation is the maximum possible considering network limitations and congestion of transmission lines

(IR: Ireland, UK: United Kingdom, BE: Belgium, NL: Netherlands, DE: Germany, FR: France, ES: Spain, PT: Portugal, DK: Denmark, SE: Sweden, FI: Finland, AU: Austria, IT: Italy, SI: Slovenia, CZ: Czech Republic, SK: Slovakia, PL: Poland, HU: Hungary, LV: Latvia, EE: Estonia, LT: Lithuania, HR: Croatia, RO: Romania, BG: Bulgaria, EL: Greece)

Table 19: Results of the capacity allocation model - Capacity offering from participants to capacity markets in GW (EUCO27, 2030)

CAPACITY OFFERING FROM PARTICIPANTS TO CAPACITY MARKETS IN GW																									
2030	Capacity markets																								
	IE	UK	BE	NL	DE	FR	ES	PT	DK	SE	FI	AU	IT	SI	CZ	SK	PL	HU	LV	EE	LT	HR	RO	BG	EL
Participants IE	3.70																								
UK		41.78																							
BE	0.01	0.50	6.09	1.65																					
NL	0.01	0.34		11.47																					
DE	0.10	0.92	2.64	0.98	50.98																				
FR	0.36	3.01	0.89	0.57	2.06	78.74																			
ES		1.91	1.91		2.15	6.04	39.42																		
PT						3.44		9.51																	
DK									2.11																
SE				1.28	1.80					23.34															
FI		0.12	0.13	0.17	0.16						9.92						0.05								
AU		0.43		1.14	4.21							10.39					0.44								
IT		0.14			8.00								50.20				0.01								
SI					0.22	0.10							0.10	2.17											
CZ				0.09	2.30										9.56										
SK					1.13						0.10					4.45	0.78								
PL																	20.93								
HU					0.96						0.58		0.32				1.02	3.48							
LV											0.25						0.29	0.24	1.27	0.45					
EE											0.57						0.41	0.03		0.49					
LT					0.08												0.14				2.02				
HR													0.31					0.74				2.64			
RO					0.88						0.74						0.76	0.88		0.37			10.60		
BG													0.24											7.04	
EL						0.15							1.56												8.95
Total	4.17	49.15	11.66	17.34	74.91	88.46	39.42	9.51	2.11	23.34	12.16	10.39	52.73	2.17	9.56	4.45	24.83	5.36	1.27	1.31	2.02	2.64	10.60	7.04	8.95
% XB offer to total	11%	***15%***	***48%***	34%	32%	11%	0%	0%	0%	0%	18%	0%	***5%***	0%	0%	0%	16%	35%	0%	63%	0%	0%	0%	0%	0%

(00%): cross-border participation is equal to the Capacity Import Limit of the market, meaning that cross-border participation is the maximum possible considering network limitations and congestion of transmission lines

(IR: Ireland, UK: United Kingdom, BE: Belgium, NL: Netherlands, DE: Germany, FR: France, ES: Spain, PT: Portugal, DK: Denmark, SE: Sweden, FI: Finland, AU: Austria, IT: Italy, SI: Slovenia, CZ: Czech Republic, SK: Slovakia, PL: Poland, HU: Hungary, LV: Latvia, EE: Estonia, LT: Lithuania, HR: Croatia, RO: Romania, BG: Bulgaria, EL: Greece)

Figure 10: Cross-border participation indicators by country (EUCO27 context, for 2025 and 2030)

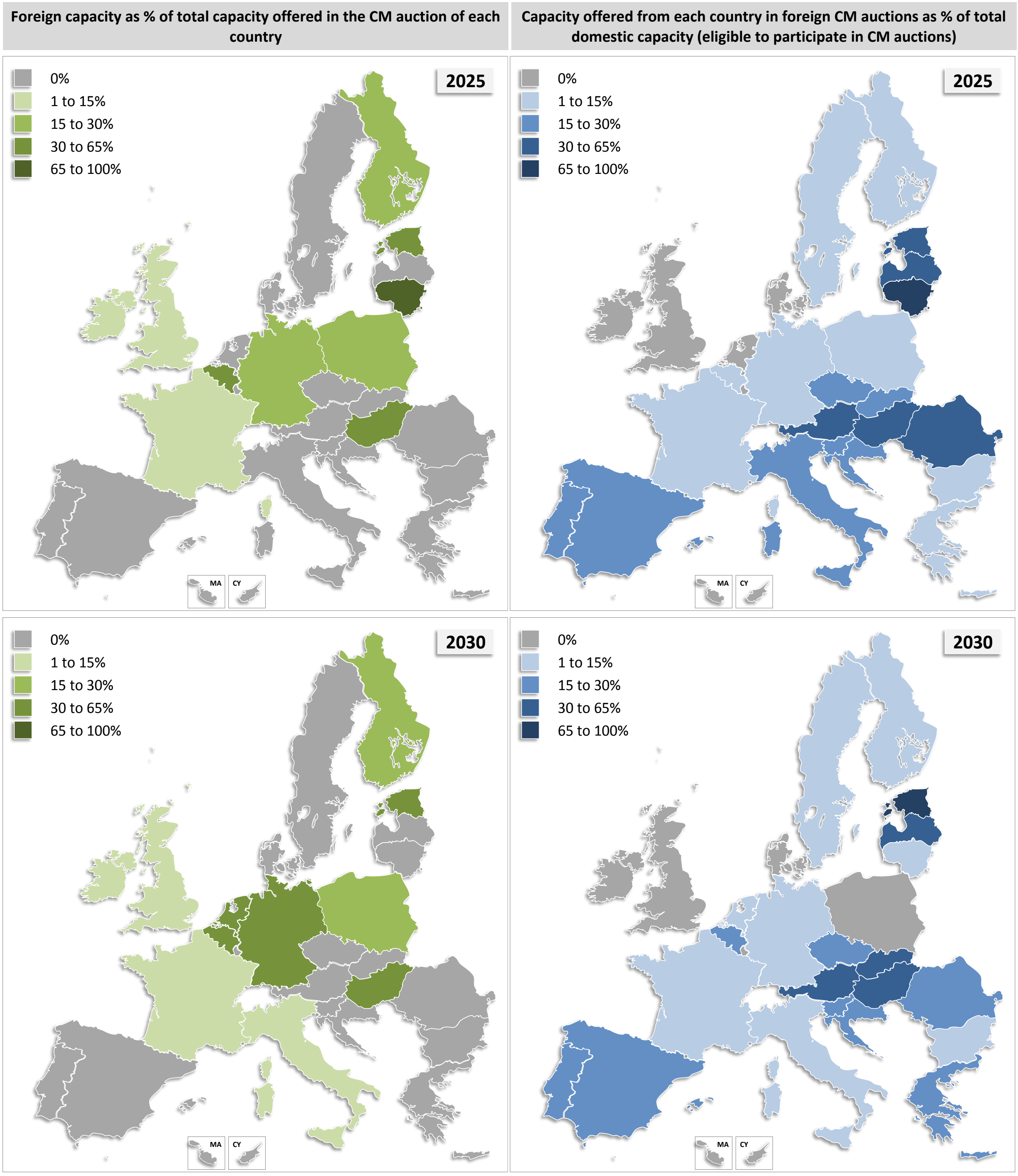


Table 20: Examples of clustering of hypothetical capacity markets based on the capacity allocation model results

	Clustering example A			Clustering example B			
	Germany Cluster	France Cluster	Italy Cluster	Germany Cluster	France Cluster	Poland Cluster	Italy Cluster
Ireland		✓			✓		
United Kingdom		✓			✓		
Belgium	✓			✓			
Netherlands	✓			✓			
Germany	✓			✓			
France		✓			✓		
Spain		✓			✓		
Portugal		✓			✓		
Denmark	✓			✓			
Sweden	✓			✓			
Finland	✓					✓	
Austria	✓			✓			
Italy			✓				✓
Slovenia	✓			✓			
Czech Republic	✓			✓			
Slovakia	✓			✓			
Poland	✓					✓	
Hungary	✓					✓	
Latvia	✓					✓	
Estonia	✓					✓	
Lithuania	✓					✓	
Croatia	✓					✓	
Romania	✓					✓	
Bulgaria			✓				✓
Greece			✓				✓

II - 4 Simulations using the PRIMES Oligopoly model and the Investment Evaluation model

II - 4.1 Overview of the analysed Cases

The base context of the analysis with the PRIMES Oligopoly model is defined by the assumptions for the Case 2 of the study with PRIMES-IEM presented in Part I (see I - 1.1). In summary:

- The EU market is well integrated by 2030, with pan-EU market coupling in Day-Ahead and intraday markets
- The entire load and generation fleet participates in the wholesale markets, after abolishment of dispatching privileges except for industrial CHP and small-scale RES
- The generating companies have interest in submitting complex bidding of the portfolio of plants in the Day-Ahead market to limit the exposure in the intraday and balancing markets; as a result, the scheduling of plants resulting from the Day-Ahead markets respects the cycli-

cal operation constraints of the plants and keep adequate resources to meet the ancillary services

- The analysis assumes that the market provides sufficient incentives for demand response, limited though to large entities[62]
- Only market-based procurement of reserves and ancillary services
- The entire physical capacity of interconnectors is allocated to every stage of the wholesale markets and a flow-based allocation is practiced. The Net Transfer Capacity restrictions are abolished.
- The generating companies apply scarcity bidding modelled as a scarcity bidding function; see Appendix C.

The model considers the market-related assumptions used for the Case 2 of Part I to apply in a variety of market contexts regarding the existence or not of capacity mechanisms. The Cases assessed using the PRIMES-OM model are the following:

- **Case B - EOM with scarcity bids**
  A non-distorted energy-only market as in Case 2 of the MDI study. No CMs are in place but market participants exhibit strategic behaviour through scarcity bidding.
- **Case C - CM in 4 MS w/o X-B**
  As in Case B but with CMs in place in four Member States (United Kingdom, Ireland, France and Italy). The choice of countries is made so as to include countries which already implement or plan to implement market-wide CMs, and is based on the CMs examined under DG COMP's Sector Inquiry [63].
- **Case D - CM in all MS w/o X-B**
  As in Case B but with harmonized CMs in place across all Member States.
- **Case E - CM in all MS with X-B**
  As in Case D but with explicit cross-border participation of power plants in the CMs of all Member States.
- **Case F - CM in 4 MS with X-B**
  This is as Case C but with explicit cross-border participation of power plants in the CMs of the four Member States.

The analysis considers further two cases where capacity mechanisms are implemented unilaterally in a country, one where the CM is applied only in France (Case CMFR) and one where the CM is applied only in Germany (Case CMGE).

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[62] The analysis assumes that the full potential of demand response as in Case 3 of the study with PRIMES-IEM (presented in Part I) is not realised. Full exploitation of the demand response potential would have contradictory implications for the revenues of the plants. The smoothing of the load curve, due to the demand response, and the reduction in balancing requirements implies lower needs for peak and flexible capacities, than in a case without the demand response. In case the peak and flexible plants are in excess of optimal amounts, they would fail recovering their capital costs. At the same time, base-load plants would be favoured, but they will need to bid much above their (low) marginal costs to recover their capital costs. A general trend in this context is to see shifting to a system almost entirely dominated by fixed costs; recovering the fixed costs in a wholesale market where the plants have no or very little marginal costs is a challenge because of the uncertainties surrounding a pure spot market compared to a futures market. The present study has not fully explored these issues and notably the implications of extreme demand response contexts on the recovery of capital costs and the role of capacity mechanisms.

[63] European Commission (2016) and ACER (2013).

II - 4.2 The capacity mechanisms' blueprint

In all the cases assessed (Cases C to F), the CM auctions are modelled in a stylised manner. The blueprint of the CMs is the following[64]:

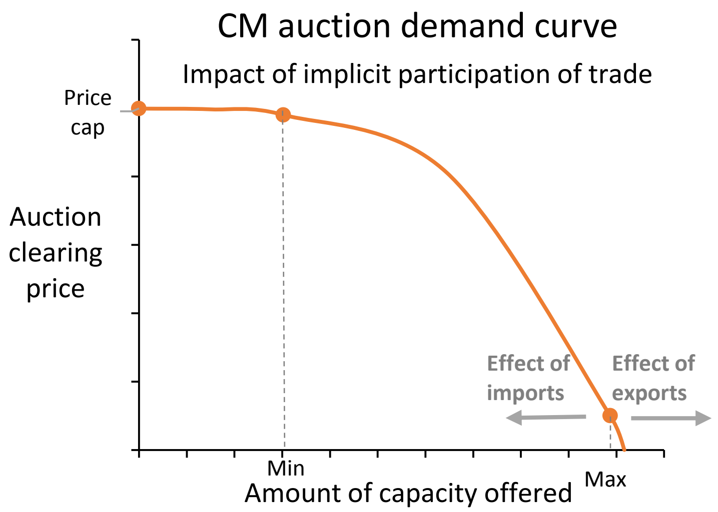
- **Eligibility:** All capacities are eligible, if dispatchable, including hydro lakes and storage, provided that they are not under a different support scheme. For example, CHP and biomass capacities are excluded. Also, plants in the process of decommissioning or operating few hours per year due to environmental restrictions (as projected in the EUCO27 scenario) are excluded.
- **Remuneration:** All capacities are remunerated for the available capacity, excluding outages (i.e. for the unforced capacity).
- **Auction rules and clearing price:** The CM auctions are single price clearing, sealed envelope price-quantity offers (with stepwise functions) and single round. The CM price is derived from the intersection of demand for capacity and the offers, sorted in ascending price order.
- **Reliability options:** The CM winners sign a reliability option (one way option) which has a strike price. If the SMP is above the strike price, they sign to return the revenues above strike price. The level of the strike price is an assumption linked to the price outcome of the CM auction. At this point, it is worth noting that it is extremely difficult to forecast what will be the strike price if a general purpose CM auction applies. If the CM remunerates a small part of the eligible capacities, those remunerated may accept strike prices close to their marginal costs, as they expect that other plants not covered by the CM will bid high enough in day ahead markets. But if the CM remunerates the majority of the eligible capacities, it is unlikely that the strike prices are equal to marginal costs, they would be somehow above marginal costs, unless the CM price is sufficiently high.

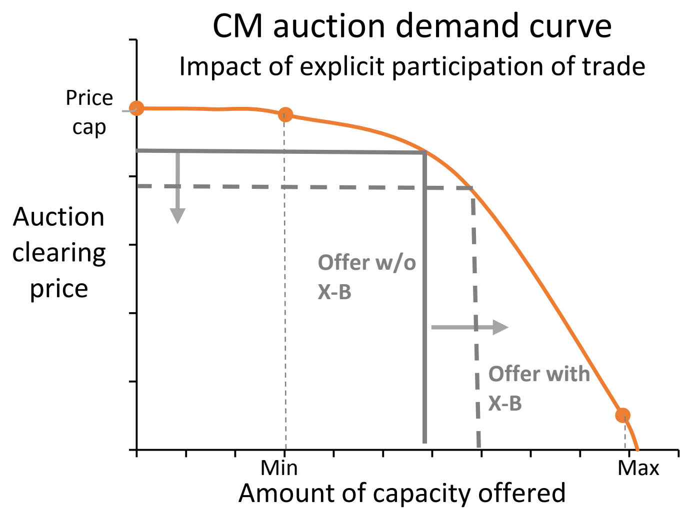
The demand for capacity in CM auctions is a negative-sloped line depending upon a price cap and linking two capacity points: the minimum and maximum requirements of capacity of each. For all capacity offered up to the minimum requirement, the auction clearing price is equal to the price cap, whereas for the maximum requirement it is equal to zero. The definition of the demand curve takes into account trusted imports (the majority in our case) at peak load times and the guaranteed proportion of exports. Therefore implicit participation of flows over interconnections is taken into account. More details on the definition of the CM demand curves are provided in section II - 3.2.2.

In the cases with explicit cross-border participation (cases E and F) the amount of capacities offered may increases, hence auction clearing prices tend to decrease in the country receiving the foreign capacity offers. However, as a plant's capacity cannot be offered twice to capacity mechanism auctions, the offer abroad decreases capacity offered domestically, which implies that in case of shortage the auction clearing prices in the national CM may tend to increase.

[64] The blueprint of the CM auctions and the modelling of reliability options are mainly based on the work of Cramton and Stoft (2008), Batlle and Pérez-Arriaga (2008) and Haikel (2011). An overview of different CM designs can be found in Batlle and Rodilla (2010) and Cailliau (2011).

Figure 11: Illustration of CM auction demand curves and impact of implicit or explicit participation of trade





II - 4.3 Methodology of the Investment Evaluation model

In all cases under study, the PRIMES Oligopoly model takes as a basis the capacities projected for the EUCO27 scenario. The model simulates the operation of wholesale markets, yielding with a stream of revenues for each plant. The purpose is to evaluate the value of each plant based on these revenues AS seen from the perspective of an investor or of a plant owner. Based on this value the investor or plant owner may decide to retire the plant or cancel a refurbishment or a new construction decision that have been included in the main scenario EUCO27. This is an "investment evaluation" process which uses the results of the Investment Evaluation model. The results constitute a deviation of the capacity mix[65] from the one projected in the EUCO27 scenario. The methodology fol-

[65] See section II - 2 for a detailed discussion on the comparison between deviated capacities and EUCO27 capacities.

lowed to evaluate the value of the plants in each Case under study includes uncertainty factors and the heterogeneity of decision makers[66] regarding risk aversion.

The plant capacities that are under evaluation old plants (existing in the base year of the modelling analysis, which is 2015) and new plants, resulting either from new investments or from old plants refurbishment.

In order to account for the uncertain market conditions, the approach introduces three random variables: EU ETS prices, gas prices and variable RES development. Each of these factors is modelled as a Brownian motion which applies to the whole time series of the EUCO27 projection.

An assumed matrix of variances-covariances represents the interdependencies of the three random variables[67]. The EU ETS prices and the gas prices are positively correlated, as high gas prices would imply high chances to see coal-based generation and thus the EU ETS prices need reaching high levels to achieve the EUCO27 emissions targets[68]. The EU ETS prices and the development of variable RES have a complex relationship. High support schemes to the variable RES imply lower EU ETS prices, but also high EU ETS prices drive a high market-driven development of variable RES. The gas prices and RES development are positively correlated because higher gas prices improve the competitiveness of variable RES.

The modelling of uncertainties defines a set of probabilistic scenarios resulting from a Monte Carlo technique of random generation. Each scenario is representative of a particular "event" of ETS prices, gas prices and RES development. After reducing the number of random scenarios-events of the sample following a scenario reduction technique[69], the PRIMES Oligopoly model runs for each scenario event to compute the stream of revenues of each plant and for each scenario.

The streams of revenues are then used to calculate the plant's values for each scenario-event. In particular, the value of a plant is an indicator which compares the capital cost of the plant to the stream of revenues from the wholesale markets (Day-Ahead, intraday, balancing and ancillary services) and the CM markets, when applicable, minus the variable costs and the fixed O&M costs.

The approach uses the concept of a hurdle rate, which serves to evaluate the present value of the stream of revenues minus the operating costs. Also, the approach considers that the plant owners and investors have heterogeneous idiosyncrasies regarding the hurdle rates, and therefore considers a distribution of hurdle rates (desired rates of return[70]) and their frequencies, assuming a log-

[66] See Botterud (2004), Bushnell (2007), Grimm (2008), De Vries (2008), Dahlan (2011).

[67] According to the approach followed, the trajectory of the random variables in time is a random process which is the outcome of a 3-dimensional stochastic differential equation, with mean that the respective trajectories of the EUCO27 scenario and a covariance matrix are defined so as to reflect the relationship between the three random variables. In the literature of stochastic calculus, this approach is used to describe stochastic processes with multiple sources of uncertainty. We refer the reader to chapter 3 of Fwu-Ranq Chang (2004).

[68] See Appendix A

[69] The number of scenarios obtained with the Monte Carlo simulation is very large. As the computer time of running the PRIMES Oligopoly model is high, it was necessary to reduce the size of the sample and retain the most representative ones. The reduction algorithm applies the Fast Backward Method, and is available in the modelling-system platform GAMS on which we built our models. Detailed description of the algorithmic approach is available in this link:
https://www.gams.com/help/index.jsp?topic=%2Fgams.doc%2Ftools%2Fscenred%2Findex.html

[70] It is common to evaluate projects by comparing the internal rate of return, or IRR, to the hurdle rate, which is a minimum acceptable rate of return. If the IRR is equal to or greater than the hurdle rate, the project is like-

Gaussian distribution with assumed mean and standard deviation. The mean and the standard deviation of the hurdle rates distribution is different for each Member State, reflecting the varying financing conditions, and their values take into account the risk factors related to the case under study. For example, if high risk is attributed to the source of revenues the mean of the hurdle rates increases and the standard deviation also increases, compared to a low-risk case. Regarding the country risk factors, we assume a range which leading to hurdle rates which have a mean equal to 7% for Germany and 10% for Greece. A typical value for the standard deviation is 1.5-2%.

We have varied the values of the mean and standard deviation parameters to reflect the impacts of competition context and the degree of uncertainty surrounding the future revenues by origin. We postulate that when future revenues are considered to be more certain, the investors would be willing to accept lower rates of return (hurdle rates) to undertake a project, than otherwise. Similarly, in conditions of intense competition, the investors would tend to lower their hurdle rates, as otherwise, they risk to be kicked out of the market.

Following this logic, the investment evaluation process postulates that the revenues from the wholesale markets are less certain from the revenues from the CM markets (Cramton & Stoft 2005; Cepeda & Finon 2011), hence total revenues in cases with CM (Cases C to F) compared to the EOM case (Case B) are more certain and therefore decision makers would apply a lower hurdle rate when evaluating investments than in the pure EOM case. This is reflected by lowering the mean of the distribution of the hurdle rates in the cases with CM compared to the cases without CM.

Moreover, the investment evaluation process postulates that in the CM cases with cross-border participation, the market competition is more intense than without cross-border participation. Therefore cross-border participation makes investors to consider smaller hurdle rates. This is reflected, by lowering the mean of the distribution of the hurdle rates in the CM cases with cross-border participation (Cases E and F) compared to the Cases without (Cases C and D).

The investment evaluation process calculates the value of a plant by applying the method described in the following paragraphs. We may denote:

- t: time
- s: a scenario-event, with probability of occurrence π_s
- ρ: the various categories of decision makers, each applying a different hurdle rate r_ρ, with frequency π_ρ
- i: a power plant

The present value of net revenues $PV_{\rho,s,i}$ includes the revenues $RV_{\rho,s,i,t}$ in all the stages of the wholesale market and from the capital mechanism, if any, minus the variable $VC_{\rho,s,i,t}$ and fixed operating $OM_{\rho,s,i,t}$ costs, including maintenance costs.

$$PV_{\rho,s,i} = \sum_t (1 + r_\rho)^{-t} \cdot [\, RV_{\rho,s,i,t} - (\, VC_{\rho,s,i,t} + \, OM_{\rho,s,i,t})]$$

Then, the process described so far leads for every plant, old or new, to a collection of present ues $PV_{\rho,s,i}$, each with probability $\pi_s \cdot \pi_\rho$

ly to be approved, but if not, it is typically rejected. The IRR, on the other hand, is the interest rate at which the net present value of all cash flows from a project is equal to zero. Investors conceive the hurdle rate by considering the costs of capital both for equity and the cost of debt.

The next step of the investment evaluation process is to compare the present values of net revenues to the capital cost of the plant. In the case of a new plant, if the net revenues succeed to recoup the investment expenditures, then the project is financially appropriate. If the recovery of capital costs is partial and below a certain threshold, the project should be rejected as it is likely to entail a financial loss. Between this threshold and the full recovery of capital costs, some investors would reject the project but some other would retain it, depending on their preferences for risk taking. Therefore a probability will represent in this case the frequency of investors maintaining the investment project for which the recovery of capital costs is partial but at a degree above a certain threshold. The model represents the probability of maintaining the project as a cumulative distribution function depending on the ratio of the present value of expected net revenues over the investment expenditures.

The non-recovery of capital costs is not a major reason to retire an old plant as long as it successfully recovers the operating costs including the fixed operation and maintenance costs[71], which can significantly increase with the age of the plant. An aged power plant can always have a certain non-zero capital value. An analogy is the salvage value of the plant, which in accounting is an estimated amount that is expected to be received at the end of a plant asset's useful life. In case the present value of net revenues indicates a net loss, retiring the plant implies forsaking the salvage value of the plant. Therefore, for old plants, the indicator used for deciding regarding maintaining or retiring the plant is one minus the ratio of the present value of net revenues (taken in absolute terms only if it is negative) over the salvage value. We define the salvage value as mainly depending on the not-yet amortised capital cost. Given that the decision is taken in a highly uncertain context, there is always a probability that the plant encounters positive net revenues which may be seen as an opportunity for risk-prone investors. We take into account an estimation of this opportunity to calculate the salvage value of an old plant, as by definition a salvage value corresponds to the estimated resale value of the asset. If the indicator is close or above 1, maintaining the plant in operation is financially appropriate. If the indicator is below a certain threshold, the appropriate decision is to retire the plant. Between the two values, we use a cumulative distribution function to represent the frequency, among the various plant owners with different risk behaviours, of maintaining the plant in operation as a function of the value of the indicator.

Formally, we define the indicators representing the value of a plant using the formulas shown below. The value of the i plant $Val_{\rho,s,i}$ differs by scenario s and the typical decision maker category ρ and is calculated differently for new and old plants:

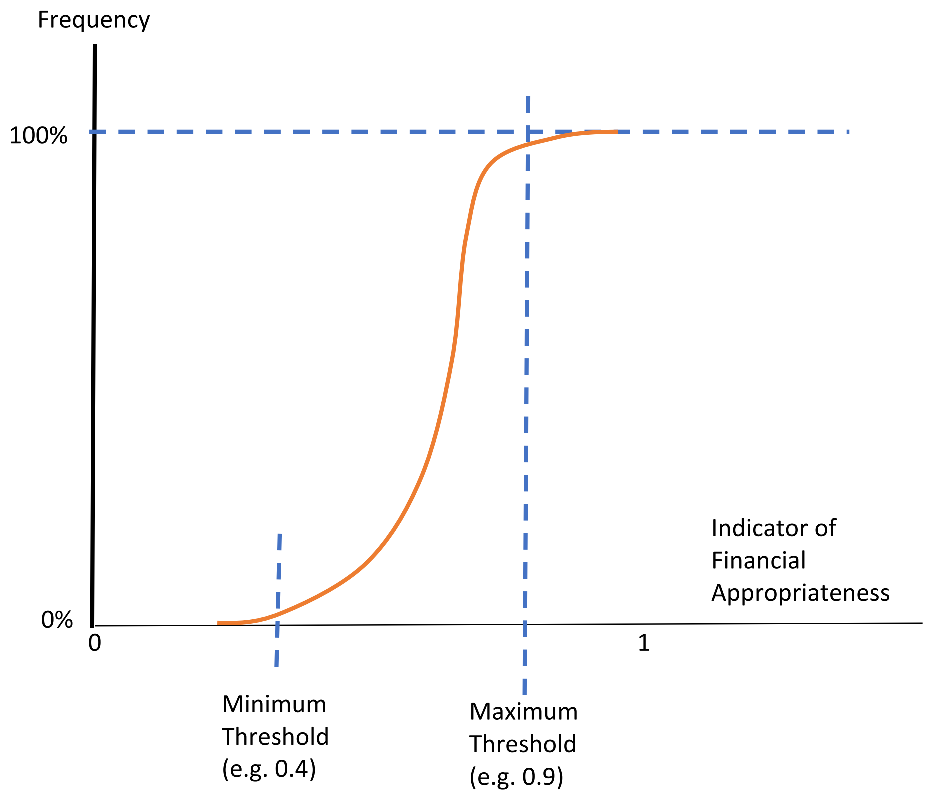
$$Val_{\rho,s,i}^{new} = \begin{cases} \dfrac{PV_{\rho,s,i}^{new}}{I_i^{new}} \text{ if } PV_{\rho,s,i}^{new} > 0 \\ \\ \quad 0 \text{ otherwise} \end{cases}$$

[71] Some plant owners often consider that it is necessary that the plant also recovers the repayment of the principal and the interest of the part of capital costs corresponding to the debt to maintain operation. We have not included this rule in our modelling, but only the recovery of operation costs. The retirement of the plant obviously rules out any possibility to service the debt and therefore usually the companies and the banks explore all possible ways of servicing the debt before opting for a bankruptcy.

$$Val_{\rho,s,i}^{old} = \begin{cases} 1 - \frac{\left|PV_{\rho,s,i}^{old}\right|}{S_i^{old}} \text{ if } PV_{\rho,s,i}^{old} < 0 \\ \\ 1 \text{ otherwise} \end{cases}$$

The plant value indicator enters as an argument of a cumulative probability function, which represents the frequency of maintaining the investment in a new plant or the operation of an old plant. This probability function referred to as probability of financial appropriateness. Figure 12 demonstrates a graphic representation of the function that has been implemented. The probability function is specified for each scenario and each typical decision-maker category ($\pi_{\rho,s,i}$). We vary the thresholds depending on the degree of risk aversion[72] of the decision maker represented by the hurdle rate assumed for each category ρ. The shape of the probability function indicates that even if the present value of net revenues is low compared to the investment expenditure there is still some probability that the investment is undertaken by some investors.

Figure 12: Graphic representation of the probability of financial appropriateness



At this stage, the model can calculate the probability of survival of old plants and the probability of maintaining the investment in new plants. Both are denoted as π_i which is derived by multiplying the probability of each scenario-event times the frequency of the decision maker types times the probability of financial appropriateness and summing over the whole range of possibilities:

[72] For an approach in modelling risk aversion see (Pineda and Conejo 2012).

$$\pi_i = \sum_s \sum_\rho \pi_{\rho,s,i} \pi_s \pi_\rho$$

These probabilities of survival imply that part of the plant capacities included in the EUCO27 scenario projection is excluded. As a next step in the modelling analysis, the adjusted plant capacities enter as inputs to the PRIMES-OM model re-calculate the generation mix, the interconnection flows, the costs for the consumers and the revenues per plant.

II - 4.4 Overview of results

In this section, we discuss the results of the simulations using the PRIMES-OM model, focusing on:

- the ability of power plants to recover capital costs in the market context of each Case (Table 21),
- the results of the investment evaluation process which determines which investments of the EUCO27 scenario have a probability to be realised in each context (Figure 13),
- the total payments by load[73] (Table 22),
- the system marginal prices (Table 23),
- the CM auction prices (Table 24), if applied in the examined case, and
- the trade flows

The Case B represents an energy-only market (EOM), assumed to operate as in the context of the Case 2 of the first Part of this study. As explained in previous sections, the modelling found that the Case 2 market context provides cost figures which are very close to the results of the EUCO27 scenario projection. In this context, the generation fleet is able to recover the entire costs as a portfolio but not necessarily on an individual plant basis. The standard PRIMES model has considered portfolio-based cost recovery as a sufficient condition for projecting investments, refurbishment and decommissioning of plants, also knowing that future revenues are certain and perfectly foreseeable.

As explained, these ideal conditions are never met in practice. Large uncertainties prevail, and the investors are having a risk aversion attitude and prefer evaluating the financial vulnerabilities for each plant individually. The PRIMES-OM model mimics this attitude having the EUCO27 capacity projections as a starting point. The model calculates revenues from wholesale markets and in some cases optionally also from capacity mechanisms and explores a large number of possible uncertain futures to compute a probabilistic measurement of the value of each plant. Depending on this value, the model computes a probability of plant survival for old plants and a probability of maintaining the investment for new plants.

In case the policy option under question includes a capacity mechanism, the model considers that the revenues from the CM are more certain than from the wholesale markets, but at the same time the remunerated plants in the CM take the obligation to abstain from submitting scarcity bidding in the wholesale markets. Therefore, in the Cases with capacity mechanisms (Cases C to F), the model-

[73] Total payments by load have two components, the payments to CM auctions and the payments to the wholesale and reserve markets. Payments to CM auctions are calculated as the auction clearing price of each market times the capacity eligible to receive remuneration. Payments to the wholesale and reserve markets are calculated as the load-weighted annual average system marginal price of the markets times the annual demand of the markets. The figures reported are the sum of the load payments of all countries and of years 2021-2030.

ling reduces the hurdle rates of investors compared to the EOM (Case B). Also, the cross-border participation, facilitated by the assumed effective market harmonisation, implies more intense competition which also induces a reduction in the hurdle rates. The reduced hurdle rates increase the chances of maintaining the capacities of the EUCO27, but at the same time, the reduction in the scarcity bidding, in the wholesale markets, reduces the revenues of the plants from the market, due both to the reliability options and the stronger competition in the cross-border participation cases.

In the asymmetric CM cases, as for example in the Cases where capacity mechanisms are implemented in four countries of the IEM (Cases C and F), only the plants located in the control areas with a CM receive capacity remuneration, except if they participate cross-border participation, provided that it is allowed. The system control areas without a CM operate as energy-only markets. The modelling assumes that the asymmetric implementation of the CMs influences the attitude of investors, differently by country.

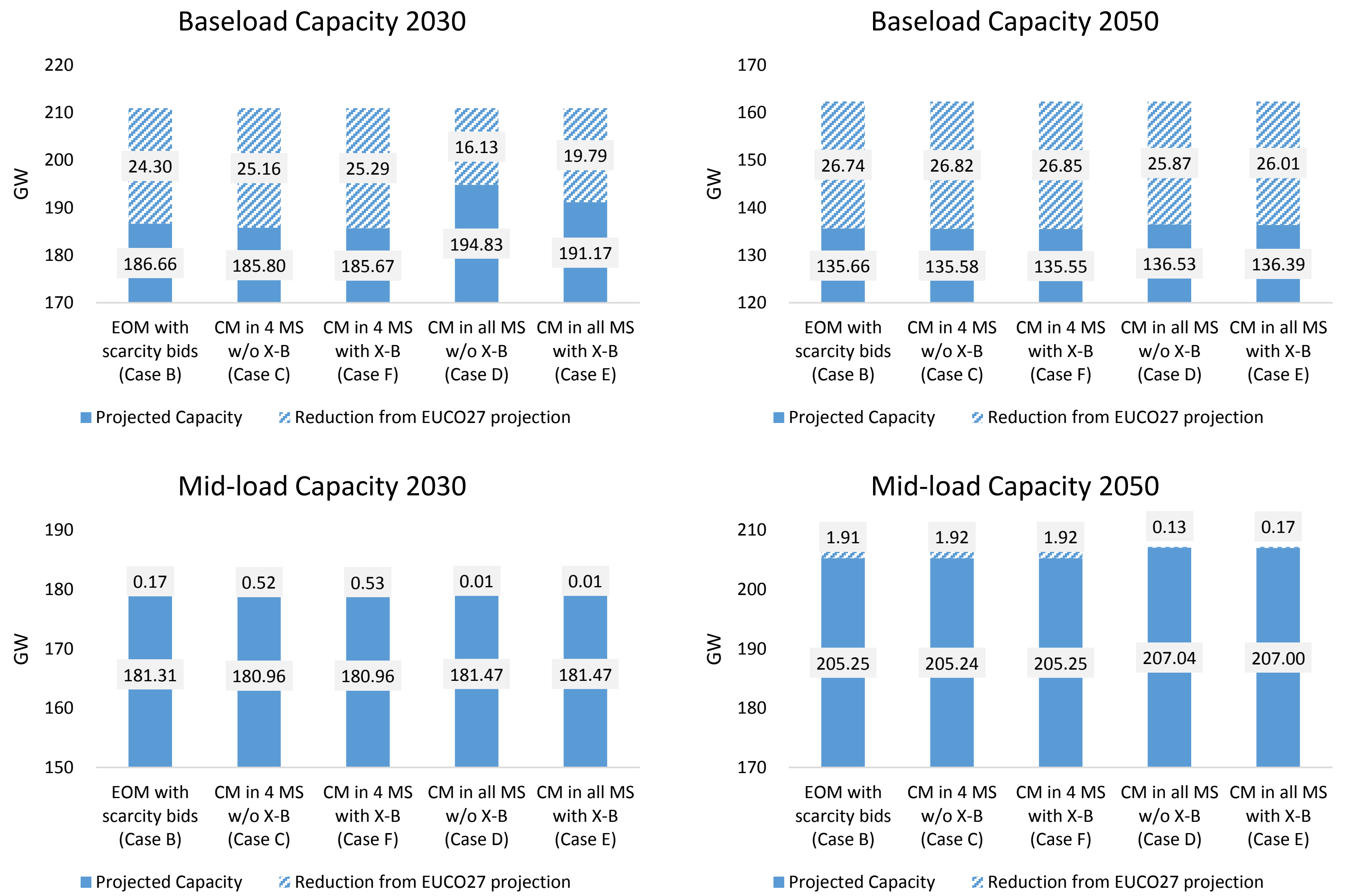
The simulation using the PRIMES-OM model of wholesale markets with reduced capacities compared to the EUCO27 projection establishes a comparable level of system reliability by investing, by assumption, in peak devices at a high cost. These costs pass on to the consumers and are accounted for in the load payments, as shown in Table 22. Thus, in the cases with significant capacity reductions, relative to the EUCO27, the costs for replacing capacity increases.

It is worth noticing, that we have not studied in this Part the case of full exploitation of the demand response potential (as in the Case 3 presented in the first Part of this study). As already mentioned, the demand response flattens the load curve and implies limited requirements for peak units also allowing the base-load generation to obtain a larger load basis and more certainty regarding the revenues. However, it remains unexplored whether a system with few variable costs and little variability between unit variable costs will be able to recover total costs in pure spot markets.

It has been explained in section II - 2 that the amount of peak capacity rented by the TSOs (and whose cost is included in the payments for reserves) does not fully cover the replacement reserve requirements, which by definition requires non-spinning capacities. The capacity mix of the EUCO27 scenario includes replacement reserve requirements, which are met by plant capacities that are non-economical to produce energy. Old base-load plants, inherited to the system by past, which are non-optimal in the power mix of the EUCO27 scenario context, due to higher ETS prices by 2030, are mainly foreseen in the EUCO27 projection as capacities remunerated as replacement reserve. The standard PRIMES model finds more appropriate to maintain them for replacement reserve purposes, instead of decommissioning them and invest in new ones. However, the PRIMES Oligopoly model finds (some of) these capacities as non-economical to maintain, and suggests retiring them. In case the TSOs has to rent the equivalent of the total capacity reduction, covering fully replacement reserve, the cost would increase and would amount to 0.3-0.5% of the total turnover value of the market (Table 25).

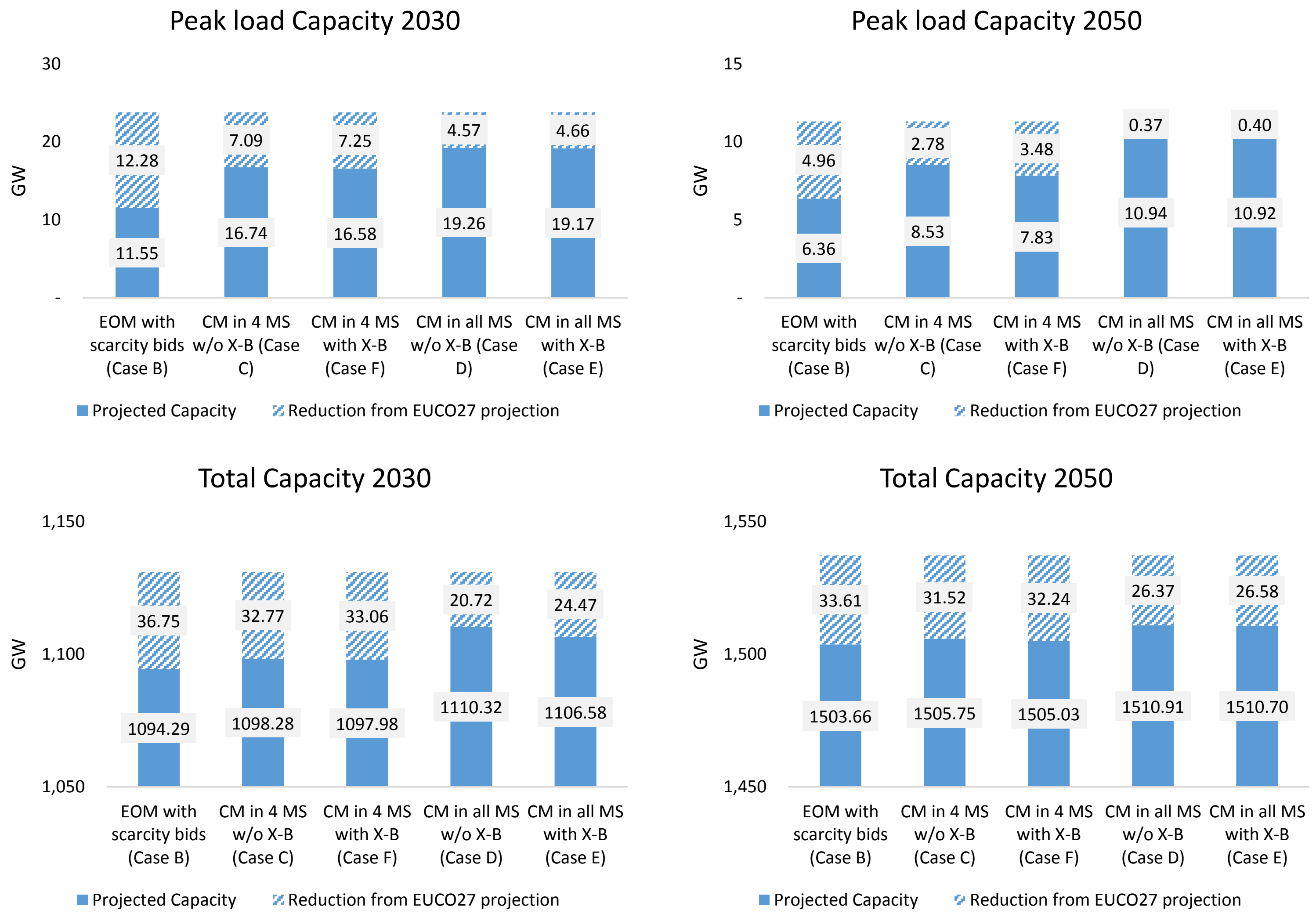
We provide in the Tables and Figures included below a summary of the simulation results for the various Cases using the PRIMES-OM model. More details are shown separately by Case in subsections 0 to II - 4.4.5. The presentation puts emphasis on years 2030 and 2050, or cumulatively on two periods, one before 2030 and one after. Until 2030, the capacity mix of the EUCO27 includes a substantial part inherited from the past, as the power plant fleet cannot be entirely renewed by that time. This means that by 2030, the capacity configuration under evaluation is non-optimal. As we move closer to the 2050 horizon, the EUCO27 capacities approach an optimum generation mix.

Figure 13: Projected capacities in the simulations with the PRIMES Oligopoly model and deviations from the capacity projections of the EUCO27 scenario (base load and mid-load capacity*)



(*)Baseload: Solids-fired and nuclear, Mid-load: CCGTs

Figure 14: Projected capacities in the simulations using the PRIMES-OM model and deviations from the capacity projections of the EUCO27 scenario (peak load* and total capacity)



(*)Peak load: Peaking units and steam turbines fired with oil and gas

Table 21: Revenues by plant type as % of minimum revenues required for full capital cost recovery, by Case (EU28)

	Percentage total cost recovery after final stage of market simulation, including only the plants that "survive" the plant evaluation process									
	EOM with Scarcity bids (Case B)		CM in 4 MS w/o X-B (Case C)		CM in 4 MS with X-B (Case E)		CM in all MS w/o X-B (Case D)		CM in all MS with X-B (Case F)	
	2021-2030	2031-2050	2021-2030	2031-2050	2021-2030	2031-2050	2021-2030	2031-2050	2021-2030	2031-2050
Solids	99%	76%	99%	83%	99%	82%	99%	82%	99%	82%
Nuclear	98%	100%	98%	100%	98%	100%	98%	100%	98%	100%
Lakes	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Wind onshore	97%	100%	97%	100%	96%	100%	97%	100%	97%	100%
Wind offshore	76%	97%	73%	97%	72%	96%	74%	96%	73%	96%
Solar thermal	14%	35%	14%	34%	13%	34%	14%	44%	14%	40%
Geothermal	92%	98%	92%	98%	91%	98%	92%	98%	92%	98%
Tidal	5%	63%	5%	62%	5%	61%	5%	72%	5%	55%
Biomass	69%	86%	75%	91%	72%	90%	71%	90%	70%	89%
Peak	27%	83%	72%	93%	66%	91%	39%	86%	39%	86%
CCGT	79%	94%	91%	99%	89%	99%	85%	98%	84%	96%
Steam turbines oil/gas	15%	21%	43%	69%	38%	64%	24%	35%	23%	35%
Run of River	100%	99%	100%	99%	100%	99%	100%	100%	100%	99%
Solar PV (large)	84%	99%	82%	99%	81%	99%	83%	98%	83%	98%
RES (small)	55%	92%	52%	91%	51%	91%	53%	91%	53%	87%
CHP	59%	51%	58%	50%	57%	50%	58%	52%	58%	53%
Total	70%	85%	68%	84%	68%	84%	69%	89%	68%	86%

Source: PRIMES-OM model

Table 22: Various cost indicators for the various Cases (cumulative figures for the period 2021 -2030 and 2031-2050, for the EU28)

	Load Payment(*) in M€'13	Load Payment in M€'13 to wholesale and reserves	Load Payment in M€'13 to CM	Missing money in M€'13 (**)
Cumulative figures for the period 2021-2030				
EOM with Scarcity bids (Case B)	3,169,614	3,169,586	0	496,244
CM in 4 MS w/o X-B (Case C)	3,151,523	3,064,535	86,912	444,104
CM in 4 MS with X-B (Case E)	3,117,316	3,043,131	74,106	459,612
CM in all MS w/o X-B (Case D)	3,259,022	3,018,655	240,238	372,511
CM in all MS with X-B (Case F)	3,172,495	2,962,557	209,792	392,094
Cumulative figures for the period 2031-2050				
EOM with Scarcity bids (Case B)	9,363,453	9,362,596	0	496,244
CM in 4 MS w/o X-B (Case C)	9,501,564	9,276,740	223,600	444,104
CM in 4 MS with X-B (Case E)	9,433,114	9,241,862	189,821	459,612
CM in all MS w/o X-B (Case D)	9,820,770	9,198,403	619,144	372,511
CM in all MS with X-B (Case F)	9,697,174	9,149,059	545,063	392,094

(*): Total load payments have two components, the payments to CM auctions and the payments to the wholesale and reserve markets. The payments to CM auctions are calculated using the auction clearing price of each market times the capacity eligible to receive remuneration. The payments to the wholesale and reserve markets are calculated as the load-weighted annual average system marginal price of the markets times the annual demand of the markets. The figures reported are the sum of the load payments of all countries for the periods 2021-2030 and 2031-2050.

(**): Missing money refers to the revenues required additionally for full capital cost recovery.

Source: PRIMES-OM model

Table 23: EU28 average annual SMP across all years and Cases

	EU28 average annual SMP in €'13/MWh						
	2020	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
EOM with Scarcity bids (Case B)	82.70	94.96	103.11	117.74	115.27	135.12	122.02
CM in 4 MS w/o X-B (Case C)	82.70	90.62	99.96	117.32	114.32	132.97	122.60
CM in 4 MS with X-B (Case E)	82.70	89.39	99.79	117.25	114.26	131.74	122.20
CM in all MS w/o X-B (Case D)	82.70	88.58	98.94	117.68	113.76	130.22	122.01
CM in all MS with X-B (Case F)	82.70	85.84	97.87	117.31	113.36	129.67	120.70

Source: PRIMES-OM model

Table 24: CM auction clearing prices in €'13/kW (EU28 average)

	CM auction clearing prices in €'13/kW (EU28 average)					
	2025	**2030**	**2035**	**2040**	**2045**	**2050**
CM in 4 MS w/o X-B (Case C)	46	50	50	50	51	50
CM in 4 MS with X-B (Case E)	39	43	42	43	43	43
CM in all MS w/o X-B (Case D)	55	60	60	60	60	60
CM in all MS with X-B (Case F)	48	53	53	53	53	53

Source: PRIMES-OM model

Table 25: Cost of renting missing capacity (to ensure reliability standard equal to the EUCO27 scenario) and comparison to CM costs, as % of total turnover value, in 2030

	EOM with scarcity bids (Case B)	CM in 4 MS w/o XB (Case C)	CM in 4 MS with XB (Case E)	CM in all MS w/o XB (Case D)	CM in all MS with XB (Case F)
Cost equivalent to replace missing capacity(*) (% of total turnover value)	0.60%	0.55%	0.56%	0.35%	0.42%
CM payments (% of total turnover value)	-	3.38%	2.88%	9.30%	8.30%

(*): It refers to the capacity reduction from the EUCO27 scenario which occurs in the simulations owing to the inclusion of uncertainty in the investment evaluation process. TSOs are assumed to rent the capacity that ensures equal reliability standards apply, thus avoiding load curtailments. This amount does not fully cover the replacement reserve requirements, which by definition are provided by non-spinning capacities, it is, therefore, less than the total capacity reduction from the EUCO27 scenario. The respective cost is part of the payments for reserves by consumers. However, the cost reported in this Table is the equivalent of replacing the total capacity reduction from EUCO27, as if TSOs were to cover the replacement reserve fully.

Source: PRIMES-OM model

Table 26: Total volume of trade, in TWh

	Total volume of trade(*), in TWh					
	2025	**2030**	**2035**	**2040**	**2045**	**2050**
EOM with Scarcity bids (Case B)	683	717	785	929	1002	1078
CM in 4 MS w/o X-B (Case C)	678	724	788	928	1002	1089
CM in 4 MS with X-B (Case F)	673	723	792	925	1000	1083
CM in all MS w/o X-B (Case D)	672	724	771	930	1003	1096
CM in all MS with X-B (Case E)	669	728	774	933	1005	1093

(*): Volume of trade = absolute value of imports plus absolute value of exports

Source: PRIMES-OM model

II - 4.4.1 Results from the simulation of the energy-only market (Case B)

The Case B is an energy-only market context with conditions as those assumed for the Case 2 shown in the first Part of this study. According to these assumptions, the EU market is fully integrated, the interconnectors are utilised fully with flow-based allocation of capacities and the power plants participate at the wholesale markets without exceptions (only industrial CHP and very small-scale RES are exempted) bidding at prices that reflect scarcity and by considering the technical constraints and the system services in the offering of their portfolio in the Day-Ahead market. The analysis with the

PRIMES-IEM model that has been presented in Part I of this study has found that such a context (similar to the Case 2 of the analysis with PRIMES-IEM in Part I) entails the lowest costs for the consumers, compared to the Cases 0 to 1 in which market distortions persist.

The simulation of the wholesale markets using the PRIMES-OM model, as expected, confirms the least cost performance of the market under the conditions of the Case 2. The PRIMES-OM model goes a step further and estimates the probability of capacity reductions compared to the EUCO27 projection due to the uncertainties and risk-avert behaviours[74]. According to the results, in the context of the EOM Case (Case B) the total capacity appears to be lower by approximately 37GW relative to the EUCO27 projection in 2030 (Table 27 and Figure 13). The deviation from the EUCO27 capacity is approximately 23GW in 2040 and 34 in 2050.

Table 27: Deviation of capacities from the EUCO27 scenario owing to cancelling of investments or early retirements in the simulations of the EOM with scarcity bids (GW)

	Deviation of capacities from the EUCO27 scenario owing to cancelling of investments or early retirements in the simulations of the EOM with scarcity bids (GW)		
	2030	**2040**	**2050**
Solids	24.30	14.21	24.69
Nuclear	0.00	0.00	2.05
Peak	6.23	5.05	4.25
CCGT	0.17	2.14	1.91
Steam turbines oil/gas	6.05	1.31	0.71
Total	36.75	22.73	33.61

Source: PRIMES-OM model

The solids-fired power plants (coal and lignite) have by far the largest share of the capacity reductions. The EUCO27 projection includes very limited new investments in coal and lignite power plants, therefore the reduction regards cancellation of refurbishments of old plants (as those have been endogenously projected in the EUCO27), and mostly early retirements of old coal and lignite plants. In the context of the EUCO27 these plants have been maintained in the system to serve as replacement reserves, and implicitly they have received (as a result of the optimisation not as a result of any institutional arrangements) a remuneration for the reserve services (in the form of the dual variable associated with the reserve constraints). In this way they have succeeded to mitigating their economic losses in the EUCO27 scenario. The PRIMES-OM takes a more risk avert perspective and applies the postulate that the high operation and maintenance costs, which entail the losses, have few chances to be recovered in the spectrum of a large range of future events, while the salvage value (resale value) of the plant is modest due to its age and the persistence of high ETS prices in the future. Thus the probabilistic financial evaluation model suggests retiring part of the old coal and lignite plants, and in particular the most vulnerable financially.

A similar financial evaluation finds that the nuclear plants succeed recovering their fixed costs very comfortably based on revenues from the wholesale markets, and even get profits above normal; thus, the nuclear capacity as projected in the EUCO27 remains intact. In the 2021-2030 period, the

[74] Section II - 2 includes a detailed discussion on the reduction of capacities in the simulations with the PRIMES Oligopoly model compared to EUCO27. Section II - 4.3 describes in detail the methodology followed for evaluating investments.

investments in question are mainly extensions of lifetime and include only a few new investments. New investments (which are more costly than refurbishments) appear mostly in the period post 2030. As in that period the ETS carbon prices further increase in the context of the EUCO27 projection, the financial evaluation of nuclear plants, including the new nuclear investments, confirms a comfortable cost recovery in the wholesale markets.

The CCGT power plants appear to perform quite well in the EOM, regarding the recovery of fixed and capital costs, and only a small part of the CCGT capacity projected in the EUCO27 scenario is not maintained in the investment evaluation process (see Table 27 and Figure 13 for Mid-load capacity). The CCGT plants have diverse sources of revenues, as they receive payments from both the wholesale and the balancing and reserve markets. Moreover, the uncertainty surrounding the ETS prices is beneficial to them as the increase in the ETS prices make them even more competitive vis-à-vis the coal plants. In the context of high RES shares, although the RES may imply lower ETS prices, the CCGTs continue to maintain their cost advantage as they are remunerated for flexibility and reserve purposes.

The simulation results of the EOM reveal that the financial assessment of old steam turbine gas and oil plants is negative, similarly to the old coal plants. Therefore, a considerable part of old oil and (open cycle – steam turbine) gas capacities have to retire early. However, part of the capacity of open cycle/gas turbine oil or gas plants serves specific purposes, as for example in islands and district heating supplied by CHP. For this reason, the accounting of costs should probably include additional (real or virtual) revenues for these plants, to represent the value of the services in islands or in district heating. In this case, the financial appropriateness calculation may lead to a different conclusion.

The peaking units (e.g. GT) perform better than the old open cycle gas/oil plants, but still, a considerable part of the relevant investments are suggested to be cancelled. Overall, the reduction in peak load capacities (peaking units and steam turbine gas and oil plants) is responsible for half of the total capacity reduction in the period up to 2030 and for approximately 20% in later years (Table 27). It should be noted at this point that the assumed level of scarcity bidding affects the results regarding the peak load capacities considerably. If the bidding submitted high economic offers, the peak load units could be evaluated as financially viable. The financial evaluation calculation does not include remuneration of strategic or replacement reserves in the EOM market. In contrast, the standard PRIMES model includes such reserves as a constraint, and thus the optimisation implicitly associates a value with the provision of reserve services by the peak load plants; this explains why the standard PRIMES model projection suggests maintaining the capacity of such plants. Once having reduced the capacity of peak plants, the final simulation using the PRIMES-OM model shows that the remaining peaking plants are particularly profitable in the wholesale markets, assuming scarcity bidding behaviours. Should the accounting include additional remuneration of strategic and replacement reserve, the reduction of the capacity of the peaking plants would have been much lower.

So far, we have discussed how the level of investments of EUCO27 re- adjusts owing to the uncertainty perceived by investors. It remains to see how the remaining thermal capacities, after eliminating the financially vulnerable plants, perform in the energy-only market context. In Table 21 we show the rate of recovery of total cost, including capital costs, after eliminating the vulnerable plants. The fact that even after the adjustment of capacities there are still units that are not recovering their costs fully is because the investment evaluation process does not cancel all investments if they present negative (expected) profits (II - 4.3), but only those that encounter large negative profits. In this sense, it accounts for investors that could accept a loss of a reasonable magnitude, instead of retiring the plant or cancelling the investment and thus forsaking all chances of possible positive earnings in the future. In reality, large supply companies could in some cases accept maintaining financially vulnerable plants in their fleet, provided that they recover all costs, including capital costs, on a portfolio basis. The reason is that they may perceive benefits from considering maintaining a diversified fleet to hedge risks, even if a few plants in the portfolio are not entirely successful financially.

As shown in Table 21, the capacities remaining after the reductions recover their costs to a rather satisfactory extent. In particular, the remaining (old) solids-fired power plants produce comfortable revenues in the period up to 2030. Their profitability drops in the following decades, owing to the high ETS prices. The nuclear plants maintain comfortable revenues throughout the projection period. Similarly, the CCGT units recover their costs to a large extent, as anyway there has been hardly any reduction of their capacity.

In general, the CHP plants seem unable to recover their total costs from the revenues in the wholesale markets. The model accounts for additional revenues from the supply of heat and steam to balance total costs. For this reason, the capacity of CHP plants is largely maintained at the same levels as in the EUCO27.

The model finds that the RES plants which are competitive by 2030, such as hydro, solar and wind onshore, recover their capital costs comfortably from revenues in the wholesale markets (Table 21). This confirms the projection of the EUCO27 where market-based investments in the mature RES technologies are possible without feed-in tariff support. In contrast, the not yet fully mature RES technologies, such as the wind offshore, solar thermal, some of the biomass applications (those with expensive feedstock, notably solid biomass, not those using waste energy) and some segments of the rooftop solar PV potential, see difficulties in recovering total costs before 2030 in the wholesale markets, as they are not projected to have fully achieved the learning potential by 2030.

II - 4.4.2 Overview of simulation results for the energy-only market (Case B) by Member State

The focus of this section is on the results by Member State of the simulation of the energy-only market. Detailed figures by Member State are provided in Appendix H.

The model runs the wholesale markets simultaneously for all countries linked to each other by endogenous power flows over the interconnection grid. But, the costs of the fuels, the efficiencies of the plants and other cost elements are specific to each country, while the grid possibilities also influence the countries differently. Therefore, the reduction of capacities cannot be the same in all countries, also given that the capacity mix differs as projected by the standard PRIMES model for the EUCO27 scenario context.

The main conclusions drawn for the EU28 are valid also at a Member State level; the simulations using the PRIMES-OM model suggest for a few member-states significant cancelling of part of investments or an early retirement of some of the old capacities, relative to the EUCO27 capacity projection. The deviations from the EUCO27 are mainly for solids-fired units, the old open cycle oil and gas plants, and to a lesser extent for peak gas-firing devices. In contrast, the CCGT units maintain to a large extent their capacity in all countries.

The solids-fired capacities as projected in the EUCO27 context are in their large majority old capacities, which have high operating costs further increasing with age. The salvage (resale) value of these plants depends on its age and the remaining operation possibilities given the restrictions imposed by the large combustion plant legislation. Thus, it is logical that the largest reductions in solids-fired capacities are observed for the Member States with the oldest fleet of solids-fired plants.

The interconnection limitations (although the scenario assumes no NTC restrictions and implementation of the grid extensions included in the ENTSOE planning) imply for some regions inability to operate under full market coupling with the rest of regions, i.e. to experience different system marginal prices due to congestions. If this happens in regions, such as in the Eastern European area where old coal plants are a significant part of the fleet, then these plants may succeed getting substantial revenues in the wholesale markets thanks to scarcity bidding. The scarcity bidding would not have been possible at the same level if there were no interconnection limitations. In such countries, the old coal/lignite plants may remain in operation despite their age and the increase in the costs.

According to the simulations for 2030, the largest reduction in solids-fired capacity from the EUCO27 level is observed for Germany and the Czech Republic (Table 44). Both countries are among the Member States with a large fleet of old solids-fired units. They have good interconnection in their broader region, especially Germany. Therefore, both the increasing costs of maintenance and the limits on scarcity bidding make the coal plant fleet in these countries particularly vulnerable from a financial perspective. Therefore, it is logical that the model suggests large retirements of old coal plants in Germany and in the Czech Republic.

The conditions are different in other countries with a large fleet of old coal or lignite plants, as for example Poland and the rest of Eastern or Southern countries. In Poland, the unit cost conditions of the old coal/lignite plants are slightly better than in Germany. In other countries, e.g. Italy and countries in the Balkans, the interconnection limitations allowing high bids provide opportunities for getting revenues at a sufficient level for covering the increasing operating costs. Therefore the model suggests few retirements of old coal plants in these countries. Large reductions of solids-fired capacities are also observed in Spain and, to a lesser extent in Greece, mainly because of the difficulty of maintaining operation of solid fuel plants in the context of a system with large amounts of variable RES. In this context the old coal plants are penalized because of their inflexibility, while the system needs operation of gas and hydro plants to support the flexibility services.

Similarly to the solids-fired capacities, the steam turbine oil and gas plants are aged, and thus they present the largest reductions in countries with a large fleet inherited from the past, as in Italy and Germany.

The financial performance of the remaining capacities, after eliminating the financially vulnerable plants, follows more or less the same patterns across the Member States (Table 45 for 2025 and Table 46 for 2030), as seen in the results of the PRIMES-OM model.

II - 4.4.3 Impacts from implementing CMs to all EU MS (Case D)

As it has already been stated, we postulate that the generators and investors perceive lower risk associated with the revenues from capacity mechanisms compared to revenues from the wholesale markets. This implies a lowering of investors' hurdle rates. By assumption, the generators accept reliability options in exchange for the CM remuneration, and thus the revenues from the wholesale markets decrease.

The Case D assumes market conditions as in the Case 2 of the 1st Part of the present study and implementation of CMs in all the Member-States, according to fully harmonised rules and procedures. The harmonisation is important not only for the market integration but also as a risk-reducing condition. The Case D does not assume explicit participation of foreign plants in the national CM auctions, but only an implicit participation of cross-border flows via the interconnections and depending on the importing or exporting practice of each country.

The results of the simulations using the PRIMES-OM model for the Case D confirm that the amount of financially vulnerable capacities are lower than in the case of energy only market (Case B). The plants succeed a more comfortable recovery of costs in the Case D compared to the Case B, as shown in Table 21. The simulation of the capacity auctions foresees market clearing prices at 55€/kW-year on average in 2025 and at 60€/kW-year on average in 2030 (Table 24).

Regarding the coal and lignite plants, the capacity remuneration implies significantly lower early retirements than in the Case B. A similar result holds for the old open cycle gas and oil plants. This is a remarkable result for the assessment of the CMs. This means that the CMs maintain in operation old plants which otherwise would not be able to recover their fixed operating and maintenance costs in the energy-only markets. The CMs do this because by assumption it is not allowed to discriminate between technologies of the plants, or regarding the age, the efficiency or the environmental footprint of the plants, or the flexibility.

To this respect we could put forward two contrasting points of view:

A. The CM which naturally aims at promoting investment is obliged to support old plants which otherwise would retire and leave room to new investment; from this perspective, the CM entails unnecessary costs.
B. The CM, in essence, provides a remuneration to old plants to maintain them in operation and so meet replacement and strategic reserve requirements in a non-expensive way, as it may be cheaper to prolong the lifetime of old plants rather than to build new plants which will rarely be used; from this perspective, the CM entails justified costs.

We are not attempting in this study to provide an answer to this dilemma, because of the difficulty of validating the robustness of the behavioural assumptions related to the CMs. However, it is logical to think that the agency costs of the CM, being an out-of-the-market intervention, although largely unknown, have to be added to the cost comparisons.

The plants remaining after the capacity reduction seem to recover their costs comfortably in the Case D, and they do complement wholesale market revenues with capacity remuneration (Table 21). The CCGT units, which perform financially well in the EOM (Case B) do even better with the CM remuneration and the markets simulated for the Case D as the CMs provide additional revenues to the CCGT plants than under the EOM conditions.

The plants that do not participate in the CM auctions, i.e. RES and CHP, have a worse financial performance under the assumption of the CMs compared to the EOM. This is due to the decrease in the system marginal prices of the wholesale markets owing to the reliability options.

The simulations do not find substantial differences in the trade flows among countries between the two cases, Case D and Case B. This is related to the assumption of the modelling that the wholesale markets are fully integrated and that the trade flows derive from the flow-based allocation of interconnection capacities without barriers.

According to the results of the simulations, the cost of the case with CMs in all EU MS (Case D) is higher than the cost of the EOM (Case B). Total payments by the consumers, in other terms total payments by the load, as shown in Table 22, amount to 12533 BN€'13 for years 2021-2050 for the EOM case, while for the CM case of Case D they amount to 13080 BN€'13 for the same years, which is a 4% increase. Nevertheless, the distribution of costs differs between the two cases. The total cost of the CMs in Case D, shown as load payment to CM in Table 22 is 859 BN€'13 while by assumption it is zero in the Case B since no CMs are in place. The Case D reduces total payments by load to wholesale and reserve markets by 315 BN€'13, compared to the Case B. This is due to the reliability options in the Case D. Moreover, as Case D has higher levels of capacity, the costs of renting peak devices by the TSOs to avoid load cuts are reduced by 18 BN€'13.. The reliability options imply lower SMPs on average in the Case D compared to Case B (Table 23). Ultimately, the net cost of Case D above the costs of Case B amounts to 547 BN€'13 in the period 2021-2030.

II - 4.4.4 Impacts from implementing CMs only to four MS (Case C)

This Case illustrates the impacts of establishing CMs asymmetrically across the Member-States. The assumption is that the stylised CMs (centralised capacity auctions and reliability options) apply only in United Kingdom, Ireland, France and Italy. It is logical that they choice of the Member-States which implement a CM is important for the results and the comparisons of costs. Due to time limitations, we have not examined other combinations of Member-States.

Table 28: Illustration of the results of Cases B, C and F per group of the MS

	EOM with scarcity bids (Case B)	CM in 4 MS w/o X-B (Case C)	CM in 4 MS with X-B (Case F)
Load Payments in 2030 (billion €'13)			
MS with CMs	133	140	137
MS directly interconnected to ones with CM	129	126	127
Rest of the MS	88	85	86
Load Payments for energy and reserves (billion €'13)			
MS with CMs	133	129	127
MS directly interconnected to ones with CM	129	126	127
Rest of the MS	88	85	86
Load Payments to capacity mechanisms (billion €'13)			
MS with CMs	0	11	10
MS directly interconnected to ones with CM	0	0	0
Rest of the MS	0	0	0
Average SMP (€'13/MWh)			
MS with CMs	104	100	98
MS directly interconnected to ones with CM	103	100	100
Rest of the MS	103	100	100
Deviations from EUCO27 in 2030 (reduction, in GW)			
MS with CMs	8	3	4
MS directly interconnected to ones with CM	22	23	23
Rest of the MS	6	7	6
Deviations from EUCO27 in 2050 (reduction, in GW)			
MS with CMs	9	6	7
MS directly interconnected to ones with CM	18	19	19

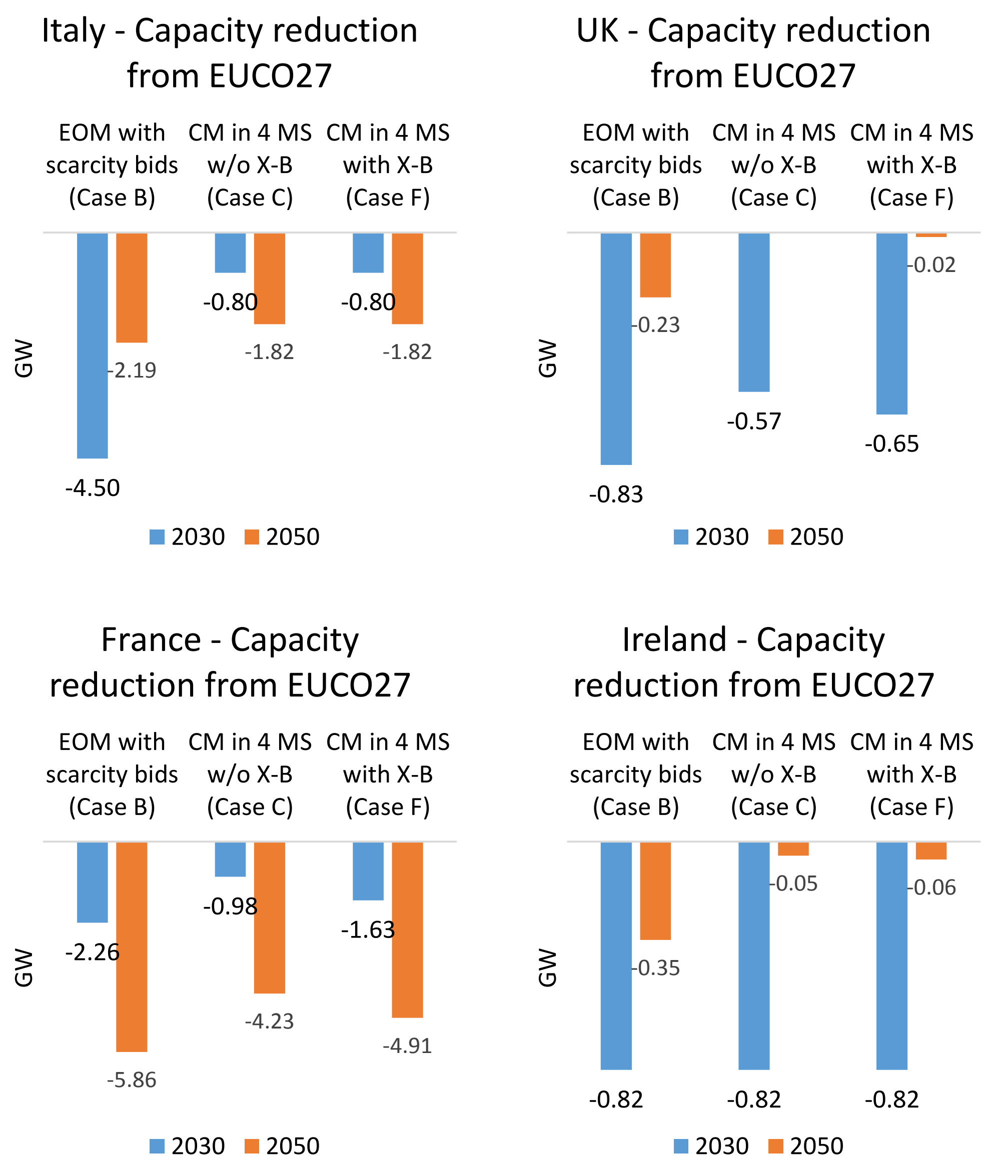
	EOM with scarcity bids (Case B)	CM in 4 MS w/o X-B (Case C)	CM in 4 MS with X-B (Case F)
Rest of the MS	7	7	7

Source: PRIMES-OM model

It is natural that the countries implementing a CM succeed to maintain higher volumes of capacities compared to the EOM (Case B), while other countries, in particular, those that are well interconnected to the countries with a CM, can benefit regarding capacity adequacy from capacity being available cross-border, without bearing the costs of a CM. This is known in the literature as a "free-riding" effect.

Indeed, the results of the simulation show that Italy, France, the UK and Ireland maintain higher levels of capacity compared to the EOM case (comparison of CM in 4 MS w/o X-B case and the EOM with scarcity bids case as shown in Table 28, while in other countries the capacities reduce compared to the EOM. The total capacity at the EU level is in the Case C quite close to the EOM Case B (Figure 13b).

Figure 15: Capacity reductions from the EUCO27 projections due to cancelling of investments or early retirement in four countries with MS in the Case C (w/o X-B), and the Case F (with X-B) and comparisons with the Case B



Source: PRIMES-OM model

Per plant type, the Case C seems to facilitate maintaining the peak plants compared to the Case B (Figure 13 and Figure 14). It is logical that the asymmetric implementation of CMs favours peak plants in the countries with a CM. The CMs favour the economics of peak plants while the CMs, in particular in France, Italy and the UK (Figure 15), while hardly affecting the base-load plants. Ireland mainly increases its mid-load capacity (CCGT) due to the CM.

The total volume of trade flows across the countries increase in the Case C compared to the Case B, and the effects by country also differ, as the countries with a CM increase exports, whereas the rest of the countries increase imports. This change manifests a free-riding effect.

The results show that the Case C entails higher total payments for the load than the EOM Case (Table 22). The difference amounts to 120 BN€'13 in the period 2021-2050. The additional costs are asymmetrically distributed across the MS due to the free-riding effect. As it can be seen from Table 28 for 2030, the total load payments are higher in the Case C, compared to the Case B, mainly in the MS that implement the CM, and are slightly lower in the rest of the countries. This result also shows the effects of the free-riding. The payments by the load in the wholesale and reserve markets alone decrease in all countries in the Case C, compared to the Case B, in all countries, but more in the countries that implement CMs. This is logical as the CM remuneration is assumed to be accompanied by a reliability option that has a strike price and thus limits the revenues obtained from the whole-sale markets.

When comparing the Case C to the Case of harmonised CMs in all MS (Case D), the costs are overall lower, by approximately 425 BN €'13 for the period 2021-2050. It is intuitive that payments by the load for the CMs are lower in Case C than in the Case D, as the former case applies the CMs only partially. Because of the implementation of fewer CMs in the Case C compared to the Case D the reliability options are also more limited in the former Case. Consequently the marginal prices in the wholesale markets are higher in the Case C compared to the Case D and the load payments in the wholesale markets are also higher (Table 22 and Table 23).

II - 4.4.5 Impacts of cross-border participation in CMs (Cases E and F)

The Cases E and F explore the impact of explicit cross-border participation in the CMs, in 4 MS (Case F) or in all the MS (Case E). The differential impacts result from comparisons of the Cases F and E to the Cases C and D, respectively, which do not include explicit cross-border participation in the CMs.

The explicit cross-border participation in the CMs increases the number of plants that compete with each other in the national CM auctions. As the CM demand curves are negatively sloped, the increase in the supply of capacities implies lower auction clearing prices[75] compared to the cases without explicit cross-border participation.

Consequently, the average revenue of a generator from the CM auctions slightly decrease when foreign participation is possible. Therefore, the likelihood of insufficient revenues to maintain the plant in operation is higher when cross-border participation is allowed, and therefore larger volumes of capacities reduce in the Cases with cross-border participation compared to the Cases without.

The simulations confirm this effect showing larger capacity reduction when cross-border participation is allowed (Figure 13b, comparison of Cases E to D and F to C). The differences are however small. The changes are most pronounced for base-load capacity (mainly applying to coal and lignite capacity), whereas the changes for the mid-load CCGT plants and the peak plants are negligible.

The increase in competition due to explicit cross-border participation naturally implies lower total payments in the CM markets compared to the cases without cross-border participation. In particular, in the Cases with CMs in all the MS, the payments to CM markets without cross-border participation (Case D) amount to 859 BN€'13, cumulatively in the period 2021-2050 (Table 22), The same amount decreases to 755 BN€'13 in the case with cross-border participation (Case E). This represents a reduction of 12%. In the cases of implementing the CMs in four MS, the total cost of the CMs in the

[75] Note however that as it is assumed that a plant's capacity cannot be offered twice to capacity mechanism auctions, the offer abroad decreases capacity offered domestically (if CM is applied also domestically, as the case of harmonised CMs), which implies that in case of shortage the auction clearing prices will tend to increase domestically. Overall though, auction clearing prices appear to be lower.

case without cross-border participation (Case C) is 310 BN€'13 whereas in the case with cross-border participation (Case F) it is 264 BN€'13 (Table 22), which represents a reduction of 6%.

The intense competition has implications also in the wholesale markets. The generators perceive higher threats from competition in the cases with explicit cross-border participation. The harmonised CMs, the reliability options applying to domestic and to foreign plants, as well as the strong coordination of the TSOs to manage the cross-border participation, are all factors which explain intensification of competition also in the wholesale markets. In addition, the increased competitive pressure naturally implies change in the behaviours leading investors and plant owners to accept lower hurdle rates, than in the cases without cross-border participation.

Therefore, in the cases with cross-border participation we expect slightly lower bids in the wholesale and reserve markets, lower system marginal prices and lower revenues for generators than in the cases without cross-border participation. In fact, in the cases with harmonised CMs in all the MS, total load payments in the wholesale and reserve markets amount to 12217 BN€'13 in the case without cross-border participation (Case D) (cumulatively in the period 2021-2050 as shown in Table 22) which is 1% higher than the load payments of 12112 BN€'13 in the case with cross-border participation (Case E). In the cases of CMs in four MS, the load payments to wholesale and reserve markets is 12341 BN€'13 in the case without cross-border participation (Case B) and 12285 BN€'13 in the case with cross-border participation (Case F), that is a 0.5% difference.

We may summarize that cross-border participation reduces the cost of CMs by 6-12%, as well as the load payments to wholesale and reserve markets by 0.5-1%. The overall payments by the load, adding the CMs and the wholesale markets, decrease by 1-2% due to the cross-border participation.

The results of the simulations show that the differences regarding total volumes of trade[76] between the cases with and the cases without cross-border participation in the CMs are very small. It should be reminded that implicit participation of flows is taken into account in all cases, with and without cross-border participation in the CMs, in the definition of the CM demand curves (see discussion in section II - 4.1).

II - 4.4.6 Additional sensitivity analysis for asymmetric CMs (France and Germany)

The PRIMES-OM model has also assessed two additional cases of asymmetric implementation of a CM. In the first case the CM applies only in France (Case CMFR), and in the second case the CM applies only in Germany (Case CMGE). In both cases we assume the stylised CM design, as also in the other cases assessed.

The implementation of capacity mechanisms unilaterally in one country provides incentives for investing in the particular country and not in other countries. Consequently, the unilateral CM deviates investment towards the country with a CM to the detriment of countries without a CM. However, the countries without a CM can still benefit regarding capacity adequacy provided that they are well connected to the country with a CM. But the capacity adequacy benefit is free of charge in the countries without a CM as they do not participate in the capacity remuneration which takes place only in the country with a CM and is borne only by the consumers in this latter country. Hence, a

[76] Volumes of trade is measured as the sum of absolute values of both export and import flows over all time segments and interconnections.

free-riding effect occurs, and a significant distortion is introduced[77]. The purpose of the sensitivity cases is to confirm this free-riding effect empirically.

II - 4.4.6.1 Capacity remuneration only in France

In the Case CMFR, which assumes a CM only in France, the increased incentives to invest in France due to the CM implies that significantly larger capacity is maintained in operation compared to the EOM case. This is depicted in Table 30 as lower capacity reductions in the CMFR case than in the Case B relative to the capacities projected in the EUCO27.

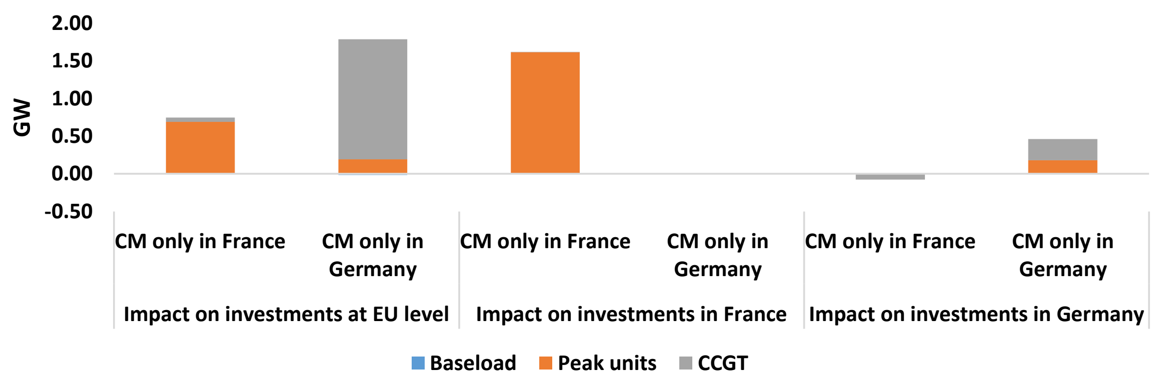
Table 29: Total imports of all Member States in TWh for 2030 for unilateral CMs in Germany and France

	Total imports in TWh
EOM with scarcity bids (Case B)	242.1
CM only in France	253.9
CM only in Germany	240.6

Source: PRIMES-OM model

The capacity reductions are larger in the CMFR compared to the Case B in the neighbouring, interconnected countries, especially in the long term (2050). This is a demonstration of the free-riding effect. The increase in investments in France mainly includes peak load plants (Figure 16) and only few CCGTs, while the two cases do not differ regarding the baseload plants. The decrease in capacities, in the CMFR compared to the Case B, in the rest of the EU regards mainly peak load plants. The peak load plants in the country with a CM provides the free riding benefit to countries without a CM.

Figure 16: Impacts on investments from the implementation of unilateral CMs in the EU (comparison to the EOM case)



The cross-border trade flow adjust accordingly. The exports of France increase (Table 29) and these exporting flows of France are mainly peak load flows for balancing and reserve purposes. The changes in cross-border trade has an impact on prices not only in France but in other countries as well. The effect of the asymmetric CM is towards reducing the SMP differential (price separation) between neighbouring countries with a market coupling (Table 30).

The unilateral application of a CM in France affects mainly adjacent regions, namely the Iberian, Central and Central-South regions of Europe. In Table 30 for 2030 we show that the total load payments

[77] Supported also in the literature (Cepeda and Finon 2011; Meulman and Méray 2012; Tennbakk and Capros 2013).

in neighbouring countries reduce by 3 BN €'13, which is the same amount by which the load payments increase in France.

Table 30: Distribution across MS of the simulation results for Case B and the case of CM only in France

	EOM with scarcity bids (Case B)	CM only in France
Load Payments in 2030 (billion €'13)		
France	54	57
Germany	62	61
MS directly interconnected to ones with CM	178	175
Rest of the MS	119	119
Load Payments for energy and reserves (billion €'13)		
France	54	53
Germany	62	61
MS directly interconnected to ones with CM	178	175
Rest of the MS	119	119
Load Payments to capacity mechanisms (billion €'13)		
France	0.00	3.81
Germany	0.00	0.00
MS directly interconnected to ones with CM	0.00	0.00
Rest of the MS	0.00	0.00
Average SMP (€'13/MWh)		
France	102	102
Germany	104	103
MS directly interconnected to ones with CM	103	102
Rest of the MS	103	103
Deviations from EUCO27 in 2030 (reduction, in GW)		
France	2	1
Germany	16	16
MS directly interconnected to ones with CM	24	24
Rest of the MS	10	10
Deviations from EUCO27 in 2050 (reduction, in GW)		
France	6	4
Germany	13	13
MS directly interconnected to ones with CM	16	17
Rest of the MS	11	11

Source: PRIMES-OM model

II - 4.4.6.2 Capacity remuneration only in Germany

Similarly to the previous case, the implementation of a CM only in Germany, implies higher capacities (remaining after the reductions from the capacities of the EUCO27) in Germany and lower capacities in neighbouring countries, including France (mainly observed for 2030 as seen in Table 31), compared to the case without the CM in Germany. The CM in Germany favours mainly CCGT and at a less extent peak load plants, in contrast with the case of a CM only in France which favours mainly peak load plants (Figure 16).

The difference between the two is due to the differences in the generation mix of the two countries, notably the dominance of nuclear energy in France. The CM do not affect baseload plants compared to the case without a CM. The increased capacity of CCGT in Germany, to the unilateral CM, implies a significant reduction of CCGT capacity in the rest of the EU, according to the model results.

The trade flows change in the unilateral German CM, compared to the case without the CM. The model results show a decrease in energy imports of Germany, both for mid-load and baseload energy, and a decrease in the total volume of trade flows. This can be seen in Table 29.

Table 31: Distribution across MS of the simulation results for Case B and the case of CM only in Germany

	EOM with scarcity bids (Case B)	CM only in Germany
Load Payments in 2030 (billion €'13)		
France	54	53
Germany	62	63
MS directly interconnected to ones with CM	169	166
Rest of the MS	120	119
Load Payments for energy and reserves (billion €'13)		
France	54	53
Germany	62	61
MS directly interconnected to ones with CM	169	166
Rest of the MS	120	119
Load Payments to capacity mechanisms (billion €'13)		
France	0.00	0.00
Germany	0.00	2.11
MS directly interconnected to ones with CM	0.00	0.00
Rest of the MS	0.00	0.00
Average SMP (€'13/MWh)		
France	102	101
Germany	104	102
MS directly interconnected to ones with CM	103	102
Rest of the MS	103	102
Deviations from EUCO27 in 2030 (reduction, in GW)		
France	2	3
Germany	16	10
MS directly interconnected to ones with CM	10	11
Rest of the MS	11	11
Deviations from EUCO27 in 2050 (reduction, in GW)		
France	6	6
Germany	13	13
MS directly interconnected to ones with CM	14	15
Rest of the MS	6	6

Source: PRIMES-OM model

The changes in the overall trade flows compared to the changes of trade of Germany indicate that the rest of the Member States exploit the electricity not imported by Germany domestically and because of the ensuing improvement of reserve they need less capacities of CCGTs for covering flexibility and reserves.

Unlike the case of France, where a unilateral CM has an impact on a limited number of regions, the unilateral CM in Germany has impacts on imports and exports of a large number of Member States. This is depicted seeing total load payments in Table 31, where with a 1 BN €'13 increase in the cost of Germany, neighbouring countries benefit by 3 BN €'13 and the rest of the MS by another billion. The strong and diversified interconnections of Germany with the rest of the EU countries can explain this result (see also Table 41 in Appendix G).

II - 5 Caveats and limitations of the analysis

The comparisons of costs between the EOM and the CM cases are highly uncertain, as the results heavily depend on at least two assumptions of major importance. Firstly, the level of scarcity the more aggressive, the more expensive the EOM case becomes. Secondly, the level of the strike price of the reliability options that plants sign when participating in the CM auctions. Inevitably, part of the costs of the capacity mechanisms is unnecessary: it is possible that some of the capacities that receive remuneration in the simulation may not be justified from a cost minimisation perspective.

The PRIMES-OM model assumes that generators bid strategically at the wholesale markets applying scarcity pricing (above variable costs for some plants), as this is considered to mimic real market pricing. The level of scarcity pricing is an assumption which affects the differences in costs between the Cases with CM and the Case of the EOM. The more aggressive the bidding behaviour of generators, the higher the level of payments they receive from the wholesale markets, and hence the less the capacity remuneration required for recouping total costs. But the bidding behaviour mainly depends on the degree of concentration of the underlying market. The modelling has no means of projecting market concentration endogenously, and has no knowledge about the causality between the market design options considered in this study and the degree of concentration. The modelling has assumed bidding above marginal costs only as a result of capacity scarcity over few periods of time, annually. Naturally, other bidding assumptions would lead to different estimations about the role of the CMs in securing cost recovering.

In the cases which include CMs, the plants sign reliability options which involve a strike price, making generators to forsake part of the revenues from the wholesale market that could otherwise obtain. However, the bidding in the CM auctions and the determination of the strike prices are connected to each other. The modelling quantified this connection empirically and not fully endogenously. Logically, other assumptions regarding the strike prices would imply different revenues from the wholesale markets and would affect the estimation of total costs.

In all implementations of CMs in the model, the demand curves for the CM auctions include part of the flows through interconnectors as implicit participation of cross border flows. As a result, importing countries reduce demand for capacities and exporting countries increase demand. The volume of imports/exports taken as implicit cross-border participation is an assumption, not a model result. We refer to a part of imports that can be viewed as “trusted” in terms of generation adequacy, while a part of exports can be viewed as “guaranteed” as if bilateral contracts were in place. The quantification of this assumption plays an important role for the determination of the auction clearing prices and the estimation of costs.

Probably, the most uncertain assumptions concern the behaviour of plant owners and investors regarding the decision of maintaining or not the plant in operation and the decision of investing in a new plant or a refurbishment of an old plant. Two assumptions are crucial in this modelling, namely the hurdle rates and the probability of a positive decision about the plant as a function of the degree of cost recouping. We have assumed that the CMs imply higher certainty than wholesale markets for the revenues and we have considered that competition implies a reduction of acceptable hurdle rates. These causalities make sense but their quantification is highly uncertain. In addition, we have ignored all other factors which influence the risks and the hurdle rates, for example country or technology risks. It is logical that in reality there is a non-zero probability of maintaining a positive decision about a plant when the cost recovery is not complete. However, the assumption about a threshold regarding the degree of cost recovery is highly uncertain. The results regarding reduction of capacities relative to the EUCO27 projection are highly depending on these behavioural assumptions.

Finally, it is worth emphasising that we have not performed a full closed-loop simulation because of time limitations, also because of the complexity. We have not rerun the entire PRIMES model after having estimated the capacity reductions using the PRIMES-OM model, due to the uncertainties and the market design options. We have only run again the PRIMES-OM model at the end of the loop, not the entire PRIMES, which could show the entire impacts on the EU ETS prices, the demand behaviour if consumers, the revision of the capacity expansion projection, etc.

II - 6 Concluding remarks

The EUCO27 projection involve a significant transformation of the electricity system towards low emissions of carbon dioxide. The generation mix will have unprecedentedly high share of variable RES, a merit order strongly influenced by the increasing EU ETS carbon prices and very significant requirements of flexibility, balancing and backup reserves. The transformation and the emerging new system requirements add uncertainty to the decisions of generators. The imminent decisions that are surrounded by high uncertainty concern the destiny of old solid fuels plants, the spending in maintenance and refurbishment for aged plants, the building of new flexible gas-firing plants and the nuclear investments which are capital intensive and carbon-free. The standard PRIMES model projection applies for the EUCO27 scenario a view that the decisions are taken in a perfect market and without uncertainty, thus they address the capacity expansion transformation optimally. At present, the electricity markets experience low prices due to over-capacity and the penetration of RES. This context adds to the uncertainties. Naturally, capacity mechanisms (CM) emerged in the policy agendas in several countries, as a means of mitigating the uncertainties regarding the revenues of the plants. But, as an out-of-the-market intervention a capacity mechanism can cause market distortions and bring inefficiencies. Also, a capacity mechanism is a national measure and thus serious adverse effects on the EU market integration could arise from implementation of CMs in a non-coordinated fashion. At the same time, a strong policy effort is under way to truly integrate the EU market as a fully coupled system of wholesale markets, in all stages of Day-Ahead, intraday, balancing and reserve. A completely integrated EU market can in theory provide generators with considerable opportunities of cost recovery, and a cost-efficient sharing of resources. Liquidity, competition and unobstructed trade over the interconnections are conditions for the market completion.

Therefore, the policy question whether the CMs are necessary or whether the completely integrated energy-only market (EOM) suffices is inevitably posed. It is a hard question because the answer heavily depends on assumptions about the behaviours of the market participants, and as always in economics, there is no way of validating such assumptions. As explained in the previous sections, we clearly state that the present study does not provide an answer to the question regarding CMs or EOM. The study provides quantitative simulations of various cases with CMs or EOM and their impacts on the generation capacities, but the results have no forecasting validity and cannot support any conclusion about the comparison of a CM with an EOM. Nonetheless, the study provides more robust results regarding certain aspects, as for example the coordination of the CMs across the EU if adopted, the importance of including explicit cross-border participation in the CMs if adopted, and the critical importance of completing a fully integrated EU market for the ability of the EOM to secure revenue sufficiency.

The power generation industry is capital intensive and anticipation is of crucial importance given that the investments have a long lifetime. Logically, the investors on the power sector are particularly risk-averse. The uncertainties raise the hurdle rates for deciding positively about new plant investment and for maintaining old plants in operation. The PRIMES model projection shows that the current overcapacity is likely to vanish before 2025 and that a large fleet of old coal/lignite plants will become less and less competitive in a market characterised by rising carbon prices. The modelling of uncertainties, performed in the present study, indicated that in all market cases the risk-aversion is likely to lead plant owners to retire prematurely a large number of old coal/lignite plants in several countries before 2030. The modelling reaches a similar result for the old open-cycle gas and oil plants, but in contrast the results show the CCGTs are able to recover their total costs under several market conditions considered in the study, whereas the nuclear plants recover their costs very comfortably. Concerns may rise for the economics of pure peak devices, which strongly depend on the pricing of peak load in the markets. The analysis shows, however, that the economics of peak devices can be accommodated through the adequate functioning of the market for ancillary services and the remuneration of replacement reserves.

The modelling of uncertainties surrounding investment and plant-related decisions deliberately assumes strong risk aversion, and thus it applies the financial evaluation individually for each plant. In contrast, the standard PRIMES model has considered financial appropriateness at the level of the portfolio of plants taken as a whole. The individual financial evaluation is detrimental for old and new solid fuel plants and the open cycle gas/oil plants. Although, the profits of other plant types can compensate these losses on a portfolio basis, the current business practices indicate that the expectation of losses on an individual plant basis is a sufficient condition for mothballing an old plant or cancelling a candidate investment.

The modelling assumes that the CMs do provide some certainty to plant owners about revenues but at the same time the CMs limit the degree of scarcity bidding in the Day-Ahead markets as part of the reliability options included in the CM auctions. The study developed and applied a sophisticated tool to simulate stylised CM auctions regarding the volume of participation and the auction clearing prices, with or without cross-border participation.

The simulations showed clearly that although the CMs mitigate uncertainties they are not able to invert the negative financial evaluation of the solid-fuels and the open cycle oil and gas plants. The assessment of total costs indicate that in all examined cases the EOM design entails lower total costs than any of the CMs studied for the same level of system reliability. However, as mentioned above, this cost comparison is uncertain and cannot be validated. But the study clearly shows that the CMs do sacrifice money to remunerate plants which are inherited from past and are not competitive in the new market conditions to the horizon of 2030. We have assumed non-discrimination between technologies or other plant features for the CMs and we have not evaluated CMs with particular focus, which would discriminate for some reason (e.g. remunerate only new plants, or plants with sufficient flexibility).

The results of the simulations show that the implementation of CMs despite the fact that they change the level and mix of investments compared to the EOM have a small and inconclusive impact on electricity trade. This is because full market integration is assumed in all cases examined, both CM and EOM, thus utilisation of interconnectors is very efficient in all cases.

If the CMs are implemented in a non-uniform manner, i.e. only in some countries, the study clearly finds a distortion of optimal distribution of investment among the countries. The countries where CMs are implemented attract more investments compared to the EOM, while neighbouring countries can “free-ride” on capacity being available cross-border, without bearing the costs of a CM. Therefore, the asymmetry introduced in investments distorts trade and the allocation of costs.

Focusing on explicit considerations on the CM design, and in particular in opening capacity mechanisms to cross-border participation, the analysis attempted to quantify that increased participation of capacities in a capacity mechanism enhances competition, thus resulting in lower auction clearing prices. The estimation of total system costs under increased participation assumptions is a measurement of the likely economic value to the consumers that participation would provide compared to non-participation.

Indirect participation from imports in a national CM takes place through the consideration of imports in the definition of demand functions that the regulators approve for the CM auctions. The consideration of imports shifts the demand curve of the CM and lowers auction clearing prices. The consideration of exports in the demand curve of the CM would conversely increase prices. The study provides an illustration of typical demand curves for CM auctions and illustrates the impacts of implicit cross-border participation in the CMs.

The main aim of the study was to assess explicit cross border participation of power plants in the CM auctions and get a pan European view on this matter. The participation cross-border is endogenous in the model resulting from the estimation of deliverability of the capacity availability service at system’s stress times through the interconnections and the estimation of profitability depending on the allocation of the plants in various CM markets. A complete pan-EU implementation of an explicit cross-border participation in the CMs requires strong coordination of the TSOs and perfect harmonisation of the regulations. The study assumes that this context would increase the intensity of competition both in the CM auctions and in the wholesale markets. A clear benefit regarding costs stems from the intense competition due to cross-border participation.

The results of the modelling clearly support that the cross-border participation of power plants in the CMs enables for better price signals as to where capacity should be built and therefore results in reduced overall system costs. On the other hand, when cross-border participation is not implemented, an increased amount of capacity is necessary in order for a certain level of security of electricity supply to be achieved, which results in increased total system costs.

The study concludes that CMs with foreign participation are less costly than those without. Moreover, due to the better allocation of resources in CM auctions, less capacity is maintained. The payments to capacity payments have been found to reduce by 6-12%, while the impact on total load payments is a decrease of 1 to 2%. Also, the simulation results indicate that energy trade does not change significantly when CMs allow foreign participation compared to the CMs without cross-border participation.

Appendix A. THE MODELLING APPROACH OF THE STANDARD PRIMES MODEL FOR DERIVING THE EUCO27 SCENARIO

The quantification of the EUCO27 scenario has been conducted using the standard PRIMES model[78].

The model simultaneously solves optimal power flows over the European grid, least-cost unit commitment and optimal capacity expansion assuming prefect foresight up to 2050. Investment is endogenous and is thus derived from inter-temporal optimization.

Flow-based optimization across interconnections is simulated by considering a system with a single bus by country and all current and future AC and DC interconnections. The flows are restricted by the first and second Kirchhoff laws and by administratively defined Net Transfer Capacity (NTC) limitations applying to pairs of adjacent countries. The NTC values are assumed to change over time depending on grid enhancements and on the degree of coordination of system operation. The EUCO27 scenario assumes abolishment of the NTCs and a pure flow-based allocation after 2020.

The EUCO policy framework

The EUCO27 is a decarbonisation scenario which is designed to meet the following policy targets at EU level:

- 40% GHG emission reduction in 2030 (from 1990)
- 43% CO2 emission reduction in ETS in 2030 (from 2005)
- 30% GHG emission reduction in non-ETS (from 2005)
- 27% RES-share in 2030
- 27% Energy Efficiency in 2030

The main policy instruments to achieve the targets is carbon emission pricing in the ETS sectors, following auctioning of emission allowances, and a series of sectorial policies: energy efficiency supports for houses, buildings, equipment and appliances; CO2 car standards and other policies in the transport sector, etc. Direct supports of RES in the power sector are assumed to phase out post 2020, except for yet immature RES technologies, such as wind offshore and others.

Investment in power generation distinguishes green-field from brown-field investment, and considers endogenously the possibility of refurbishment of old plants allowing extension of their lifetime. The model handles endogenously the contributions of power generation resources to system reserves. A power plant may well stay operational for reserve purposes only. Investment in power generation is also driven by demand for heat (district heating) or steam (industrial units supplying steam) by deploying cogeneration equipment.

The model represents direct recovery of generation and grid costs from consumer payments based on tariffs, which are endogenous. The prices (tariffs) by customer category (sectors of activity) are calculated so as to recover exactly all generation costs including return to capital, which is valued using a standard weighted average cost of capital (WACC), by considering the economics at the level of the entire fleet of plants taken as a whole. The model does not explicitly represents a market design which would render cost recovery effective. In other words, the model does not simulate any sort of wholesale market or any market for bilateral contracts but simply calculates directly what the revenues and payments are required to be to recover total costs, which are evaluated optimally in the context of a perfect long-term market.

[78] A detailed description of the PRIMES model is available in Capros P. et al., 2016.

The certainty implied by both the cost recovery and the perfect foresight implies that the choice of generation investment is optimal without any distortion of optimality due to uncertainty. The optimality is validated directly at a multi-country scale, to the extent the countries are linked to each other through the network.

The generation capacity expansion is influenced by the stock of generation resources that exist in the base year and the plants that are under construction. The long-term expansion heavily depends on policy-related restrictions for technologies or the support of technologies. For example, nuclear investment is not allowed in some countries and RES investment is supported directly. Although the generation capacity expansion is optimised in the model, the generation capacity mix is not optimal at all times due to the capacities inherited from past and the out-of-market policies. The mix tends to an optimal mix only in the long term. In other words, at a certain point in time, some resources in the capacity mix may be in excess, and some resources may be in scarcity. An individual plant being in excess cannot recover total costs (including fixed and capital costs) in a perfect market, although all costs are recovered collectively by the fleet of plants. Similarly, an individual plant being in scarcity may earn above total costs in a perfect market, although all costs are collectively recovered. Despite the different cost recovery degrees of the plants, investment is not influenced by the economics at the individual plant level, as it is implicitly assumed that collective recovery of all costs can allow cross-subsidisation among plants without any restriction.

The electricity prices by consumer category are derived as part of the production costing sub-model which applies a so-called Ramsey-Boiteux method. According to the Boiteux method the price of electricity to be sold to a certain category of customers, which share a common pattern of demand load profile, reflects the long term marginal cost of the system for serving the demand load profile of the customer category. In other words, this method applies a matching of load of profiles of generation units with load profiles of customer categories following an order from base load profile to mid-merit and peak load profiles of customers. The background justification of this pricing approach is that it represents a stable long-term pricing method having the merit of recovering capital costs of the plants while mimicking the conclusion of long-term bilateral contracts between groups of plants and groups of customers provided that they share a common load profile. The Ramsey method of pricing aims at distributing fixed and non-recouped costs (for example stranded costs or market power mark-ups if applicable) across the customer categories. The principle is to distribute the costs in an inverse proportion of the price elasticity of customers' demand. An example of applying the Ramsey method is the distribution of recovery of RES support costs.

Appendix B. PRIMES-IEM MODELS DETAILED DESCRIPTION

DAY-AHEAD MARKET SIMULATOR (DAM_SIMUL)

Known Parameters and Functions		**Unknown Variables**	
$d_{i,h}$	Inverse demand function	$Q_{i,h}$	Consumption of electricity
$b_{i,n,h}$	Price bidding function	$P_{i,h}$	System Marginal Price
$\overline{q}_{i,n,h}$	Power quantities in priority dispatch	$q_{i,n,h}$	Commitment schedule of power plants
$K_{i,n,h}$	Power plant capacities	$Up_{i,n,a,h}$	Supply of upward ancillary service
$M_{i,n,h}$	Technical minimum operation of a plant	$Dn_{i,n,a,h}$	Supply of downward ancillary service
$R_{i,n}$	Ramping capability of plant	$u_{i,n,h}$	Operating status of a plant (binary)
$Mup_{i,n,h}$	Minimum up time of a plant	$sd_{i,n,h}$	Shut down of a plant (binary)
$Mdn_{i,n,h}$	Minimum down time of a plant	$su_{i,n,h}$	Start-up of a plant (binary)
$fup_{i,n,a,h}$	Price bidding for upward ancillary services	$\sigma_{i,h}$	Inflows minus Outflows in a node of the network
$fdn_{i,n,a,h}$	Price bidding for downward ancillary services	$\theta_{i,h}$	Voltage phase angles at a node
$net_{i,k}$	Network topology matrix	$f_{k,h}$	Flows over interconnectors (positive or negative)
$\omega_{k,kk}$	Matrix of line admittances	Sets	
T_k	Capacity of interconnectors	$i\ or\ ii$	Nodes of the network (one or many per country)
$NTC_{i,ii}$	Net Transfer Capacity between two nodes	$h\ or\ hh$	Time intervals (hours) in a year
		n	Power plants
		a	Reserve types
		$k\ or\ kk$	Interconnectors

Constraints for Day Ahead Market Simulator (energy only market)	
$z_h = \sum_i \left(\int_0^{Q_{i,h}} d_{i,h}(y_{i,h})\, dy_{i,h} - P_{i,h} \sum_n b_{i,n,h}^{-1}(P_{i,h}) \right)$	Social Surplus to maximize
$P_{i,h} = d_{i,h}(Q_{i,h})$	Inverse Demand Function
$B_{i,n,h} = b_{i,n,h}(q_{i,n,h})$	Price bidding by plant as function of volume
$q_{i,n,h} \leq K_{i,n,h}$	Capacity constraints of power plants
$\sigma_{i,h} = \sum_i \theta_{i,h} net_{i,k} \sum_{kk} \omega_{k,kk} net_{kk,i}$	Inflows minus Outflows in a node of the network
$f_{k,h} = -\sum_i \theta_{i,h} \sum_{kk} \omega_{k,kk} net_{kk,i}$	Flows over interconnectors (positive or negative)
$\lvert f_{k,h} \rvert \leq T_k$	Physical capacity constraint for flows over interconnectors
$\left\lvert \sum_{k \subseteq net_{ii,k}} \sum_{k \subseteq net_{i,k}} f_{k,h} \right\rvert \leq NTC_{i,ii}$	Restriction of bilateral flows due to Net Transfer Capacity
$d_{i,h}^{-1}(P_{i,h}) - \sum_n \left(q_{i,n,h} + \overline{q}_{i,n,h} \right) = \sigma_{i,h}$	Balance of inflows and outflows in a node

Constraints for Unit Commitment Simulator (or Day Ahead Market with co-optimization of reserves)	
$z_h = \sum_i \left(\int_0^{Q_{i,h}} d_{i,h}(y_{i,h})\, dy_{i,h} - P_{i,h} \sum_n b_{i,n,h}^{-1}(P_{i,h}) - \sum_a Pup_{i,a,h} \sum_n fup_{i,n,a,h}^{-1}(Pup_{i,a,h}) - \sum_a Pdn_{i,a,h} \sum_n fdn_{i,n,a,h}^{-1}(Pdn_{i,a,h}) \right)$	Social Surplus to maximize
$P_{i,h} = d_{i,h}(Q_{i,h})$	Inverse Demand Function
$\sum_n Up_{i,n,a,h} \geq Dup_{i,a,h}$	Balance for upward ancillary services
$\sum_n Dn_{i,n,a,h} \geq Ddn_{i,a,h}$	Balance for downward ancillary services
$B_{i,n,h} = b_{i,n,h}(q_{i,n,h})$	Price bidding by plant as function of volume
$Bup_{i,n,a,h} = fup_{i,n,a,h}(Up_{i,n,a,h})$	Bidding for upward ancillary services
$Bdn_{i,n,a,h} = fdn_{i,n,a,h}(Dn_{i,n,a,h})$	Bidding for downward ancillary services
$q_{i,n,h} + \sum_a Up_{i,n,a,h} \leq u_{i,n,h} K_{i,n,h}$	Capacity constraints of power plants
$q_{i,n,h} + \sum_a Dn_{i,n,a,h} \geq u_{i,n,h} M_{i,n,h}$	Operation above technical minimum
$\lvert q_{i,n,h} - q_{i,n,h-1} \rvert \leq u_{i,n,h-1} R_{i,n} + su_{i,n,h} R_{i,n}$	Ramping constraints
$\sum_{hh \in [(h - Mdn_{i,n,h} - 1 \leq hh) \cap (hh \leq h)]} sd_{i,n,hh} \leq 1 - u_{i,n,h}$	Minimum down time constraint
$\sum_{hh \in [(h - Mup_{i,n,h} + 1 \leq hh) \cap (hh \leq h)]} su_{i,n,h} \leq u_{i,n,h}$	Minimum up time constraint
$u_{i,n,h} - u_{i,n,h-1} = su_{i,n,h} - sd_{i,n,h}$	Operation status constraint
$su_{i,n,h} + sd_{i,n,h} \leq 1$	Shut or start constraint
$\sigma_{i,h} = \sum_i \theta_{i,h} net_{i,k} \sum_{kk} \omega_{k,kk} net_{kk,i}$	Inflows minus Outflows in a node of the network
$f_{k,h} = -\sum_i \theta_{i,h} \sum_{kk} \omega_{k,kk} net_{kk,i}$	Flows over interconnectors (positive or negative)
$\lvert f_{k,h} \rvert \leq T_k$	Physical capacity constraint for flows over interconnectors
$\left\lvert \sum_{k \subseteq net_{ii,k}} \sum_{k \subseteq net_{i,k}} f_{k,h} \right\rvert \leq NTC_{i,ii}$	Restriction of bilateral flows due to Net Transfer Capacity
$d_{i,h}^{-1}(P_{i,h}) - \sum_n \left(q_{i,n,h} + \overline{q}_{i,n,h} \right) = \sigma_{i,h}$	Balance of inflows and outflows in a node

INTRADAY AND BALANCING MARKETS SIMULATOR (IDB_SIMUL)

Known Parameters and Functions		**Unknown Variables**	
$D^{up}_{i,h}$	Upward deviations	$q^{up}_{i,n,h}$	Upward balancing power output of power plants already opened
$D^{down}_{i,h}$	Downward deviations	$q^{down}_{i,n,h}$	Downward balancing power output of power plants
$b^{up}_{i,n,h}$	Price bidding function for upward offers	$q^{open}_{i,n,h}$	Upward balancing power output of power plants already opened
$b^{down}_{i,n,h}$	Price bidding function for downward offers	$pos_{i,n,h}$	Deviation from DAM variable (binary, 1 if plant committed in IDM and closed in DAM)
$\bar{g}^{dam}_{i,n,h}$	Commitment schedule of power plants from DAM	$neg_{i,n,h}$	Deviation from DAM variable (binary, 1 if plant committed in DAM and closed in IDM)
$\bar{g}^{uc}_{i,n,h}$	Commitment schedule of power plants from UC	$u^{id}_{i,n,h}$	Operating status of a plant (binary) taken into account DAM schedule
$\bar{u}_{i,n,h}$	Operating status of a plant (binary) from DAS and UC	$sd^{id}_{i,n,h}$	Shut down of a plant (binary)
$D^{dam}_{i,h}$	Demand from DAM	$su^{id}_{i,n,h}$	Start-up of a plant (binary)
$D^{uc}_{i,h}$	Demand from UC		
$\bar{f}^{dam}_{k,h}$	Flows over interconnectors from DAM		
$\bar{\sigma}^{dam}_{k,h}$	Inflows minus Outflows in a node of the network from DAM	Sets	
$C^{su}_{i,n,h}$	Bidding for starting up a power plant in IDM	$int(n)$	Intermittent RES power plants
$C^{su}_{i,n,h}$	Bidding for shutting down a power plant in IDM	$tn(n)$	Power plants that are cannot offer up or down deviation due to technical constraints or due to TSO instruction

Constraints for intraday Ahead Market Simulator	
$z_h = \sum_i \sum_{n \notin (int \cup tn)} \left(B^{up}_{i,n,h} q^{up}_{i,n,h} + B^{down}_{i,n,h} q^{down}_{i,n,h} + su^{id}_{i,n,h} C^{su}_{i,n,h} + sd^{id}_{i,n,h} C^{sd}_{i,n,h}\right)$	Cost of deviations to minimize
$D^{up}_{i,h} = \max(D^{uc}_{i,h} - \sigma^{uc}_{i,h} - D^{dam}_{i,h} + \sigma^{dam}_{i,h} + \sum_{n \in (int \cup tn)} \bar{g}^{dam}_{i,n,h} - \sum_{n \in (int \cup tn)} \bar{g}^{uc}_{i,n,h}, 0)$	Upward deviations
$D^{up}_{i,h} = \max(D^{dam}_{i,h} - \sigma^{dam}_{i,h} - D^{uc}_{i,h} + \sigma^{uc}_{i,h} + \sum_{n \in (int \cup tn)} \bar{g}^{uc}_{i,n,h} - \sum_{n \in (int \cup tn)} \bar{g}^{dam}_{i,n,h}, 0)$	Downward deviations
$B^{up}_{i,n,h} = b^{up}_{i,n,h}\left(q^{up}_{i,n,h}\right)$	Price bidding by plant as function of volume for upward offers
$B^{down}_{i,n,h} = b^{down}_{i,n,h}\left(q^{down}_{i,n,h}\right)$	Price bidding by plant as function of volume for upward offers

$\bar{g}_{i,n,h} + q^{up}_{i,n,h} \le K_{i,n,h}\,(1 - neg_{i,n,h})$	Capacity constraint for upwards offers of power plants
$q^{down}_{i,n,h} \le \bar{g}_{i,n,h}\,(1 - neg_{i,n,h})$	Capacity constraint for downwards offers of power plants
$q^{open}_{i,n,h} \le K_{i,n,h}\,pos_{i,n,h}$	Capacity constraint for upwards offers of power plants
$q^{open}_{i,n,h} \ge M_{i,n,h} pos_{i,n,h}$	Technical minimum constraint for upwards offers of power plants
$\left\lvert q^{up}_{i,n,h} - q^{up}_{i,n,h-1}\right\rvert \le R_{i,n}$	Ramping Constraint for upwards offers
$\left\lvert q^{open}_{i,n,h} - q^{open}_{i,n,h-1}\right\rvert \le pos_{i,n,h-1} R_{i,n} + su^{id}_{i,n,h} R_{i,n}$	Ramping Constraint for upwards offers
$\left\lvert q^{down}_{i,n,h} - q^{down}_{i,n,h-1}\right\rvert \le R_{i,n}$	Ramping Constraint for downwards offers
$u^{id}_{i,n,h} = \bar{u}_{i,n,h} + pos_{i,n,h} - neg_{i,n,h}$	Commitment Constraint
$pos_{i,n,h} - pos_{i,n,h-1} \le su^{id}_{i,n,h}$	Start-up constraint in IDM
$neg_{i,n,h} - neg_{i,n,h-1} \le sd^{id}_{i,n,h}$	Shut-down constraint in IDM
$su^{id}_{i,n,h} + sd^{id}_{i,n,h} \le 1$	Shut or start constraint for IDM
$pos_{i,n,h} + neg_{i,n,h} \le 1$	Shut or start deviation constraint
$\sum_{hh \in \left[(h - Mdn_{i,n,h} - 1 \le hh) \cap (hh \le h)\right]} neg_{i,n,hh} \le 1$	Minimum down time constraint
$\sum_{hh \in \left[(h - Mup_{i,n,h} + 1 \le hh) \cap (hh \le h)\right]} pos_{i,n,h} \le 1$	Minimum up time constraint
$\sigma_{i,h} + \bar{\sigma}^{dam}_{k,h} = \sum_{i} \theta_{i,h} net_{i,k} \sum_{kk} \omega_{k,kk} net_{kk,i}$	Inflows minus Outflows in a node of the network
$f_{k,h} + \bar{f}^{dam}_{k,h} = -\sum_{i} \theta_{i,h} \sum_{kk} \omega_{k,kk} net_{kk,i}$	Flows over interconnectors (positive or negative)
$\left\lvert f_{k,h} + \bar{f}^{dam}_{k,h}\right\rvert \le T_k$	Physical capacity constraint for flows over interconnectors
$\left\lvert \sum_{k \subseteq net_{ii,k}} \sum_{k \subseteq net_{i,k}} f_{k,h} + \bar{f}^{dam}_{k,h} \right\rvert \le NTC_{i,ii}$	Restriction of bilateral flows due to Net Transfer Capacity
$D^{up}_{i,h} - D^{down}_{i,h} - \sum_{n \notin (int \cup tn)} \left(q^{up}_{i,n,h} + q^{open}_{i,n,h} - q^{down}_{i,n,h}\right) = \sigma_{i,h}$	Balance of inflows and outflows in a node

RESERVE AND ANCILLARY SERVICES MARKET SIMULATOR (RAS_SIMUL)

Known Parameters and Functions		Unknown Variables	
$\bar{g}_{i,n,h}^{id}$	Commitment schedule of power plants after IDM	$c_{i,h}$	Contribution of flows to reserve and ancillary service market
$c_{i,h}^{up}$	Upper limit of contribution of flows to RAS		
$\bar{f}_{k,h}^{id}$	Flows over interconnectors from DAM and IDM		
$\bar{\sigma}_{k,h}^{id}$	Inflows minus Outflows in a node of the network from DAM and ID		

Constraints for Reserve and Ancillary Services Simulator

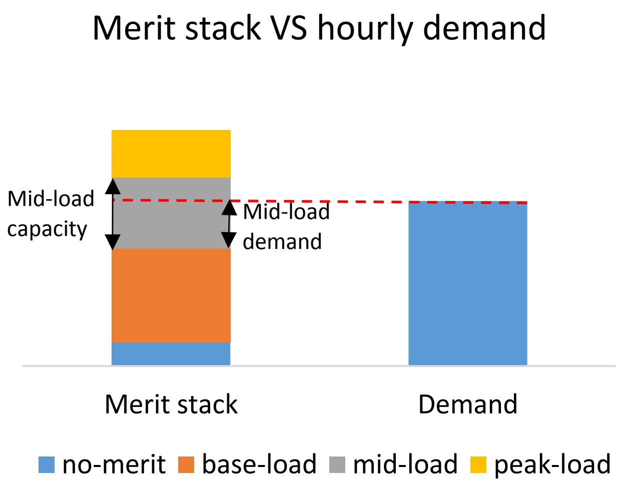
$z_h = \sum_i \sum_a \sum_n \left(Bup_{i,n,a,h} Up_{i,n,a,h} + Bdn_{i,n,a,h} Dn_{i,n,a,h} \right)$	Cost of ancillary services to minimize
$Bup_{i,n,a,h} = fup_{i,n,a,h}\left(Up_{i,n,a,h}\right)$	Bidding for upward ancillary services
$Bdn_{i,n,a,h} = fdn_{i,n,a,h}\left(Dn_{i,n,a,h}\right)$	Bidding for downward ancillary services
$\bar{g}_{i,n,h}^{id} + \sum_a Up_{i,n,a,h} \leq u_{i,n,h}^{id} K_{i,n,h}$	Upper bound of contribution to upward ancillary service constraint for power plants
$\bar{g}_{i,n,h}^{id} + \sum_a Dn_{i,n,a,h} \geq u_{i,n,h}^{id} M_{i,n,h}$	Upper bound of contribution to downward ancillary service constraint for power plants
$c_{i,h} \leq c_{i,h}^{up}$	Upper bound of contribution to upward ancillary service constraint for x-border flows
$\sum_n Up_{i,n,a,h} \geq Dup_{i,a,h} + c_{i,h}\, \bar{\sigma}_{k,h}^{id}$	Balance for upward ancillary services
$\sum_n Dn_{i,n,a,h} \geq Ddn_{i,a,h}$	Balance for downward ancillary services

Appendix C. SIMULATION OF THE BIDDING BEHAVIOUR OF GENERATORS IN PRIMES-IEM AND PRIMES-OM

In the analysis with PRIMES-IEM and PRIMES-OM, we employ a scarcity bidding function as a means to mimic the strategic behaviour of market players in oligopolistic market conditions. Such conditions are found to be representative of current EU markets (Willems et al. 2009). Moreover, literature supports that scarcity pricing facilitates long-term resource adequacy (Hogan 2005; Hogan 2006; Hogan 2013), by providing more accurate price signals to investment. It is thus appropriate to consider scarcity bidding of generators in the context of this analysis.

The bidding function employed is specific to each individual plant and it takes into account hourly demand, plant technology and plant fixed costs in order to evaluate the hourly bid price of each generator.

Figure 17: Determining the merit-order type expected to be on the margin



To model the bidding behaviour of plants we consider their place in the merit order using the variable costs. Non-dispatchable generators are considered as must-take, and therefore are assumed to bid at zero price. We determine scarcity per horizontal zone of the merit order, namely for base load, md merit and peak load.

Using the plants ranked in a merit stack we determine the marginal price per zone, based on variable costs and the steps of the marginal cost curve per zone which is out of the order. In this sense, the marginal plant in a zone of the merit order knows the upper possible bidding margin based on the variable cost of the next more expensive plant, which is out of the merit order in the same zone. The marginal plant has then an opportunity to bid by applying a mark-up on marginal costs up to the level of the bid of the competitor. Obviously, this approach is an empirical implementation of the concept of supply-function equilibrium. We do not apply this approach in a fully rigorous manner because of the complexity to implement it for a large-scale model.

The next step is to determine the level of mark-up applied to the marginal costs of the plant, and in particular those that are likely to be price-makers in the three zones of the merit order. The mark-up depends on an overcapacity ratio per zone of the merit order, meant as a metric of scarcity. The overcapacity ratio is the division of the available capacity over the power of demand per zone of the merit order, as it can be depicted in Figure 17. The mark-up uses the following equation:

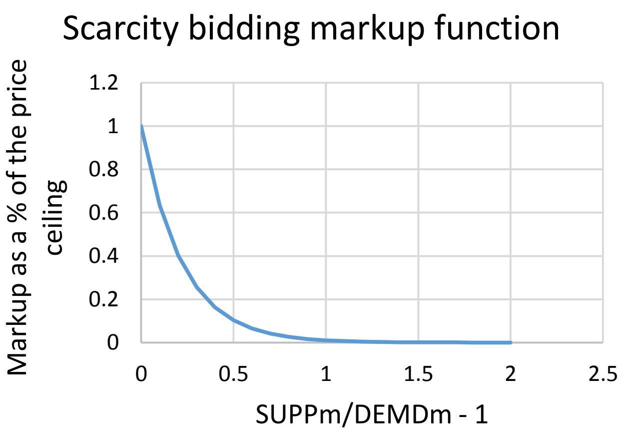
$$SB_p = MC_p + CEIL_m * \mathrm{e}^{-\mathbf{RATE}_p \cdot \left[\frac{\mathbf{SUPP}_m}{\mathbf{DEMD}_m} - 1\right]}$$

Where,

p: Plant identifier,
m: Merit order zone,
MC: Marginal cost,
$SUPP$: Total supply capacity per zone
$DEMD$: Power of demand per zone
$CEIL$: Price ceiling per zone
$RATE$: Coefficient
SB: Resulting Scarcity bidding price

The price ceiling per merit order zone reflects the supply-function equilibrium competition. The available capacities and their varieties determine the intensity of competition as the price margin available for bidding above marginal costs without losing the price-making place in the merit order zone. We also include the effect of the fixed costs of the plant, which includes annualised capital costs and fixed operation and maintenance costs, on the determination of the mark up, always within the range permitted by competition. The consideration is that the price-making bidders do not necessarily bid at the level of the next more expensive competitor but below this level driven by a risk aversion behaviour. Plants with high fixed costs are more reluctant to apply a high mark-up to their marginal cost in fear of staying out-of-merit. In contrast, low fixed cost plants, such as the peak devices, afford taking risks and can apply relatively higher mark-ups. But even for such plants, the model does not allow the bidding prices to exceed the price ceilings that express a supply-function equilibrium. Naturally, the level of mark-up signifies the degree of market power of a type of generator.

Figure 18: Typical scarcity bidding mark-up function



Appendix D. EXPERIMENTS OF THE RANDOM EVENTS GENERATOR (PRIMES-IEM)

Table 32: Example of experiments generated using the Random Events Generator

#	Day cluster	Load	Wind	Solar	Large Plant	NTC	Probability
		Deviations in real time from day ahead forecast (%)					
1	Winter Working Day	0%	**0%**	**0%**	**0%**	**0%**	0.333
2	Winter Working Day	0%	25%	10%	0%	0%	0.105
3	Winter Working Day	0%	-25%	-23%	0%	0%	0.184
4	Winter Working Day	0%	25%	-23%	0%	0%	0.140
5	Winter Working Day	0%	-25%	10%	0%	0%	0.143
6	Winter Working Day	10%	25%	10%	-65%	-15%	0.021
7	Winter Working Day	10%	-25%	-23%	-65%	-15%	0.029
8	Winter Working Day	-10%	25%	10%	-65%	-15%	0.018
9	Winter Working Day	-10%	-25%	-23%	-65%	-15%	0.028
10	Winter Holiday	0%	0%	0%	0%	0%	0.411
11	Winter Holiday	0%	25%	10%	0%	0%	0.105
12	Winter Holiday	0%	-25%	-23%	0%	0%	0.184
13	Winter Holiday	0%	25%	-23%	0%	0%	0.140
14	Winter Holiday	0%	-25%	10%	0%	0%	0.143
15	Winter Holiday	-10%	25%	10%	-65%	-15%	0.018
16	Spring/Autumn Holiday	10%	-25%	-23%	-65%	-15%	0.411
17	Spring/Autumn Holiday	0%	25%	10%	0%	0%	0.105
18	Spring/Autumn Holiday	0%	-25%	-23%	0%	0%	0.184
19	Spring/Autumn Holiday	0%	25%	-23%	0%	0%	0.140
20	Spring/Autumn Holiday	0%	-25%	10%	0%	0%	0.143
21	Spring/Autumn Holiday	-10%	25%	10%	-65%	-15%	0.018
22	Spring Working Day	0%	0%	0%	0%	0%	0.361
23	Spring Working Day	0%	25%	10%	0%	0%	0.105
24	Spring Working Day	0%	-25%	-23%	0%	0%	0.184
25	Spring Working Day	0%	25%	-23%	0%	0%	0.140
26	Spring Working Day	0%	-25%	10%	0%	0%	0.143
27	Spring Working Day	10%	25%	10%	-65%	-15%	0.021
28	Spring Working Day	10%	-25%	-23%	-65%	-15%	0.029
29	Spring Working Day	-10%	25%	10%	-65%	-15%	0.018
30	Autumn Working Day	0%	0%	0%	0%	0%	0.361
31	Autumn Working Day	0%	25%	10%	0%	0%	0.105
32	Autumn Working Day	0%	-25%	-23%	0%	0%	0.184
33	Autumn Working Day	0%	25%	-23%	0%	0%	0.140
34	Autumn Working Day	0%	-25%	10%	0%	0%	0.143

#	Day cluster	Deviations in real time from day ahead forecast (%) Load	Wind	Solar	Large Plant	NTC	Probability
35	Autumn Working Day	10%	25%	10%	-65%	-15%	0.021
36	Autumn Working Day	10%	-25%	-23%	-65%	-15%	0.029
37	Autumn Working Day	-10%	25%	10%	-65%	-15%	0.018
38	Summer Working Day	0%	0%	0%	0%	0%	0.333
39	Summer Working Day	0%	25%	10%	0%	0%	0.105
40	Summer Working Day	0%	-25%	-23%	0%	0%	0.184
41	Summer Working Day	0%	25%	-23%	0%	0%	0.140
42	Summer Working Day	0%	-25%	10%	0%	0%	0.143
43	Summer Working Day	10%	25%	10%	-65%	-15%	0.021
44	Summer Working Day	10%	-25%	-23%	-65%	-15%	0.029
45	Summer Working Day	-10%	25%	10%	-65%	-15%	0.018
46	Summer Working Day	-10%	-25%	-23%	-65%	-15%	0.028
47	Summer Holiday	0%	0%	0%	0%	0%	0.411
48	Summer Holiday	0%	25%	10%	0%	0%	0.105
49	Summer Holiday	0%	-25%	-23%	0%	0%	0.184
50	Summer Holiday	0%	25%	-23%	0%	0%	0.140
51	Summer Holiday	0%	-25%	10%	0%	0%	0.143
52	Summer Holiday	-10%	25%	10%	-65%	-15%	0.018

Appendix E. ADDITIONAL PRIMES-IEM RESULTS

Table 33: Final operation schedule and cost accounting in Case 0, EU28

Case 0	Final Generation Schedule (GWh)	Curtailment (GWh)	Average Annual Operating Hours	Total Generator Revenues, in M€'13	Profit (+) or Loss (-), in M€'13	Total Generator Revenues, in €'13/kW	Profit (+) or Loss (-), in €'13/kW
Solids	420848	0	4165	49416	763	489	8
Nuclear	689899	0	6277	68730	26711	625	243
Lakes	196068	1326	2088	14927	-2139	159	-23
Wind onshore	546594	6940	2221	54280	14194	221	58
Wind offshore	126472	743	3333	12311	-4668	324	-123
Solar thermal	12236	49	1967	1270	-2583	204	-415
Geothermal	6884	600	6685	759	422	737	410
Tidal	2239	10	2161	217	-232	209	-224
Biomass	198067	2381	4545	20340	-8680	467	-199
Peak	5376	0	921	1517	676	260	116
CCGT	564453	0	3574	72728	10558	461	67
Steam turbines oil/gas	16247	0	903	2390	-972	133	-54
Run of River	163801	3876	4155	15952	8971	405	228
Solar PV (large)	168167	3123	1179	17796	957	125	7
RES (small)	83134	0	978	8643	-5428	102	-64
CHP solids	10221	0	2499	957	-232	234	-57
CHP gas	82216	0	3488	8029	-1755	341	-74
CHP biomass	32350	0	3409	3042	-3119	321	-329
CHP oil	11373	0	2595	1152	-1619	263	-369

Source: PRIMES-IEM model

Table 34: Final operation schedule and cost accounting in Case 1, EU28

Case 1	Final Generation Schedule (GWh)	Curtailment (GWh)	Average Annual Operating Hours	Total Generator Revenues, in M€'13	Profit (+) or Loss (-), in M€'13	Total Generator Revenues, in €'13/kW	Profit (+) or Loss (-), in €'13/kW
Solids	367160	0	3633	36905	-6827	365	-68
Nuclear	677470	0	6164	70487	28557	641	260
Lakes	196414	979	2091	12573	-4494	134	-48
Wind onshore	552546	988	2246	54093	14007	220	57
Wind offshore	127085	130	3349	12210	-4769	322	-126
Solar thermal	12245	40	1969	2257	-1596	363	-257
Geothermal	7382	103	7168	755	418	733	406
Tidal	2248	0	2170	208	-241	201	-233
Biomass	190793	3650	4378	24968	-3340	573	-77
Peak	4122	0	706	1208	510	207	87
CCGT	627869	0	3976	69601	2067	441	13
Steam turbines oil/gas	15074	0	838	1849	-1346	103	-75
Run of River	166441	1237	4222	15912	8931	404	227
Solar PV (large)	170932	380	1199	17755	916	125	6
RES (small)	83134	0	978	8547	-5524	101	-65
CHP solids	10637	0	2600	990	-228	242	-56
CHP gas	82219	0	3488	7970	-1814	338	-77
CHP biomass	32350	0	3409	3030	-3131	319	-330
CHP oil	11373	0	2595	1143	-1628	261	-371

Source: PRIMES-IEM model

Table 35: Final operation schedule and cost accounting in Case 2, EU28

Case 2	Final Generation Schedule	Curtailment (GWh)	Average Annual Operating	Total Generator Revenues, in	Profit (+) or Loss (-), in	Total Generator Revenues, in	Profit (+) or Loss (-), in

	(GWh)		Hours	M€'13	M€'13	€'13/kW	€'13/kW
Solids	357823	0	3541	35431	-8169	351	-81
Nuclear	678318	0	6172	68947	27011	627	246
Lakes	196873	520	2096	21295	4229	227	45
Wind on-shore	552893	641	2247	50197	10110	204	41
Wind off-shore	126953	263	3345	11856	-5123	312	-135
Solar thermal	12285	0	1975	1680	-2173	270	-349
Geothermal	7484	0	7268	727	390	706	379
Tidal	2248	0	2170	222	-227	214	-219
Biomass	199462	988	4577	23041	-6082	529	-140
Peak	4262	0	730	666	-48	114	-8
CCGT	629771	0	3988	60420	-7309	383	-46
Steam tur-bines oil/gas	13181	0	733	1629	-1321	91	-73
Run of River	167216	462	4242	15274	8293	387	210
Solar PV (large)	171225	87	1201	16861	22	118	0
RES (small)	83134	0	978	8666	-5406	102	-64
CHP solids	10637	0	2600	1070	-148	261	-36
CHP gas	82281	0	3491	7764	-2026	329	-86
CHP biomass	32352	0	3409	3017	-3144	318	-331
CHP oil	11373	0	2595	1049	-1722	239	-393

Source: PRIMES-IEM model

Table 36: Final operation schedule and cost accounting in Case 3, EU28

Case 3	Final Gener-ation Schedule (GWh)	Curtailment (GWh)	Average Annual Op-erating Hours	Total Gen-erator Rev-enues, in M€'13	Profit (+) or Loss (-), in M€'13	Total Gen-erator Rev-enues, in €'13/kW	Profit (+) or Loss (-), in €'13/kW

Solids	433969	0	4294	38107	-10562	377	-105
Nuclear	678197	0	6171	62769	20834	571	190
Lakes	196980	413	2097	19807	2741	211	29
Wind on-shore	553086	449	2248	49951	9864	203	40
Wind off-shore	126962	254	3346	11358	-5621	299	-148
Solar thermal	12285	0	1975	1114	-2739	179	-440
Geothermal	7484	0	7268	745	408	724	397
Tidal	2248	0	2170	205	-244	198	-235
Biomass	193758	473	4446	18884	-9649	433	-221
Peak	2026	0	347	194	-267	33	-46
CCGT	564007	0	3572	47817	-14042	303	-89
Steam tur-bines oil/gas	10690	0	594	1039	-1589	58	-88
Run of River	167337	340	4245	14692	7711	373	196
Solar PV (large)	171234	78	1201	16134	-705	113	-5
RES (small)	83132	2	978	8177	-5895	96	-69
CHP solids	10637	0	2600	953	-265	233	-65
CHP gas	82138	0	3485	7575	-2203	321	-93
CHP biomass	32352	0	3409	2900	-3261	306	-344
CHP oil	11373	0	2595	1079	-1692	246	-386

Source: PRIMES-IEM model

Appendix F. UPPER BOUNDS ON CROSS-BORDER TRANSFERRED CAPACITY

Table 37: Maximum capacity that can be delivered from a country (participant) to a hypothetical capacity market (Bilateral transfer limit) in GW (EUCO27 context, 2025)

		BILATERAL TRANSFER LIMITS* (GW)																								
2025		Capacity markets**																								
		IE	UK	BE	NL	DE	FR	ES	PT	DK	SE	FI	AU	IT	SI	CZ	SK	PL	HU	LV	EE	LT	HR	RO	BG	EL
Participants	IE		0.52	0.59	0.59	0.53	0.59	0.85	1.08	0.59	0.59	0.52	0.59	0.85	0.59	0.59	0.52	0.52	0.85	0.59	0.35	0.59	0.52	1.08	1.08	0.85
	UK	1.64		4.88	7.58	7.66	7.35	1.50	1.12	5.28	7.58	5.48	7.39	0.97	4.25	7.55	5.05	5.21	6.58	1.70	1.70	3.63	4.78	4.67	4.07	1.00
	BE	1.64	2.78		2.85	2.78	2.85	1.50	1.12	2.85	2.85	2.78	2.85	0.78	2.85	2.85	2.78	2.78	3.92	1.70	1.70	2.85	2.78	3.04	4.07	1.00
	NL	1.64	3.56	3.74		5.93	4.38	1.50	1.12	4.38	4.38	3.56	4.38	0.70	4.02	4.38	3.56	3.56	4.71	1.70	1.70	3.63	3.56	4.67	4.07	1.00
	DE	1.64	3.13	5.05	7.75		3.80	1.50	1.12	5.28	11.69	5.48	8.73	0.66	3.92	9.21	5.02	5.05	6.46	1.70	1.70	3.63	4.56	4.57	4.06	1.00
	FR	1.64	4.18	4.87	7.47	8.11		1.50	1.12	5.28	7.47	5.48	7.39	0.97	4.25	7.47	5.05	5.22	6.66	1.70	1.70	3.63	4.78	4.67	4.07	1.00
	ES	1.64	3.68	4.79	5.26	5.15	5.26		1.12	5.26	5.26	5.13	5.26	0.97	4.25	5.26	5.05	5.13	5.69	1.70	1.70	3.63	4.78	4.67	4.07	1.00
	PT	1.64	3.68	3.60	3.60	3.60	3.60	3.60		3.60	3.60	4.31	3.60	0.97	3.60	3.60	4.31	4.31	3.60	1.70	1.70	3.60	4.31	4.67	3.60	1.00
	DK	1.64	2.14	2.14	2.14	2.30	2.14	1.50	1.12		2.14	2.14	2.14	0.66	2.14	2.14	2.14	2.14	2.06	1.70	1.70	2.14	2.14	2.30	1.40	1.00
	SE	1.64	2.97	3.79	3.79	3.86	3.63	1.50	1.12	3.39		4.06	3.79	0.66	3.79	3.79	4.00	4.06	6.46	1.70	1.70	2.97	3.96	4.08	4.05	1.00
	FI	0.24	0.24	0.66	0.66	0.78	0.66	1.50	0.96	0.66	0.66		0.66	0.66	0.66	0.66	0.24	0.24	4.10	0.66	0.36	0.66	0.24	0.96	1.77	1.00
	AU	1.41	1.41	2.25	2.77	1.98	1.71	1.50	1.12	3.13	3.16	2.59		0.48	1.79	4.14	2.67	2.65	5.72	1.70	1.70	3.17	1.73	1.88	3.72	1.00
	IT	1.64	4.18	5.02	7.95	8.15	11.31	1.50	1.12	5.28	7.72	5.48	5.56		3.74	7.04	5.08	5.45	5.24	1.70	1.70	3.63	4.64	4.68	4.07	1.01
	SI	0.43	0.43	0.44	0.44	0.70	0.44	0.93	0.49	0.44	0.44	0.43	0.44	0.77		0.44	0.43	0.43	0.93	0.44	0.48	0.44	0.43	0.49	0.44	0.93
	CZ	1.64	2.40	3.45	3.45	3.46	2.92	1.50	1.12	3.45	3.45	3.47	3.45	0.60	3.16		3.47	3.47	5.91	1.70	1.70	3.45	3.47	4.08	4.05	1.00
	SK	1.64	1.87	1.34	1.34	1.16	1.34	1.50	1.12	1.34	1.34	1.87	1.34	0.65	1.34	1.34		1.87	1.99	1.34	1.70	1.34	1.87	1.59	1.77	0.99
	PL	1.64	2.26	3.17	3.17	2.86	3.17	1.50	1.12	3.17	3.17	2.26	3.17	0.65	3.17	3.17	2.26		2.73	1.70	1.70	3.17	2.26	4.00	4.04	1.00
	HU	1.64	1.75	1.99	1.99	2.03	1.99	1.50	1.12	1.99	1.99	1.75	1.99	0.67	1.99	1.99	1.75	1.75		1.70	1.70	1.99	1.75	2.07	2.34	0.98
	LV	0.17	0.17	0.30	0.30	0.36	0.30	0.50	0.21	0.30	0.30	0.17	0.30	0.52	0.30	0.30	0.17	0.17	0.50		0.23	0.30	0.17	0.21	0.49	0.50
	EE	0.40	0.40	0.22	0.22	0.19	0.22	0.59	0.51	0.22	0.22	0.40	0.22	0.59	0.22	0.22	0.40	0.40	0.59	0.22		0.22	0.40	0.51	0.21	0.59
	LT	0.73	0.73	0.81	0.81	0.79	0.81	0.80	0.82	0.81	0.81	0.73	0.81	0.66	0.81	0.81	0.73	0.73	0.80	0.81	0.80		0.73	0.82	0.94	0.80
	HR	1.11	1.11	1.41	1.41	2.21	1.41	1.50	1.12	1.41	1.41	1.11	1.41	0.82	1.41	1.41	1.11	1.11	1.82	1.41	1.70	1.41		1.22	1.67	1.01
	RO	1.60	1.60	1.31	1.31	0.88	1.31	1.50	1.12	1.31	1.31	1.60	1.31	0.67	1.30	1.31	1.52	1.60	1.72	1.31	1.24	1.31	1.58		3.01	0.85
	BG	1.37	1.37	1.24	1.24	1.25	1.24	1.50	1.12	1.24	1.24	1.37	1.24	0.61	1.24	1.24	1.37	1.37	1.86	1.24	1.51	1.24	1.37	1.33		0.76
	EL	1.64	1.98	1.50	1.51	1.63	1.50	1.50	1.12	1.51	1.51	1.98	1.51	0.92	1.50	1.51	1.98	1.98	2.03	1.51	1.50	1.51	1.98	1.98	1.53	

(*):The Bilateral Transfer Limit is the maximum capacity (incremental to normal market-driven flows) that can be transferred from country B to country A under system stress conditions, considering network limitations and existing congestion of transmission lines, when all other countries maintain the same power balance

(**): IR: Ireland, UK: United Kingdom, BE: Belgium, NL: Netherlands, DE: Germany, FR: France, ES: Spain, PT: Portugal, DK: Denmark, SE: Sweden, FI: Finland, AU: Austria, IT: Italy, SI: Slovenia, CZ: Czech Republic, SK: Slovakia, PL: Poland, HU: Hungary, LV: Latvia, EE: Estonia, LT: Lithuania, HR: Croatia, RO: Romania, BG: Bulgaria, EL: Greece

Source: PRIMES-IEM model

Table 38: Maximum capacity that can be delivered from a country (participant) to a hypothetical capacity market (Bilateral transfer limit) in GW (EUCO27 context, 2030)

		BILATERAL TRANSFER LIMITS* (GW)																							
2030		Capacity markets**																							
		IE	UK	BE	NL	DE	FR	ES	PT	DK	SE	FI	AU	IT	SI	CZ	SK	PL	HU	LV	EE	LT	HR	RO	BG	EL
Participants	IE		1.40	1.17	1.17	1.39	1.17	0.97	1.17	1.17	1.17	1.40	1.17	0.96	1.17	1.17	1.40	1.40	0.97	1.17	1.26	1.17	1.40	1.17	1.40	0.97
	UK	1.40		5.40	10.39	9.74	10.39	3.60	2.41	10.07	10.39	3.89	10.39	2.04	4.63	9.62	5.39	8.41	5.75	2.46	1.69	4.64	7.11	5.30	5.95	1.60
	BE	1.40	3.53		3.53	3.53	3.53	3.60	2.41	3.53	3.53	3.53	3.53	1.99	3.53	3.53	3.53	3.53	3.70	2.46	1.69	3.53	3.53	3.53	3.53	1.60
	NL	1.40	4.54	2.01		5.23	2.01	2.79	2.41	2.01	2.01	3.89	2.01	1.75	2.01	2.01	4.54	4.54	2.79	2.01	1.69	2.01	4.54	3.95	4.54	1.59
	DE	1.40	5.94	5.57	10.21		11.92	3.60	2.41	10.07	11.92	3.89	11.92	1.66	4.99	9.94	5.39	8.21	5.71	2.46	1.69	4.64	7.04	5.25	5.95	1.59
	FR	1.40	5.97	5.31	11.66	11.76		3.60	2.41	10.07	12.84	3.89	10.19	2.04	4.57	9.57	5.39	7.70	5.75	2.46	1.69	4.64	7.11	5.31	5.95	1.60
	ES	1.40	4.90	5.24	6.29	5.70	6.29		3.18	6.29	6.29	3.89	6.29	2.04	4.54	6.29	5.39	5.52	5.03	2.46	1.69	4.64	5.52	5.31	5.52	1.60
	PT	1.40	4.81	3.96	3.96	4.84	3.96	3.96		3.96	3.96	3.89	3.96	2.04	3.96	3.96	4.81	4.81	3.96	2.46	1.69	3.96	4.81	4.74	4.81	1.60
	DK	0.89	0.89	0.43	0.43	0.77	0.43	2.10	1.12		0.43	0.89	0.43	1.67	0.43	0.43	0.89	0.89	2.10	0.43	0.89	0.43	0.89	1.12	0.89	1.59
	SE	1.40	3.80	4.40	4.40	4.74	4.40	3.60	2.41	4.40		3.80	4.40	1.66	4.40	4.40	3.80	3.80	5.71	2.46	1.69	4.40	3.80	5.25	3.80	1.59
	FI	0.47	0.47	0.70	0.70	0.82	0.70	3.48	0.89	0.70	0.70		0.70	1.64	0.70	0.70	0.47	0.47	3.49	0.70	0.31	0.70	0.47	0.89	0.47	1.58
	AU	1.40	2.62	5.55	7.67	7.98	7.67	3.60	2.41	7.67	7.67	3.89		1.20	4.87	7.67	4.65	4.84	5.46	2.46	1.69	4.64	3.02	5.16	2.88	1.59
	IT	1.40	5.97	5.54	7.40	9.59	9.92	3.60	2.41	7.18	7.18	3.89	5.15		3.88	6.56	5.36	8.64	6.30	2.46	1.69	4.64	7.17	5.41	5.82	1.63
	SI	0.10	0.10	0.51	0.51	0.65	0.51	1.00	0.73	0.51	0.51	0.10	0.51	1.22		0.51	0.10	0.10	1.00	0.51	0.39	0.51	0.10	0.73	0.10	1.00
	CZ	1.40	3.08	3.11	3.11	3.07	3.11	3.60	2.41	3.11	3.11	3.08	3.11	1.52	3.11		3.08	3.08	4.84	2.46	1.69	3.11	3.08	3.70	3.08	1.57
	SK	1.40	1.78	1.64	1.64	1.98	1.64	2.34	1.82	1.64	1.64	1.78	1.64	1.66	1.64	1.64		1.78	2.34	1.64	1.65	1.64	1.78	1.82	1.78	1.54
	PL	1.40	2.29	2.64	2.64	3.12	2.64	2.63	2.41	2.64	2.64	2.29	2.64	1.64	2.64	2.64	2.29		2.63	2.46	1.69	2.64	2.29	4.43	2.29	1.58
	HU	1.40	2.37	2.39	2.39	2.08	2.39	3.03	2.41	2.39	2.39	2.37	2.39	1.76	2.39	2.39	2.37	2.37		2.39	1.69	2.39	2.37	2.69	2.37	1.51
	LV	0.44	0.44	0.44	0.44	0.50	0.44	0.62	0.49	0.44	0.44	0.44	0.44	0.71	0.44	0.44	0.44	0.44	0.62		0.49	0.44	0.44	0.49	0.44	0.62
	EE	0.77	0.77	0.77	0.77	0.77	0.77	0.88	0.78	0.77	0.77	0.77	0.77	0.88	0.77	0.77	0.77	0.77	0.88	0.77		0.77	0.77	0.78	0.77	0.88
	LT	0.78	0.78	0.76	0.76	0.94	0.76	1.01	0.86	0.76	0.76	0.78	0.76	0.98	0.76	0.76	0.78	0.78	1.01	0.76	0.64		0.78	0.86	0.78	1.01
	HR	1.17	1.17	1.49	1.49	2.34	1.49	1.62	1.10	1.49	1.49	1.17	1.49	1.75	1.49	1.49	1.17	1.17	1.62	1.49	1.60	1.49		1.10	1.17	1.55
	RO	1.17	1.17	2.33	2.32	1.26	2.35	2.10	1.61	2.32	2.31	1.16	2.32	1.99	2.42	2.26	1.09	1.15	1.83	2.29	1.69	2.29	1.31		4.75	1.23
	BG	1.21	1.21	1.38	1.38	1.50	1.38	2.26	1.39	1.38	1.38	1.21	1.38	1.81	1.38	1.38	1.21	1.21	2.06	1.38	1.69	1.38	1.21	1.39		1.06
	EL	1.40	2.01	2.92	2.92	2.12	2.93	2.91	2.41	2.92	2.92	1.96	2.92	2.53	2.87	2.92	1.77	1.95	2.87	2.46	1.69	2.92	2.44	2.35	2.01	

(*):The Bilateral Transfer Limit is the maximum capacity (incremental to normal market-driven flows) that can be transferred from a country B to a country A under system stress conditions, considering network limitations and existing congestion of transmission lines, when all other countries maintain the same power balance

(**): IR: Ireland, UK: United Kingdom, BE: Belgium, NL: Netherlands, DE: Germany, FR: France, ES: Spain, PT: Portugal, DK: Denmark, SE: Sweden, FI: Finland, AU: Austria, IT: Italy, SI: Slovenia, CZ: Czech Republic, SK: Slovakia, PL: Poland, HU: Hungary, LV: Latvia, EE: Estonia, LT: Lithuania, HR: Croatia, RO: Romania, BG: Bulgaria, EL: Greece

Source: PRIMES-IEM model

Table 39: Contribution of each country (participant) to the Capacity Import Limit of every hypothetical capacity market in GW (EUCO27 context, 2025)

	2025	CONTRIBUTION OF PARTICIPANTS TO THE CAPACITY IMPORT LIMIT (CIL) OF EACH CAPACITY MARKET* (GW)																								
		Capacity markets**																								
		IE	UK	BE	NL	DE	FR	ES	PT	DK	SE	FI	AU	IT	SI	CZ	SK	PL	HU	LV	EE	LT	HR	RO	BG	EL
Participants	IE		0.52																							
	UK	1.64			1.37	0.60	6.05			0.84	0.84	0.51														
	BE		0.60		2.85	2.78	2.85																			
	NL		0.77			4.11	4.38			1.25	1.21	0.42														
	DE		0.11	4.40	1.24		1.86			3.19	6.30		1.62			5.48						1.62				
	FR		2.00		3.33	0.20		1.20					1.53	0.87												
	ES						5.16		1.12					0.10												
	PT							3.60																		
	DK		0.07		0.47	2.30					2.14															
	SE		0.62		0.47	0.07						3.01									0.24					
	FI		0.01								0.66					0.07			0.06	0.66	0.36			0.08		
	AU			0.20		2.10									0.54		1.85	2.18						0.10		
	IT			0.37		7.11	7.61	0.30					1.41		1.27		0.60	0.30	4.36				2.93	0.41	1.69	
	SI			0.08									0.44						0.93				0.10		0.44	
	CZ					3.46							3.39				3.47	3.47								
	SK					0.70					0.40	0.40			0.68	1.34			0.72					0.80		
	PL					0.80					0.88	0.17				2.94					0.10	1.50				
	HU					0.20					0.53				1.99	0.31								2.07		
	LV										0.30	0.17									0.23	0.30				
	EE										0.22	0.40								0.22		0.22				
	LT										0.81	0.41				0.13		0.32	0.05	0.79	0.80			0.15		
	HR												1.41						0.75						1.67	1.01
	RO					0.06					0.05									0.16	0.20					
	BG																						1.10	1.33		
	EL												1.21	0.08					0.91				1.42	0.82	0.31	
CIL			1.64	4.70	5.05	9.73	24.5	27.9	5.10	1.12	5.28	14.3	5.48	11.0	1.06	4.48	10.3	5.92	6.26	7.78	1.82	1.93	3.63	5.55	5.78	4.12

(*):The Capacity Import Limit of a country is the maximum amount of capacity (incremental to normal market-driven flows) that can be transferred to a country A simultaneously from all other countries under system stress conditions, considering network limitations and existing congestion of transmission lines.
(**): IR: Ireland, UK: United Kingdom, BE: Belgium, NL: Netherlands, DE: Germany, FR: France, ES: Spain, PT: Portugal, DK: Denmark, SE: Sweden, FI: Finland, AU: Austria, IT: Italy, SI: Slovenia, CZ: Czech Republic, SK: Slovakia, PL: Poland, HU: Hungary, LV: Latvia, EE: Estonia, LT: Lithuania, HR: Croatia, RO: Romania, BG: Bulgaria, EL: Greece
Source: PRIMES-IEM model

Table 40: Contribution of each country (participant) to the Capacity Import Limit of every hypothetical capacity market in GW (EUCO27 context, 2030)

CONTRIBUTION OF PARTICIPANTS TO THE CAPACITY IMPORT LIMIT (CIL) OF EACH CAPACITY MARKET* (GW)

	2030	Capacity markets**																								
		IE	UK	BE	NL	DE	FR	ES	PT	DK	SE	FI	AU	IT	SI	CZ	SK	PL	HU	LV	EE	LT	HR	RO	BG	EL
Participants	IE		1.40																							
	UK	1.40			3.65	1.13	9.26				1.70															
	BE		1.20		3.53	3.53	3.53			0.60	0.60															
	NL		0.77			5.23	2.01			1.97	2.01											0.04				
	DE		0.60	5.57	3.29		2.22			5.19	6.80		9.94			7.22	0.34					0.10				
	FR		3.39					3.06									0.03									
	ES						6.19		3.18																	
	PT							3.96																		
	DK				0.04	0.77					0.43											0.36				
	SE				1.51	2.77				1.57		2.36								0.22	0.29	0.14				
	FI									0.70	0.70					0.06				0.63	0.31	0.70				
	AU					4.82									3.05		2.41	5.43							1.55	
	IT					8.92	4.60	0.54									0.25	0.74	4.11				5.37	2.88	1.48	1.62
	SI												0.51						1.00					0.73	0.10	
	CZ				0.07	3.07							1.59				3.08	3.08							0.67	
	SK					0.84										1.64						0.40				
	PL										2.36	0.17	0.21			1.46				0.70		2.15			0.12	
	HU														0.66	0.09						0.56				
	LV										0.19										0.49	0.44				
	EE										0.60	0.60								0.77		0.77				
	LT									0.05	0.06	0.56				0.08				0.76	0.60					
	HR												1.49		1.49				1.62					1.10	1.17	
	RO					0.12					0.08	0.20	0.97		0.77					0.16		0.20			1.67	
	BG														0.45								0.29	1.39		
	EL													2.53					0.70				2.16	1.08		
CIL			1.64	1.40	7.37	5.57	12.1	31.2	27.8	7.56	3.18	10.1	15.5	3.89	14.7	2.53	6.41	10.6	6.12	9.24	7.44	3.23	1.69	5.86	7.83	7.18

(*):The Capacity Import Limit of a country is the maximum amount of capacity (incremental to normal market-driven flows) that can be transferred to a country A simultaneously from all other countries under system stress conditions, considering network limitations and existing congestion of transmission lines.

(**): IR: Ireland, UK: United Kingdom, BE: Belgium, NL: Netherlands, DE: Germany, FR: France, ES: Spain, PT: Portugal, DK: Denmark, SE: Sweden, FI: Finland, AU: Austria, IT: Italy, SI: Slovenia, CZ: Czech Republic, SK: Slovakia, PL: Poland, HU: Hungary, LV: Latvia, EE: Estonia, LT: Lithuania, HR: Croatia, RO: Romania, BG: Bulgaria, EL: Greece

Source: PRIMES-IEM model

Appendix G. PROXIMITY OF EU COUNTRIES IN TERMS OF ELECTRICITY NETWORK

Table 41: Proximity of EU countries in terms of electricity network, for years 2025 and 2030, as calculated using the network model

Proximity of countries in terms of Electricity network(*)

(2025, 2030)	IR	UK	BE	NL	GE	FR	SP	PL	DK	SV	FI	AU	IT	SN	CZ	SK	PD	HU	LA	ES	LI	HR	RO	BG	GR
IR	(0,0)	(1,1)	(2,2)	(2,2)	(3,2)	(2,2)	(3,3)	(4,4)	(3,3)	(3,3)	(3,3)	(4,3)	(3,3)	(4,4)	(4,3)	(5,4)	(4,3)	(5,4)	(5,5)	(4,4)	(4,4)	(5,5)	(5,5)	(5,5)	(4,4)
UK		(0,0)	(1,1)	(1,1)	(2,1)	(1,1)	(2,2)	(3,3)	(2,2)	(2,2)	(2,2)	(3,2)	(2,2)	(3,3)	(3,2)	(4,3)	(3,2)	(4,3)	(4,4)	(3,3)	(3,3)	(4,4)	(4,4)	(4,4)	(3,3)
BE			(0,0)	(1,1)	(2,2)	(1,1)	(2,2)	(3,3)	(2,2)	(3,2)	(3,2)	(3,3)	(2,2)	(3,3)	(3,3)	(4,4)	(3,3)	(4,4)	(5,4)	(4,3)	(4,3)	(4,4)	(5,4)	(4,4)	(3,3)
NL				(0,0)	(1,1)	(2,2)	(3,3)	(4,4)	(1,1)	(2,2)	(2,2)	(2,2)	(3,3)	(3,3)	(2,2)	(3,3)	(2,2)	(3,3)	(4,4)	(3,3)	(3,3)	(4,4)	(4,4)	(5,5)	(4,4)
GE					(0,0)	(1,1)	(2,2)	(3,3)	(1,1)	(1,1)	(2,2)	(1,1)	(2,2)	(2,2)	(1,1)	(2,2)	(1,1)	(2,2)	(3,3)	(3,3)	(2,2)	(3,3)	(3,3)	(4,4)	(3,3)
FR						(0,0)	(1,1)	(2,2)	(2,2)	(2,2)	(3,3)	(2,2)	(1,1)	(2,2)	(2,2)	(3,3)	(2,2)	(3,3)	(4,4)	(4,4)	(3,3)	(3,3)	(4,4)	(3,3)	(2,2)
SP							(0,0)	(1,1)	(3,3)	(3,3)	(4,4)	(3,3)	(2,2)	(3,3)	(3,3)	(4,4)	(3,3)	(4,4)	(5,5)	(5,5)	(4,4)	(4,4)	(5,5)	(4,4)	(3,3)
PL								(0,0)	(4,4)	(4,4)	(5,5)	(4,4)	(3,3)	(4,4)	(4,4)	(5,5)	(4,4)	(5,5)	(6,6)	(6,6)	(5,5)	(5,5)	(6,6)	(5,5)	(4,4)
DK									(0,0)	(1,1)	(2,2)	(2,2)	(3,3)	(3,3)	(2,2)	(3,3)	(2,2)	(3,3)	(3,3)	(3,3)	(2,2)	(4,4)	(4,4)	(5,5)	(4,4)
SV										(0,0)	(1,1)	(2,2)	(3,3)	(3,3)	(2,2)	(2,2)	(1,1)	(3,3)	(2,2)	(2,2)	(1,1)	(4,4)	(3,3)	(4,4)	(4,4)
FI											(0,0)	(3,3)	(4,4)	(3,3)	(3,3)	(2,2)	(2,2)	(2,2)	(2,2)	(1,1)	(2,2)	(3,3)	(2,2)	(3,3)	(4,4)
AU												(0,0)	(1,1)	(1,1)	(1,1)	(2,2)	(2,2)	(1,1)	(3,3)	(3,3)	(3,3)	(2,2)	(2,2)	(3,3)	(2,2)
IT													(0,0)	(1,1)	(2,2)	(3,3)	(3,3)	(2,2)	(4,4)	(4,4)	(4,4)	(2,2)	(3,3)	(2,2)	(1,1)
SN														(0,0)	(2,2)	(2,2)	(3,3)	(1,1)	(3,3)	(3,3)	(3,3)	(1,1)	(2,2)	(3,3)	(2,2)
CZ															(0,0)	(1,1)	(1,1)	(2,2)	(3,3)	(3,3)	(2,2)	(3,3)	(3,3)	(4,4)	(3,3)
SK																(0,0)	(1,1)	(1,1)	(2,2)	(2,2)	(2,2)	(2,2)	(2,2)	(3,3)	(4,4)
PD																	(0,0)	(2,2)	(2,2)	(2,2)	(1,1)	(3,3)	(2,2)	(3,3)	(4,4)
HU																		(0,0)	(2,2)	(2,2)	(2,2)	(1,1)	(1,1)	(2,2)	(3,3)
LA																			(0,0)	(1,1)	(1,1)	(3,3)	(2,2)	(3,3)	(4,4)
ES																				(0,0)	(2,2)	(3,3)	(2,2)	(3,3)	(4,4)
LI																					(0,0)	(3,3)	(2,2)	(3,3)	(4,4)
HR																						(0,0)	(2,2)	(2,2)	(3,3)
RO																							(0,0)	(1,1)	(2,2)
BG																								(0,0)	(1,1)
GR																									(0,0)

(*)The Proximity level represents the number of nodes in between two countries. Proximity level 1 implies that the countries are directly interconnected.

Source: PRIMES-IEM model

Appendix H. ADDITIONAL PRIMES-OM RESULTS

Table 42: Load payment and generator revenues across all cases in the period 2021-2030

	Load Payment in M€'13 2021-2030					Generator Revenues Total in M€'13 2021-2030					Generator Revenues from CM in M€'13 2021-2030				
Member States	EOM with scarcity bids (B)	CM in 4 MS w/o X-B (C)	CM in all MS w/o X-B (D)	CM in all MS with X-B (E)	CM in 4 MS with X-B (F)	EOM with scarcity bids (B)	CM in 4 MS w/o X-B (C)	CM in all MS w/o X-B (D)	CM in all MS with X-B (E)	CM in 4 MS with X-B (F)	EOM with scarcity bids (B)	CM in 4 MS w/o X-B (C)	CM in all MS w/o X-B (D)	CM in all MS with X-B (E)	CM in 4 MS with X-B (F)
AT	71,877	70,126	74,438	72,617	70,494	66,005	64,020	68,649	67,401	64,743			5,625	4,923	
BE	91,367	89,278	90,416	88,277	89,370	57,275	53,589	59,098	58,203	53,150			3,828	3,368	
BG	31,552	30,793	33,200	32,773	30,352	43,978	42,179	46,021	44,428	41,395			3,483	2,904	
CY	5,722	6,220	6,098	6,007	5,770	5,662	6,115	6,023	5,929	5,710			593	520	
CZ	66,315	64,413	69,491	67,566	64,492	84,548	81,803	83,879	78,682	78,224			6,040	5,124	
DK	36,138	34,952	36,842	35,955	34,900	37,760	36,371	37,890	36,408	36,175			2,330	2,042	
EE	8,641	8,344	9,016	8,781	8,339	12,264	11,804	12,267	11,939	11,797			737	646	
FI	82,267	79,401	84,199	82,173	79,170	86,603	83,096	88,848	86,714	82,464			5,380	4,716	
FR	491,660	496,964	511,871	496,287	486,049	563,173	577,248	580,995	566,062	565,592		25,725	43,414	38,065	21,835
DE	562,359	548,352	561,692	549,159	549,673	545,122	512,410	543,405	524,767	510,362			25,674	22,323	
EL	50,060	49,429	52,140	50,741	49,338	49,286	45,106	52,739	51,706	44,615			4,942	4,311	
HU	40,777	39,538	42,073	40,984	39,418	32,570	30,455	34,509	34,054	30,287			3,153	2,766	
IE	29,135	29,289	29,561	28,572	28,469	24,026	26,747	24,601	24,075	26,239		1,770	1,926	1,686	1,456
IT	328,509	345,110	343,108	332,156	338,161	297,362	330,108	314,468	303,339	328,513		30,767	30,928	26,942	29,567
LV	8,262	7,996	8,433	8,244	7,993	6,208	5,157	6,653	6,749	5,274			509	446	
LT	11,251	10,835	11,729	11,386	10,832	8,793	7,868	10,299	10,112	7,659			989	828	
LU	8,327	8,137	8,600	8,365	8,107	1,931	1,801	2,705	2,581	1,808			813	713	
MT	2,946	2,894	3,103	3,008	3,121	2,956	2,702	3,145	3,054	2,350			352	309	
NL	116,222	113,699	118,769	115,924	113,798	111,019	102,729	116,108	114,520	102,815			7,884	6,907	
PL	165,350	159,972	169,642	166,386	160,529	164,118	157,162	163,909	159,776	157,115			11,004	9,857	
PT	52,554	51,005	54,913	53,135	50,555	48,491	45,699	51,222	49,959	45,544			4,783	4,195	
RO	54,301	53,237	57,545	57,088	52,538	65,663	63,457	67,248	67,487	62,335			6,546	5,691	
SK	29,988	29,000	31,722	30,944	28,870	32,151	30,959	33,781	32,789	30,809			3,035	2,662	
SI	14,421	14,046	15,049	14,657	13,937	15,990	15,449	16,340	16,084	15,252			1,288	1,123	
ES	273,665	267,382	287,216	277,294	265,478	262,683	250,266	276,065	267,062	248,231			25,659	22,148	
SE	148,416	143,217	150,105	147,227	142,895	167,125	160,795	169,683	167,488	159,237			9,446	8,283	
UK	370,204	381,044	380,230	369,365	367,935	345,545	375,538	358,700	352,337	366,480		28,650	28,626	25,209	21,248
HR	17,330	16,848	17,824	17,423	16,733	16,364	15,353	16,963	16,925	15,136			1,303	1,143	
EU	3,169,614	3,151,523	3,259,022	3,172,495	3,117,316	3,154,668	3,135,986	3,246,212	3,160,630	3,099,311		86,912	240,291	209,851	74,106

(IE: Ireland, UK: United Kingdom, BE: Belgium, NL: Netherlands, DE: Germany, FR: France, ES: Spain, PT: Portugal, DK: Denmark, SE: Sweden, FI: Finland, AT: Austria, IT: Italy, SI: Slovenia, CZ: Czech Republic, SK: Slovakia, PL: Poland, HU: Hungary, LV: Latvia, EE: Estonia, LT: Lithuania, HR: Croatia, RO: Romania, BG: Bulgaria, EL: Greece, MT: Malta, LU: Luxembourg, CY: Cyprus, EU: European Union)

Source: PRIMES-OM model

Table 43: Capacity reduction due to cancelling of investment or retirements in 2025 across all cases and plant types, in GW

Member States	Baseload Plants					Mid-load Plants					Peak load Plants				
	EOM with scarcity bids (B)	CM in 4 MS w/o X-B (C)	CM in all MS w/o X-B (D)	CM in all MS with X-B (E)	CM in 4 MS with X-B (F)	EOM with scarcity bids (B)	CM in 4 MS w/o X-B (C)	CM in all MS w/o X-B (D)	CM in all MS with X-B (E)	CM in 4 MS with X-B (F)	EOM with scarcity bids (B)	CM in 4 MS w/o X-B (C)	CM in all MS w/o X-B (D)	CM in all MS with X-B (E)	CM in 4 MS with X-B (F)
AT	0.123	0.124	0.041	0.065	0.126						0.182	0.182			0.182
BE	2.008	2.008	2.008	2.008	2.008						0.323	0.323	0.031	0.031	0.335
BG	0.580	0.580		0.580	0.580										
CY											0.114	0.114	0.114	0.114	0.114
CZ	0.041	0.042	0.669	0.675	1.063						0.132	0.132			0.132
DK											0.593	0.593	0.525	0.525	0.527
EE											0.169	0.169	0.169	0.169	0.169
FI	0.039	0.040	0.031	0.031	0.040	0.015	0.027	0.009	0.010	0.024					
FR	0.865	0.859	0.833	0.844	0.860						0.621	0.251	0.096	0.096	0.328
DE	4.321	9.492	7.365	8.349	10.235						2.709	2.723	1.628	2.343	2.723
EL	1.547	1.887	1.340	1.395	1.911						0.333	0.333			0.333
HU											0.260	0.260			0.260
IE											0.257	0.257	0.257	0.257	0.257
IT											7.056	3.462	2.854	3.481	3.464
LV															
LT											0.323	0.323	0.048	0.219	0.323
LU															
MT											0.011	0.011	0.011	0.011	0.011
NL	0.091	0.103	0.063	0.071	0.104	0.056	0.164			0.157	0.057	0.069			0.069
PL	0.116	0.116	0.105	0.106	0.306	0.018	0.020			0.018	0.007	0.007		0.007	0.007
PT											0.158	0.094	0.012	0.013	0.158
RO	0.184	0.184	0.184	0.184	0.184						0.532	0.532	0.143	0.190	0.532
SK											0.003	0.003	0.003	0.003	0.003
SI						0.068	0.068			0.068					
ES											0.969	0.969	0.234	0.234	0.969
SE	0.013	0.013	0.004	0.007	0.013						0.278	0.278			0.278
UK											0.882	0.566	0.566	0.629	0.634
HR											0.105	0.105	0.105	0.105	0.105
EU	9.927	15.448	12.643	14.315	17.429	0.157	0.279	0.009	0.010	0.267	16.072	11.753	6.794	8.426	11.910

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Source: PRIMES-OM model

Table 44: Capacity reduction due to cancelling of investment or retirements in 2030 across all cases and plant types, in GW

	Baseload Plants					Mid-load Plants					Peak load Plants				
Member States	EOM with scarcity bids (B)	CM in 4 MS w/o X-B (C)	CM in all MS w/o X-B (D)	CM in all MS with X-B (E)	CM in 4 MS with X-B (F)	EOM with scarcity bids (B)	CM in 4 MS w/o X-B (C)	CM in all MS w/o X-B (D)	CM in all MS with X-B (E)	CM in 4 MS with X-B (F)	EOM with scarcity bids (B)	CM in 4 MS w/o X-B (C)	CM in all MS w/o X-B (D)	CM in all MS with X-B (E)	CM in 4 MS with X-B (F)
AT	0.12	0.12	0.04	0.07	0.13		0.35			0.35	0.01	0.01			0.01
BE											0.32	0.32	0.16	0.16	0.32
BG	0.58	0.58	0.58	0.58	0.58										
CY											0.11	0.11	0.11	0.11	0.11
CZ	3.00	3.00	1.95	2.32	3.05										
DK											0.52	0.52	0.52	0.52	0.52
EE											0.17	0.17	0.17	0.17	0.17
FI	0.04	0.04	0.03	0.03	0.04	0.01	0.03	0.01	0.01	0.02	0.03	0.03			0.03
FR	0.86	0.86	0.83	0.84	1.43						1.39	0.12	0.10	0.10	0.20
DE	13.94	14.22	10.47	11.71	14.22						1.97	1.97	1.58	1.59	1.97
EL	1.83	2.23	1.37	1.42	1.91						0.30	0.30			0.30
HU															
IE	0.56	0.56	0.56	0.56	0.56						0.26	0.26	0.26	0.26	0.26
IT						0.03					4.47	0.80	0.80	0.80	0.80
LV															
LT											0.28	0.28			0.28
LU															
MT											0.01	0.01	0.01	0.01	0.01
NL	0.43	0.45	0.06	0.07	0.45						0.07	0.07			0.07
PL	0.40	0.40		0.00	0.40	0.05	0.07			0.08	0.02	0.02			0.02
PT											0.13	0.13	0.01	0.01	0.13
RO	0.28	0.28	0.18	0.28	0.28						0.24	0.24	0.10	0.10	0.24
SK	0.13	0.31	0.05	0.05	0.13						0.00	0.00	0.00	0.00	0.00
SI						0.07	0.07			0.07					
ES	2.09	2.09		1.86	2.09						0.78	0.78	0.08	0.08	0.78
SE	0.01	0.01	0.00	0.01	0.01						0.28	0.28			0.28
UK											0.83	0.57	0.58	0.65	0.65
HR											0.10	0.10	0.10	0.10	0.10
EU	24.30	25.16	16.13	19.79	25.29	0.17	0.51	0.01	0.01	0.52	12.28	7.09	4.57	4.66	7.25

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Source: PRIMES-OM model

Table 45: Profit (+) or loss (-) of plants by merit order type in M€'13 in 2025

	Baseload Plants					Mid-load Plants					Peak load Plants				
Member States	**EOM with scarcity bids (B)**	**CM in 4 MS w/o X-B (C)**	**CM in all MS w/o X-B (D)**	**CM in all MS with X-B (E)**	**CM in 4 MS with X-B (F)**	**EOM with scarcity bids (B)**	**CM in 4 MS w/o X-B (C)**	**CM in all MS w/o X-B (D)**	**CM in all MS with X-B (E)**	**CM in 4 MS with X-B (F)**	**EOM with scarcity bids (B)**	**CM in 4 MS w/o X-B (C)**	**CM in all MS w/o X-B (D)**	**CM in all MS with X-B (E)**	**CM in 4 MS with X-B (F)**
AT	10	4	12	-9	3	-177	-193	-49	-75	-188			10	8	
BE	472	471	493	470	475	-48	-126	149	83	-153	-49	-49	-11	-17	-13
BG	419	254	326	405	208	36	24	46	42	15	-12	-15	-7	-8	-15
CY						-23	40		-13	-23	-58	-55	-37	-40	-58
CZ	-134	-406	144	-167	-315	28	23	32	26	22	-7	-7	5	4	-7
DK	101	36	121	54	25	-7	-10	4		-10	-28	-28	-10	-13	-28
EE	204	159	225	186	152						-2	-8	-5	-6	-7
FI	1,650	1,433	1,731	1,546	1,384	-131	-152	-30	-64	-167	-41	-41	-5	-10	-41
FR	1,883	1,422	2,750	1,095	267	-381	61	-79	-125	7	-127	-81	-24	-39	-92
DE	4,973	3,537	4,761	3,537	3,343	-792	-960	-19	-153	-883	-73	-72	27	-20	-72
EL	-52	-25	-66	-113	-28	-275	-307	-73	-121	-307	-63	-63	-33	-40	-63
HU	342	243	411	339	232	-127	-146	-53	-64	-148	-57	-57	-8	-15	-57
IE	72	59	65	35	36	-190	-76	-75	-109	-107	-44	-19	-14	-17	-22
IT	571	549	509	320	417	-2,135	-407	-697	-1,287	-766	-68	-92	-159	-136	-104
LV						-64	-82	-11	-19	-82					
LT						-36	-54	26	14	-68	-13	-13	1	-11	-13
LU						11	10	16	11	5	1		2	2	
MT						8	-6	22	7	-23	-6	-6	-4		
NL	548	434	550	378	412	-509	-624	51	-46	-571	-27	-28	-6	-8	-28
PL	2,037	1,484	2,273	1,798	1,436	-81	-101	46	33	-104	-2	-2	-2	-1	-2
PT						-131	-155	-20	-54	-188	-19	-29	4		-57
RO	519	362	428	486	306	-70	-76	-35	-26	-83	-313	-313	-152	-168	-313
SK	820	716	875	786	699	-76	-78	-31	-38	-78	-22	-22	-7	-9	-22
SI	180	153	182	161	128	-3	-3	-4	-4	-3	-3	-3	10	9	-3
ES	1,611	1,092	1,661	1,199	982	-2,685	-2,783	-1,227	-1,445	-2,785	-112	-112	-16	-28	-112
SE	3,981	3,758	4,033	3,963	3,690	-35	-85	104	77	-99	60	53	-34	-39	76
UK	893	958	884	531	568	-913	757	262	-108	178	-5	-8	-10	-12	-12
HR	56	38	57	42	32	-25	-42	20	24	-44	-19	-19	-6	-9	-19
EU	21,154	16,731	22,423	17,039	14,454	-8,831	-5,552	-1,626	-3,433	-6,653	-1,109	-1,090	-492	-624	-1,087

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Source: PRIMES-OM model

Table 46: Profit (+) or loss (-) of plants by merit order type in M€'13 in 2030

Member States	Baseload Plants					Mid-load Plants					Peak load Plants				
	EOM with scarcity bids (B)	CM in 4 MS w/o X-B (C)	CM in all MS w/o X-B (D)	CM in all MS with X-B (E)	CM in 4 MS with X-B (F)	EOM with scarcity bids (B)	CM in 4 MS w/o X-B (C)	CM in all MS w/o X-B (D)	CM in all MS with X-B (E)	CM in 4 MS with X-B (F)	EOM with scarcity bids (B)	CM in 4 MS w/o X-B (C)	CM in all MS w/o X-B (D)	CM in all MS with X-B (E)	CM in 4 MS with X-B (F)
AT	93	73	107	101	81	-140	-178	-23	-15	-157					
BE						489	264	845	764	266	-46	-46	-14	-19	-46
BG	354	295	519	441	263	16	14	31	26	9	5	5	12	10	4
CY						-31	-27	3	2	-32	-48	-46	-25	-26	-47
CZ	69	-91	255	168	-61	50	43	55	53	44	-7	-7		-2	-7
DK	-128	-169	-98	-119	-168	-11	-11	-4	-5	-11	-30	-30	-14	-15	-30
EE	53	12	76	54	20						-12	-12	-5	-5	-12
FI	798	648	919	854	678	-32	-78	64	40	-71	-43	-43	-4	-8	-43
FR	7,889	9,204	10,153	9,173	8,463	-255	117	33	80	81	-58	17	57	43	5
DE	1,069	415	1,605	1,416	565	1,578	1,141	2,042	1,912	1,195	-38	-38	21	14	-38
EL	-140	-61	-172	-193	-157	-241	-312	-30	-72	-318	-48	-48	-8	-12	-48
HU	555	378	683	615	397	-88	-106	-18	-28	-107	-78	-79	-21	-27	-79
IE	-28	-33	-35	-37	-38	-181	-33	-49	-82	-78	-11	-5	11	-10	-11
IT	-154	5	-51	-393	-219	-2,120	-321	-463	-749	-388	-60	-35	-34	-66	-44
LV	-2	-2	-1	-2	-2	-24	-60	22	18	-53	2	2	3	3	2
LT	31	-2	59	38	20	37	1	68	56	7	10	-4	5	3	-3
LU						25	9	48	44	9	5	5	2	2	6
MT						-20	-22	8		-25	-7	-7		-6	-7
NL	115	-15	225	147	7	-37	-356	347	342	-376	-2	-2	9	8	-2
PL	-294	-712	121	-62	-585	395	292	539	489	334			-1	-1	
PT						-178	-208	-37	-94	-178	-3	-36	27	19	-15
RO	526	491	628	523	459	-5	-53	45	73	-68	-320	-320	-135	-157	-320
SK	268	244	417	365	190	13	-4	30	25		-5	-7	11	10	-6
SI	178	139	201	185	135	6	6	6	5	6	2	2	3	3	2
ES	1,436	1,443	1,526	1,538	1,404	-2,316	-2,310	-780	-1,010	-2,316	-68	-68	22	12	-68
SE	1,241	1,040	1,439	1,388	1,020	390	313	482	456	327	-44	-49	-27	-32	-49
UK	1,704	2,065	2,074	1,832	1,698	-1,007	654	460	220	207	-4	-2		-7	-10
HR	-14	-32	-13	-21	-34	31	3	62	56	-3	-24	-24	-10	-12	-24
EU	15,622	15,336	20,637	18,012	14,135	-3,656	-1,222	3,789	2,608	-1,696	-933	-876	-114	-281	-890

(IE: Ireland, UK: United Kingdom, BE: Belgium, NL: Netherlands, DE: Germany, FR: France, ES: Spain, PT: Portugal, DK: Denmark, SE: Sweden, FI: Finland, AT: Austria, IT: Italy, SI: Slovenia, CZ: Czech Republic, SK: Slovakia, PL: Poland, HU: Hungary, LV: Latvia, EE: Estonia, LT: Lithuania, HR: Croatia, RO: Romania, BG: Bulgaria, EL: Greece, MT: Malta, LU: Luxembourg, CY: Cyprus, EU: European Union)

Source: PRIMES-OM model

Annex A. TECHNICAL NOTE ON THE ASSESSMENT OF THE 550 G CO2/KWH EMISSION LIMIT AS INCLUDED IN THE EC PROPOSAL FOR A REVISED ELECTRICITY REGULATION [COM(2016) 861 FINAL/2]

A.1. INTRODUCTION

In its proposal for a revised Regulation on the internal electricity market (COM(2016) 861), the European Commission sets out new principles for addressing resource adequacy concerns of Member States (MS) and determines the conditions for the introduction of market-compatible capacity mechanisms. The Commission proposes (Art. 23 par. 4) (hereinafter '550 Provision') that:

(a) New generation capacity for which a final investment decision has been made after the entry into force of the Regulation shall only be eligible to participate in a capacity mechanism (CM) if CO_2 emissions are below 550 gr/kWh (hereinafter CM limit) and that

(b) Existing generation capacity emitting 550 gr CO_2/kWh, or more, shall not be committed in capacity mechanisms five years after the entry into force of the Regulation.

The objective of this study is to provide a quantitative assessment of the potential effects of the Regulation on the energy systems and particularly on solid-fired generation, which is the main technology emitting higher than the aforementioned CM limit.

The impact assessment draws on a comparison of PRIMES scenarios. The baseline scenario is the so-called PRIMES EUCO27 (hereinafter 'EUCO27') included in the Commission's Clean energy for all Europeans Package[79]. The EUCO27 was designed to achieve the 2030 targets agreed by the European Council[80]: i.e., the GHG reduction target of at least -40% in 2030 in comparison to 1990s levels, a 27% share of renewables in primary energy consumption and a 27% of energy efficiency improvement. The scenario also meets the targets for GHG reductions in the ETS and non-ETS sectors of -43% and -30% respectively (compared to 2005 levels). In other words, the EUCO27 delivers an EU generation mix which can achieve the 2030 climate and energy objectives at least cost.

The EUCO27 scenario does not take into account the potential adoption of the 550 Provision. Thus it provides projections in the absence of the 550 limit but under perfect foresight conditions and market-based portfolio financing without considering which market arrangements make possible the cost recovery.

The baseline is then compared to an alternative scenario (hereinafter 'DOMESTIC FUEL SUPPORT' scenario), which assumes that the 550 gr CO_2/kWh limit is not adopted and certain Member States decide to support solid-fired generation.

[79] http://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition

[80] http://www.consilium.europa.eu/uedocs/cms_data/d ocs/pressdata/en/ec/145397.pdf

The 'DOMESTIC FUEL SUPPORT' assumes, all other assumptions being equal, that some MS are adding solid-fired capacity with a view to maintaining (approximately) solid power generation capacity in 2025 at the level of 2020 or 2015 (by adding new such capacity as compared to EUCO27). The 'DOMESTIC FUEL SUPPORT' scenario includes around 5.7 GW more solid-fired generation in four selected Member States (Poland, Romania Greece, Estonia) compared to the baseline. The four Member States were selected based on the assumption that they have indigenous coal or lignite or shale oil (only in the case of Estonia) and aim at continuing their use if supported.

The PRIMES model is used to make scenario-projections of this alternative variant of the EUCO27. The projections include readjustment of demand, investment, supply and prices in the energy system, and include readjustment of the carbon prices within the Emissions Trading System (ETS) and the feedback effects on power sector investments, electricity costs, prices and demand.

It is important to note that in the 'DOMESTIC FUEL SUPPORT' scenario the increased use of coal/solid fired generation is not an output of the model, but it is exogenously determined. With other words, the comparison of scenarios (i.e. 'EUCO27' with 'DOMESTIC FUEL SUPPORT') does not give an answer to the question how much more coal/solid fired generation the EU would see if the 550 gr threshold would not apply. The exercise is rather an attempt to illustrate how the EU power system would be affected by incremental coal/solid fired generation. The modelling exercise and the present document cannot, and are not intending to, provide any suggestion whether a capacity mechanism is necessary for any of the Member States and how much capacity it would retain (also of other fossil fuel generation capacity) and thus what its possible impact would be on the overall market.

A.2. DEFINITION OF SCENARIOS

This section provides a description of the scenarios considered in the study: the specifications of the EUCO27 scenario and the scenario in the absence of the CM limit, named ‘DOMESTIC FUEL SUPPORT’.

- **EUCO27[81] (baseline scenario):** For the EUCO27, PRIMES produces a projection of power sector capacities (influenced by investment, refurbishment of old plants and old plant retirement, which are all endogenous in the model) based on the lowest inter-temporal total cost of the system. The economics of investment assume a portfolio-based financing and cost-recovery for the fleet of plants under perfect foresight of demand, the need to meet the target for emissions covered under the EU ETS, fuel prices and technology costs. The model sets the consumer prices to allow generators to recover exactly total costs.

  The modelling approach does not consider which market design arrangements make possible the cost recovery. Instead, it takes the view that as long as investments correspond to a least-cost strategy, the energy market will ensure cost recovery, thereby allowing for investments to materialise. The EUCO27 scenario achieves all 2030 climate and energy targets agreed by the European Council[82], as already outlined in the introduction to this document.

[81] See the technical report on EUCO scenarios, available on: https://ec.europa.eu/energy/sites/ener/files/documents/20170125_-_technical_report_on_euco_scenarios_primes_corrected.pdf

[82] http://www.consilium.europa.eu/uedocs/cms_data/d%20ocs/pressdata/en/ec/145397.pdf

In other words, in the EUCO27 scenario, the projected coal/lignite capacities are part of the least cost system structure that achieves the required targets. As by assumption, there is no uncertainty, and new built is based on economic grounds.

The EUCO27 scenario does not take into account the potential adoption of the 550 Provision. Thus it provides projections in the absence of the 550 limit but under perfect foresight conditions and portfolio financing as outlined above.

- **'DOMESTIC FUEL SUPPORT' (alternative scenario):** The 'DOMESTIC FUEL SUPPORT' scenario includes the following assumptions additional to those of EUCO27:
  - From a legal perspective, it is possible that a mechanism such as a capacity mechanism supports old and new coal/lignite plants.
  - As mentioned the EUCO27 scenario does not consider any mechanism of direct support for capital cost recovery, such as a capacity mechanism. The projected coal/lignite capacities are part of the least cost system structure. As by assumption, there is no uncertainty there is no need for a capacity mechanism.
  - Assuming in this variant that a support mechanism supports coal/lignite plants implies that coal/lignite capacities may be higher than in the EUCO27 projection.
  - Therefore, to design the 'DOMESTIC FUEL SUPPORT' variant, we need to assume which countries may introduce some form of a support mechanism for coal/lignite capacities. In the context of increasing carbon prices, as in the EUCO27 projections, it is obviously unlikely to see significant new coal/lignite investment in the period post-2020[83]. In this context, some countries are likely to see discontinuation in the use of domestic solid fuel resources in the power sector and may consider mechanisms to support new investment using indigenous solid fuels. As a stylised example, we select four countries, and we assume that these countries introduce a support mechanism for new coal/lignite plants to maintain generation using indigenous solid fuels despite the unfavourable economic conditions.
  - This assumption implies that in the 'DOMESTIC FUEL SUPPORT' case includes new solid-fired investment in the selected countries, in addition to capacities projected for the EUCO27 scenario.
  - We assume that this happens in Poland, Romania, Greece and Estonia, which are endowed with domestic resources (hard coal, lignite and oil shale) and see a significant decline of solid fuel firing capacities in the EUCO27 context. We have also considered the Czech Republic, Slovakia and Bulgaria, but we have not retained them due to the consideration that the new coal plants would be to some extent in conflict with the development of nuclear in these countries, as projected in the context of the EUCO27 scenario[84].

[83] The industry has also been supporting this view. See for example a recent Eurelectric statement: http://www.eurelectric.org/media/318380/eurelectric_statement_on_the_energy_transition_2-2017-030-0250-01-e.pdf

[84] The consideration of maintaining domestic resources is achieved in these countries (also or mainly) by reinforcing the nuclear program as this policy option is available for them. Therefore, to make the assumption

- The supporting mechanism concerns new plants which are assumed to operate in 2025. We define the amount of new capacity to support with a view to maintaining (approximately) solid power generation capacity in 2025 at the level of 2015 or 2020 in these countries. Table 47 shows the new additional solid-fired capacity assumed in this scenario variant. Appendix B provides further details.

Table 47: Solid fuel firing plant capacity in the EUCO27 and the 'DOMESTIC FUEL SUPPORT' scenarios.

MW net	Year	Estonia	Greece	Poland	Romania	4 countries
Net Installed Capacity in EUCO27	**2015**	1871	3923	28461	6441	40697
	2020	1413	3054	23057	5626	33150
	2030	1413	2869	19345	1909	25536
Additional new capacity in 2025 assumed for the 'DOMESTIC FUEL SUPPORT' scenario	**2025**	300	300	3500	1600	5700
Total capacity in the 'DOMESTIC FUEL SUPPORT' scenario in 2030	**2030**	1713	3168	22880	3509	31271

Source: PRIMES model

- To simulate this stylised case, we further assume that the supporting mechanism implements a Contract for economic differences (CFDs) which secures total cost recovery of the new solid-fired investments[85] up to 2040. The CFDs include must-run obligations in the period of 2025-2040 (6000 hours annually) and a remuneration that allows for the recovery of all costs plus an economic rent (at 8.5% rate of return on capital). We preferred a CFD with must run obligation instead of a capacity remuneration support because only the former would make sure that the new plant will operate in a future market with escalating carbon prices; otherwise, the limited use of the plant would not reflect the policy desire to use domestic resources.
- All other assumptions (policies and incentives) are the same in this variant as in the EUCO27. However, the ETS market equilibrium readjusts by modifying (in this case by increasing) carbon prices to account for the increased emissions due to the additional new solid-fired plants. Thus comparability with EUCO27 is assumed regarding the ETS emission levels. However, interactions with the Market Stability Reserve beyond the EUCO27 scenario were not modelled explicitly.

A.3. RESULTS

A.3.1. Impacts on ETS carbon prices

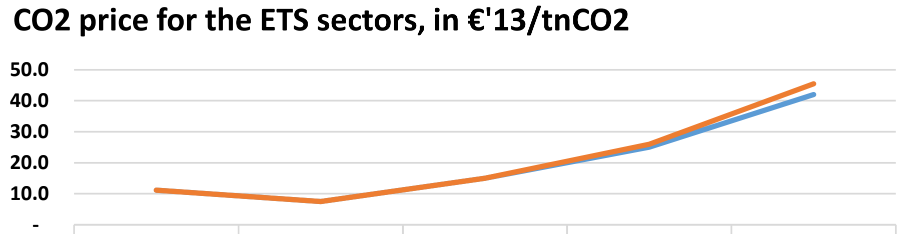
The 'DOMESTIC FUEL SUPPORT' scenario involves an increase in coal/lignite capacities in four countries, compared to the EUCO27 projection, and assumes that the support schemes provide for a must-take obligation until 2040 for the new solid fuel plants included in the scenario. Due to the consequent increase in the production of electricity using solid fuels, the CO2 emissions in these

about the support of domestic coal/lignite resources we take into consideration the development of nuclear in the context of the EUCO scenario.

[85] See the Appendix B for more detailed information, regarding the additional new solid-fired investments

Member States also tend to increase. Therefore the model readjusts the ETS carbon prices (Figure 19) to meet emission target under the ETS. This modified ETS carbon price has further effects on the power sector mix and the structure of investment. The changes in ETS price, together with the necessity to finance additional investment costs and other changes in power generation costs, also influence the electricity prices, which in turn influence the demand for electricity.

Figure 19: ETS Carbon prices in EUCO27 and the 'DOMESTIC FUEL SUPPORT' variant



	2010	2015	2020	2025	2030
EUCO27	11.2	7.5	15.0	25.0	42.0
DOMESTIC FUEL SUPPORT'	11.2	7.5	15.0	26.0	45.5

Source: PRIMES model

Compared to the EUCO27 ETS prices, the additional coal/lignite plants in the context of the 'DOMESTIC FUEL SUPPORT' variant induces 8.5% higher ETS prices in 2030, or increase by €3.5 per tonne CO2. This difference in carbon price in the 'DOMESTIC FUEL SUPPORT' variant, compared to the EUCO27, increases somewhat further during the next decade, but subsequently starts to decrease, in particular after the end of the contracts for differences. Both scenarios project comparable emissions (i.e. cumulative emissions until 2050) for the ETS sector and achieve the same targets in 2030 and 2050

A.3.2. Effects on power capacity and generation mix

The projections in the context of the EUCO27 scenario show a decline of conventional solid fuel firing power plants, driven by the ETS carbon prices in this scenario in line with reaching the 2030 climate and energy objectives at least cost. The reduction in total installed capacity of the solid fuel firing plants, from 176 GW in 2015 down to 98.5 GW in 2030 and 37 GW in 2050. The refurbishment of old solid-firing plants in the period 2016-2030 amounts to 35 GW, which extends the lifetimes of the plants between 5 and 15 years, depending on the technical features of each plant. The investment in new coal/lignite plants without CCS is only 5 GW, and concern plants commissioned up to 2020. The investment in new coal/lignite plants with CCS amounts to 7 GW and concern plants commissioned from 2035 onwards. The utilisation rate of coal/lignite plants in 2030 is on average only 50%. The additional solid fuel plants assumed to receive support in the 'DOMESTIC FUEL SUPPORT' scenario have a stable operation in the period 2025-2040 despite the increase in the ETS prices in the context of the 'DOMESTIC FUEL SUPPORT' scenario, as by assumption they are covered by a must-take privilege.

Table 48 provides an overview of the differences in installed capacities by type between the EUCO27 and the 'DOMESTIC FUEL SUPPORT' scenarios. Thus, their capacity remains the same in all scenarios. In Poland, the additional solid fuel plants act to the detriment of CCGT in the medium term (reduced by 2GW compared to the EUCO27 projection) and to new nuclear and CCS investment in the long-term. Nuclear in Poland is 1.6 GW lower in the 'DOMESTIC FUEL SUPPORT' scenario compared to the EUCO27 and CCS is 0.3 GW lower. The additoinal coal plants displace nuclear and CCS, because all these plants compete to each other mainly in the base load.The increase in ETS prices also favours variable RES investment, but only in the period after 2030. In Romania, the additional solid fuel plants displace investment in CCGT and variable RES lower in the 'DOMESTIC FUEL SUPPORT' scenario compared to the EUCO27. In Greece, the additional solid fuel plant mainly replaces investment in variable RES, whereas in Estonia it replaces investment in a CCGT plant. In the rest of the countries, the increase in the ETS prices due to the additional solid fuel plants induces higher investment in RES and a bit more CCS in the long term. The results show rather small effects on the CCGT plants in these countries.

The table below shows no changes of the refurbished capacities of solid fuel plants in the 'DOMESTIC FUEL SUPPORT' case, compared to the EUCO27, because the refurbishments projected endogenously by PRIMES for the EUCO27 take place in other MS than those adding new solid fuel plants. However, the same table shows a reduction of the refurbishment of gas plants in the 'DOMESTIC FUEL SUPPORT' case, compared to the EUCO27, as part of the displacement of gas capacities induced by the new solid fuel plants.

Table 48: Differences in net installed capacity between the DOMESTIC FUEL SUPPORT and the EUCO27 in EU28

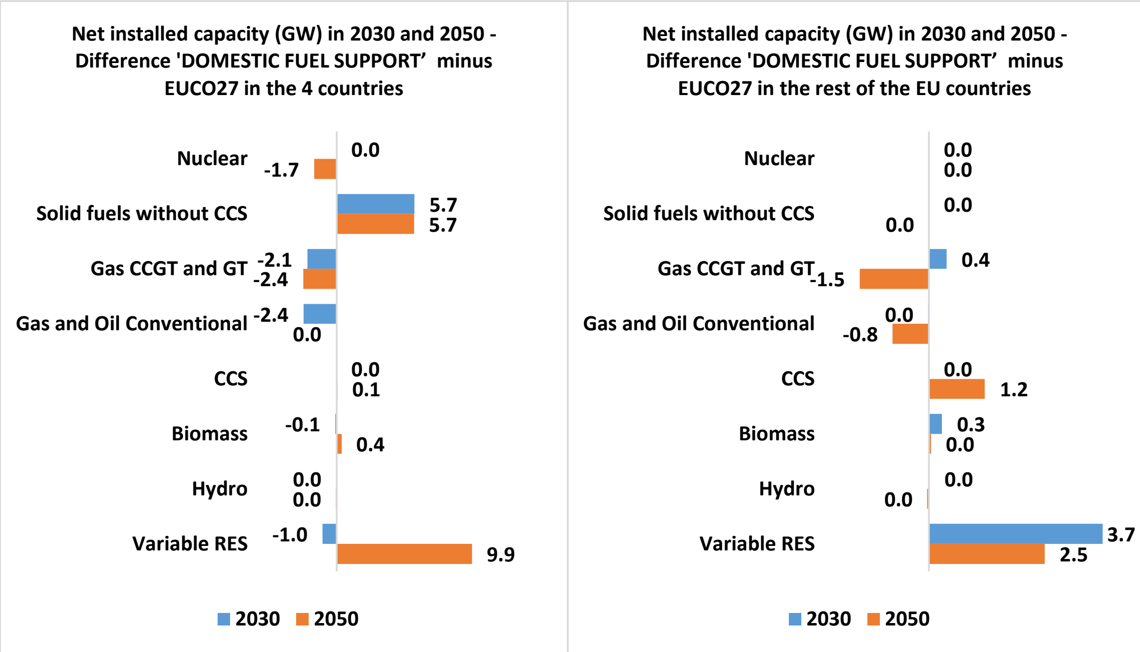
Net installed capacity (GW net)	2025	2030	2040	2050
Nuclear	0.0	0.0	-1.7	-1.6
Solid fuels without CCS	5.7	5.7	5.7	5.7
Gas CCGT and GT	-0.5	-1.8	-4.0	-3.9
Gas and Oil Conventional	-2.3	-2.4	-0.7	-0.8
CCS	0.0	0.0	1.3	1.3
Biomass	0.0	0.2	-0.1	0.4
Hydro	0.0	0.0	-0.1	-0.1
Variable RES	-0.8	2.7	-0.8	12.4
Total	2.1	4.4	-0.3	13.3
New plants (GW net)	2025	2030	2040	2050
Nuclear	0.0	0.0	-1.7	-1.7
Solid fuels without CCS	5.7	5.7	5.7	5.7
Gas CCGT and GT	-0.5	-1.7	-3.1	-3.1
Gas and Oil Conventional	-0.1	-0.2	-0.6	-0.8
CCS	0.0	0.0	1.3	1.3
Biomass	0.0	0.2	-0.1	0.4
Hydro	0.0	0.0	-0.1	-0.1
Variable RES	-0.7	2.8	-0.7	12.5
Total	4.4	6.7	0.7	14.2
Refurbished plants (GW net)	2025	2030	2040	2050
Nuclear	0.0	0.0	0.0	0.0
Solid fuels without CCS	0.0	0.0	0.0	0.0
Gas CCGT and GT	-0.1	-0.1	-0.9	-0.5
Gas and Oil Conventional	0.0	0.0	-0.1	-0.1
CCS	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0
Variable RES	0.0	0.0	0.0	1.0

Total	0.0	-0.1	-1.0	0.5

Source: PRIMES model

Figure 20 shows the impacts on installed capacities separately for the four countries supporting the solid fuel plant investments and for the rest of the EU.

Figure 20: Differences in net installed capacity between the DOMESTIC FUEL SUPPORT and the EUCO27, separately in the four countries and the rest of the EU



Source: PRIMES model

Table 49: Differences in electricity generation between the DOMESTIC FUEL SUPPORT and the EUCO27

Net Power Generation in the 'DOMESTIC FUEL SUPPORT', in TWh

	2025	2030	2035	2040	2045	2050
Nuclear	683.8	736.9	797.8	895.2	932.6	932.2
Solid fuels without CCS	604.5	465.3	221.6	39.5	1.1	0.1
Gas CCGT and GT	468.8	439.9	502.3	172.5	20.2	11.4
Gas and Oil Conventional	121.3	117.4	123.1	116.3	99.3	91.7
CCS	5.7	11.9	105.3	455.6	568.7	508.5
Biomass	233.4	237.2	263.1	255.2	272.8	276.6
Hydro	371.8	375.1	385.1	394.6	404.6	418.3
Variable RES	826.4	1009.6	1156.3	1526.2	1803.8	2119.2
	3315.7	3393.3	3554.7	3855.0	4103.1	4358.0

TWh differences from the EUCO27

	2025	2030	2035	2040	2045	2050
Nuclear	0.0	-1.4	0.0	-12.6	-13.1	-13.1
Solid fuels without CCS	18.0	20.8	12.0	33.4	0.4	-0.1
Gas CCGT and GT	-15.0	-23.7	-22.9	-28.9	-4.8	-0.5
Gas and Oil Conventional	-1.2	-2.6	-1.4	0.1	-2.0	0.5
CCS	0.0	0.0	5.4	8.0	6.8	3.5
Biomass	-0.1	-0.9	1.3	-2.3	1.3	-1.4

Hydro	-0.1	0.0	-0.3	-0.3	0.0	-0.3
Variable RES	-2.7	4.5	2.8	-2.1	9.0	15.9
	-1.1	-3.4	-3.0	-4.6	-2.4	4.6

Source: PRIMES model

With the termination of the CFD by 2040 and under the given carbon constraint, the plants supported by the CFD under the DOMESTIC FUEL SUPPORT scenario become no longer competitive. Therefore, the plants are stranded assets after 2040. In 2030, the additional electricity production using solid fuels is 5% higher in the DOMESTIC FUEL SUPPORT compared to the EUCO27 (Table 49). The additional electricity amount from solids mainly displaces electricity production using gas in 2030. The impacts on production of other plant types are small in the same year. As already mentioned, the increase in the RES and a small increase in the CCS in the DOMESTIC FUEL SUPPORT scenario, compared to the EUCO27, and are due to the increase in the ETS prices. The reduction in the nuclear energy takes place only in one country and is a direct effect of the assumed additional coal plants which compete with nuclear in the base-load part of the demand for electricity.

A.3.3. Effects on cross-border electricity trade

The simulation of the coupled wholesale markets of the EU in 2030 was performed taking into account the ETS prices as projected in the EUCO27 and the 'DOMESTIC FUEL SUPPORT' scenarios and a significant development of RES. In this context, the marginal costs of solid fuel plants are comparable to those of CCGT plants. The simulations have shown that the main drivers of exports are the nuclear energy, the availability of hydro and the balancing which involves sharing of flexible resources. As shown, the new solid fuel plants mainly substitute gas-based generation in 2030. Thus, there is no excess electricity in the four countries, the marginal prices do not significantly decrease, and the flexibility services decrease. In such conditions, the additional solid fuel plants do not provide a competitive advantage for exporting electricity to the four countries.

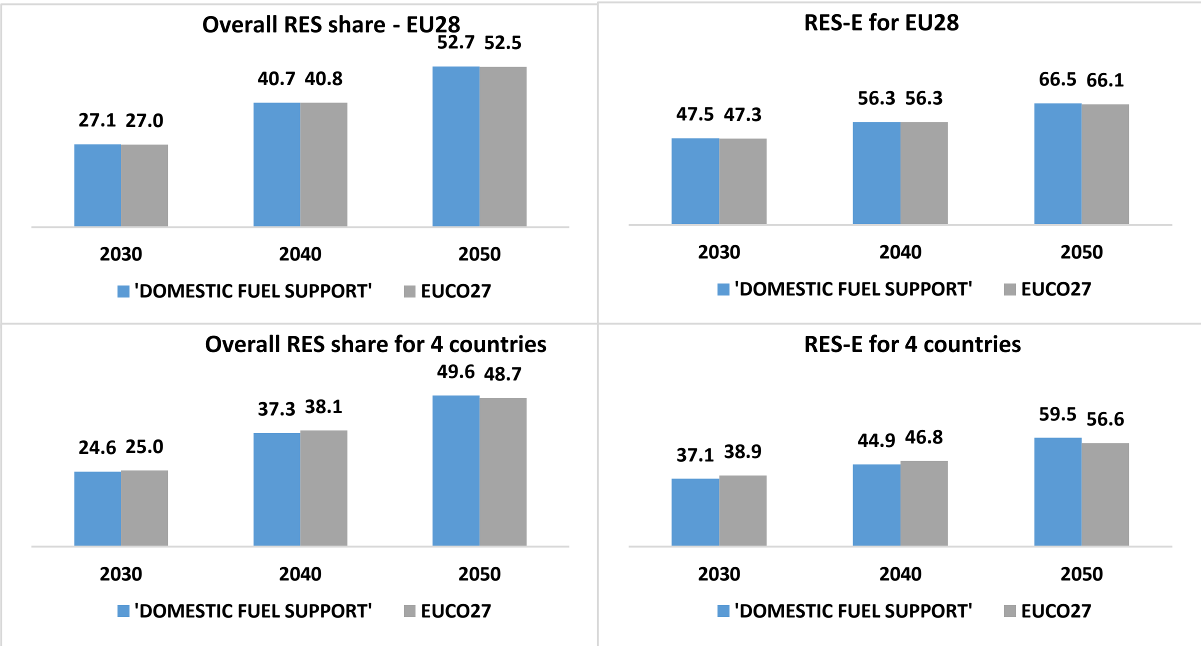
Romania is a significant net exporter of electricity in the EUCO27 scenarios and has few possibilities to increase exports. The same applies to Estonia. Greece is a significant net importer of electricity in the EUCO27, and the additional lignite plant has significantly higher marginal costs than the imported electricity based on nuclear and hydro; therefore the additional lignite plant does not provide any opportunities for exporting electricity from Greece. The systems neighbouring Poland have more competitive prices in 2030, due to nuclear energy in the Czech Republic and Slovakia and to the abundance of RES in Germany. It is unlikely to see changes in exports as the marginal costs of the new coal plants are high relative to other sources of electricity generation on the market.

Based on these considerations, and also to simplify the comparison of scenarios, the modelling kept the same net imports by country in the 'DOMESTIC FUEL SUPPORT' scenario as in the EUCO27.

A.3.4. Effects on RES Shares and emissions

The DOMESTIC FUEL SUPPORT variant implies positive but small changes in the overall RES shares (Figure 21) when seen in the entire EU, compared to the EUCO27 projection. The changes in the RES-E share are also positive but again small. The positive effect on the RES is due to the increase in the ETS prices. There is no direct substitution effect on the RES because according to the model results, the additional solid fuel plant capacities mainly displace gas-firing generation. The impacts of the new solid fuel plants in 2030 are slightly negative for RES in the four countries, but positive in the long term, as solid plants become stranded.

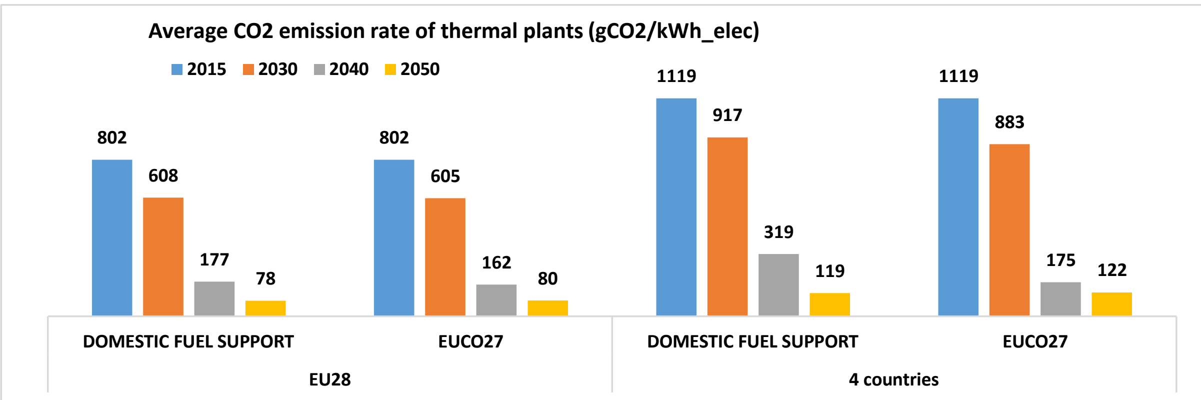
Figure 21: Impacts on the Overall RES and the RES-E shares



Source: PRIMES model

As the PRIMES model readjusts the ETS prices in the DOMESTIC FUEL SUPPORT variant and emission reductions should occur elsewhere in the system so as to ensure overall ETS emission are below the ETS cap, the carbon emissions of the ETS sectors remain roughly unchanged compared to the EU-CO27 projection.

Figure 22: CO2 intensity of power generation using fossil fuels



Source: PRIMES model

The increase in ETS prices by 3.5 € or 8.5% in 2030 in the DOMESTIC FUEL SUPPORT scenario compared to the EUCO27 leads to reductions elsewhere in carbon intensity and emissions that compensate for the emission effects of the solid fuel plants. In the long-term, the projections show a cumulative increase by only 1% in power sector emissions in the DOMESTIC FUEL SUPPORT case compared to the EUCO27.

In the four countries concerned by the assumptions of the DOMESTIC FUEL SUPPORT variant the increase of carbon dioxide emissions in power generation (Table 50), compared to the EUCO27, are significant (2%) in the period until 2030. They are much more pronounced after 2030, reaching 20% increase in cumulative emissions above EUCO27. It is a logical consequence of the must-take privilege, and given that the investments in new coal capacity are not in line with a cost-effective transition towards lower emissions. The increase in RES-E induced by the increase in ETS prices do not offset the increase in emissions due to the additional solid fuel plants, except in Greece and Estonia but only in the period until 2030.

Table 50: CO2 emissions in power generation cumulatively in Mt

	Results for DOMESTIC FUEL SUPPORT	EU28	4 countries
2016-2030	Mt CO2	14332.2	3060.7
	% change from EUCO27	*0.06*	*1.99*
2031-2050	Mt CO2	5156.8	1208.2
	% change from EUCO27	*0.99*	*19.26*

		Central-West Europe	Rest of Central East and South EU	Iberian	British Isles	Scandinavian and rest of Baltic states
2016-2030	Mt CO2	7208.8	1364.5	966.2	1271.3	460.7
	% change from EUCO27	*-0.38*	*-1.11*	*-0.39*	*-0.23*	*-0.41*
2031-2050	Mt CO2	2780.4	427.5	119.7	438.7	182.3
	% change from EUCO27	*-3.14*	*-8.09*	*-4.48*	*-1.39*	*-2.52*

Central-West Europe: Germany, France, Austria, Belgium, Netherlands, Luxembourg, Italy
Rest of Central East and South EU: Czech Republic, Slovakia, Slovenia, Hungary, Bulgaria, Croatia, Cyprus, Malta
Iberian: Spain, Portugal
British Isles: UK, Ireland
Scandinavian and rest of Baltic States: Sweden, Finland, Denmark, Lithuania, Latvia

Source: PRIMES model

A.3.5. Effects on prices and demand for electricity

The impacts on average electricity prices in the retail market (Table 51) and the consequent effects on the demand for electricity (Table 52) are moderate when seen at the level of the entire EU. By 2030, the average electricity price is slightly higher in the DOMESTIC FUEL SUPPORT variant compared to the EUCO27. The results show a stronger increase in electricity prices in the four countries concerned by the assumption about new solid fuel plants supported by the CFDs. The increase in prices in the DOMESTIC FUEL SUPPORT variant continue until 2050.

At the EU level, the price impacts in the DOMESTIC FUEL SUPPORT variant are mainly due to the increase in the ETS carbon prices and, by 2050, the increased investment costs. Although the fuel costs of the new solid fuel plants are lower than in the displaced gas plants, the increase in the cost of purchasing ETS allowances, the higher emissions and the increased investment costs renders the DOMESTIC FUEL SUPPORT generation mix more expensive than in the EUCO27 scenario, in the entire EU and the four MS.

The cost increases are more pronounced in the four concerned countries than in the rest of the EU. In these countries, electricity is 2-5 EUR/MWh more expensive in the DOMESTIC FUEL SUPPORT than in the EUCO27 in 2030 and 5-15 EUR/MWh more expensive in 2040 and 2050. By 2050 this relates largely to the remaining costs associated with increased investment needs in these countries. Logically the change in the power mix as foreseen in the DOMESTIC FUEL SUPPORT scenario is not economical compared to the EuCo27 in the four countries, and in the long term, the new solid fuel plants are clearly stranded assets, which will lead to higher costs for consumers because these investments still need to be paid off.

The modelling finds increases in the electricity prices in all the rest of the EU MS. The impacts are mainly due to the increase in the ETS prices and are more pronounced in 2030 than in the longer term. The eastern and central European countries bear higher impacts on prices than the rest of the EU MS.

In other words, the electricity bills increase compared to the EUCO27 scenario, creating additional costs for the EU energy system as a whole. The results clearly confirm that the DOMESTIC FUEL SUPPORT configuration is economically detrimental for final energy consumers, compared to the EUCO27 scenario and therefore from this perspective including the additional solid fuel plants is not appropriate. This result holds true for the entire EU, and it is very obvious in each of the four countries concerned by the new solid fuel plant construction.

The impacts are even more pronounced after 2030. After 2040 the new plants supported by the CFDs become stranded assets (because after the end of the CFD and the must-take privileges, the capital costs of the plants still need to be recouped from final consumer prices while other investments are necessary to satisfy demand), and other investments, such as in increased RES, need to replace them.

Table 51: Impacts on electricity prices

Average retail electricity price at end-consumer level (€'13/MWh)	DOMESTIC FUEL SUPPORT				% change from EUCO27			
	2025	2030	2040	2050	2025	2030	2040	2050
EU28	156	161	175	173	0.23	0.54	0.78	0.40
4 countries	133	147	170	163	0.42	1.60	7.10	3.81
Central-West Europe	155	159	179	180	0.21	0.57	0.17	0.14
Rest of Central East and South EU	126	134	143	138	0.60	1.50	0.66	0.15
Iberian	163	162	163	152	0.16	0.12	0.04	0.01
British Isles	177	178	177	180	0.15	0.07	0.14	0.03
Scandinavian and rest of Baltic states	137	143	149	147	0.07	0.19	0.07	0.03

Source: PRIMES model

Overall electricity demand decreases slightly due to the increase in prices of electricity. But this in turn changes some of the load profiles (e.g. load following, baseload, etc.) affecting some of the prices for industrial consumers, which leads in a limited amount of cases to small demand increases.

Table 52: Impacts on electricity demand

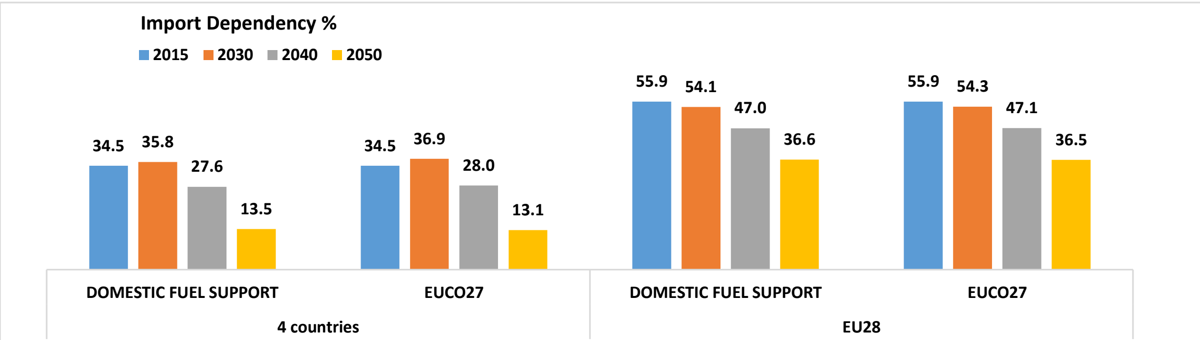
	DOMESTIC FUEL SUPPORT				% change from EUCO27			
Gross electricity consumption (TWh)	2025	2030	2040	2050	2025	2030	2040	2050
EU28	3464	3523	4028	4532	-0.01	-0.08	-0.05	0.09
4 countries	249	272	287	292	0.43	0.28	-1.26	-0.79
Central-West Europe	1827	1838	2071	2300	-0.06	-0.13	0.12	0.36
Rest of Central East and South EU	236	241	281	320	-0.24	-0.51	-0.04	-0.26
Iberian	342	345	386	454	-0.03	-0.02	-0.04	0.00
British Isles	422	444	533	610	-0.03	0.01	-0.03	0.00
Scandinavian and rest of Baltic states	310	318	367	412	-0.01	-0.04	0.20	0.03

Source: PRIMES model

A.3.6. Impacts on import dependency

It could be argued that the interest in maintaining electricity generation based on domestic resources, such as coal or lignite, derive from the objective of minimising dependency on energy imports. The results (Figure 23) show that in the four concerned countries, the DOMESTIC FUEL SUPPORT variant implies very small gains regarding import dependency in 2030. Compared to the EUCO27, the import dependency indicator decreases between 2.2 percentage points (in Romania) and 0.3 percentage points (in Greece), in 2030. However, in these four countries, except in Greece, the import dependency levels are very low, and thus the gains are insignificant. The low carbon pathway of EUCO27 involves a significant reduction of import dependency in the long term, in all countries. Therefore the gains due to the additional solid fuel plants are insignificant also in the long-term. At the level of the entire EU, the gains regarding import dependency in the DOMESTIC FUEL SUPPORT variant are only 0.2 percentage points in 2030.

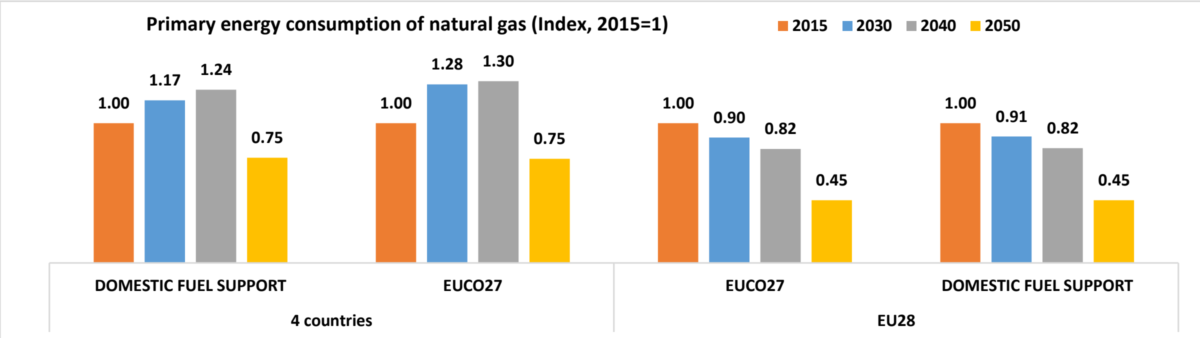
Figure 23: Impacts on import dependency



Source: PRIMES model

Import dependency could be seen from the angle of total primary energy consumption of natural gas, which is in the majority imported in the EU and raises concerns about the security of in some of the MS supply. The results (Figure 24) show that in the entire EU the DOMESTIC FUEL SUPPORT variant reduces total gas consumption by 0.9% in 2030 compared to the EUCO27and it implies no change in consumption in 2050. The reduction of gas consumption is significant in the four countries concerned by the DOMESTIC FUEL SUPPORT assumptions. The reduction in 2030, relative to the EUCO27, ranges between 10% (Poland) and 5% (Greece). The impacts on gas consumption in 2050 are slightly positive in the four countries. The EUCO27 projects total gas consumption in the four countries to increase by approximately 7.4 Mtoe in 2030 compared to 2015 (28% above 2015). The DOMESTIC FUEL SUPPORT assumptions limit this increase to 4.4 Mtoe (16.5% above 2015 levels). Therefore, the additional solid fuel plants in the four countries reduce total gas consumption by 3 Mtoe in 2030 (10% drop in total consumption of gas in the four countries) and reduce total net imports of gas by 2.3 Mtoe, compared to the EUCO27.

Figure 24: Impacts on total requirements of natural gas



Source: PRIMES model

A.4. CONCLUSIONS AND SUMMARY

The PRIMES model was used to quantify the energy-related impacts of the Art. 23 par. 4 of the Commission's proposal for a Regulation on the internal electricity market (COM(2016) 861). According to the proposed regulation, existing and new solid-fired power plants emitting more than 550 gr CO_2/kWh shall not be eligible to participate in capacity mechanisms.

The study aims to illustrate the impact of the 550 gr emission threshold on:

- CO2 emissions
- installed generation capacities
- electricity production
- electricity costs and prices

APPROACH

The impacts are compared relative to the EUCO27 scenario. This scenario is included in the Commission's Clean Energy for all Europeans Package and designed to achieve the 2030 targets agreed by the European Council. This baseline is then compared with an alternative scenario which assumes that the 550 gr CO_2/kWh limit is not adopted ('**DOMESTIC FUEL SUPPORT**' scenario). The 'DOMESTIC FUEL SUPPORT' scenario assumes that around 5.7 GW of solid-fired capacity, additional to that of EUCO27, are installed in 4 MS (Poland, Romania, Greece and Estonia) and are supported by contract for economic differences and must take privileges until 2040. The 4 MS were selected to provide a stylised example based on the assumption that they have indigenous coal or solid fuels which could be exploited if supported.

It is important to note that in the 'DOMESTIC FUEL SUPPORT' scenario the increased use of coal/solid fired generation is not an output of the model, but it is an assumption. In other words, comparing the two model scenarios (i.e. 'EUCO27' with 'DOMESTIC FUEL SUPPORT') we do not provide an answer to the question how much more coal/solid fired generation the EU would see if the 550 gr threshold would not apply. The exercise is rather an attempt to illustrate how our power system would be affected by incremental coal/solid fired generation. The modelling exercise and the present document cannot, and are not intended to, provide any information about deciding whether a CM is needed in any of the Member States and how much capacity it would retain (also of other fossil fuel generation capacity) and thus what its possible impact would be on the overall market.

RESULTS

CO2 emissions: The additional solid fuel plants in four countries in the DOMESTIC FUEL SUPPORT variant, endowed by a must-take privilege, lead to higher demand for allowances and a resulting increase in ETS carbon prices by 2030 by 3.5 € or 8.5%. The EU emission target would be delivered at higher costs (the EU ETS price in 2030 would increase from 42 euro/t ('EUCO27' scenario) to 45.5 euro/t ('DOMESTIC FUEL SUPPORT' scenario).

Installed generation capacities: The operation of the solid fuel plants primarily displace gas-based generation. Nevertheless, as a side effect, increased coal/ solid-fired generation would also result in a slight average increase in RES generation, as a result of higher ETS price.

Electricity production: In line with the impacts on installed capacities, power generation from coal/ solid fired generation increases mostly at the expense of gas-fired generation.

Electricity costs and prices: The additional solid fuel plants have fuel costs lower than the displaced gas plants, but higher total costs when including the costs related to increased carbon emissions and the increased investments needs once they become stranded. Beyond 2030, the energy costs increase even further in the DOMESTIC FUEL SUPPORT compared to the EUCO27 in the four concerned countries, with significantly higher emissions. Beyond 2040 the new solid fuel plants are stranded assets after the termination of the support scheme.

The impacts of the DOMESTIC FUEL SUPPORT assumptions on the rest of the EU are limited, coming mainly as a result of the increase in ETS prices, and thus the electricity price as borne by the final consumers increase in the DOMESTIC FUEL SUPPORT variant compared to the EUCO27.

Import dependency: The impacts regarding import dependency and gas imports in the four concerned countries are small in 2030 and insignificant in the long term. The main reason is that the EUCO27 scenario already results in lower import dependency over time.

CONCLUSION

Uncoordinated support of solid fuel plants implies additional costs for the consumers of the concerned countries, which propagate to the entire EU, via increased demand for allowances and the resulting upward readjustment of ETS carbon prices. Without a long-term support having the form of a CFD with must-take privilege, the new solid fuel plants investments would not be made, as they are not part of the least cost system structure that achieves the required climate and energy targets. The benefits regarding the security of supply are minimal and without a must-run obligation these plants will become stranded assets. In the long term, it leads to substantial sunk costs linked to these subsidised carbon intensive investments.

The distortion of the optimal power mix is significant and is mainly to the detriment of gas-based generation, which is needed to complement the increasing development of RES.

Appendix A.A. Methodology of the Primes Model

The power sector model of PRIMES applies a sophisticated optimisation algorithm to handle generation capacity expansion simultaneously with optimal power flows over the European grid and power plant dispatching, while assuming perfect foresight up to 2050. The endogenous investment decisions distinguish between green-field, brown-field and refurbishment of old plants. The various investment decisions, as well as, the operation of plants and consumption of fuels are endogenous and derive from an inter-temporal optimisation which takes into account the hourly simulation of unit commitment over the entire European network limited by power flow use of interconnectors and technical constraints of system and plant operation. Within the optimal capacity expansion strategy, the model takes into technical restrictions of plant operation by technology type, reliability and reserve constraints at a system level, including for ancillary services and a reserve margin needed to address outages of plants, stochastic resources or unforeseen demand increases. The model is deterministic and handles the uncertainty of load, plant availability and intermittent RES by assuming standard deviations, which influence reserve margin constraints. Ramping up and ramping down restrictions on plant operation, balancing and reserve requirements for intermittent renewables and reliability restriction on flows over interconnectors are also included. The trade of electricity across countries respects a DC-power flow simulation of the interconnected system. The expansion of the network system is exogenously assumed. The unit commitment simulation is on an hourly basis for a few typical days which are distinguished by season, working day or holiday and the intensity of variable renewables. The financial and pricing model of PRIMES determines electricity tariffs by demand sector. The algorithm uses marginal costs and a Ramsey-type distribution of remaining fixed costs to consumer categories, so as to recuperate all costs, including capital and operating costs (and possible stranded investment costs), costs related to schemes supporting renewables, grid costs and other supply costs. In this manner, the model mimics a well-functioning market in which suppliers would conclude efficient and stable bilateral contracts with each customer category based on the specific load profile of the customer.

The PRIMES model simulates emission reductions in ETS sectors as a response to current and future ETS prices, with perfect foresight of the carbon price progression in the period 2025-50 and the fact that no borrowing from the future is permitted. ETS prices are endogenously derived with model iterations until the cumulative ETS cap is met and the provisions of the MSR are respected.

Appendix A.B. Assumptions for new additional solid-fired capacity

Below we provide more details regarding the choice of the four countries for the 'DOMESTIC FUEL SUPPORT' scenario as examples of supporting solid fuel power plant investment. Firstly, we collected information regarding business interest about the investment of new solid fuel plants or refurbishment of old plants. Several of the EU MS have announced an intention to phase out coal in the power sector, and several large-scale electricity companies have excluded coal in their investment programs. Our survey indicated that business interest for coal plants exists only in 6-7 EU MS.

Among them, the Czech Republic has less aged solid fuel plants compared to other countries and at the same time pursues an active nuclear policy. Under such conditions, it is rather unlikely that this country sets up a support mechanism for new coal power plant.

Slovakia has few solid fuel resources domestically. There are no business proposals for new solid fuels plants, and the country has no priority in further exploitation of the small lignite resources. In contrast, Slovakia has an active nuclear policy. Therefore, it is unlikely to see a support mechanism for new coal investment in Slovakia.

The energy policy focuses on nuclear energy in Hungary Historically, generation using solid fuels has represented only 15-20% of total electricity production in Hungary. There have been proposals to open a new lignite mine and build a new lignite power plant, but the plan was stopped for environmental reasons related to the region. There exist no other sites for lignite exploitation, therefore in Hungary as well the support of new coal investment is unlikely.

The power mix in Bulgaria is dominated by nuclear and solid fuels. The latter produce a little above 40% of total electricity generation. The existing solid fuel fleet suffers from non-compliance to the Industrial Emissions Directive. Significant decommissioning of capacities is underway, while the remaining capacity undergoes refurbishment to limit air pollution. At present, business interest for new coal plants exists in Bulgaria, namely for two plants of 600-700MW each. At the same time, priority has been given to attract financing for a new nuclear power plant. Given also the financing constraints, we have assumed that a support mechanism for new coal plant has low chances also in Bulgaria.

Croatia has a small coal power capacity. A new coal plant started operation a few years ago, and new constructions are not foreseen. Therefore, it is unlikely to see the support of new coal investment both in Croatia and Slovenia.

Business and governmental proposals for new solid fuels plants are currently under discussion only in four countries, namely Poland, Romania, Greece and Estonia.

In Estonia, oil shale is considered as a domestic fuel of strategic importance. A new plant burning oil shale has been recently commissioned, while an extension of 300MW is among the possible plans, which would replace capacities planned for decommissioning after 2020.

In Greece, lignite is considered as an important domestic fuel for the security of supply. A significant part of the current capacity of the lignite plant fleet undergoes decommissioning until 2020. The lignite-based generation risks not exceeding 30% by 2025 of the historical average. Constructing an additional lignite plant of 300 MW is under discussion.

In Romania, refurbishing the aged fleet of coal and lignite plants is economically doubtful. Although the country is active in nuclear policy and envisages a new nuclear construction, the government considers preserving an amount of lignite-based generation for the security of supply reasons. The new lignite plant projects, under discussion, amount to 1600 MW, which if built will still imply a significant reduction of solid fuels plant capacity in 2030 compared to 2015.

Poland has considerable coal resources and historically has based its energy system mainly on coal. The fleet of coal plants is aged and requires refurbishment. However, in order to maintain coal capacity at levels equal to 2020 levels, new investments will need to be undertaken. Compared to the EUCO27 scenario this is estimated at a total capacity of 3500MW new coal plants.

There are no issues about coal or lignite plant investments in the rest of the EU MS.

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