The Variation in Capacity Remunerations Requirements in European Electricity Markets

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Highlights:

- Detailed power operations optimisation modelling reveals different capacity remuneration requirements across the EU
- Novel investment, infrastructure legacy and sovereign factors are evaluated
- Wide variation of investment returns for similar gas power plants in each member state
- Energy market harmonisation with sufficient resource adequacy is not yet achievable

Abstract:

This paper provides the first EU wide analysis of the variation in Capacity Remuneration Requirements throughout Europe which aim to resolve the “missing money” problems in various member states. The findings of this analysis point to an asymmetric investment case for gas-fired peaking power plants throughout the EU. Under the assumptions of the European Commission Reference Scenario, pan-European power optimisation and investment models are specified for 2030. The results show that future investment in gas generators will depend on the availability of capacity payments. Capacity remuneration mechanisms can provide this “missing money”, but we show that capacity remuneration requirements vary considerably across countries. We consider and model the impacts of country specific climate policy targets, sovereign risk, capital allowances, corporate taxes and future gas network tariffs on investor returns and therefore remuneration requirements. In the context of harmonised energy trading, this raises questions of how generation adequacy should be achieved, particularly in the context of higher penetrations of renewables.

Keywords: Electricity Investment, Gas, Market Design, Capacity Remuneration Mechanisms, Missing Money

1. Introduction

Harmonisation of the trading arrangements and regulations between connected electricity markets has produced efficiency gains in many regions and the economic case for further harmonisations has been persuasive (Cicala, 2019; Cramton, 2017; Mansur and White, 2007). Trading across larger markets provides access for the most efficient generating facilities, the sharing of reserves and greater dispersion of weather effects. Perhaps the most notable example has been within the EU where a single energy market for electricity has been legislated (European Union, 2012) and wholesale market coupling, intraday balancing, emission trading and industry code harmonisations have resulted. However, at the same time, support for renewable and other low carbon generating technologies has been selective and this has distorted the fundamental economics of the wholesale market. Subsides for renewables have allowed them to be profitable, despite their low marginal costs causing wholesale market prices to fall (Green and Staffell, 2016). Furthermore, harmonised interregional market coupling has also facilitated the greater penetration of renewable technologies, as intermittent large swings in output are more easily accommodated across the interconnected markets. As a consequence, substantially lower wholesale prices have emerged (Newbery et al., 2018).

Whilst there are many benefits from this evolution, nevertheless, for the fossil generators, such as gas-fired power plants, these lower wholesale prices, together with their lower load factors, have reduced revenues and caused asset impairments (Tulloch et al., 2017). This is a concern to policy makers, as well as the asset owners, because these facilities remain essential for the security of the system. Therefore policy-makers have increasingly, often reluctantly, accepted that there is a need for capacity remuneration mechanisms (CRMs) to maintain their essential presence in the system and to incentivise adequate new investment (Bublitz et al., 2019). CRMs arise to compensate generators for the 'missing money' i.e. insufficient returns from the energy only market to recover capital costs and incentivise investment.

As expected, EU policy makers, for example, have been seeking to follow their principles of co-ordination and harmonisation in this respect (Haffner et al., 2017). Specifically, EU energy market harmonisation objectives include implementing a process of open, transparent and non-discriminatory practices to allow foreign bidders to gain access to capacity markets. EU policy makers expect that harmonised capacity markets should ensure that overall costs are reduced, and that cross-border investment incentives and short-term merit order operations of the integrated electricity system are not distorted (Tennbakk et al., 2016). Within the EU single energy market, competition is fair across countries because generators generally face the same input costs and state aid decisions have sought to avoid country advantages. However, with the introduction of CRMs, there is additional competition between generators benefitting from selective state aid, even if approved by the EU.

Different levels of 'missing money' to keep incumbent facilities operational could exist between EU member states because of their existing generation portfolio mix, demand, penetration of renewables, levels of interconnection etc, impacting wholesale electricity prices and capacity factors.[1] It is usually assumed by policy makers however that to incentivise new capacity to meet reliability standards, the long-run marginal cost of a gas peaking facility would provide the basis for the required capacity remuneration. Whilst the technology cost of gas-fired power plants may be the same in each member state, sovereign risk (cost of debt), fiscal measures (taxes and allowances on profits), and the impacts of gas network legacy infrastructure (tariffs) will create variations in the amount of costs which will need to be remunerated through CRMs. These factors could create country specific cost advantages in cross border mechanisms and distort cross border investment decisions. For example, if a generator in a low risk country prefers to get higher capacity payments from a high risk country,

[1] Capacity factors represents the actual output from a generating unit relative to its potential maximum capacity – a measure of technology utilisation.

is the justification of the higher returns based upon compensation for higher counterparty risk? If so, there would be a contradiction with the wholesale energy trading, which is fully harmonised to avoid any country risk premia in the transactions. Plant developers susceptible to higher sovereign risk, network legacy tariffs and taxes with reduced taxable allowances on profits are unlikely to be able to compete with investors facing more favourable cost advantages. This could create challenges in how the fairness of state aid impacts these markets. The open question that follows therefore, and which is analysed in this paper, is whether these CRMs can be introduced into co-ordinated markets in a manner consistent with harmonisation objectives.

An emerging body of research suggests that the unilateral implementations of CRMs, as in Europe, have negative impacts for welfare. Inefficiency results from under/over capacity procurements in interconnected markets in which the CRMs differ (Bhagwat et al., 2017; Cepeda, 2018; Hawker et al., 2017; Höschle et al., 2018; Meyer and Gore, 2015). This arises from capacity payments which are awarded to some generators, who can then offer their electricity production more competitively in their own market and in neighbouring bidding zones. Generators which are non-recipient of capacity payments rely fully on the energy market for their revenues, and therefore would not be able to lower their energy market offer prices. Thus, capacity payments implemented in one bidding zone, but not in a neighbouring one, may potentially distort dispatch decisions. Since the differences in capacity payments tends to be higher than differences in generation tariffs, it is likely that these distortions are more significant than any distortions that would be caused by the lack of transmission tariff structure harmonisation (ACER, 2015a). This issue is raised by Bhagwat et al., (2017) in a different context in which they argue that in an interconnected market a capacity market causes crowding out of generators in the adjacent energy only market. Prior research from McInerney and Bunn, (2013) shows that in order to achieve full market coupling and price convergence between neighbouring electricity markets, the price spread has to be greater than the capacity payment when capacity payments are based on actual power flows. This may create an effective “deadband” where the “energy only” price spread has to be greater than the value of the capacity payment to incentivise export.

The overall objective of this paper is to compute the capacity payments necessary to facilitate investment in new gas assets in each EU country in 2030. CRMs generally evaluate gas peaking facilities as the marginal providers of energy security. We demonstrate that variations in capacity payments required to incentivise resource adequacies arise from different sovereign risks and infrastructure legacies in addition to market operation. We use the results of a European Commission EU Reference Scenario (EC Ref) as a starting point for our analysis. This is a projection of how the EU energy system might evolve in the future assuming all EU and Member State policies and measures implemented by December 2014 are taken into account. Many of these member state polices taken by individual Member States may make sense when agreed at Member State level, but may appear “irrational” when the collective impacts of all Member State policies is viewed through the lens of results from an EU wide energy systems model scenario analysis. Collins et al., (2017) scrutinise the EC Ref in the context of market and operational impacts of renewable energy ambition, and (Gaffney et al., 2018) investigated RES-E exports and imports between member states and highlights concerns regarding uncoordinated support mechanisms, price distortions and cost inequality.

Although we develop our results from extensive and detailed modelling of the capacity remuneration requirements across the various countries in the EU, two research questions feature strongly in our analysis, with general implications beyond the EU. Considering the same technology, combined cycle gas turbines (CCGTs), subject to the same input commodity costs (wholesale gas), we test how the cost of debt, which typically varies by country, influences the costs of capital and thereby becomes a differentiator in the capacity remuneration requirements. Secondly, as load factors for gas generation decrease, and decarbonisation scenarios may project reduced market shares for gas, the legacy costs of gas infrastructure becoming somewhat stranded in different regions could increase the use of system costs for gas generators in substantial and regionally discriminated ways. It is an open question, how material this factor may be in the capacity remuneration requirements. These two locational factors, capital investment risks and stranded gas infrastructures, are considered carefully in our analysis, and contribute to the novelty of our modelling.

Despite the significant research on capacity remuneration in power markets (Brown, 2018; Bublitz et al., 2019; Cepeda, 2018; Fabra, 2018; Hogan, 2017; Joskow, 2008; Meyer and Gore, 2015; Milstein and Tishler, 2019; Newbery, 2016), the challenges of cross-border solutions in this context are apparently under-researched. Using the official European Commission energy system modelling scenario for 2030 (EC Ref), we assess the capacity remuneration requirements using an investment model of gas-fired power plants in each European member state. To generate endogenously a set of inputs for the valuation model, we adapt the approach of Deane et al. (2012) in linking a power system model to an energy system model and utilise the Collins et al. (2017) optimised European dispatch model based on the EC Ref. The market conditions from the 2030 simulation for the gas generation assets are replicated for 20 years under the modelling assumptions as outlined, in order to cover the economic life of the asset.

We also estimate future gas transmission network tariff increases with the EC Ref country scenarios (European Commission, 2016). The deficits in the investment cases for gas-fired power plants (so-called "missing monies") create member state specific requirements for capacity remuneration, or other remedies. In particular, the results challenges the EC's vision of an EU harmonised, market wide solution, needed to mitigate this market distortion. Our focus is not to consider what these solutions might be or their design, but to quantify this difference in investment risk by way of the level of "missing money" for gas-fired power plants throughout Europe. To the best of our knowledge this is the first study to do so. In addition to the key drivers of the cost of debt and infrastructure legacy risks from the gas network, we also consider two further factors which may cause differing capacity remuneration requirements between EU member states, namely diversity in climate policy targets and fiscal policies relating to capital allowances.

The paper proceeds as follows: the next section provides a review of relevant background research on capacity remuneration in power markets; Section 3 outlines the modelling and Section 4 provides the results and section 5 concludes.

2 Background Research

We focus upon new investment in marginal gas-fired generating units since this is the standard way that policy-makers evaluate the need for capacity payments (Fabra, 2018; Newbery, 2016). Gas turbines provide the flexibility, reliability and economic asset of choice for system security. We therefore analyse the investment case for a gas-fired power plant in each EU member state to calculate how much extra capital is needed for their investments to be economically attractive. Note that we are not suggesting that each country needs just one standard size gas peaking plant, rather it is the cost of one of these that provides the marginal cost of new capacity.

2.1 "Missing money" and climate policy

Analysis of the investment case for gas-fired power plants has generally pointed to negative returns with increasing investment risk if the growth of renewable sources of electricity are considered. Green and Vasilakos (2011) find a moderate increase in the volatility of fossil fuel plant profits given year-to-year wind output variations for a wind capacity share of about 30% compared to a case with solely year-to-year demand variations. The Monte Carlo simulation by Muñoz and Bunn (2013), also incorporating other risk factors (e.g. fuel price risks), results in substantially higher financial risks for wind, nuclear and Combined Cycle Gas Turbine (CCGT) plants if wind capacities replace coal. Traber and Kemfert (2011) find falling market prices from increased wind supply disincentivizes investments in gas-fired power plants, with increased wind supply eroding their attractiveness further. Consequently, a gap between the need for and the incentive to provide flexibility can be expected. This is consistent with Steggals et al. (2011) who notes a further concern is that the revenues of fossil fuel plants might also be affected by increasing renewable shares.

2.2 Existing models

Prior research has not incorporated the main features of our modelling which includes the risks of future climate policy targets, the impact of gas network infrastructure legacy risks, corporate tax and capital allowances, sovereign debt risk and a broad technically robust optimisation of the entire European internal electricity market. Roques et al. (2008) use Monte Carlo simulations to generate inputs for portfolio optimization to calculate Net Present Value (NPV) distributions. Similar to our analysis they use a cash flow model, but they simplify with fixed production volumes and normally distributed fuel, CO2 and electricity prices. Other studies pursue a similar approach but calculate endogenous production volumes and power prices with supply function models (Green, 2008) or use stochastic processes for fuel and power prices (Ziegler et al., 2012). Lynch et al. (2013), using a least-cost unit commitment and dispatch model of Ireland, determine production volumes and electricity prices endogenously. Following a Monte Carlo simulation approach for inter-annual fuel and CO2 price risks they calculate long-term investment risks, but pursue a non-equilibrium approach. Tietjen et al. (2016) pursue a non-equilibrium approach in their theoretical analysis under different carbon prices, but do not provide direct insight into the investment case for gas-fired power plants, focusing instead on the risk benefits of renewables.

Going beyond this body of work, our modelling determines optimal dispatch decisions and related power prices endogenously based upon the high temporal resolution and large geographical coverage of a detailed European energy system model. We calibrate this to an official EC Ref for the whole energy system, transport and greenhouse gas emission developments. There are natural uncertainties in the development of the EU power system that will cause future projections to deviate from the limited scenarios examined here. The increased or reduced development of renewable electricity in Member States, the phasing out of thermal power plants, the levels of CO2 and fuel prices and the impact of changing electricity demand, would all impact the volume and direction of flows across European electricity markets. These factors could directly impact how cross border capacity mechanisms operate. One of the difficulties encountered in the study of cross-border effects is the large number of influential factors such as the regarded markets, generation technologies, uncertainty of fuel and carbon costs, different interconnector capacities or asymmetric market sizes. Furthermore, cross-border effects are strongly influenced by competition between market participants and the possibility of exerting market power (Meyer and Gore, 2015). Thus, deriving common conclusions is extremely challenging.

3. Methodology

A cash flow model was formulated to assess the investment case for gas-fired power plants in the target year of 2030 in all European countries. The required parameters for this cash flow model, i.e. market prices, production, plant cycling, carbon emissions and fuel consumption, are generated from another model which optimises least-cost unit commitment and dispatch across the European markets. The carbon prices and wholesale gas prices for plant operation are consistent with the EC 2016 Ref (see appendix). The other exogenous costs, including capital costs, fixed and variable operation and maintenance costs (see appendix) are also aligned with European Commission estimates (JRC, 2014).

3.1 Pan-European Optimisation Model for Market Prices and Power Plant Operations

The EC Ref specifies the parameters for a power system model comprising of the 30 interconnected European countries (EU-28 Member States, plus Norway and Switzerland) focusing on the year 2030. We applied these parameters to a specification of the PLEXOS® Integrated Energy Model, which is widely used worldwide for power and gas market modelling (Clancy et al., 2015; Deane et al., 2012; European Commission and IRENA, 2018). The software is a unit commitment and economic dispatch modelling tool that optimises, at least cost, the operation of the electricity system over the simulation period, using high technical and temporal resolution, whilst respecting operational constraints. Using hourly dispatch, in line with the EU Target Model day-ahead market scheduling platform, 365 days were simulated to replicate 2030. The installed power generation capacities for the EU-28 Member States are specified in the EC. Ref Scenario by generation class, for example; Hydro, Oil, Gas, Solids, Biomass/Waste, etc. The portfolios were disaggregated into individual power plant types by fuel class and assigned standard technical characteristics as shown in the appendix, following Deane et al. (2013) and Collins et al. (2017). Inertia and fast frequency response are not accounted for in the simulations. Given the large quantity of conventional synchronous generation in the scenario inertia is not an issue in the results for 2030. Assumptions based on ENTSOE (2015) were used to represent the Swiss and Norwegian power systems. The model is simulated as a closed loop comprising of 30 European countries and 58 interconnectors, such that overall regional generation must meet regional load in each hour simulated. The interconnection capacities between countries represented in the model are based on projections from ENTSOE (2015). Net transfer capacities are limited for this work to Interconnection between Member States and no interregional transmission is considered below Member State level. The electricity network expansion is aligned with the latest 10 Year Development Plan from ENTSO-E, without making any judgement on the likelihood of certain projects materialising. An in-depth discussion on the model parameters and their key sensitivities is provided at Collins et al., (2017), in addition to an open source version of the model. This optimisation model therefore provides the load factors and average achieved market prices for a new gas turbine as specified above in each of the European countries. The range of average market prices achieved is shown in Table 8 and 9 in the Appendix, along with a flowchart of model input parameters.

3.2 Description of the valuation model

The outputs from the above optimisation model feed into the valuation model for a new gas turbine. As in Collins et al. (2017), we assume a gas-fired power plant size of 450 MW. We focus on the hurdle rate for capital to be forthcoming from investors, as this investment criterion is consistent with general investment practice (Graham and Harvey, 2001). A pre-tax Weighted Average Costs of Capital (WACC) is used as an input variable to the model which sets a minimum hurdle rate each project would need to achieve to receive investment. A project with a hurdle rate above the cost of its capital is commonly assumed to create value (Fama and French, 1998; Pratt and Grabowski, 2008; Titman and Martin, 2008). Empirical surveys of US and European power companies indicate that corporate WACCs have generally been in the range of 7-8% (KPMG, 2018). This is consistent with the Eurelectric (2013) estimate of an average WACC of 8.2% for leading European power utility companies in 2012. We therefore take 8% as our base case, but, in order to reflect the difference in risk profiles for investments across Europe, we consider a sensitivity range of hurdle rates, 4%, 6%, 8% and 10%, in each member state.

The cash-flow model is used to evaluate the financial performance of the asset over 20 years based on its operational performance in the year 2030. Whilst the operational life of facilities may be much longer, 20 years is usual for investment evaluations (EPRS, 2017). If a generator makes a loss in a year, the model is programmed to allocate capacity payments to the generator in order to achieve the target hurdle rate over the asset's 20yr life. To be clear about the motivation, it is not suggested that gas fired power plants will be able to fully recoup costs of the predeteremined hurdle rate in the future; rather that, if generators are to depend on revenues outside of selling energy, we compute what they would need to be on average, to create an investment case. For a full discussion of the considerations of using the hurdle rate in investment appraisals see Pike and Neale (2012) or Brealey, Myers, and Allen (2016). The table below summarises how the cash flow model was specified.

Table 1: Assumptions for calculations in the cash flow model

EC Reference Scenario & ENTSO-E	PLEXOS Power System Simulation	Valuation Model
EC Ref. provides: • Installed capacities • Fuel Prices • Carbon Prices • Electricity Demand ENTSO-E provides: • Interconnector capacities by member state	PLEXOS provides: • Wholesale Market Prices • MWhs Produced • Plant Cycling • Fuel Offtake	Valuation Model Calculations: Revenue: • Market Price x Generator Output Start & Shutdown Cost: • Cycling x Start & Shutdown Cost Fuel Cost: • Nat Gas Price x Fuel Offtake Emissions Cost: • Emissions Cost x Fuel Offtake Fixed O&M: • % of Capital Cost Variable O&M: • Generator Output

The flow chart from Table 1 describes the transfer of inputs and outputs between models to calculate the financial performance and capacity payments. Outputs from the EC Ref provides a projection of installed capacities of power plants and interconnectors for all Member States. EC Ref results act as inputs into a PLEXOS EU-wide unit commitment and economic dispatch model developed previously by Collins et al., (2017). The PLEXOS model, generates market prices, production, plant cycling, carbon emissions and fuel consumption. These inputs are used in the valuation model for a new gas turbine to evaluate the financial performance and capacity payments of the asset over 20 years based on its operational performance in the year 2030.

3.3 Assumptions for debt financing

The cost of capital is a linear combination of the risk-free interest rate plus a market risk premium (Bruner et al., 1998; Graham and Harvey, 2001; Lintner, 1965; Markowitz, 1952;

Sharpe, 1964; Van Binsbergen et al., 2010). In estimating the cost of debt, we have taken the risk-free rate in each country, (a power utility-specific debt premium of 2.5% and assumed a debt-to-equity ratio of 70%, as in Donovan and Corbishley (2016). The CAPM approach to valuing returns to utilities is well established in theory and practice (Brigham et al., 1985; Brigham and Crum, 1977; Litzenberger et al., 1980).

Table 2 Cost assumptions combined cycle gas turbine (CCGT) power plant

Country	Corporate Tax	Cost of Debt	Capital Allowances	Network Costs (€/MWh)
AT	25.0%	3.7%	62.8%	€3
BE	34.0%	4.0%	76.3%	€21
BG	10.0%	4.2%	100.0%	€21
CY	12.5%	4.1%	100.0%	€6
CZ	19.0%	5.1%	73.3%	€22
DE	32.9%	3.4%	61.5%	€5
DK	22.0%	3.8%	68.2%	€29
EE	20.0%	4.1%	100.0%	€5
ES	28.0%	4.6%	54.5%	€4
FI	20.0%	3.9%	68.7%	€13
FR	33.3%	3.9%	73.2%	€8
GR	29.0%	7.5%	63.1%	€4
HR	20.0%	4.7%	100.0%	€23
HU	9.0%	5.4%	60.3%	€4
IE	12.5%	4.1%	62.5%	€29
IT	27.9%	5.7%	66.8%	€3
LT	15.0%	4.2%	100.0%	€10
LU	29.2%	4.1%	70.9%	€30
LV	15.0%	4.1%	100.0%	€7
MT	35.0%	4.5%	100.0%	€6
NL	25.0%	3.5%	67.3%	€1
PL	19.0%	5.3%	59.3%	€6
PT	21.0%	5.2%	72.6%	€7
RO	16.0%	6.3%	100.0%	€24
SE	22.0%	3.8%	70.3%	€34
SI	19.0%	4.3%	65.3%	€8
SK	22.0%	4.1%	78.2%	€9
UK	17.0%	4.4%	57.2%	€6

For the 20-year project horizon, a 20-year spot yield on government bonds was estimated and applied as the risk-free rate in each member state. For member states in which 20-year bond yields were not available the below regression equation was utilised as a predictor. All yields were applied on the 24th of May 2018.

$$R_{20}^{10} = \beta_0 + \beta_1 R_{10} \qquad (1)$$

The 20 year government bond, in member states which have not issued one, is a function of the spread or difference between 10 and 20 year government bonds in member states in which they are issued. This spread reflects the difference in the risk or premium of a 20 year bond in comparison to a 10 year bond. We follow a simplified version of (Taylor, 1992) to estimate government bond yields. The overall approach is consistent with the Donovan and Corbishley (2016) approach to estimating the cost of capital for utilities. Figure 1 summarises the range in the cost of debt across the member states.

3.4 Fiscal Matters

Tax and Capital Allowances vary by country and influence the model for valuation. For example, corporate taxes are higher in France (33.3%) and Belgium (34.9%) and lower in Ireland (12.5%) and Hungary (9%). Generally, the depreciation of an asset can be deducted against its corporate tax liability from profits earned, creating a capital allowance. The level of depreciation that can be deducted also varies in Europe. From Spain (54.5%), UK (57.2%), and Poland (59.3%) to 100% in Estonia and Latvia of an assets total cost, assuming a weighted average capital allowance. This influences the amount of tax paid on profits annually and therefore contributes to determining the capacity payments needed to achieve the target hurdle rate.

3.5 Gas network cost implications

Our modelling of gas turbine investment is unusual in terms of the detail that we pursue in taking account of the cost of using the gas network as well as the wholesale cost of gas. The motivation for this is that with lower load factors for gas generation following decarbonisation scenarios, the legacy costs of the gas network will be levied on less demand, rendering the per MWh costs more substantial. We model this carefully.

The cost per MWh of gas transported is calculated based on a principle that all users of the gas network contribute proportionally depending on their respective utilisation, as follows:

$$CPK_t = \frac{G_t}{C_{t=1} + O_{t=1} + D_{t=1}} \qquad (2)$$

CPK = Cost per MWh transported
G = Gross national Consumption — *D* = Depreciation
C = Capital Expenditure — *t* = time period
O = Operational Expenditure — *t = 1* = at time period 2015

At a high level, gas network operator revenues are a function of three components of capital expenditure, operational expenditure and depreciation of the asset base (IERN, 2010). The sum of these components equates to the required revenue to operate the network annually. If the revenue received exceeds the required revenue it equates to an over recovery and results in reduced tariffs to compensate and vice versa for a revenue under recovery. The base year costs per €/MWh of gas by member state is sourced from a European Commission report of energy sector costs in 2017 (European Commission, 2019). For example, in 2017 the cost of transporting gas to power plants in the Netherlands was approximately €1/MWh of gas transported, €3/MWh in Italy and €6/MWh in the UK in comparison to €13/MWh in Finland, €12/MWh in Denmark and Sweden.

Prior work has shown that to reach European climate targets in 2050 a large amount of gas infrastructure could be underutilised (Trinomics, 2016). Almost all gas-fired power plants in Europe receive their fuel from the networks and are charged the regulated network tariffs. Throughout the EU, the regulated tariffs are based on an allowed return on the value of the assets, known as the regulatory asset base. A full recovery of investor capital would aims to ensure there is no stranded asset risk for investors, providing an incentive for further investment in gas network infrastructure (Stern, 2013). If gas use declines in power generation through lower utilisation rates, due to the networks fixed cost nature, the tariffs would therefore increase.

In our analysis going forward to 2030, we model capital expenditure in the gas network by multiplying the cost per kilometre of transmission pipeline at €1,098,820/km by the network length in that member state. This data is taken from a survey on infrastructure unit investment costs sourced from EU energy regulators (ACER, 2015b) and from a report on gas entry and exit regimes throughout the EU (DNV KEMA, 2013). Compressor stations are also included at €14,904.59 bcma/ km, operational costs assumed at 1% of pipeline installed capital costs and at 4% of installed compressor capital costs, all sourced from the TIGER model (Lochner, 2011). The asset life is assumed to be 50 years. Annual straight-line depreciation is estimated at 1% of the asset base. An expansion constant is formulated for member states that experience increased gas use relative to today's levels, under the previously described costs parameters. Where gas consumption exceeds historic levels increased capital expenditure is required followed by higher operating costs and a higher depreciation expense follows as a result of that increased gas consumption. The formula to calculate the level of under or over recovery is

$$\pi_i = R_{i=1} -/+\left(CPK_i \times ((G_i - PE_i) + PP_i)\right) \tag{3}$$

π = Level of Under or Over Recovery

R = Required Revenue

PE = Gas Consumption in Power Generation with reference to the PRIMES Model (EC. Ref)

PP = Gas Consumption in Power Generation with reference to the Power System Model

The increase or decrease in tariffs required to ensure the network remains viable is a direct function of the level of under or over recovery of revenues in the period. In equation 3, R_i is the revenue required to cover the annual costs of the gas network. If the required revenue is under recovered, due to lower gas demand, then tariffs will need to increase to compensate network operators. Gas in the EC Ref separates gas demand in the power sector from gas demand in other sectors. The combined level of gas demand in aggregate is then multiplied by CPK, the original tariff in 2015. If CPK by the gas demand projection is less than the required, the tariff, increases. While the assumption that the stranded cost of gas networks would be paid on a per MWh transmission tariff is debatable, we use this approach to simply illustrate the potential change in tariffs to maintain the RAB." Hickey et al., (2019) provide a detailed discussion on the relationship between gas demand scenarios and gas network tariffs.

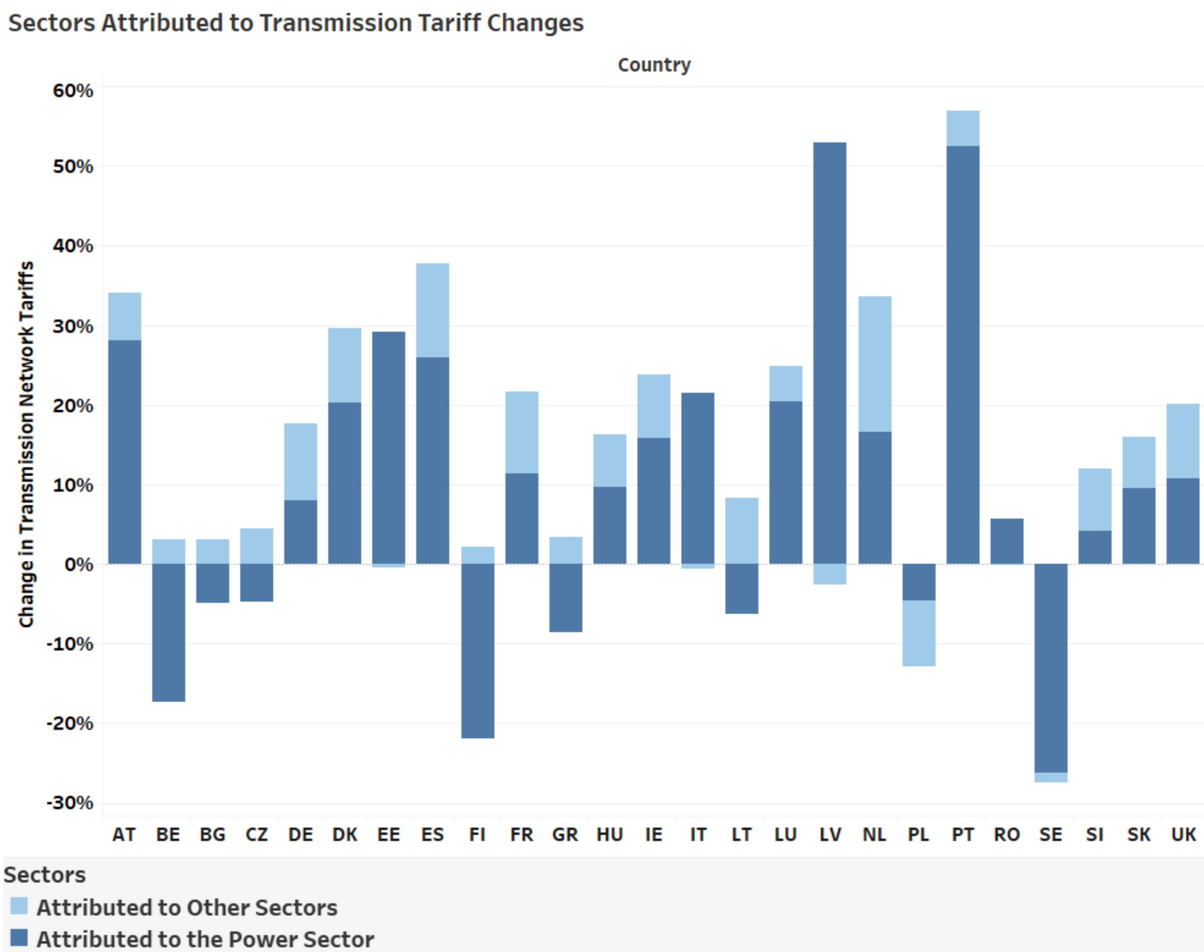

Figure 1. Change in gas transmission network tariffs by member state 2015 to 2030

In Figure 2 the tariff changes are shown per country and attributed to Power or Other Sectors, the latter including residential, services, industry and transport. The projections for gas demand in the power generation sector are from the fuel offtakes of gas-fired power plants in the power system optimisation model, with the gas demand outside of the power sector sourced from the EC Ref. Networks with a greater proportion of gas used in power generation relative to final energy demand are subject to a greater risk of high tariff increases in this period and we observe for example that Portugal, Latvia and Spain and the Netherlands are most exposed to tariff increases. In order to assess the materiality these tariff changes in the operating costs for the gas turbines in each country, we compute the capacity remuneration requirements firstly assuming the gas network costs to power plants at 2017 levels, and then by including the gas network tariff increases.

4. Results on Capacity Remuneration Requirements

Gas-fired power plant revenues are calculated by multiplying the average annual wholesale electricity price gas-fired power plants receive in each country by their units of electricity produced. Market prices are modelled from the average hourly system marginal price in each country. Additionally, the optimisation ensures generators recover both start-up costs and variable operating costs as well as future increases in CO_2 prices. Scarcity pricing is part of the modelling but filtered out in the determination of regional wholesale energy prices. Uplift was enabled in the determination of pricing to ensure generators recovered fixed costs, but this did not affect the optimal dispatch. However, this means the model-based prices are not directly comparable to today's wholesale energy pricing. The prices reflected in the results of this work are higher than current levels at the time of modelling because of this uplift coupled with higher assumed CO2 and gas prices. However this does not invalidate the relative implications taken from the analyses. The model computes the average market price received by the gas turbines, according to when they are dispatched.

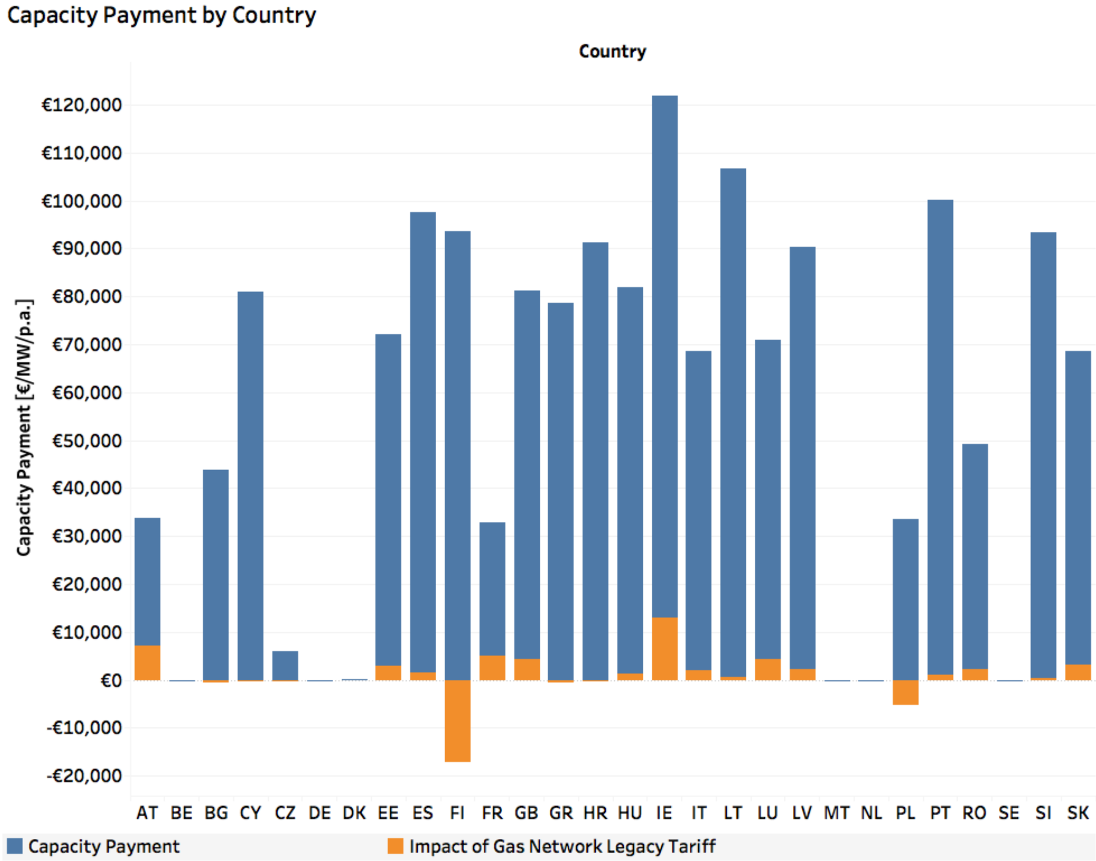

Figure 2. Capacity payments required (€/MW/p.a.) by country

In Figure 2, we summarise with a bar chart the country variations in capacity payments required (€/MW/p.a.) as may be acquired through a capacity auction process. The capacity auction process assumes each generator will offer in a price at which they can procure a MW of installed capacity of CCGT (Net cost of New Entry). The prices in Figure 2, assume uniform auctions implying that the price each bidder receives is set by the most competitive bidder at the margin to meet the quantity required by each country at the auctions. We presume that these marginal competitive bidders will be offering CCGTs. Figure 3 converts those capacity payments, via computed load factors, to €/MWh and displays them together with the computed market prices to show the aggregate effective market prices (aka "long run marginal costs", or "levelised" costs) required by generators across the countries. Figure 4 shows this geographically in terms of proportion of revenue required from capacity payments. In the Appendix, the capacity payments (Capacity Remuneration Requirements) are reported for all countries in Tables 6 to 11, for various hurdle rate sensitivities, with and without the gas legacy tariff increases.

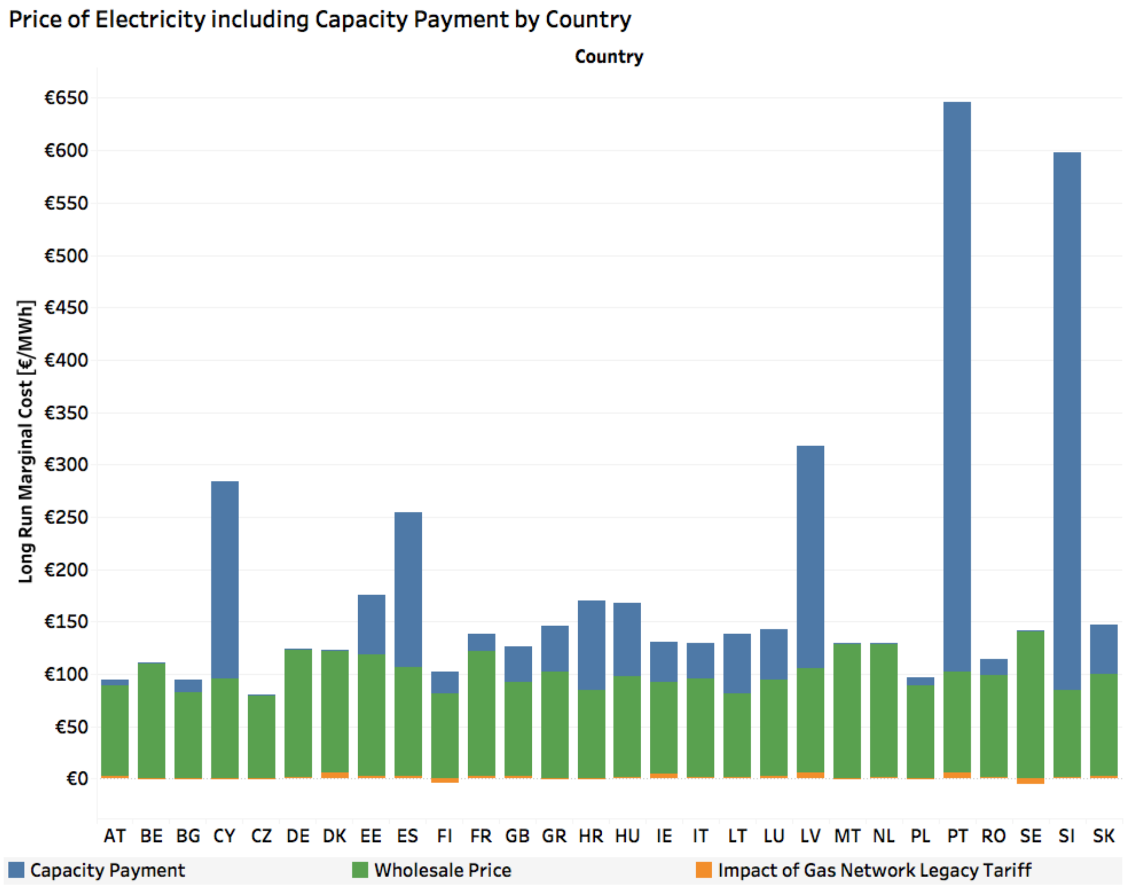

Figure 3. Effective market price of electricity including capacity payments by country

A wide variation across countries is evident, with respect to capacity remuneration requirements and long-run marginal costs (LRMC), under the assumptions of the modelling approach exists. The difference in wholesale prices received by CCGT operators in each country reflects the dispatch of generation units throughout the year and how gas-fired power plants operate on the merit order supply function for generation. The LMRC sometimes referred to as levelised costs, represent what the average price each generator would need to receive to achieve a given hurdle rate, and these include the annuitized capital costs as well as the short-run marginal running costs. The LRMC is split into the wholesale price received and its capacity payment component in Figure 3. It is useful to reflect upon the main factors behind the wide disparity in country capacity remuneration requirements. The differences between capacity payments (€/MW/p.a.) and LRMCs is largely influenced by low capacity factors or utilisation rates and prices of gas plants.

The capacity payments in Ireland, Latvia and Portugal exceeds €100,000/MW/p.a. which contrasts with the zero capacity remuneration requirements in Belgium, Germany, Denmark, Malta, the Netherlands and Sweden. For comparison, capacity has been procured in Ireland in 2018 at a capacity auction clearing price of €46,150/MW/p.a. (Eirgrid, 2019). There are clear outliers with respect to electricity prices inclusive of capacity payments in Portugal, Slovenia, Latvia, Spain and Cyprus due to low plant utilisation rates, this emulates the difficulty and variation by country for gas plants to recover sufficient revenue from energy only markets. We also note that the gas legacy effect through tariff changes is small but significant in its difference from one member state to another. For example in Austria gas legacy effects account for 27% of the capacity payment, 15% in France and 10% in Ireland, which is more than double the capacity payment for the Czech Republic. The expansion and resultant economies of scale gained in Finish and Polish gas networks reduces gas network tariffs and capacity payments by 23% and 19% respectively.

Table 3: Capacity Factors

Capacity Factors	France		Germany		Ireland		Italy		Spain		Sweden		UK	
%	2015	2030	2015	2030	2015	2030	2015	2030	2015	2030	2015	2030	2015	2030
Gas	30	20	42	34	36	25	24	21	19	7	5	31	40	23
Coal	19	4	59	57	65	65	71	61	64	6	49	14	59	24
Nuclear	80	75	91	0	0	0	0	0	90	75	69	75	79	75
Solar	16	13	10	10	7	9	14	14	19	17	10	8	9	9
Wind	24	33	17	28	28	35	19	30	26	28	25	28	29	33
Hydro	31	36	46	54	35	36	30	37	23	27	50	44	37	27

From Figure 2, Belgium, Denmark, Germany, Malta, the Netherlands and Sweden do not receive capacity remunerations. These countries have the most efficient gas-fired-power plants, therefore they receive the greatest profits on each unit of electricity sold, these units are also the most competitive. The decommissioning of nuclear power in Germany and retirement of coal capacity in these countries creates an opportunity for new efficient gas-fired power plants. The increasing installed capacity of renewables across the EU coupled with their low marginal cost nature is displacing gas to some degree in all member states. Thus low capacity factors coupled with suppressed market prices, from a further integration of renewables, are the main drivers of "missing money" and need for capacity remuneration. Countries with generators receiving relatively high capacity payments (€/MW/p.a.) from Figure 2 are generally operating in environments where the prices they receive are too low to recover capital and financing costs. For example Ireland's capacity payment is four times greater than that of France, while France's capacity factor is lower, Irelands gas-fired power plants are receiving amongst the lowest prices in Europe. The same reasons can explain the need for capacity payments in Austria, Finland, Bulgaria and Poland where capacity factors exceed 40%.

Table 3 provides a summary of capacity factors for plants in seven member states. The increase in renewable energy generation has contributed to lowering electricity wholesale prices in many markets by causing a shift in the merit order curve and substituting part of the generation of conventional thermal plants, which have higher marginal production costs. This merit order effect can affect revenues of conventional power plants, especially in Member States experiencing rapid deployment of variable renewables. Countries with high LRMCs, in Figure 3, including Cyprus, Slovenia, Latvia and Portugal have low capacity factors of less than 5%. Capital costs and the cost of debt are spread over fewer units of electricity leading to higher LRMCs. Therefore, three components can assist in reducing the capacity remuneration needed if any at all. One is more favourable wholesale prices, two more efficient generators as they will be more competitive and three is lower LRMC needed to recover capital and financing costs.

It is considerably more favourable to invest in the same technology in one member state relative to another from the findings of this study. Other drivers including the cost of capital, the treatment of deprecation, corporate taxes and infrastructure legacies can contribute to the amount of revenue that would need to be remunerated outside of short run marginal costs. The cost of capital produced the most significant change to capacity remuneration requirement estimates. For example, the annual debt interest payments, under the modelling approach, in Greece are more than double those of Germany. Over the course of the investment cycle, financing the original capital outlay at 70% leverage, the aggregate interest payment difference could be 27% between Germany and Greece over the “project lifetime”. Outside of market dynamics, this represents a significant difference in the levels of capital costs to be recovered across Europe. Debt is generally repaid through the issuance of new debt, also known as rolling over debt, and can present challenges if a company’s financial performance is weak (Cheng and Milbradt, 2012). The maturity profile of existing debt and financing policy, and future market rates could therefore potentially impact our capacity remuneration estimates and widen their variation.

Factoring in gas network costs affects the “missing money” problem throughout Europe, but not as substantially as initially conjectured. Due to the low utilisation rates of gas-fired power plants in some member states, little gas is used. Less gas demand reduces the aggregate annual gas network costs to the plant operator, even with higher tariffs. For example, gas network tariffs are estimated to increase by 57% in Portugal, however the plant’s capacity factor is 5%. The countries most impacted by gas network cost increases are Austria, France and Ireland with significant increases in required capacity payments. Gas network costs decrease in Finland and Poland, due to increases in gas demand.

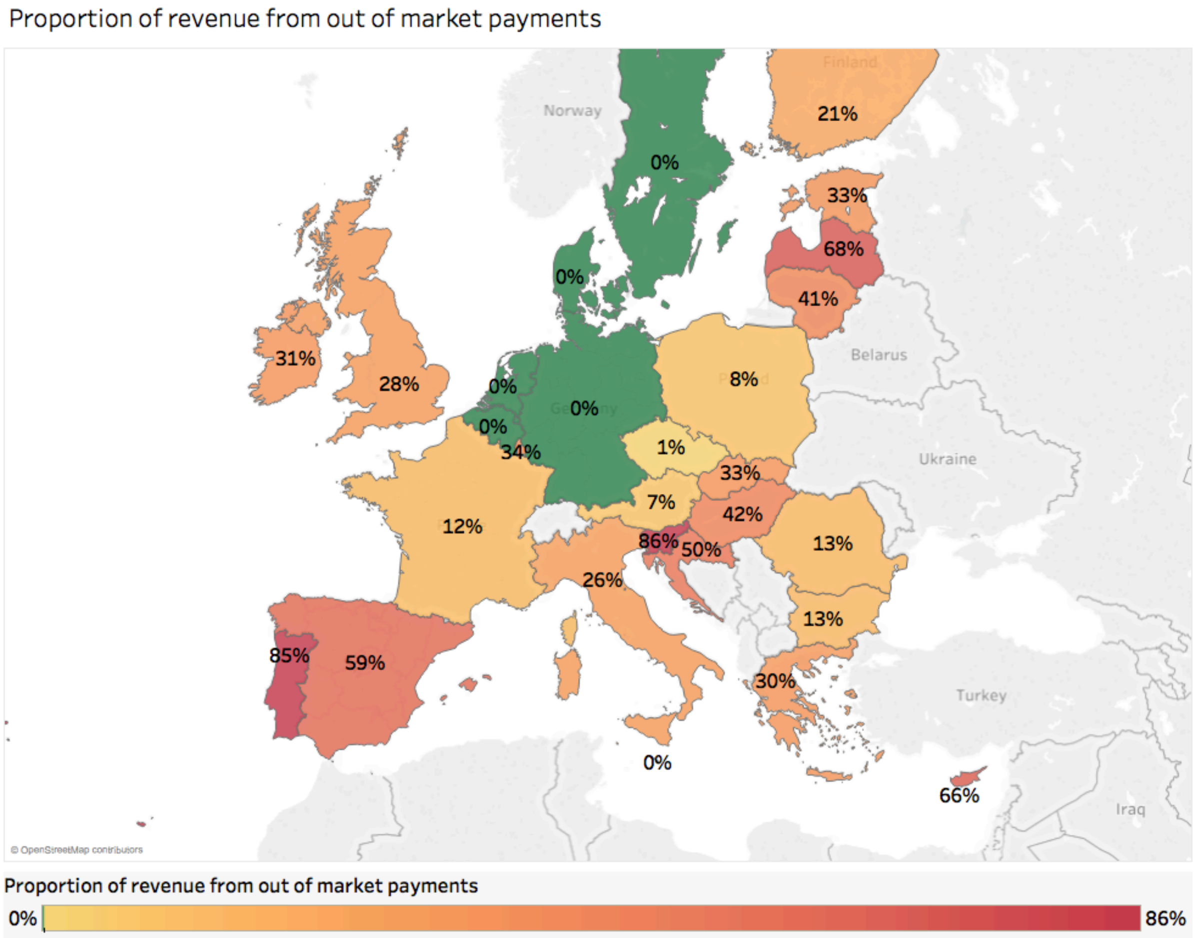

Figure 4. Proportion of Revenue from Capacity Payments to Gas-Fired Power Plants

Examples of countries which have adopted some form of capacity mechanism to support their electricity market include Ireland, Spain and GB (Linklaters, 2014). The European Commission has approved, under EU State aid rules, electricity capacity mechanisms in Belgium, France, Germany, Greece, Italy and Poland (European Commission, 2018). For the purposes of this analysis all revenues earned to compensate for "missing money" are classified as capacity payments. With the exception of Belgium, Denmark, Germany, Malta and Sweden the average European gas-fired power plant could be susceptible to the "missing money" problem in 2030. The countries at most risk, under the assumptions of the valuation model, are the southern states of Portugal, Spain, Slovenia, Croatia, Cyprus and the Baltic states which could be dependent on exceeding more than 40% of their revenue from outside of the energy only market. With the exception of Spain there are no capacity mechanisms currently in place in these member states.

5. Conclusion

This paper provides the first EU wide assessment of the comparative "missing money" problem in each EU member state, factoring climate policy targets, capital allowances, corporate tax, sovereign risk and gas network infrastructure legacy risk. The findings of this analysis point to an asymmetric investment case for gas-fired power plants in each EU member state. Under the assumptions of the EC Ref and a pan-European power optimisation model, future investment will depend on the availability of capacity payments. Capacity remuneration mechanisms are appearing to provide this "missing money", but capacity remuneration requirements vary considerably across countries.

The research literature on this topic suggests that cross border capacity market participation between interconnected markets has many benefits, including welfare, efficiency and optimising the procurement of suitable capacity (Bhagwat et al., 2017; Cepeda, 2018; Hawker et al., 2017; Höschle et al., 2018; Meyer and Gore, 2015). These studies observe competing market structures and note that harmonisation has the potential to provide these benefits. However, externalities outside of the electricity market may create a harmonisation problem. If capacity remunerations vary due to sovereign risks, fiscal measures and legacy infrastructures, this could in itself distort competition. Rationally, generators in member states which operate in low risk markets could bid into high risk markets to receive the largest capacity payments to maximise profits. Generators in high risk member could then be unable to compete in low risk markets due to their higher cost base.

What are the consequences of this? If each country undertakes its own resource adequacy analysis, as appears to be happening, and seeks to motivate investment to achieve its reliability target, then different capacity payments will be required for the same investments in different countries. This will challenge how the fairness of state aid approvals by the competition authority at EU level should be determined. Harmonisation of investment subsidies for equivalent technology support would not be possible. However, if a pragmatic view is taken that there are structural differences in the economies and infrastructures across countries, then differentiated capacity remunerations essentially create a fair basis for the same technology to be investable to the same hurdle rate in any country. That is a pragmatic form of harmonisation within the electricity market to compensate for more fundamental disharmonisation in fiscal, sovereign risk and infrastructure legacies across the countries.

The current ambition of the European Union to integrate member states through the 'Energy Union', 'Capital Markets Union' and 'Fiscal Union' may reduce the need for this pragmatic view and allow harmonised capacity payments to emerge. Existing literature rarely discusses harmonisation outside of the energy market and its impact on "missing money" and a market-based cross-border solution. True energy market harmonisation with sufficient resource adequacy may only be achievable if the cost of capital, the treatment of taxes and allowances, and climate policies are all harmonised throughout the EU. In contrast, our investigation of potentially insufficient returns due to infrastructure legacy risks from stranded gas networks revealed only minor distortions.

This analysis represents just one vision for the future, with an assumed price of gas, and there are limitations to the financial modelling approach. The energy system and power system modelling of Europe are sourced from published literature and therefore we have not conducted sensitivity analysis on these inputs, as it is beyond the scope of this analysis. Instead, we have investigated the different circumstances for overall profitability of the project through a series of different hurdle rates. There is also uncertainty as to how the current European power generation portfolio may evolve which is not captured in this study. While scenarios from energy system modelling can provide useful insights for the future, they aim to solve for cost optimal configurations in the development of the European energy system. The prolonged operation of inflexible, carbon-intensive power plants, along with the planned construction of new fossil fuel capacity, could translate into higher costs for decarbonising Europe's power sector by locking it in to a dependence on a high-carbon capacity, while simultaneously exposing owners and shareholders to the financial risk of capacity closures (potentially stranded assets). There is also a lack of certainty for fuel prices which have a high degree of impact on the dispatch of gas generation due to its high variable cost nature. Moreover, the costs of debt and sovereign risks in each member state of the EU as a whole are likely to change in the future. These uncertainties are not examined here but are important avenues for further research. The cost of debt is the main driver in the difference in project costs relating to what needs to be remunerated in each member state. Market dynamics will categorise how that capacity may be remunerated: whether through the energy market or a CRM. Our sensitivity analysis has focused on the level of project returns in each member state as incentivising investment is the core objective of any CRM. In summary, whilst the EC Ref will not be an accurate forecast, we believe the comparative insights developed are robust in identifying the relative consequences of country specific factors influencing capacity remuneration requirements. Further research could investigate optimal social planning of firm capacity in member states based on the favourable conditions for investment in one member states over another.

6. Acknowledgements

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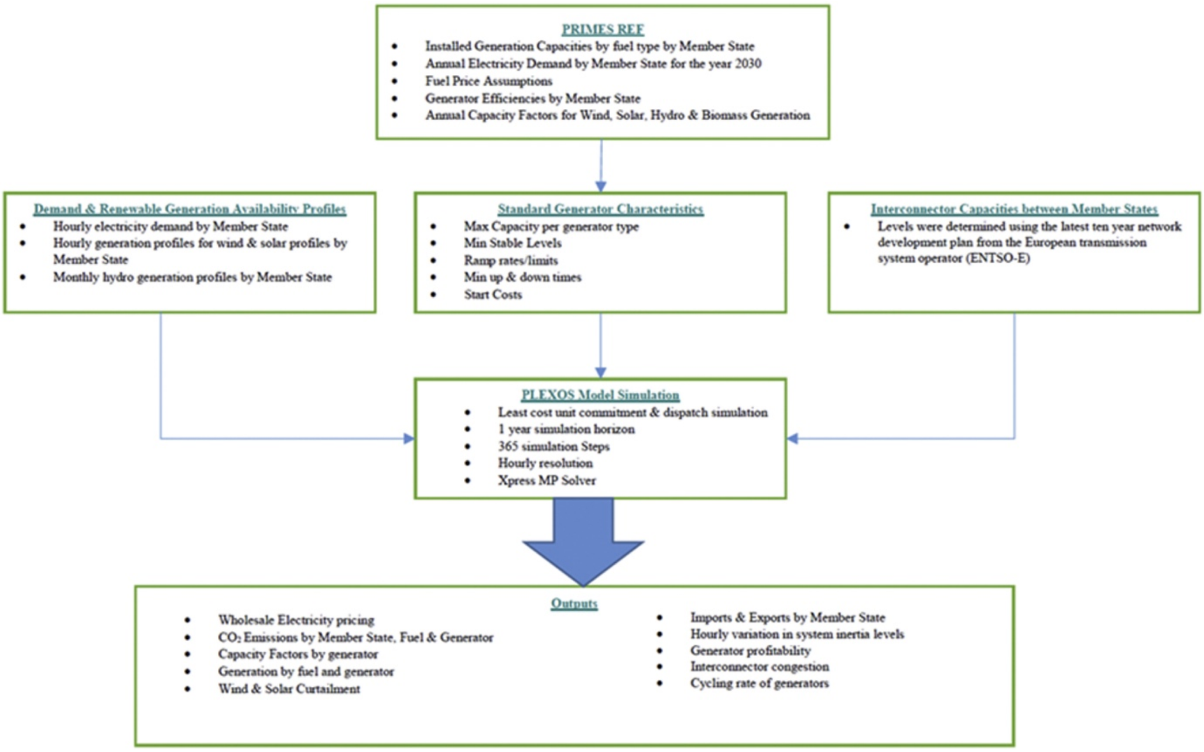
9. Appendix:

9.1 Technical assumptions to financial model

Figure 6: Flow diagram of the reference scenario to outputs for a financial model



Source: Collins et al 2017

Figure 6 illustrates the flow of inputs and outputs from the PRIMES model, which produces the European Commission's Reference Scenario, and the PLEXOS power system model used. The PRIMES Energy System Model is a partial equilibrium model of the European Union's energy system, used for forecasting, scenario analysis and policy impact studies. It is a behavioural model that also explicitly captures the demand, supply and pollution abatement technologies relating to energy use (E3Mlab, 2014). The technology attributes used in the PRIMES model are exogenous with both supply and demand side technologies considered. These technology attributes are reflected by parameters that are based on a variety of up to date reliable sources such as studies, expert judgement and existing databases (European Commission, 2016).

In the European Commission's Reference Scenario, results for the installed power generation capacities for each Member State are broken down into various modes of generation such as Hydro, Solids Fired, Oil Fired, Gas Fired, Biomass waste etc. The results issued from PRIMES are aggregate figures. To avoid model bias, aggregate generator portfolios are created using standard generators with standard characteristics (max capacity, min stable factors, ramp rates, min up and down times, maintenance rates, forced outage rates, start costs etc), as opposed to developing portfolios as projected by individual Transmission System Operators. A selection of these characteristics can be seen in Table 3 for thermal generators. Each disaggregated generation capacity was made up by numerous identical generators summing to the total capacity as split by fuel type in the Reference Scenario results. For natural gas fired generation 10% of installed capacity was allocated as Open Cycle (OCGT) to reflect and capture the flexibility of these less efficient plants on the power system with the remainder of natural gas fired plants being modelled as Combined Cycle units (CCGT). Heat rates for the various types of power plant are defined on a Member State by Member State basis, in the Reference scenario results.

Table 3: The standardised generation characteristics applied[1]

Fuel Type	Capacity (MW)	Start Cost (€)	Min Stable Factor (%)	Ramp Rate (MW/Min)
Biomass/waste	300	10000	30	30
Derived gas	150	12000	40	30
Geothermal heat	70	3000	40	30
Hydro (lakes)	150	0	0	30
Hydro (run of river)	200	0	0	30
Hydrogen	300	5000	40	30
Natural gas CCGT	450	80000	40	30
Natural gas OCGT	100	10000	20	30
Nuclear	1200	120000	60	30
Oil	400	75000	40	30
Solids	300	80000	30	30

Table 3 is a list of how each quantity of installed capacity of a given technology was disaggregated i.e. the plant size for each technology disaggregated from the installed capacity. The start cost of each technology and each technologies min stable factor and ramp rate.

Table 4: Fuel and carbon price assumptions

Fuel Type / Carbon	2030
Oil (€2010 per boe)	€90
Gas (€2010 per boe)	€52
Coal (€2010 per boe)	€18
Carbon - ETS (€2010 per Tonne)	€40

Demand profiles: Hourly resolution demand curves were attained from historic ENTSO-E data and linearly scaled to the overall demand estimates outlined in the European Commission's Reference Scenario. We assume that the peak demand increases by 10% in 2030 relative to 2012 across all Member States, and we linearly scale the demand accordingly.

Wind, solar and hydro profiles: Hourly generation profiles for wind power were sourced from. Solar profiles were created from NREL's PVWatts® calculator which estimated the solar radiance from assumptions around system location and basic system design parameters for each country. Hydro profiles are decomposed from monthly generation constraints provided by to weekly and hourly profiles in the optimisation algorithm function in PLEXOS®. Pumped hydro energy storage is also simulated in this model.

Table 5: Cost Assumptions for combined cycle gas turbine (CCGT) power plant

Capital Cost (450 MW)	€382.5 million
Expected Technical Lifetime	20 Years
% total cost in Debt	70%
% total cost in Equity	30%
Loan term in years	20
No of loan payments per annum	12
Debt	€267.8 million
Equity	€141.7 million
Variable O&M (€/MWh)	€20
Fixed O&M (% of CAPEX)	2.5%

The capital allowances and corporate taxes used are sourced from (El-Sibaie, 2018; European Commission, 2018) .

9.2 Sensitivities and comparison of member states

Table 6 and 7 quantifies the revenue streams in monetary terms that generators would need to receive annually to achieve the attributed IRR. Table 8 and 9 extrapolates those required revenues into long run marginal costs.

Table 6. Capacity Payments €/MW/p.a. (Excluding Infrastrcuture Legacy Risks)

€/MWh/p.a.	4%	6%	8%	10%
Country	Capacity Payment out of market	Capacity Payment out of market	Capacity Payment out of market	Capacity Payment out of market
AT	€6,187	€16,168	€26,707	€37,695
BE	€0	€0	€0	€0
BG	€25,082	€34,160	€43,787	€53,946
CY	€67,703	€73,971	€80,912	€88,536
CZ	€0	€0	€6,052	€17,605
DE	€0	€0	€0	€0
DK	€0	€0	€0	€0
EE	€53,630	€61,046	€69,086	€77,744
ES	€81,255	€88,260	€95,980	€104,371
FI	€71,940	€82,466	€93,547	€105,017
FR	€11,037	€19,097	€27,841	€37,165
GR	€61,212	€69,626	€78,653	€88,216
HR	€76,425	€83,495	€91,202	€99,547
HU	€65,691	€72,889	€80,717	€89,175
IE	€89,745	€99,039	€108,874	€119,227
IT	€49,524	€57,736	€66,579	€76,004
LT	€89,414	€97,436	€106,054	€115,260
LU	€51,247	€58,524	€66,504	€75,159
LV	€74,709	€81,064	€88,089	€95,791
MT	€0	€0	€0	€0
NL	€0	€0	€0	€0
PL	€12,482	€22,749	€33,532	€44,778
PT	€85,953	€92,173	€99,058	€106,639
RO	€27,844	€37,127	€46,946	€57,280
SE	€0	€0	€0	€0
SI	€80,189	€86,277	€93,046	€100,506
SK	€50,151	€57,444	€65,367	€73,915
UK	€59,717	€67,997	€76,867	€86,348

Table 7. Capacity Payments €/MW/p.a. (Including Infrastrcuture Legacy Risks)

€/MWh/p.a.	4%	6%	8%	10%
Country	Capacity Payment	Capacity Payment	Capacity Payment	Capacity Payment
AT	€13,164	€23,252	€33,847	€44,901
BE	€0	€0	€0	€0
BG	€24,484	€33,554	€43,166	€53,296
CY	€67,703	€73,971	€80,906	€88,514
CZ	€0	€0	€6,039	€17,563
DE	€0	€0	€0	€0
DK	€0	€0	€239	€11,906
EE	€56,575	€64,031	€72,101	€80,779
ES	€82,835	€89,866	€97,575	€105,969
FI	€55,284	€65,550	€76,349	€87,615
FR	€16,027	€24,171	€32,938	€42,308
GR	€60,645	€69,051	€78,031	€87,567
HR	€76,425	€83,495	€91,195	€99,523
HU	€66,867	€74,082	€81,918	€90,373
IE	€102,461	€111,925	€121,915	€132,402
IT	€51,522	€59,765	€68,605	€78,035
LT	€89,969	€97,999	€106,617	€115,811
LU	€55,449	€62,793	€70,816	€79,503
LV	€76,988	€83,374	€90,421	€98,136
MT	€0	€0	€0	€0
NL	€0	€0	€0	€0
PL	€7,401	€17,591	€28,290	€39,443
PT	€87,088	€93,323	€100,230	€107,808
RO	€30,114	€39,428	€49,268	€59,609
SE	€0	€0	€0	€0
SI	€80,467	€86,558	€93,324	€100,773
SK	€53,299	€60,635	€68,590	€77,160
UK	€63,918	€72,254	€81,174	€90,687

Table 8. Market prices and long run marginal costs (Excluding Infrastrcuture Legacy Risks)

IRR		4%	6%	8%	10%
Country	Marginal Price Received	Long Run Marginal Cost	Long Run Marginal Cost	Long Run Marginal Cost	Long Run Marginal Cost
AT	€87	€88	€91	€93	€96
BE	€111	€84	€86	€88	€91
BG	€82	€89	€92	€95	€97
CY	€96	€253	€268	€284	€302
CZ	€79	€76	€78	€80	€82
DE	€123	€97	€100	€103	€106
DK	€117	€106	€108	€111	€114
EE	€117	€161	€167	€174	€181
ES	€103	€229	€239	€251	€264
FI	€81	€97	€100	€102	€105
FR	€119	€125	€130	€135	€140
GR	€102	€136	€141	€146	€151
HR	€85	€156	€163	€170	€178
HU	€97	€154	€161	€167	€175
IE	€87	€119	€122	€126	€130
IT	€95	€120	€124	€128	€133
LT	€80	€128	€133	€137	€142
LU	€92	€129	€134	€140	€146
LV	€99	€280	€295	€312	€331
MT	€129	€85	€87	€90	€92
NL	€128	€92	€95	€98	€102
PL	€89	€92	€95	€97	€100
PT	€96	€568	€602	€640	€681
RO	€98	€107	€110	€113	€117
SE	€142	€111	€114	€118	€122
SI	€84	€526	€560	€597	€638
SK	€98	€134	€139	€145	€151
UK	€90	€116	€120	€124	€128

Table 9. Market prices and long run marginal costs (Including Infrastrcuture Legacy Risks)

IRR		4%	6%	8%	10%
Country	Marginal Price Received	Long Run Marginal Cost	Long Run Marginal Cost	Long Run Marginal Cost	Long Run Marginal Cost
AT	€87	€90	€93	€95	€98
BE	€111	€82	€85	€87	€90
BG	€82	€89	€92	€94	€97
CY	€96	€253	€268	€284	€302
CZ	€79	€76	€78	€80	€82
DE	€123	€98	€101	€104	€108
DK	€117	€112	€114	€117	€120
EE	€117	€163	€170	€176	€183
ES	€103	€231	€242	€254	€267
FI	€81	€94	€96	€98	€101
FR	€119	€128	€133	€138	€143
GR	€102	€136	€141	€146	€151
HR	€85	€156	€163	€170	€178
HU	€97	€155	€162	€168	€176
IE	€87	€124	€127	€131	€134
IT	€95	€121	€125	€129	€134
LT	€80	€129	€133	€138	€142
LU	€92	€132	€137	€143	€149
LV	€99	€285	€301	€318	€336
MT	€129	€85	€87	€90	€92
NL	€128	€93	€96	€99	€102
PL	€89	€91	€94	€96	€99
PT	€96	€574	€608	€646	€688
RO	€98	€108	€111	€114	€117
SE	€142	€106	€109	€113	€117
SI	€84	€528	€561	€598	€639
SK	€98	€136	€142	€147	€154
UK	€90	€118	€122	€126	€130

Table 10. Annual Revenue Streams for Gas-Fired Generators in 2030 (Excluding Infrastrcuture Legacy Risks)

IRR	4%			6%			8%			10%		
Country	Energy Only	Out of Market Payments	% Out of Market	Energy Only	Out of Market Payments	% Out of Market	Energy Only	Out of Market Payments	% Out of Market	Energy Only	Out of Market Payments	% Out of Market
AT	€144,146,493	€2,474,892	2%	€144,146,493	€6,467,387	4%	€144,146,493	€10,682,709	7%	€144,146,493	€15,078,064	9%
BE	€197,998,200	€0	0%	€197,998,200	€0	0%	€197,998,200	€0	0%	€197,998,200	€0	0%
BG	€117,144,883	€10,032,814	8%	€117,144,883	€13,663,924	10%	€117,144,883	€17,514,873	13%	€117,144,883	€21,578,381	16%
CY	€16,623,033	€27,081,379	62%	€16,623,033	€29,588,396	64%	€16,623,033	€32,364,812	66%	€16,623,033	€35,414,355	68%
CZ	€175,228,821	€0	0%	€175,228,821	€0	0%	€175,228,821	€2,420,706	1%	€175,228,821	€7,042,027	4%
DE	€152,833,239	€0	0%	€152,833,239	€0	0%	€152,833,239	€0	0%	€152,833,239	€0	0%
DK	€180,449,908	€0	0%	€180,449,908	€0	0%	€180,449,908	€0	0%	€180,449,908	€0	0%
EE	€56,401,922	€21,451,911	28%	€56,401,922	€24,418,206	30%	€56,401,922	€27,634,272	33%	€56,401,922	€31,097,655	36%
ES	€26,654,888	€32,502,037	55%	€26,654,888	€35,303,802	57%	€26,654,888	€38,392,161	59%	€26,654,888	€41,748,219	61%
FI	€137,991,632	€28,776,007	17%	€137,991,632	€32,986,207	19%	€137,991,632	€37,418,983	21%	€137,991,632	€42,006,628	23%
FR	€84,695,036	€4,414,990	5%	€84,695,036	€7,638,784	8%	€84,695,036	€11,136,522	12%	€84,695,036	€14,865,816	15%
GR	€72,855,979	€24,484,990	25%	€72,855,979	€27,850,426	28%	€72,855,979	€31,461,132	30%	€72,855,979	€35,286,269	33%
HR	€36,562,803	€30,569,836	46%	€36,562,803	€33,397,894	48%	€36,562,803	€36,480,988	50%	€36,562,803	€39,818,653	52%
HU	€44,241,171	€26,276,317	37%	€44,241,171	€29,155,721	40%	€44,241,171	€32,286,918	42%	€44,241,171	€35,670,137	45%
IE	€97,768,285	€35,897,860	27%	€97,768,285	€39,615,503	29%	€97,768,285	€43,549,406	31%	€97,768,285	€47,690,989	33%
IT	€74,603,599	€19,809,432	21%	€74,603,599	€23,094,406	24%	€74,603,599	€26,631,688	26%	€74,603,599	€30,401,714	29%
LT	€60,031,403	€35,765,640	37%	€60,031,403	€38,974,308	39%	€60,031,403	€42,421,619	41%	€60,031,403	€46,103,849	43%
LU	€50,797,420	€20,498,935	29%	€50,797,420	€23,409,783	32%	€50,797,420	€26,601,767	34%	€50,797,420	€30,063,763	37%
LV	€16,418,381	€29,883,719	65%	€16,418,381	€32,425,547	66%	€16,418,381	€35,235,410	68%	€16,418,381	€38,316,232	70%
MT	€202,644,624	€0	0%	€202,644,624	€0	0%	€202,644,624	€0	0%	€202,644,624	€0	0%
NL	€150,983,577	€0	0%	€150,983,577	€0	0%	€150,983,577	€0	0%	€150,983,577	€0	0%
PL	€152,319,122	€4,992,811	3%	€152,319,122	€9,099,776	6%	€152,319,122	€13,412,964	8%	€152,319,122	€17,911,182	11%
PT	€7,033,004	€34,381,034	83%	€7,033,004	€36,869,105	84%	€7,033,004	€39,623,073	85%	€7,033,004	€42,655,461	86%
RO	€120,698,000	€11,137,711	8%	€120,698,000	€14,850,942	11%	€120,698,000	€18,778,573	13%	€120,698,000	€22,912,116	16%
SE	€145,291,399	€0	0%	€145,291,399	€0	0%	€145,291,399	€0	0%	€145,291,399	€0	0%
SI	€6,132,701	€32,075,735	84%	€6,132,701	€34,510,746	85%	€6,132,701	€37,218,444	86%	€6,132,701	€40,202,316	87%
SK	€54,149,143	€20,060,338	27%	€54,149,143	€22,977,582	30%	€54,149,143	€26,146,632	33%	€54,149,143	€29,565,891	35%
UK	€79,473,492	€23,886,622	23%	€79,473,492	€27,198,630	25%	€79,473,492	€30,746,850	28%	€79,473,492	€34,539,200	30%

Table 11. Annual Revenue Streams for Gas-Fired Generators in 2030 (Including Infrastrcuture Legacy Risks)

IRR	4%			6%			8%			10%		
Country	Energy Only	Out of Market Payments	% Out of Market	Energy Only	Out of Market Payments	% Out of Market	Energy Only	Out of Market Payments	% Out of Market	Energy Only	Out of Market Payments	% Out of Market
AT	€144,146,493	€5,265,797	4%	€144,146,493	€9,300,626	6%	€144,146,493	€13,538,621	9%	€144,146,493	€17,960,438	11%
BE	€197,998,200	€0	0%	€197,998,200	€0	0%	€197,998,200	€0	0%	€197,998,200	€0	0%
BG	€117,144,883	€9,793,610	8%	€117,144,883	€13,421,472	10%	€117,144,883	€17,266,353	13%	€117,144,883	€21,318,537	15%
CY	€16,623,033	€27,081,365	62%	€16,623,033	€29,588,396	64%	€16,623,033	€32,362,246	66%	€16,623,033	€35,405,737	68%
CZ	€175,228,821	€0	0%	€175,228,821	€0	0%	€175,228,821	€2,415,576	1%	€175,228,821	€7,025,207	4%
DE	€152,833,239	€0	0%	€152,833,239	€0	0%	€152,833,239	€0	0%	€152,833,239	€0	0%
DK	€180,449,908	€0	0%	€180,449,908	€0	0%	€180,449,908	€95,593	0%	€180,449,908	€4,762,253	3%
EE	€56,401,922	€22,630,159	29%	€56,401,922	€25,612,449	31%	€56,401,922	€28,840,369	34%	€56,401,922	€32,311,556	36%
ES	€26,654,888	€33,133,893	55%	€26,654,888	€35,946,225	57%	€26,654,888	€39,029,961	59%	€26,654,888	€42,387,417	61%
FI	€137,991,632	€22,113,404	14%	€137,991,632	€26,220,018	16%	€137,991,632	€30,539,719	18%	€137,991,632	€35,046,040	20%
FR	€84,695,036	€6,410,791	7%	€84,695,036	€9,668,352	10%	€84,695,036	€13,175,089	13%	€84,695,036	€16,923,392	17%
GR	€72,855,979	€24,258,094	25%	€72,855,979	€27,620,341	27%	€72,855,979	€31,212,415	30%	€72,855,979	€35,026,792	32%
HR	€36,562,803	€30,569,821	46%	€36,562,803	€33,397,894	48%	€36,562,803	€36,477,906	50%	€36,562,803	€39,809,238	52%
HU	€44,241,171	€26,746,844	38%	€44,241,171	€29,632,666	40%	€44,241,171	€32,767,165	43%	€44,241,171	€36,149,293	45%
IE	€97,768,285	€40,984,250	30%	€97,768,285	€44,769,903	31%	€97,768,285	€48,766,026	33%	€97,768,285	€52,960,733	35%
IT	€74,603,599	€20,608,738	22%	€74,603,599	€23,905,920	24%	€74,603,599	€27,442,011	27%	€74,603,599	€31,214,052	29%
LT	€60,031,403	€35,987,784	37%	€60,031,403	€39,199,495	40%	€60,031,403	€42,646,636	42%	€60,031,403	€46,324,218	44%
LU	€50,797,420	€22,179,631	30%	€50,797,420	€25,117,026	33%	€50,797,420	€28,326,393	36%	€50,797,420	€31,801,129	39%
LV	€16,418,381	€30,795,345	65%	€16,418,381	€33,349,556	67%	€16,418,381	€36,168,409	69%	€16,418,381	€39,254,300	71%
MT	€202,644,624	€0	0%	€202,644,624	€0	0%	€202,644,624	€0	0%	€202,644,624	€0	0%
NL	€150,983,577	€0	0%	€150,983,577	€0	0%	€150,983,577	€0	0%	€150,983,577	€0	0%
PL	€152,319,122	€2,960,509	2%	€152,319,122	€7,036,362	4%	€152,319,122	€11,315,812	7%	€152,319,122	€15,777,068	9%
PT	€7,033,004	€34,835,328	83%	€7,033,004	€37,329,147	84%	€7,033,004	€40,092,169	85%	€7,033,004	€43,123,090	86%
RO	€120,698,000	€12,045,617	9%	€120,698,000	€15,771,208	12%	€120,698,000	€19,707,201	14%	€120,698,000	€23,843,441	16%
SE	€145,291,399	€0	0%	€145,291,399	€0	0%	€145,291,399	€0	0%	€145,291,399	€0	0%
SI	€6,132,701	€32,186,739	84%	€6,132,701	€34,623,276	85%	€6,132,701	€37,329,531	86%	€6,132,701	€40,309,180	87%
SK	€54,149,143	€21,319,492	28%	€54,149,143	€24,253,820	31%	€54,149,143	€27,435,907	34%	€54,149,143	€30,863,928	36%
UK	€79,473,492	€25,567,017	24%	€79,473,492	€28,901,798	27%	€79,473,492	€32,469,605	29%	€79,473,492	€36,274,758	31%