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Economic consequences of a capacity market implementation: The case of Poland

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ABSTRACT

This paper investigates the potential economic consequences of setting up a capacity market in Poland. A computable model of the Polish power generation system is developed and employed to analyse the impact of this mechanism. Two scenarios are designed for this study: (i) a reference scenario that reflects the energy-only market and (ii) a capacity market scenario that assumes the implementation of such an instrument. To assess the economic consequences, the following parameters are estimated: (i) annual electricity prices, (ii) Loss Of Load Hours, (iii) Expected Energy Not Served, and only for the capacity market scenario: (iv) market clearing price, (v) total budget of the capacity market, and (vi) increase in electricity price due to the introduction of the capacity market. The findings of the study indicate that the long-term maintenance of the energy-only market results in higher electricity prices when compared to putting a capacity market into operation. Introducing a capacity market enables existing resources to be used effectively without excessive capital expenditure. The methods and conclusions presented in this paper provide valuable findings and policy insights regarding the potential economic consequences of a capacity mechanism in a power system mostly dominated by coal and undergoing an energy transition.

1. Introduction

Electricity has always been treated as a key commodity that ensures energy security and contributes to economic growth (Gasparatos and Gadda, 2009; Kocaslan, 2014; Le and Nguyen, 2019). As large-scale electricity storage projects remain technically complex and highly capital intensive, transmission system operators (TSOs) face numerous challenges in order to meet electricity demand in the years ahead. Moreover, with the liberalisation of electricity markets and the introduction of competition, confidence in capacity adequacy worsened in several countries. Although various reasons can be identified, some evidence suggests that privately-owned companies in competitive markets are not being sufficiently rewarded for risk, hence a decline in power investments is observed (Bushnell et al., 2017).

The Polish power generation system relies almost exclusively on coal (ARE SA, 2018) thus making it highly vulnerable to changes in carbon pricing policies (Kudełko et al., 2011; Smale et al., 2006; Streimikiene and Roos, 2009). Numerous units are outdated and have more than 30 years of service (ARE SA, 2018). They either require refurbishment or should be decommissioned in the near future. On top of that, due to an increase in the share of renewable energy sources (RES), which has had an influence on the merit order (Bigerna and Bollino, 2016; Koltsaklis et al., 2017), a decrease in revenues of coal-fired units has been observed. In the long run, the inability of these conventional power generation units to cover their operational and capital costs, and the lack of investment incentives, may result in a problem of 'missing capacity' that leads to an increase in the risk of brownouts or blackouts (Cramton and Stoft, 2008; Hogan, 2005; Jaffe and Felder, 1996; Joskow and Tirole, 2007). The solution to the capacity adequacy problem is widely discussed in the literature (Cramton et al., 2013; Hary et al., 2016; Milstein and Tishler, 2019). Among the various policy mechanisms (such as scarcity pricing (Helman et al., 2008; Petitet et al., 2017)), there is a specific group of instruments called capacity remuneration mechanisms (CRMs) that could be applied in order to address the capacity adequacy problem (Bhagwat et al., 2016; Bolton and Clausen, 2019; De Vries, 2007). The capacity market, which is the focus of this paper, is one of them (ACER, 2013).

In Poland, the capacity market was implemented in December 2017

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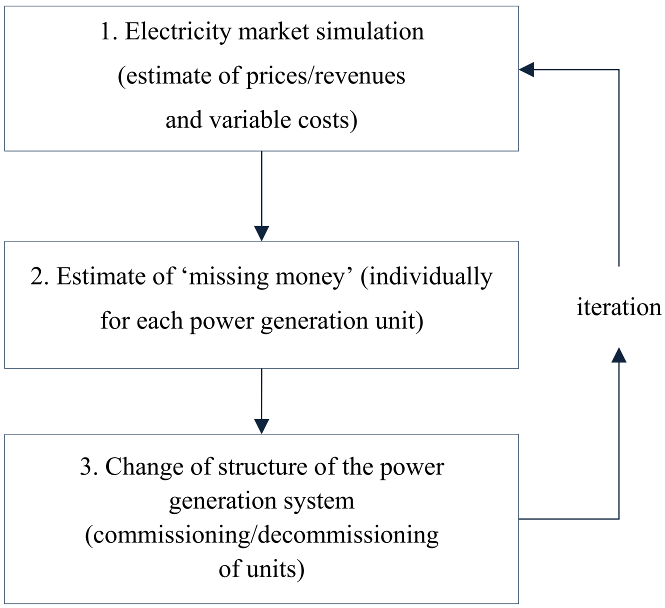

Fig. 1. Methodology of the energy-only market scenario.

to address the capacity adequacy problem in the power generation system (Ministry of Energy, 2018). In August 2015, a major event occurred when the existing units were unable to meet the demand for electricity. As a result, the TSO imposed several control measures to reduce the electricity demand from the industrial sector (Benalcazar and Nalepka, 2017). The brownouts resulted in economic and social losses. Following this incident, the introduction of the capacity market in Poland was proposed to solve the problem of inadequate power generation capacity that would lead to power cuts and electricity shortages in the future.

In this context, to the best of our knowledge, there has been no quantitative analysis of the economic consequences of the introduction of this mechanism. In particular, the impact on electricity prices, the Loss Of Load Hours and Expected Energy Not Served has been not analysed. With regard to the above, the main objective of this study is to conduct a comprehensive analysis of the consequences of capacity market implementation in Poland until 2035. This issue is crucial for policymakers as their decisions should be based on robust analyses.

To answer the abovementioned policy question a computable model of the Polish power generation system is developed and employed. The model is implemented in the General Algebraic Modeling System (GAMS) as a Mixed Integer Linear Programming (MILP) problem and solved with the CPLEX solver. Two scenarios are designed for this study: (i) a reference scenario that reflects the energy-only market (EOM), and (ii) a capacity market (CM) scenario that mimics the introduction of the policy instrument in question.

The remainder of this paper is organised as follows. Section 2 reviews the literature on the consequences of introducing a capacity market. The methodology applied in the study is described in Section 3. This section also presents the most important assumptions and input data used in numerical simulations. The main results and findings are discussed in Section 4. Section 5 presents the limitations of the study and suggestions for further research. Section 6 concludes the paper by drawing policy implications.

2. Literature review

The development of energy policy recommendations with the employment of model-based approaches is a demanding exercise due to the complexity of real power systems. The main challenges which the researchers usually face are comprehensively discussed in (Bazmi and Zahedi, 2011; Dagoumas and Koltsaklis, 2019; Jebaraj and Iniyan, 2006; Pfenninger et al., 2014; Ventosa et al., 2005). Among the major challenges associated with the development of policy recommendations based on mathematical models, the following should be pointed out challenges related to: (i) the accurate representation of policy regulations and changes in the energy market design, (ii) concerning regulations of carbon emissions, (iii) integrating the growth demand side and storage technologies, (iv) integrating intermittent renewable energy sources, (v) balancing demand and supply at all times and (vi) taking network constraints into

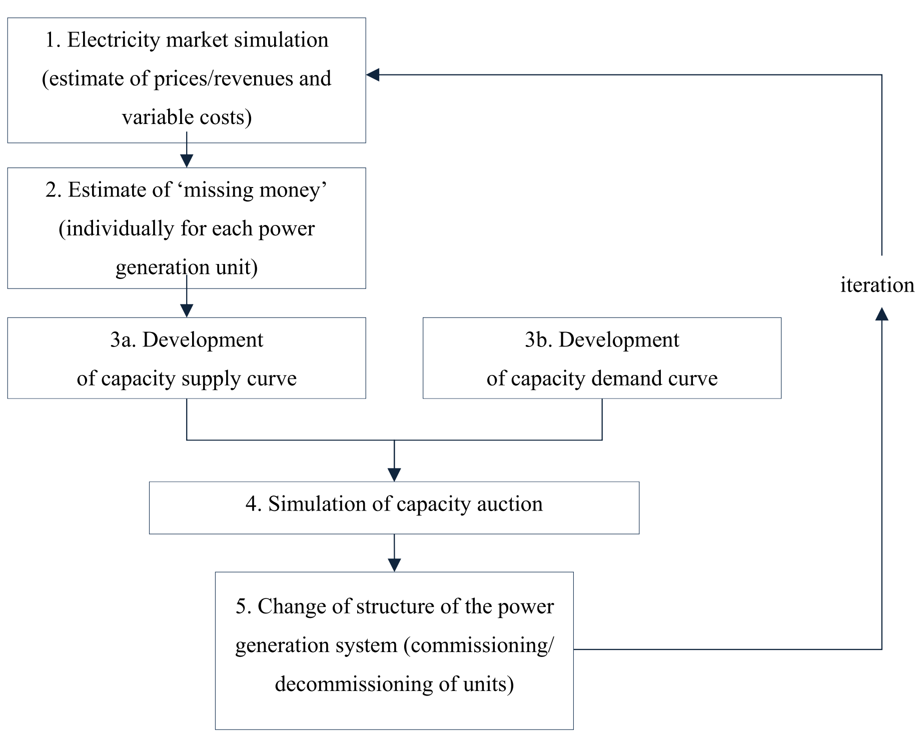

Fig. 2. Methodology of the capacity market scenario.

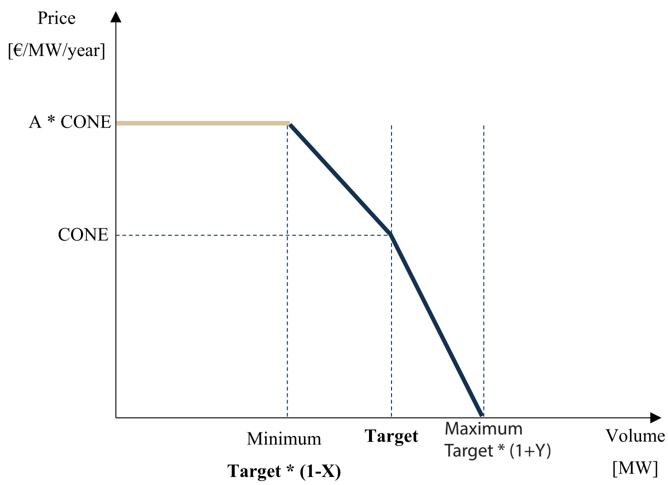

Fig. 3. The demand curve parameters for the Polish capacity market
Source: Own analysis based on (Ministry of Energy, 2017).

account.

In this context, Li et al. (2011) reviewed the literature on modelling bidding strategies of generation companies in a liberalised electricity market and classified them in four categories: (i) single generation company optimisation, (ii) game theory-based, (iii) agent-based, and (iv) hybrid. The subsequent literature review in this area was conducted by Prabavathi and Gnanadass (2015). The related literature was categorised according to modelling algorithms. They proposed a new mathematical framework to build bidding strategies for participants in the restructured electricity market (Prabavathi and Gnanadass, 2018).

The implementation of capacity remuneration mechanisms triggered new challenges in energy policy decision-making and motivated the research on modelling approaches to these questions. Cramton and Ockenfels (2012) focused on the design of capacity markets in the context of market power and risk management. Also, various consequences of the introduction of a capacity market were widely discussed in the literature. Spees et al. (2013) conducted a comprehensive analysis of consequences of setting up and operating a capacity market in the following areas in the United States of America: PJM, MISO, NYISO, ISO-NE and California Independent System Operator (CAISO). They pointed out that although capacity remuneration mechanisms had been introduced in the U.S. in the late 1990s, they still had to address many challenges. Bowring (2013) also analysed the PJM capacity market and emphasised that it had solved the missing capacity problem, admitting – however – that its design was still imperfect. Cramton et al. (2013) analysed the economic consequences of the introduction of capacity markets. They also focused on the challenges and problems that were faced in the process of designing capacity markets. Bhagwat et al. (2017a) analysed and compared the economic consequences of the introduction of a strategic reserve and capacity market in the context of an increasing share of renewables. They employed an agent-based model and concluded that it is more efficient to introduce a capacity market to solve the resource adequacy problem. Then, Bhagwat et al. (2017c) used this model to assess the cross-border consequences of a capacity mechanism and pointed out that the interconnections do not impact the capacity market while the strategic reserve is negatively affected. Bhagwat et al. (2017b) also carried out an analysis of a forward capacity market with long-term contracts. They concluded that the introduction of such an instrument leads to more stable prices and more efficient acquisition of capacity. Hasani and Hosseini (2011) conducted an assessment of investments in the power generation market considering a complementary capacity market with the employment of a systems dynamics approach. The model applied in their study simulated investment decisions assuming, as the main criterion, the maximization of profits. The systems dynamics approach was also applied to modelling the electricity market with capacity mechanisms (Assili et al., 2008; Cepeda and Finon, 2011; Gary and Larsen, 2000; Hobbs et al., 2007; Petitet et al., 2017).

Table 1
Scenario acronyms with their brief description.

Scenario	Description
EOM	The only product traded in the market is electricity. Not meeting the economic efficiency condition leads to the decommissioning of power generating units, which results in increased electricity prices due to scarcity pricing. The scenario assumes that decommissioning of units is conducted in a rational manner (generators are able to anticipate the price increase resulting from shortages in the power generation system and the unprofitable units are not all decommissioned at the same time). There is no strategic reserve and operating reserve mechanism in place.
CM	The capacity market is implemented. Apart from electricity, capacity is traded in the market. A single buyer model is assumed in which the TSO (Polish Power Grid Company) purchases capacity obligations in a descending clock auction, and the price is set in the Pay-As-Clear system. The capacity market ensures that demand is met in the long-term in nearly all conditions. There is also no strategic reserve and operating reserve system in place.

The literature review conducted confirms that the assessment of the consequences of the implementation of a capacity mechanism is a very complex exercise. Although capacity remuneration mechanisms have been implemented all over the world for several years, the literature on the analysis of their introduction in Central and Eastern European (CEE) countries is sparse, if not non-existent. In addition, there is a gap in the research on the impact of the implementation of such instruments in coal-fired power systems under transition, such as the one in Poland. In this context, this paper contributes to the literature on capacity remuneration mechanisms in the following ways: (i) methods of impact assessment of the introduction of capacity remuneration mechanisms, (ii) analyses of the long-term economic consequences of the introduction of a capacity market for policy-making purposes, and (iii) analyses of long-run developments in a power generation system mostly dominated by coal and undergoing an energy transition.

3. Methodology

To analyse the consequences of the introduction of a capacity market in Poland, the selection of an appropriate method is of the utmost importance. To the best of our knowledge, the only suitable approach to solving such policy problems is the use of systems analysis with quantitative tools such as mathematical models (Bigerna et al., 2015; Dagoumas and Polemis, 2017; Lopion et al., 2018; Neshat et al., 2014; Ventosa et al., 2005).

One of the approaches that can be employed to solve the research question posed in this paper is the application of a detailed mathematical model that considers the essential elements of the Polish power system and formulates them as a system of equations and inequalities. In

Table 2
Average fuel prices in 2021, 2025, 2030 and 2035.

	Unit	2021	2025	2030	2035
Hard coal	€/GJ	2.4	2.7	2.9	2.9
Lignite	€/GJ	1.9	2.1	2.2	2.3
Natural gas	€/GJ	5.3	6.4	7.6	8.1
Biomass	€/GJ	5.0	5.2	5.4	5.5
Nuclear fuel	€/GJ	0.3	0.3	0.3	0.3

Source: Own analysis based on (IEA, 2016).

Table 3
Forecast capacity demand to be auctioned in 2021, 2025, 2030 and 2035.

	Unit	2021	2025	2030	2035
net peak demand	GW	25.4	27.3	29.6	31.5
total demand	GW	24.6	7.9	6.9	21.1

Source: Own analysis based on (Polish Power Grid Company, 2016).

this paper, a procedure for a solution is developed based on a Mixed Integer Linear Programming approach (Arroyo and Conejo, 2000; Carrión and Arroyo, 2006; Frangioni et al., 2009; Gollmer et al., 2000; Lee, 1988; Martens et al., 2012; Viana and Pedroso, 2013; Weber, 2005). Therefore this section presents the model employed and the research procedures used for (i) an energy-only market and (ii) a capacity market. Then, the scenario assumptions are discussed followed by a description of the main data assumptions.

3.1. Model employed and research procedure

The procedure used in this study consists of independently generating numerical results from a mathematical model of the Polish power system for each year. Two model approaches are employed to assess the effects of the introduction of the capacity market on electricity prices. As a result, the model is run separately for (i) the energy-only market and (ii) the capacity market scenarios.

The research procedure for the energy-only market scenario is presented in Fig. 1.

In the first step, the electricity market is simulated to calculate (i) electricity prices and (ii) variable costs, and consequently independently for each power generation unit (iii) total revenues, (iv) total variable costs and (v) expected profits from electricity sales. The simulation is carried out with the employment of an improved and extended version of the short-run computable model of the Polish power generation system described in (Kamiński et al., 2014b, 2014a). In this model, a mathematical programming-based approach to solving the Unit Commitment Problem is applied, which is typically used for the analysis of electricity markets in the short-term perspective (Morales-España et al., 2013; Nyamdash and Denny, 2013; Palmintier and Webster, 2011). The model is implemented in GAMS as an MILP problem and solved using the CPLEX solver (Carrión and Arroyo, 2006; Frangioni et al., 2009; Viana and Pedroso, 2013). The model is characterised by the following features: (i) time resolution of 1 h, (ii) time horizon of 52 weeks per annum, (iii) existing conventional power plants and combined heat and power plants represented as individual power generation units, (iv) industrial power plants modelled at the aggregated level, (v) demand side response and import implemented at an aggregated level, (vi) renewables modelled at an aggregate level, separately for each energy carrier, (vii) new power generation units defined individually or as technologies. Each unit (or aggregate of units) implemented in the model is characterised by its technical, economic and environmental-related parameters. In this approach, such parameters as fuel prices, emission charges, and CO_2 European Emission Allowance (EUA) prices are exogenously assumed. The objective function is formulated to minimise the total variable costs of power generation. The results of the model provide the following variables: production volumes, generation costs, generation mix, and level of emissions independently for each power unit. A competitive electricity market is assumed in this study. Therefore, the market clearing price is set as the System Marginal Price (SMP) in which the generators submit offers based on their short-term marginal cost (Kirschen and Strbac, 2004).

In the second step of the procedure, the magnitude of the 'missing money' or 'net revenue gap' is estimated independently for each existing unit. This variable is calculated based on the outcome of the electricity market simulations carried out in the first step. It is assumed that the amount of 'missing money' equals the difference between the revenues from the sale of electricity and the sum of the fixed and variable costs of power generation. In other words, the 'missing money' reflects the level of additional income required to cover losses from sales of electricity.

In the third step, the decommissioning of power generation units which do not meet the economic efficiency requirement (net profit <0) takes place. As a result, a new structure of the power generation system is assumed. The iterations are repeated until the most expensive unit in the system does not generate economic losses.

The research procedure for the capacity market scenario is presented in Fig. 2.

The steps carried out for the simulations of the electricity market (steps 1 and 2) and the estimate of the magnitude of the 'missing money' are performed in the same manner as in the case of the energy-only market scenario described above. In step 3a the capacity supply curve is developed by setting the merit order of bids by each generation unit or their aggregates. It is assumed that the capacity supply curve reflects the minimum price of capacity which Capacity Market Units (CMUs) are willing to accept, based on their level of 'missing money'. The capacity supply curve is determined on this basis.

As there are other policy instruments aimed at supporting high-efficiency cogeneration and renewable energy sources in Poland, we assume that these power generation technologies do not participate in capacity auctions. The benefits that they obtain from other mechanisms are higher than potential profits from participation in the capacity market. As a result, power plants based on the following energy carriers are excluded from our study: (i) biomass, (ii) biogas, (iii) wind and (iv) solar. According to the Act Dz.U. 2018 poz. 9 of the Polish capacity market, demand side response (DSR) units can participate in such auctions (Ministry of Energy, 2018). Consequently, they are included in our investigation. Furthermore, the current Polish capacity market is an attractive opportunity for energy-intensive companies since they are qualified as eligible for an 80% reduction in the price setting of the capacity obligation. The level of the capacity obligation of units located in adjacent markets depends on the cross-border transmission capacity.

The price of capacity offered in the capacity auctions is estimated based on the results of the profitability analysis of units and on the investment expenditure on new-build power generating units. A Pay-As-Clear (PAC) system is assumed and the price bids are based on the 'missing money' concept and their level is equal to the minimum level of potential revenues from the capacity market that would allow them to maintain at least minimal profitability. The offered capacity obligation is estimated individually for each capacity market unit. This is the result of the product of the (i) net achievable capacity and (ii) capacity factor. The capacity factors depend on the technology of CMUs.

The capacity demand curve is assumed according to the parameters published in the ordinance of the Ministry of Energy (Ministry of Energy, 2016a). The shape of the demand curve (Fig. 3) and the values of the A, X and Y parameters are assumed to be at the same level over the whole period of analysis. The entry price for new-build units equals the Cost of New Entry (CONE). It is calculated individually for each year. The forecast power demand for 2021–2035 is also estimated independently for each year.

The next step in this study is to carry out the simulation of the capacity auction. We assume a competitive market without capacity being withheld. The market participants have no knowledge of the behaviour of other participants in the previous and existing rounds.

As a result of the estimate of the amount of 'missing money', the power generation units which do not meet the economic efficiency condition are decommissioned. Consequently, the configuration of the power generation system is modified and the simulation of the electricity market is repeated with the new configuration which takes into account the results of the capacity auction.

3.2. Scenario assumptions

The development of scenarios that mimic the assumed conditions of the electricity market using a modelling approach is an important step in policy planning. As was noted in the previous sections, in our study we examine two scenarios. The first scenario reflects the energy-only market, also referred to as the 'reference scenario'. There are no capacity remuneration mechanisms in place. The second scenario simulates the implementation of a capacity market alongside the electricity market. A concise list of these scenarios is given in Table 1.

3.3. Main data assumptions

The range of data used in this study is very extensive. Owing to this fact, only selected datasets are presented and described in this section. The main sources of data are: the Transmission System Operator – the Polish Power Grid Company (Polskie Sieci Elektroenergetyczne SA, PSE SA), the Energy Market Agency (Agencja Rynku Energii, ARE SA), the Energy Regulatory Office (Urząd Regulacji Energetyki, URE), the Central Statistical Office (Główny Urząd Statystyczny, GUS), the Ministry of Energy, and databases managed by the Mineral and Energy Economy Research Institute of the Polish Academy of Sciences (MEERI PAS). The data used in this study can be classified into four categories: (i) data for the electricity market simulation, (ii) data for the development of a supply curve for the capacity market, (iii) data for the development of a demand curve for the capacity market and (iv) data for the simulations of a capacity auction.

The electricity market simulations require a complete description of the supply and demand curves. The supply curve makes use of the technical and economic parameters of either individual power generation units or aggregated groups of technologies. Fuel and CO_2 European Emission Allowance prices are also considered for the estimation of the variable cost of power generation. The demand for electricity is estimated based on hourly data observed in 2017.

The price forecasts of the following fuels are used in this study: (i) hard coal, (ii) lignite, (iii) natural gas, (iv) biomass, and (v) nuclear fuel. The hard coal and natural gas prices are based on the forecasts prepared by the International Energy Agency (IEA) and published in the World Energy Outlook (WEO) 2016. The WEO provides three scenarios: (i) New Policy Scenario (NPS), (ii) Current Policies Scenario (CPS) and (iii) Sustainable Development Scenario (SDS). For this study, the assumptions of the New Policy Scenario are taken. The prices of lignite and biomass are calculated based on hard coal price forecasts and the historical relationships between these fuels and hard coal prices. The prices of nuclear fuel are taken from databases managed by MEERI PAS. Fuel prices are presented in Table 2. It can be observed that only the price of nuclear fuel is stable, while the remaining fuels follow an increasing trend over the next fourteen years.

The prices of EUA are also obtained from the World Energy Outlook 2016 (IEA, 2016). The cross-border transmission capacity in the coming years is calculated on the basis of the public information of the Polish Power Grid Company. The development of renewable energy sources is estimated according to the renewables target which was set by the European Union. Moreover, the distance restrictions on wind farm deployment imposed by the Polish 'Wind Energy Investment Act' are taken into account. According to this Act, wind farms cannot be deployed within a specified distance from residential buildings. The distance equals ten times the total height of the wind turbine (Ministry of Energy, 2016b). Thus, the estimated parameter of the capacity of renewables increases from approximately 10 GW in 2021 to 18 GW in 2035. The Value of Lost Load (VoLL) in 2021–2035 is estimated at €3000/MWh.

The development of the supply curve in the capacity market requires the estimation of the volume of capacity obligation bids by each capacity market unit. The existing power generation units are characterised by the following parameters: (i) installed capacity, (ii) fuel, (iii) efficiency of power generation, (iv) availability factor, (v) emission factors, and (vi) variable operations and maintenance (VOM) cost. The data on new-build power generation units are collected based on publicly available information on power generation companies. The installed capacity of under-construction units totals 4,235 MW in conventional public power plants and 1,246 MW in combined heat and power plants. These units are assumed to enter operation according to the plans made publicly available by the generation companies and confirmed by the TSO. The energy storage participation in the capacity market is calculated as double the ratio of the decline in capital expenditure. According to the literature, this ratio amounts to 9% (CSIRO, 2015). Consequently, the growth rate of the energy storage capacity equals 18% per annum. It is assumed that energy storage can offer 33% of their capacity in the capacity market.

The price of the capacity obligation in individual bids is calculated on the basis of the estimate of the amount of 'missing money' for existing power generation units. In the case of refurbishing units, the price is based on their investment expenditure averaged over five or fifteen years (since these units can contract capacity for either 5 or 15 years). The price offered by new-build units is calculated on the basis of an analysis of their expected costs and revenues.

The development of the demand curve in the capacity market requires data on the capacity demand in the years ahead, the Net Cost of New Entry (Net CONE), and the flexibility of the demand curve. The forecast of total demand for the capacity auction is based on the estimate of net peak demand published by the Polish TSO which is then:

- increased by a certain percentage to account for sufficient capacity reserves
- decreased by the (i) capacity of units that do not participate in the capacity market, (ii) capacity of new and refurbished units that had won previous capacity auctions and contracted capacity for more than one year and (iii) capacity intended for purchase in the secondary auction.

The forecasted net peak and total capacity demand are given in Table 3.

The Net Cost of New Entry is calculated in accordance with the methodology presented by Wilson (2010) and assumed at the level of €59,212 per MW-year. The parameters of the demand curve are assumed as follows: (i) $A = 1.2$, (ii) $X = 0.03$ and (iii) $Y = 0.03$.

Three main capacity auctions (namely for the delivery periods in 2021, 2022, 2023) are held in 2018. Further auctions are organised five years ahead of the delivery period. It is also assumed that the total volume of capacity is acquired by the Transmission System Operator in the main auctions. The secondary auctions are neglected in this study.

4. Results and discussion

The model results are analysed and discussed in this section. The following parameters are calculated in order to estimate the economic consequences of operating a capacity market in 2021–2035:

(i) average annual electricity prices in EOM and CM scenarios (calculated as the weighted average of hourly prices) [€/MWh],
(ii) Loss Of Load Hours [h],
(iii) Expected Energy Not Served [GWh],and only for the CM scenario:
(iv) market clearing price [€/MW-year],
(v) the total budget of the capacity market [M€],
(vi) increase in the price of electricity due to the introduction of the capacity market [€/MWh].

4.1. Average annual electricity prices

The results of our study indicate that electricity prices increase over 2021–2035 regardless of the scenario considered (Fig. 4), mainly due to the increase in fuel and EUA prices. The electricity price only decreases in 2030 and 2032, which stems from the fact that two nuclear units are commissioned. The price decline is, however, insignificant because the number of decommissioned coal-fired units is excessively high in these years (888 MW decommissioned in 2031–2035 and 3,358 MW throughout the entire period of analysis). The comparison of electricity prices in the EOM and CM scenarios clearly indicates much higher prices in the first case. The difference in electricity prices between the EOM and the CM scenario amounts to €6.1/MWh in 2021, then it increases to a maximum level of €11.8/MWh in 2031.

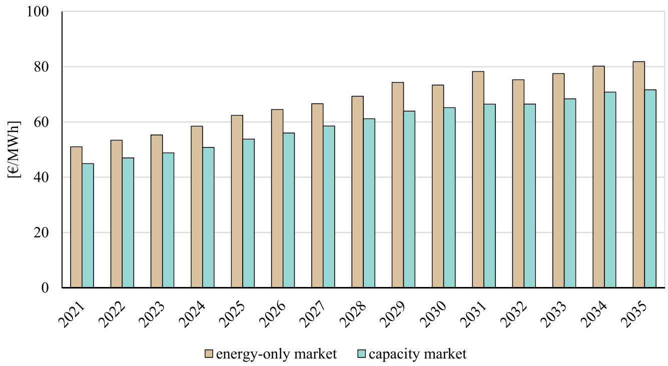

Fig. 4. Electricity prices in the EOM and the CM scenarios in 2021–2035, [€/MWh].

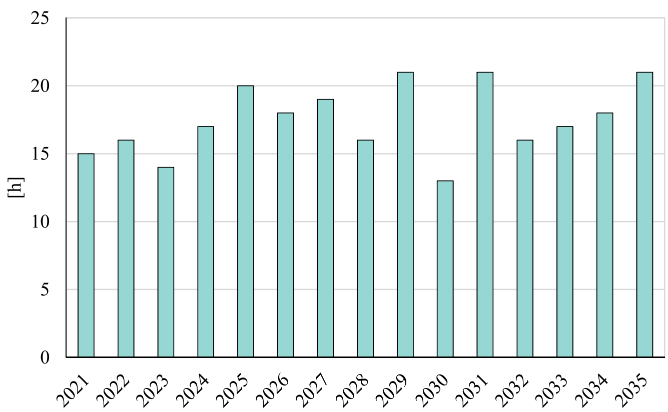

Fig. 5. Loss Of Load Hours in the EOM scenario in 2021–2035, [h].

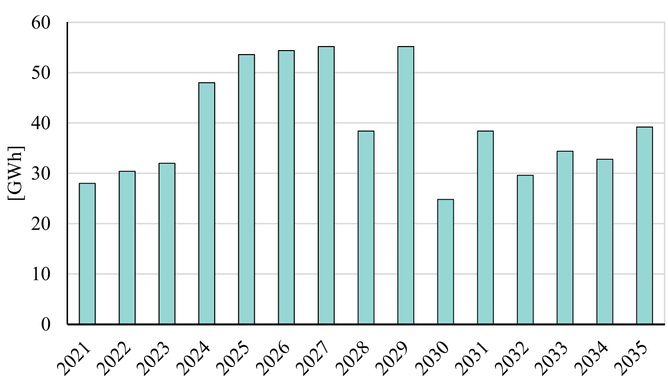

Fig. 6. Expected Energy Not Served in the EOM scenario in 2021–2035, [GWh].

4.2. Loss Of Load Hours

The analysis of the EOM scenario indicates that the total capacity of decommissioned units amounted to 3.4 GW in the entire period under analysis. Between 2021 and 2025, approximately 1.1 GW of thermal capacity is decommissioned. This level leads to an increase in prices and an improvement in the economic effectiveness of generating companies operating in the market. On the other hand, the security of supply declines to an unacceptable level. The Loss Of Load Hours (LOLH) is on average approximately 17 h per year in 2021–2029 (Fig. 5). The decrease is observed only in 2030 when the LOLH totals to 13 h per year due to the commissioning of a 1.4 GW nuclear power plant. To avoid a more drastic increase of LOLH, maintaining the operation of most of the

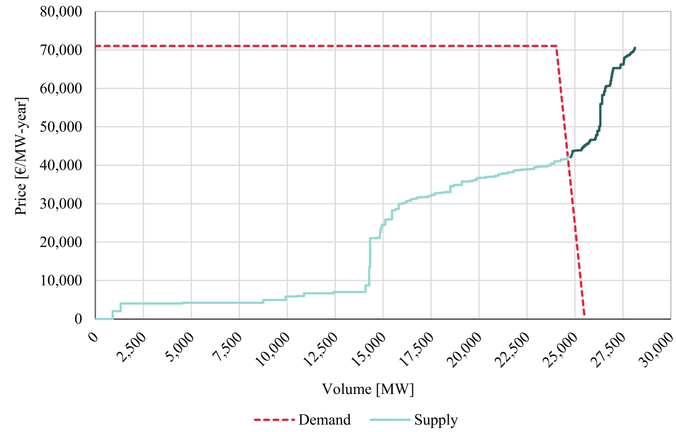

Fig. 7. The demand and supply curve in the capacity auction for delivery in 2021, [€/MW-year].

existing generating units until 2030 would be required. Consequently, (i) the commissioning of 1.6 GW of peaking units, and (ii) a relatively small increase of cross-border transmission capacity is insufficient to ensure the security of supply. Furthermore, the additional commissioning of the second unit of the nuclear power plant in 2032 does not guarantee a sufficient level of security of supply. The volume of the capacity of outdated coal-fired units to be decommissioned (due to their unprofitability) is considerable.

4.3. Expected Energy Not Served

The Expected Energy Not Served (EENS) in the EOM scenario is a consequence of the introduction of brownouts by the Transmission System Operator in 2021–2035 (Fig. 6). It can be observed that it increases from 2021 and reaches approximately 55 GWh in 2027 and 2029. The commissioning of the nuclear unit leads to a decrease in the level of EENS in 2030. However, the range of improvement is still insufficient and the level of energy security is far from optimal – Expected Energy Not Served still amounts to nearly 40 GWh next year. As previously mentioned, the commissioning of the second nuclear unit proves to be insufficient.

4.4. Market clearing price in the CM scenario

Owing to the fact that the results of the capacity auction simulations are very extensive, only the demand and supply curves of the auction simulated for delivery in 2021 are presented and discussed in detail in this section. The results of other auctions (for delivery in the period 2022–2035) are presented at an aggregated level.

The results of the capacity auction simulation for 2021 are presented in Fig. 7. The auction clears at €42,101/MW, and the total contracted volume is 24,791 MW. This cleared price is the result of competition between existing, refurbishing and new-build generating units, DSR providers, energy storage and foreign units in the market.

All refurbished and new-build capacity market units are eligible to receive payments from the capacity market, but they submit different bids to supply a specified amount of capacity. Some refurbished units are able to accept a significantly lower price, especially when they had spent funds on investment expenditure (sunk costs). Consequently, they can take into account only the risk of non-delivery of capacity in the delivery period and the potential financial penalty for not fulfilling the capacity obligation. The refurbished units that are going to start their modernisation to meet the environmental and emission obligations have to take into account capital expenditure in their bids.

Table 4 presents the market clearing prices and volumes of contracted capacity for delivery in 2021–2035. The highest market clearing

Table 4
The market clearing price and volume of contracted capacity for delivery in 2021–2035 in the CM scenario.

	2021	2022	2023	2024	2025	2026	2027	2028
Market clearing price[thousand €]	42.10	27.97	29.14	31.47	31.47	31.73	34.97	36.90
Capacity [GW]	24.79	7.42	7.81	7.84	8.02	21.11	21.41	21.66
	2029	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
Market clearing price[thousand €]	31.07	29.72	29.72	29.14	29.49	29.49	26.81	
Capacity [GW]	22.18	7.01	7.27	6.39	6.57	20.96	21.28	

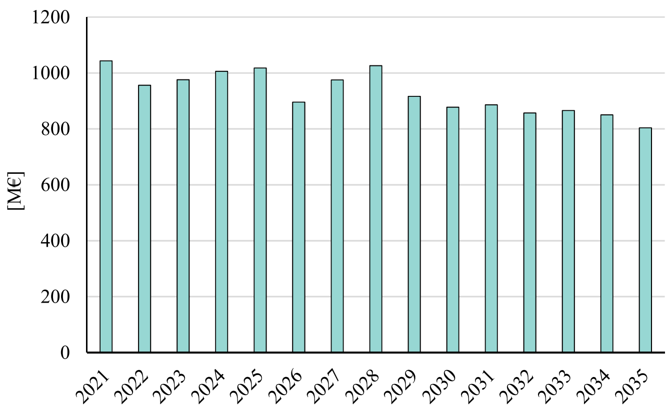

Fig. 8. The total budget of the capacity market in 2021–2035, [M€].

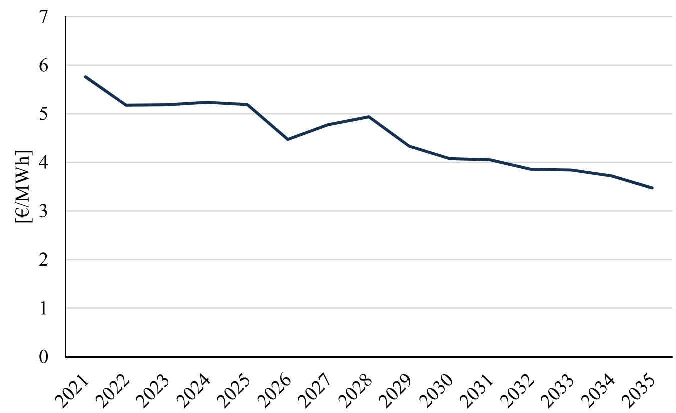

Fig. 9. The average capacity payment transferred to consumers in 2021–2035, [€/MWh].

price is observed in 2021 when the largest volume of capacity is also contracted. Most of the refurbished and new-build generation units contract capacity in this year. According to the assumption of capacity auctions, they are obliged to deliver capacity for: (i) 5 years in the case of refurbished CMUs, and (ii) 15 years in the case of new-build CMUs. Consequently, it can be observed that there are cycles of higher and lower volumes of contracted capacity. The capacity volume decreases from 24.79 GW to 7.42 GW in 2022. This level is observed up to 2025. Five years after the first capacity auction, an increase in capacity volume is observed (21.11 GW) and this is maintained until 2029. After this date, the amount of capacity is again similar to previous years.

4.5. The total budget of the capacity market and increase in price of electricity due to the introduction of the capacity market

The total cost of contracts awarded in the capacity auction for delivery in 2021 is around €1.04 billion. This amount is the highest over the whole period of analysis (Fig. 8). From 2029, the total budget is below €1 billion and it decreases to reach a minimum amount of €0.8 billion in 2035.

Table 5 and Table 6 present the share of new-build, refurbished and existing units in the total budget of a capacity market in 2021–2035. The refurbished units have the highest share for the first five years. Then, their share amounts to zero due to their transition to the category of existing capacity market units. Afterwards, the refurbished units have the highest share again in 2029–2033. After this year, these units transition to existing units once more. The share of new units amounts to 18.42% in 2021. It increases in the subsequent years to a maximum level of 29.21% in 2035.

According to the Act on the capacity market, the cost of contracts awarded in capacity auctions is transferred to consumers through their

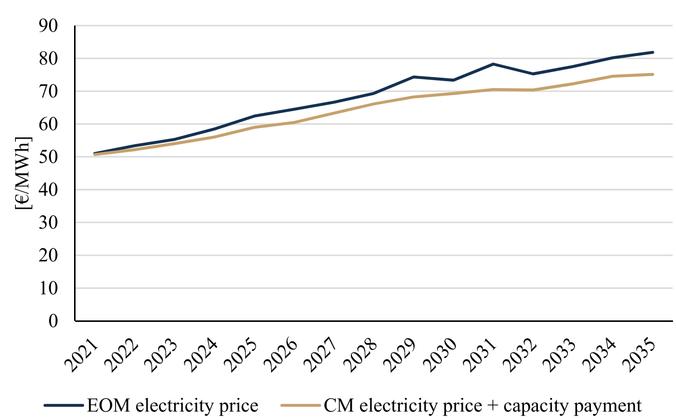

Fig. 10. Electricity price in the EOM scenario and electricity price in the CM scenario increased by the capacity payment, [€/MWh].

Table 5
Share of new-build, refurbished and existing units in the total budget of the capacity market in 2021–2028.

	Unit	2021	2022	2023	2024	2025	2026	2027	2028
new-build	%	18.42	20.11	20.77	20.80	22.21	25.27	23.26	22.16
refurbished	%	53.30	58.19	56.99	55.30	54.65	0.00	0.00	0.00
existing	%	28.29	21.71	22.25	23.89	23.15	74.73	76.74	77.84

Table 6
Share of new-build, refurbished and existing units in the total budget of the capacity market in 2029–2035.

	Unit	2029	2030	2031	2032	2033	2034	2035
new-build	%	24.88	26.07	25.91	26.91	26.77	27.43	29.21
refurbished	%	48.13	50.28	49.80	51.49	50.97	0.00	0.00
existing	%	26.99	23.66	24.29	21.60	22.26	72.57	70.79

Table 7
Forecast EUA prices under different WEO Scenario.

WEO Scenario	Unit	2020	2025	2030	2035	2040
2016 NPS	*$2015*	20.0	*28.5*[a]	37.0	*43.5*[a]	50.0
2017 NPS	*$2016*	–	25.0	*32.7*[a]	*40.3*[a]	48.0
2018 NPS	*$2017*	–	25.0	*31.0*[a]	*37.0*[a]	43.0

[a] Values interpolated.

electricity bills. The results of our study indicate that the capacity payment (on average) amounts to €5.8/MWh in 2021. Then it decreases to the minimum level of €3.4/MWh in 2035 (Fig. 9).

The results of our study indicate that operating the capacity market improves energy security and, simultaneously, ensures lower levels of electricity price, even when the capacity payment is included. Fig. 10 presents (i) the electricity price in the EOM scenario and (ii) the electricity price in the CM scenario increased by the capacity payment, expressed in €/MWh. The difference equals €0.3/MWh in 2021 and then it increases to reach €6.7/MWh in 2035.

5. Limitations of the study and suggestions for further research

We are well aware that this study has some limitations. We describe the most important ones in this section.

The calculations presented in this paper were carried out in the course of 2017–2018 (at the time when the Capacity Market Act was being introduced). All datasets and results presented in this paper were up-to-date from the perspective of Poland, considering the introduction of the capacity market.

Also, we developed and analysed only two scenarios in our investigation. Although the operating of the pure energy-only market can appear to be rare, the evidence from EU markets proves that CRMs are not introduced in all European countries. There are several countries where energy-only markets are still operating, such as Austria, Croatia, Denmark, Estonia, Hungary, Luxembourg, Norway, Romania, Slovakia, Slovenia, Switzerland, the Czech Republic and the Netherlands (ACER, 2019). Our scenarios were tailored to provide insights and answers to the policy-making questions of the economic effects of the introduction of a capacity market.

The investigation was based on the forecast of EUA prices from WEO 2016. As mentioned earlier, the model was developed in 2017–2018, and the paths of EUA prices based on the NPS scenario of WEO 2016 were assumed because these were the most up-to-date data at that time. However, these assumptions were compared and verified with WEO forecasts published later (Table 7). Consequently, EUA prices published by the IEA did not change significantly. Also, the EUA prices of the 2016 NPS scenario are even higher than the latest forecasts.

Source: Own analysis based on (IEA, 2018, 2017, 2016)

It is important to note that this paper was not intended to study the impact of EUA prices and their effects on the electricity market under various market designs (EOM vs. CM). Therefore, as in most impact assessments, we assumed the same level of EUA prices for both scenarios. Since we develop and apply a deterministic model, we assume one value per year. Although this value can change throughout the year, the results do not vary significantly since the same values are assumed for both scenarios (CM and EOM). Hence, this assumption does not influence the robustness of the results.

We are well aware that Poland is part of the EU's Energy and Climate Framework and must comply with the climate and energy targets. This aspect is in line with the current discussion (both at the national and international level) on the future of the capacity market and the changes that the Polish government will have to introduce into the Energy Law and the Capacity Market Law (for instance the 550 kg CO_2/MWh limit for CM units). This issue has not been the subject of our investigation. The paper was written from the perspective of a decision-maker that is considering the introduction of a capacity mechanism. An interesting path for future research would be to analyse the impact of EU climate and energy targets on the structure of the Polish energy system, including the effects of higher EUA prices on the capacity market. Also, future studies could look into the long-term effects of the introduction of a capacity market on the technological transformation path of the Polish power system.

At the moment, in the developed modelling approach, the deterioration of units caused by the long-term overload operation is not included. The effect of long-term overload operation is a complex issue that often involves comprehensive information regarding individual pieces of equipment. Moreover, for us to reflect this in our model, information regarding the contingency plans determined by the TSO is needed, including prescribed voltages, reactive schedules, and redispatch plans. There are plans to address this issue in future research.

6. Conclusions and policy implications

To investigate the economic consequences of operating a capacity market in Poland, two scenarios were considered in this study: (i) the energy-only market scenario, in which the only traded product was electricity, and (ii) the capacity market scenario, in which a capacity remuneration mechanism was implemented. The results of the analysis conducted indicate that the maintenance of the energy-only market in the long-term results in significantly higher electricity prices when compared to the implementation of the capacity market in Poland. The average annual electricity price in the capacity market scenario is lower by €6.1 per MWh in 2021, when compared to the energy-only market scenario. Then, the difference increases to reach a maximum level of €11.8 per MWh in 2031. This stems from the fact that meeting the economic efficiency condition using existing public power plants is complex, which leads to their decommissioning. On top of that, the lack of incentives leads to reduced investment in new power generating units. Moreover, the capacity of the decommissioning units amounts to 3.4 GW in 2021–2035. Consequently, in the Polish power generation system, the resource adequacy problem appears in the energy-only market scenario, despite the planned commissioning of the nuclear power plant in 2030 (first unit) and 2032 (second unit). The level of Loss Of Load Hours is on average approximately 17 h per year in 2021–2029 in this scenario. A decrease in LOLH is observed only in 2030 with a total of 13 h per year, mainly due to the commissioning of the nuclear power plant. This study shows that the nuclear power plant, therefore, does not guarantee an acceptable level of security of supply since the level of decommissioning of operating units is too high. The Expected Energy Not Served increases to 55 GWh per year in 2027 and 2029. Subsequently, it decreases to 35 GWh per year, although the improvement of the security of supply is insufficient.

Although the total cost of contracts awarded in capacity auctions is €1.04 billion in 2021 (decreasing to reach the minimum amount of €0.8 billion in 2035), the average capacity payment transferred to consumers changes from €5.8/MWh in 2021 to €3.5/MWh in 2035. The electricity price difference between the energy-only market scenario and the capacity market scenario (including capacity payment) proves that the operation of a capacity market brings positive effects to both, to the consumers and the producers. Not only a price reduction is achieved, but also energy security is improved.

With regard to European and global experience and the results of this study, it has been found that operating a capacity market enables effective use of existing resources without excessive capital expenditure. Moreover, the increase in capacity volume in the power generation system happens only when it is necessary to ensure energy security at a socially acceptable level.

The main policy implication derived from our analysis is that over the long run, the introduction of a capacity market in Poland will ensure the security of supply; however, policymakers now face the challenge of designing viable pathways to deal with the rapid decarbonisation of the energy system. The decarbonisation of the Polish power sector will require large-scale investments in carbon-free technologies, and considering that the expansion of renewable production tends to depress electricity prices, as it has been noted by Kavulla (Kavulla and Gülen, 2019), Martin de Lagarde (Martin de Lagarde and Lantz, 2018), Hirth (2018), Gil (Gil et al., 2012), among others, fundamental changes to the capacity market or an alternative solution will be needed to ensure the continued reliability of power capacity while increasing the deployment of renewable power generation.

Finally, from the interpretation of our results, one can argue that the introduction of a capacity market in a power system highly dependent on coal, and facing the imminent retirement of a significant number of coal-fired units, will put the fundamental legal and economic principles of the theoretical concept of capacity markets to the test, especially in a European Union where technological neutrality should be guaranteed, EUA prices have been steadily rising, and an expansion of renewables is expected. Other real-world experiences have raised serious doubts on the operation of capacity markets and have brought to light the importance of market designs that are able to cope with the effects of renewables and storage on electricity market revenues.

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CRediT authorship contribution statement

Aleksandra Komorowska: Methodology, Investigation, Data curation, Writing - original draft, Writing - review & editing, Visualization. **Pablo Benalcazar:** Methodology, Investigation, Data curation, Writing - original draft, Writing - review & editing. **Przemysław Kaszyński:** Methodology, Software, Validation, Formal analysis, Investigation, Resources, Data curation, Writing - review & editing. **Jacek Kamiński:** Conceptualization, Methodology, Writing - review & editing, Supervision.

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