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Assessment of the impact of the Polish capacity mechanism on electricity markets

A Report for the Polish Electricity Association

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Abbreviations and technical units

550 EPS	550gCO2/kWh emissions performance standard
AS	Ancillary Services
BAT	Best Available Techniques
CAPEX	Capital Expenditures
CCGT	Combined Cycle Gas Turbine
CEE	Central Eastern European
CHP	Combined Heat and Power
CM	Capacity Market
CM 550	Capacity Market with emission cap at 550gCO2/kWh
CR	Climate Reserve
DSR	Demand-Side Response
EC	European Commission
EEG	German Renewable Energy Act
ENS	Energy Not Supplied
ENTSO-E	European Network of Transmission System Operators for Electricity
EOM	Energy-Only Market
EPS	Emissions Performance Standard
ETS	Emissions Trading Scheme
EU	European Union
FGD	Flue Gas Desulphurisation (industrial process related to IED)
FO&M	Fixed Operation and Maintenance costs
GDP	Gross Domestic Product
IEA	International Energy Agency
IED	Industrial Emissions Directive
LCPD	Large Combustion Plants Directive
LF	Loop Flows
LOLE	Loss of Load Expectation
NPV	Net Present Value
NTC	Net Transfer Capacity
OCGT	Open Cycle Gas Turbine
OPEX	Operational Expenditures
PPS	Polish Power System
PSE	Polskie Sieci Elektroenergetyczne (Polish TSO)
PKEE	Polski Komitet Energii Elektrycznej (Polish Electricity Association)

RES	Renewable Energy Sources
SCR	Selective Catalytic Reduction
SR	Strategic Reserve
SRMC	Short-Run Marginal Cost
TSO	Transmission System Operator
VOLL	Value of Lost Load
VO&M	Variable Operation and Maintenance costs
WACC	Weighted Average Cost of Capital
WEO	World Energy Outlook

1. Executive summary

1.1 INTRODUCTION

Concerns over security of supply have emerged in the past couple of years in Poland, and were intensified by brownouts in 2015. The ability of the current market framework to provide adequate remuneration and investment incentives is increasingly being questioned. Many plants are not profitable with anticipated market prices, driving significant retirements at a time when new investment is required to meet the new emissions levels - the "Best Available Techniques" (BAT) adopted pursuant to the Industrial Emissions Directive (IED)[1].

In order to maintain security of supply at the politically desired level (the reliability standard), the Polish government decided to establish a capacity market (CM) with a design addressing the Polish power system specificities.

Capacity mechanisms are reviewed by the European Commission (EC) in the light of State Aid regulation. The EC's *Guidelines on State aid for environmental protection and energy 2014-2020* lists a number of criteria as conditions for compliance, including demonstrating the need for intervention, and the appropriateness and proportionality of the mechanism in comparison with other possible reforms of the electricity market, as well as its potential impacts on energy markets[2].

In this context, PKEE mandated Compass Lexecon to:

▪ **Assess the Polish CM proposal and its potential impact on the electricity market in comparison to a counterfactual Energy-Only Market (EOM).** In the CM, capacity auctions ensure the reliability standard by procuring the necessary capacity. In contrast, EOM or EOM with expanded interconnection capacity does not guarantee per se the reliability standard and available capacity is driven by the decisions of rational profit-maximising players based on the revenues expected from the energy and ancillary markets and the expected costs.

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[1] European Commission (2010), Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control) Text with EEA relevance, OJ L 334, 17.12.2010, p. 17–119.

[2] European Commission (2014), Communication from the Commission — Guidelines on State aid for environmental protection and energy 2014-2020, OJ C 200, 28.6.2014, p. 1–55.

▪ **Compare the CM proposal with the current strategic reserve** to achieve the reliability standard by estimating the differences in efficiency and social costs.

▪ **Analyse the impact of the EC proposed emissions performance standard (550 EPS) in capacity mechanisms** in terms of efficiency and costs. In its Energy Market Regulation proposal[3], the EC proposes to exclude power plants emitting more than 550gCO2/kWh from participating in capacity mechanisms.

▪ **Compare the impact of the CM with the impact of other public policy interventions in energy markets.** We determine whether the impact of the CM is significant compared to a range of other public interventions including: (1) the German strategic reserve, (2) the German Renewable Energy Sources (RES) support policy and (3) loop flows'   impact on available Net Transfer Capacity between Poland and neighbouring countries.

Our analysis is based on our proprietary European electricity market model which is calibrated to replicate the power price dynamics in the different European countries and the economic decisions of market operators regarding investment and decommissioning decisions. This allows us to model the evolution of the Polish and European power system (EU-28) power prices and resource mix over the period of 2017-2040 in the different scenarios considered through a dynamic modelling process, i.e. in which market parties'   decisions integrate their impact in the future. The following sections present our key findings.

1.2   THE CM ADDRESSES THE SECURITY OF SUPPLY CONCERNS IN A COST-EFFICIENT WAY

Intervention is necessary to maintain security of supply at the required level

In the EOM scenario, as early as 2020 and for all subsequent years, the reliability standard corresponding to 14% of the de-rated capacity margin set by the Polish public authorities is not met because of the closure of a number of unprofitable plants and later because of insufficient investments to maintain security of supply at the reliability standard (Figure 1-1).

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[3]   European Commission (2016), COM(2016) 861 final/2, Proposal for a Regulation of the European Parliament and of the Council on the internal market for electricity (recast), Brussels, 23.2.2017

In contrast, **the CM allows meeting the reliability standard in all years** after its implementation because it ensures that some market participants postpone plant closures and make investment decisions in a timely manner.
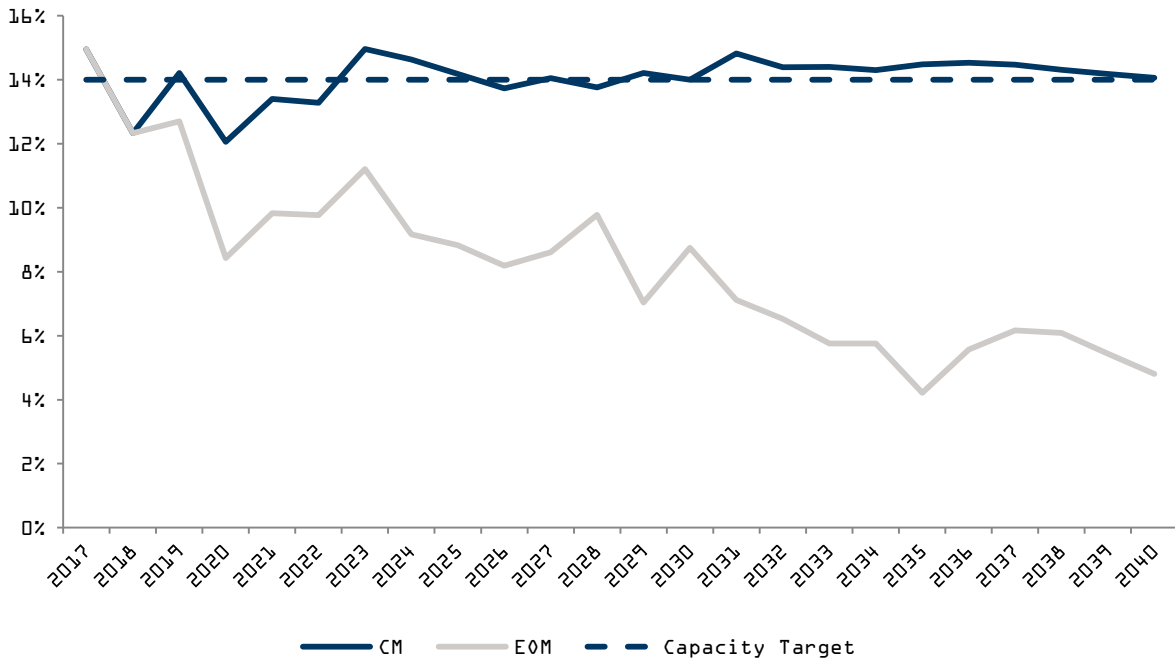
Figure 1-1: Annual de-rated capacity margin in the CM and EOM scenarios (%)

Source: Compass Lexecon, 2017

Notes: The de-rated capacity margin is defined as the ratio between the additional de-rated capacity available (including DSR and interconnection capacities) above the net average cold spell peak demand (excluding auxiliary demand). The capacity gap between available de-rated capacity and the capacity target in the EOM scenario ensures an economic breakeven of both existing and new build plants.

To guarantee resource adequacy, the CM provides incentives for the most competitive technologies in all timeframes to meet the reliability standard (Figure 1-2):

▪ Before 2024, the CM allows power producers to finance life extension's and depollution reinvestment for 1 GW of thermal plants more than in the EOM, in order to comply with the BAT conclusions and invest in retrofit CAPEX.

▪ Between 2024 and 2030, the CM triggers additional investments in Demand-Side Response (DSR) and in high-efficiency coal plants.

▪ After 2030, Combined-Cycle Gas Turbines (CCGTs) become more competitive than new coal plants in the CM auction, as the carbon price gradually increases and improves their profitability against coal.
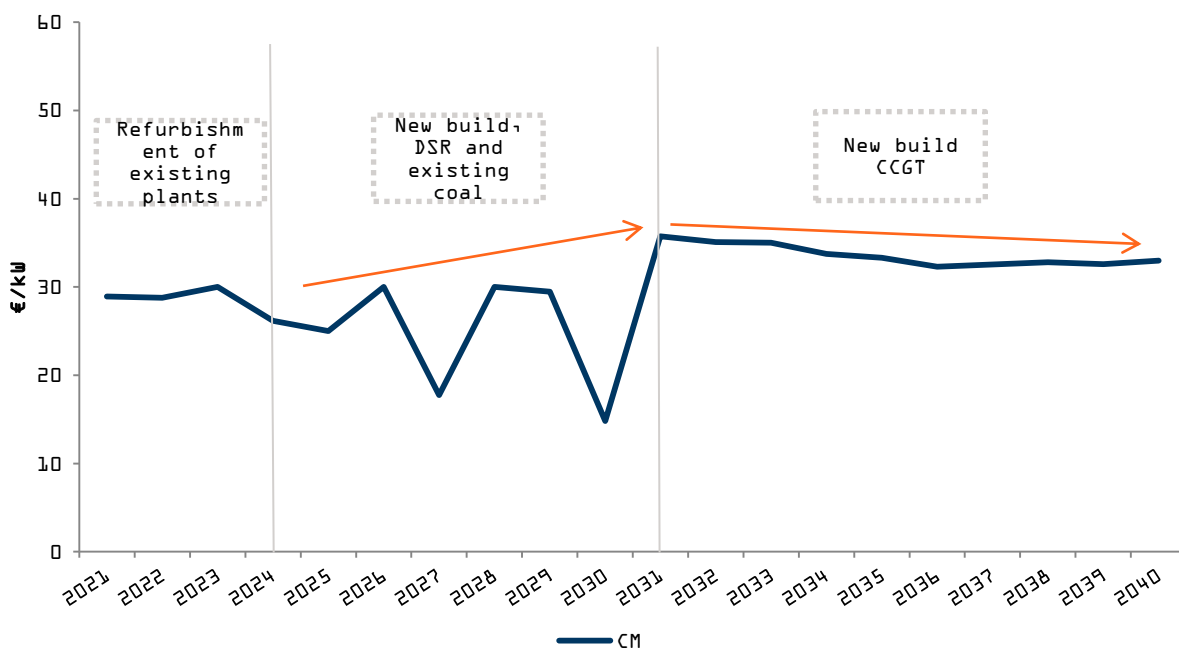
Figure 1-2: Capacity price in CM scenario (€/kW)

Source: Compass Lexecon, 2017

Notes: The vertical lines divide the evolution of the capacity price into three periods according to different price drivers: retrofit investment to comply with BAT conclusions before 2024, investment in DSR and high efficient coal capacity between 2024-2030, and investment in new CCGT capacity beyond 2030.

Based on our assumptions of commodity prices and construction costs of different technologies, new CCGTs become more competitive than new coal plants in the CM scenario from 2031 onwards: new CCGT capacity starts to develop and no new coal plants would be built post 2031. Note that alterative assumptions for commodity prices, CO2 prices, or construction costs would modify the timing of the switch between coal and gas for new build but would not modify our aggregate capacity results.

In the long run between 2031 and 2040, the CM leads to an increase in capacity of 3,900MW compared to the EOM, consisting of 1,200MW of DSR, 500MW of new coal plants and about 2,200MW of CCGTs (Figure 1-3) and a higher security of supply in Poland at the level of the reliability standard[4].

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[4]   The CM leading to a higher security of supply can be demonstrated by a lower level of energy not supplied (ENS) or a lower number of Loss of Load Expectation (LOLE). For example in 2025, the number of LOLE is 11 hours in the EOM and 0 hour in the CM, and ENS in the EOM is € 119 million.
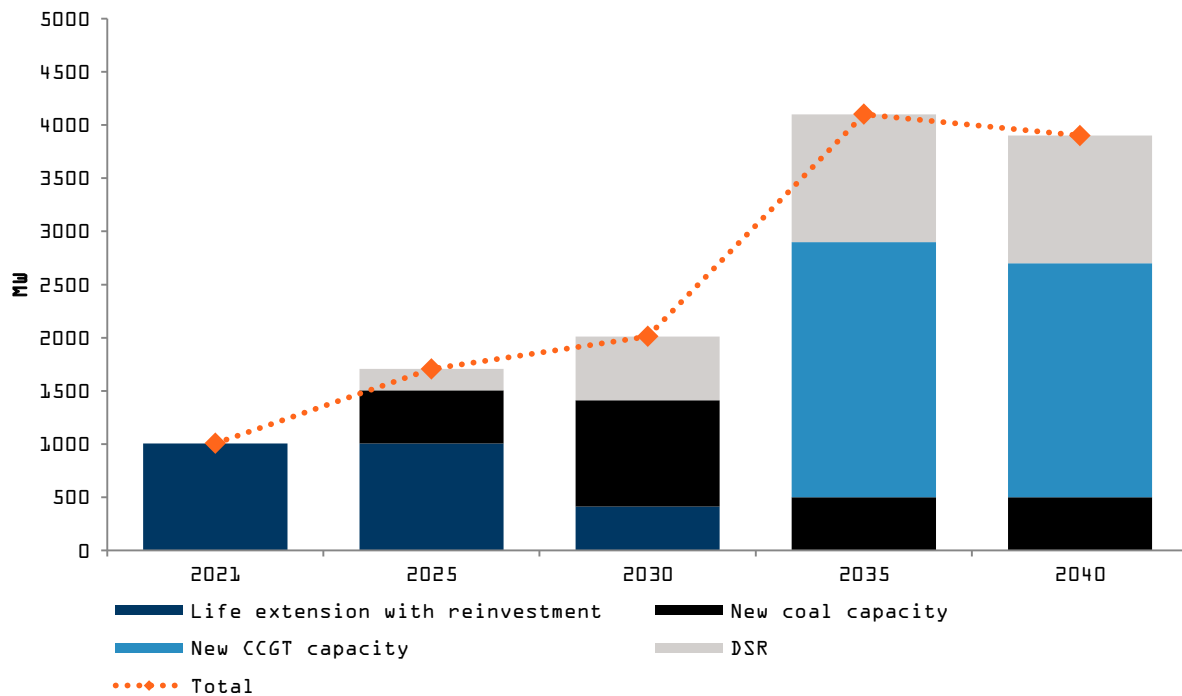
Figure 1-3: Difference in installed capacity between the CM and EOM scenarios (MW)

Source: Compass Lexecon, 2017

Notes: Difference in installed capacity is calculated as installed capacity in the CM minus installed capacity in the EOM

It is worth noting that an increase in interconnection capacity would most likely not be a sufficient solution to the adequacy concerns in Poland in the EOM scenario. Interconnection capacity may increase on a given border, but the neighbouring country may not have a sufficient capacity margin to provide electricity to Poland at times of scarcity in Poland (risk of simultaneous scarcity). In addition, increasing interconnection capacity could result in a significant increase in imports and reduce prices, negatively affecting the incentives for reinvestment of existing capacity and investment in new capacity. Belgium provides an example of a situation where despite extensive interconnection capacity with respect to the peak demand, there is still a high risk of blackouts.[5]

The introduction of a CM in Poland reduces costs for Polish consumers and improves social welfare

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[5]   The Belgian total transmission capacity is 3.5GW during the winter relative to a peak demand of 13.5GW in recent years. Interconnection projects with the UK, France, and the Netherlands will increase the interconnection capacity by another 3GW by 2020 (Source: Elia 2015, Electricity security crisis in Belgium). Unprofitable market conditions leading to decreasing available thermal capacity and uncertainty around nuclear capacity put the Belgian security of supply under pressure.

The introduction of a CM in Poland reduces costs for Polish consumers by € 7 billion in total, i.e. € 280 million per year on average over the modelling horizon, compared to the EOM scenario. Although the CM creates a new cost component (the capacity remuneration), this is more than outweighed by the reduction in the cost of unserved energy and the wholesale prices:

- **The CM reduces the cost of unserved energy** by about € 46 million per year on average over the period.

- **The CM reduces wholesale energy prices on average by €5/MWh as compared to the EOM (6% of the EOM price)** by triggering investments in more efficient technologies sooner and avoiding too frequent scarcity situations and, consequently, reducing the frequency of price spikes. This in turn reduces the cost of capital and thereby the financing costs for new investments - particularly for peaking plants that would run only a limited period of time.
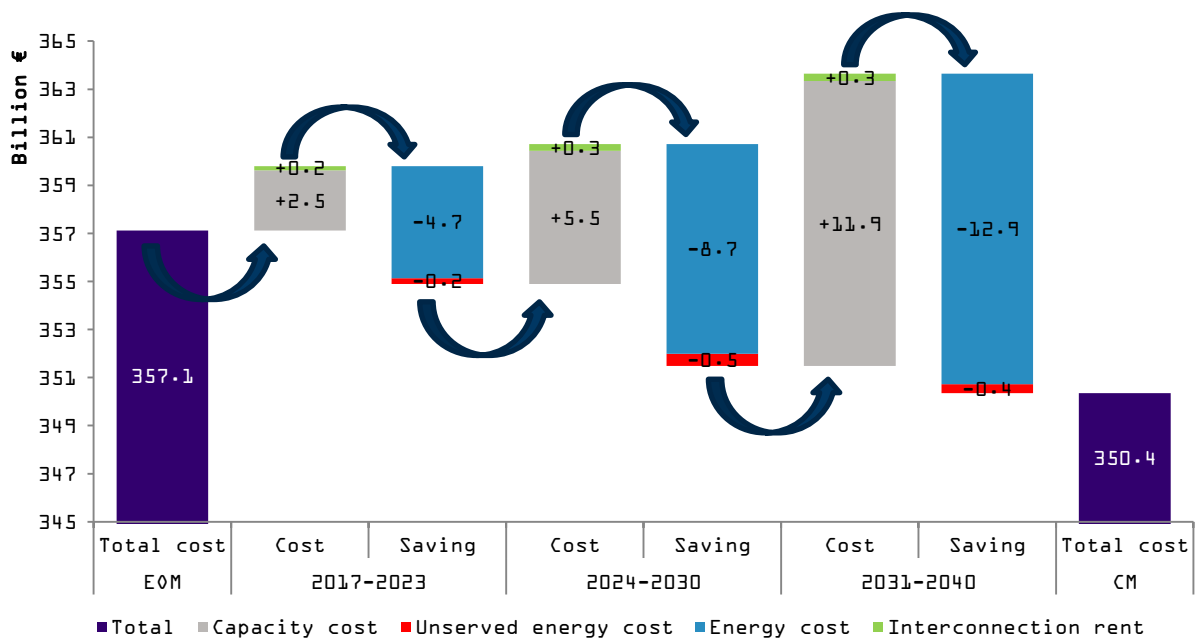
Figure 1-4: Comparison of average costs and savings for Polish consumers between the EOM and CM scenarios over 2017-2040 (billion €2016)

Source: Compass Lexecon, 2017

Notes: The figure compares the costs to Polish consumers in the EOM and in the CM and shows the variations between the two scenarios in three periods. A plus sign means an increase and a minus sign means a decrease in costs to consumers. The capacity cost is defined as the capacity price multiplied by the capacity target. The energy cost is defined as the annual energy price multiplied by load. Unserved energy cost is measured by the volume of energy not supplied multiplied by VOLL. The interconnection rent is the sum of revenue on each Polish interconnection line divided by two. We contribute the difference in interconnection rent between CM and EOM to consumer costs or savings because it is a result of the reduction in power prices and in financing and investment costs in the CM, which leads to lower congestion rent. This lower congestion rent for interconnectors introduces a cost for consumers. The cost to Polish consumers in the CM is lower than that in the EOM, representing a saving of the CM.

The CM increases social welfare in Poland by over € 1 billion in total, about € 46 million per year on average over the modelling horizon. While changes in energy and capacity prices are a value transfer between consumers and generators, the CM benefits not only consumers, but also generators and DSR operators through more predictable revenues from the capacity mechanism, and reduced market risks and cost of capital.

The CM does not modify the short-term merit order and has limited impact on market functioning

The Polish CM is effectively designed not to alter market participants' bidding strategy and dispatch decisions in the short term. Polish capacity providers bid in the energy market on the basis of their Short-Run Marginal Cost (SRMC) in the same way they would in the EOM.[6]

In the long term, the CM in Poland corrects the market failure where electricity prices are not reflecting the true cost of security of supply, and helps to obtain the optimal available capacity given the policy determined reliability standard. As a result, it has an impact on available capacity, wholesale prices and the export balance.

1.3   THE STRATEGIC RESERVE DOES NOT APPEAR AS AN ADEQUATE SOLUTION FOR POLAND

As an alternative of the CM to address security of supply concerns, Poland could have maintained and improved its strategic reserve mechanism. However, this measure is not adapted to address Polish structural adequacy concerns and it is not a cost-efficient way to ensure security of supply in the long-term.

The strategic reserve is not a mechanism adapted to the structural Polish adequacy concerns

In its final report of the sector enquiry on capacity mechanisms published on 30 November 2016**, the EC recommends introducing a strategic reserve when there is a temporary adequacy concern in a national power market due to potential plant retirement, but not to stimulate new investment.**[7]   Considering the Polish adequacy outlook, there is an increasing and persisting capacity gap between the CM and EOM scenarios (Figure 1-3). This implies that Poland would need

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[6]   We also take into account the possibility for – mostly peak – capacity providers to apply a mark-up on their SRMC when system margins are tight, in order to recover part of their fixed costs.

[7]   European Commission (2016), Final Report of the Sector Inquiry on Capacity Mechanisms, COM(2016) 752 final.

a strategic reserve in the long run (at least until 2040 based on our modelling) with up to 4,000MW of generation capacity.

The strategic reserve is not a cost-efficient measure to ensure security of supply in Poland

A "perfectly-designed" strategic reserve would have no impact on the day-ahead energy market (and very limited impact on intraday and balancing markets, if any) compared to the EOM. This means that the incentives of power producers to maintain their plants in the market or to build new plants are unaltered and, as a result, capacity mix and energy prices in the market are unchanged. Therefore, compared to the EOM, energy costs would be similar but the reserve's contracting and activation costs would largely outweigh the value of the reduction in loss of load.

A fortiori, the strategic reserve would be more costly for consumers than the CM. **Overall, the CM leads to a total saving of more than € 8 billion for consumers over 2017-2040 (assuming a VOLL at €18,000/MWh) compared to the strategic reserve**, corresponding to an average of € 350 million per year. More generally, the CM leads to a net gain of social welfare of about € 950 million between 2017 and 2040, or around € 39 million per year.

1.4   THE 550 EPS IN THE CM WOULD HAVE A NUMBER OF NEGATIVE EFFECTS

In its Electricity Market Regulation proposal the EC suggests introducing an emission performance standard (EPS) in CMs, which would impact the eligibility of some generation technologies to such schemes. More specifically, the Article 23 (4) of the proposal provides that:

 "Generation capacity for which a final investment decision has been made after [OP: entry into force] shall only be eligible to participate in a capacity mechanism if its emissions are below 550 gr CO_2/kWh. Generation capacity emitting 550 gr CO_2/kWh or more shall not be committed in capacity mechanisms 5 years after the entry into force of this Regulation".

Generation capacity for which a final investment decision has been made after entry into force of the Electricity Market Regulation, which is expected to occur in early 2019 emitting more than 550gCO_2/kWh will no longer be allowed to participate in CMs. Generation capacity, which has obtained final investment decision before this date is given with a five-year transitional period. For the purpose of our modelling we assumed that this transitional period would be ended in 2024.

In the scenario of a capacity mechanism with the restriction of EPS (the 550 EPS scenario), Poland maintains electricity security of supply but increases sharply its dependency on gas imports

compared to today's situation as well as, to a lesser extent, to other scenarios modelled in the study. In the 550 EPS scenario, security of supply would be maintained at the reliability standard through the replacement of investment in coal plants by new CCGTs.

In the absence of capacity remuneration, coal plants are not profitable and 3.8GW of new CCGT capacity would be developed in the 550 EPS scenario to replace new coal capacity developed in the CM scenario. New CCGTs are needed as early as 2021 to offset the early closure of existing coal plants.

The change in the generation mix triggered by the 550 EPS, with a significantly higher CCGT capacity as compared to the CM, would lead to a **significant increase in the country's gas consumption for electricity generation.** Over the outlook period, the 550 EPS increases Polish gas consumption by 60 bcm, a 70% increase compared to the CM scenario. This would raise significantly Polish gas import dependency, and require an upgrade of the Polish gas transport infrastructure, which may raise security of supply concerns.

Despite the reduction of capacity payment to coal/lignite plant operators, the 550 EPS increases costs for the Polish consumers compared to a technology-neutral CM

The 550 EPS increases costs for consumers by € 240 million over the 2017-2040 period despite the reduction in capacity costs. More generally, the **CM scenario outperforms the 550 EPS scenario in terms of social welfare, leading to a net gain of € 980 million between 2017 and 2040**, or around € 40 million per year.

The 550 EPS lowers the Polish domestic CO2 emissions related to electricity generation, but at a higher decarbonisation cost than the EU Emission Trading System

The CM 550 effectively reduces domestic CO2 emissions from electricity generation in Poland, as CCGT new build gradually replaces existing coal plants or substitutes coal new build (a reduction of 54 million tCO2 in total between 2020 and 2040, i.e. a 39% reduction of the 2020 level). However, in the absence of a modification of the EU Emission Trading System (EU ETS) cap, **total emissions in Europe are not reduced in the 550 EPS scenario as lower emissions in the Polish power sector are compensated by lower abatement efforts in other sectors and countries.** As a result of the 550 EPS, lower demand for CO2 allowances and a lower CO2 price would make additional interventions, e.g. through the Market Stability Reserve (MSR) further needed.

Effectively, **coal-to-gas switch and significant CO2 emission reduction could be supported more efficiently by a sufficiently high EU ETS price, which would be a more cost-efficient mechanism**

than 550 EPS. The 550 EPS scenario leads to emission reductions at an implicit carbon cost higher than the EU ETS market price. The average premium over the EU ETS price[8] of CO2 emissions' reductions achieved via the 550 EPS scenario is more than €5/tonne.

These results differ significantly from those of a study done by E3M-Lab[9], with the important caveat that **the E3M-Lab** study does not aim **to assess the efficiency of the 550 EPS**. Indeed, the modelling approach and methodology differ significantly. The E3M-Lab study does not model the impact of a CM, but instead models the impact of a subsidy (Contract for Difference) limited to coal and lignite plants. However, the CM envisaged in Poland is not a subsidy specific to coal and lignite plants, but applies to all eligible technologies, including CCGTs, DSR etc. Conversely, the 550 EPS creates a difference of treatment which favours technologies other than coal and lignite, beyond the impact of the EU ETS, but this is not what the E3M-Lab study aims to assess.

As a result, the E3M-Lab study cannot be used as a basis to assess the efficiency of the 550 EPS and its findings should be compared with our study results with great care. Indeed, the coal/lignite subsidy assessed by E3M-Lab in Poland, Romania, Greece and Estonia would mainly displace gas-firing generation. The coal and lignite support would encourage investment in new build coal, resulting in different mix, price levels and significantly higher emission levels than those of the 550 EPS scenario of our study. As a result, the E3M-Lab study finds an increase in CO2 emissions by nearly 20% in the four countries modelled beyond 2030, in comparison to a 1% increase EU-wide in our results. Furthermore, the E3M-Lab study finds higher long-term electricity price by €2-5/MWh for consumers in 2030, whilst we find a moderate net cost impact on consumer prices as the reduction in capacity costs partly compensates the power price increase and the difference in capacity prices.

1.5   THE CM HAS LOWER IMPACT ON ENERGY MARKETS THAN OTHER POLICY MEASURES

The study compares the impact of the Polish CM on the electricity market with the impact of a range of policy measures aimed at guaranteeing security of supply and/or supporting specific technologies.

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[8]   The projection of the EU ETS price is based on the New Policies scenario of the World Energy Outlook 2016 edition up to 2030. We obtain the long-run EU ETS price between 2030-2040 based on our internal EU ETS model (the EU ETS price increases to €60/tonne by 2040)

[9]   E3M-Lab (June 2017), Modelling study contributing to the Impact Assessment of the European Commission of the Electricity Market Design Initiative.

Modifications of the available capacity induced by other policy measures are comparable or more significant than the changes driven by the Polish CM

The amount of additional capacity induced by the Polish CM is comparable in the long term to the German strategic reserve. In contrast, the German high RES scenario brings in a total additional capacity of 67GW in 2030 and 74GW in 2040.

The impact of the Polish CM on power prices in the long run is not greater than the other policy measures modelled

The Polish CM has a comparable impact on the domestic power price, and its impact on other countries is much smaller, compared to other policy interventions. In 2030, the CM decreases the Polish price by 6%, while the net effect of RES policy and strategic reserve in Germany is 8% and 2% in 2030. The decreased loop flows have a variable net impact on power prices, limited to 1-2% in Poland and other countries.

The impact of the Polish CM on cross-border flows is more limited than the impact of the other policy interventions

In 2030, the Polish CM modifies cross-border flows by about 4TWh, whilst some other policy measures have a greater impact on cross-border flows: the reduced loop flows case, allows Poland to export to neighbouring countries 5TWh more, while the German strategic reserve decreases exports by 18TWh and the RES support increases net export by 64TWh respectively.

2. Introduction: The Polish capacity market

2.1 CONTEXT

Concerns over security of supply have emerged in the past couple of years in Poland as well as in a number of the EU Member States. A number of European countries have implemented or are considering CMs of different types, such as capacity payments, strategic reserves or capacity markets. The way in which these mechanisms interact with the energy market and impact market participants differs considerably.

The Polish Government Legislation Centre published on 5 December 2016 the draft bill on the Capacity Market[10] for the Polish power market. On 6 July 2017 the Bill on capacity market has been submitted to the lower chamber of the Polish Parliament[11]. However, the changes between the two versions of the Bill do not significantly change the results and conclusions of this report. This report was prepared before the issue of the latest version of the Bill in July 2017 and is based on the issue of draft bill on 5 December 2016. The purpose of the bill is to prevent generation capacity deficits by remodelling the regulatory environment of the electricity market so as to create strong economic incentives encouraging the construction, maintenance and modernisation of generating units and energy demand management on the end users side.

The capacity market will have the form of centralised auctions in which both generating units and Demand Side Response (DSR) units can participate. For the delivery scheduled for 2021-2023, Poland may hold first capacity market auctions as soon as in 2018, given the unfavourable forecasts for electricity balance and the predicted risk of shortages in 2021.

The European Commission (EC) is however particularly sensitive to potential impacts on energy markets of such mechanisms due to concerns over distortion on competition.

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[10] Polish Government Legislation Centre (2016), *Ustawa o rynku mocy – Projekt z dnia 30.11.2016 r.* (Draft bill on the Capacity Market for the Polish power market).

[11] Polish Government Legislation Centre (2017), *Ustawa o rynku mocy – Projekt z dnia 06.07.2017 r.* (Draft bill on the Capacity Market for the Polish power market).

On 30 November 2016, the EC published its Final Report of the Sector Inquiry on Capacity Mechanisms[12]. In this report, the Commission emphasised that public support for capacity providers constitutes State aid which posed the risk of distorting competition in the electricity market. As indicated by the Commission, one of the main risks related to the application of capacity mechanisms is the limitation of such mechanisms exclusively to national capacity providers, which leads to increased costs of security of supply and also hampers the achievement of the EU climate objectives.

Energy markets complemented by a CM indeed give different incentives compared to a theoretical energy-only market (EOM).

The introduction of CMs or other national policies and impacting the energy mix has in theory an impact on electricity markets, both:

▪ In the short term: The CM may influence the participation strategy (e.g. dispatch or bidding behaviour) of existing operators in energy markets; and

▪ In the medium to long term: The CM may influence investment, mothball and retirement decisions of existing and new operators.

Whilst the intrinsic goal of CMs is to influence market participants' behaviour in order to maintain security of supply in line with the politically-driven reliability standard, a sound CM design can limit the impact to what is necessary to achieve the policy objectives of the mechanism and avoid distortions on the electricity market.

In this context, Compass Lexecon has been commissioned by PKEE to provide an impact assessment of the capacity market (CM) in the Polish power system with respect to an Energy Only Market (EOM) design and a comparison with other issues' impact on the Polish energy market.

2.2   OBJECTIVES OF THE STUDY

In this context, PKEE mandated Compass Lexecon to:

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[12]   European Commission (2016), Final Report of the Sector Inquiry on Capacity Mechanisms, COM(2016) 752 final.

- **Assess the Polish CM proposal and its potential impact on the electricity market in comparison to a counterfactual Energy-Only Market (EOM).** In the CM, capacity auctions ensure the reliability standard by procuring the necessary capacity. In contrast, EOM or EOM with expanded interconnection capacity does not guarantee per se the reliability standard and available capacity is driven by the decisions of rational profit-maximising players based on the revenues expected from the energy and ancillary markets and the expected costs.

- **Compare a capacity market with a strategic reserve in terms of the impact and the efficiency** to achieve the security of supply objective. We assess comparatively the option of maintaining the Polish strategic reserve and estimate the differences in efficiency and social costs between a capacity market and a strategic reserve.

- **Analyse the impact of the emissions performance standard (550 EPS) on the electricity market.** In its Energy Market Regulation proposal[13], EC proposes to exclude power plants emitting more than 550gCO2/kWh from participating in capacity mechanisms. We quantify the additional effect of 550 EPS to CM and EOM.

- **Compare the impact of the CM with the impact of other public policy interventions in energy markets.** We determine whether the impact of the CM is significant and whether this impact is proportionate within the current European power markets through assessment of three sensitivities: (1) the German strategic reserve, (2) the German Renewable Energy Sources (RES) support policy and (3) loop flows' impact on available Net Transfer Capacity between Poland and neighbouring countries

2.3 METHODOLOGICAL APPROACH

The different scenarios modelled

Analysis of the CM impact

Our modelling aims to assess the impact of the CM in a realistic setting and to capture the current electricity market functioning in practice, including its imperfections. Our model is calibrated in order to reproduce the electricity market dynamics and this is validated by historical back-casting. Our approach is therefore different from a theoretical exercise which would evaluate the impact of the CM compared to a theoretical perfect energy market. We have for instance kept the current

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[13]   European Commission (2016), COM(2016) 861 final/2, Proposal for a Regulation of the European Parliament and of the Council on the internal market for electricity (recast), Brussels, 23.2.2017

price cap on day-ahead energy markets, i.e. of PLN1500/MWh (about €360/MWh up to 2020 and €3,000/MWh afterwards). However, this current price cap is considerably lower than the theoretical optimal price cap due to various reasons such as asymmetric information, internalisation of the probability of political intervention, as well as the absence of counterparties to accept such a high price.

We use the reliability standard of three hours of LOLE following our communication with the Polish Transmission System Operator PSE which is similar to the one used in other countries such as France, Belgium, the UK etc. Based on the adequacy assessment performed by PSE, we have established that this criterion is equivalent to a de-rated capacity margin of 14% above the average cold spell peak demand.

In order to evaluate the impact of the Polish CM, a counterfactual 'energy-only market' (EOM) theoretical scenario is considered. This should not be understood as implying that the EOM scenario is a "reference" market design, it is merely a counterfactual scenario illustrating what the market design would be without a CM.

▪ In the EOM counterfactual scenario, available capacity is driven by the investment, mothball, and retirement decisions of rational profit-maximising players based on expected costs and revenues taking into account the price cap in the day-ahead market €360/MWh before 2020 and by taking into account revenues in the energy market and other market segments (balancing and reserve markets). Before 2020, when there is a power shortage, the Polish strategic reserve would be activated. The price cap is removed and replaced by €3,000/MWh beyond 2020. The EOM does not guarantee the reliability standard set by the government is met, i.e. 14% of capacity margin above the level of peak demand.

▪ In the CM scenario, market participants have to meet the capacity obligation so the available capacity is optimised in the same way as in the EOM scenario, which will be described in section 3.2, while respecting the reliability standard set by the government and therefore taking into account the expected revenues in the CM.

Comparison with a strategic reserve

As an alternative to a capacity market, Poland could maintain and expand its strategic reserve. To assess comparatively these options, we assess the adaptation of a strategic reserve considering the identified security of supply concerns in Poland and we estimate the differences in efficiency and social costs between a capacity market and a strategic reserve. Following EC's recommendations in designing a strategic reserve, we assume that the reserve is constituted of plants that would have

closed or been mothballed otherwise and is activated out of the market, which supply is not sufficient to cover demand even at the price cap of the market.

Assessment of the impact of the 550 EPS

Generation capacity for which a final investment decision has been made after entry into force of the Electricity Market Regulation, which is expected to occur in early 2019 emitting more than 550gCO2/kWh will no longer be allowed to participate in CMs. Generation capacity, which has obtained final investment decision before this date is given with a five-year transitional period. For the purpose of our modelling we assumed that this transitional period would be ended in 2024.

We model the impact of the 550 EPS CM eligibility criteria on the electricity market in a dedicated scenario and compare against the counterfactual EOM theoretical scenario as well as against the CM scenario previously described. In the CM 550 scenario, eligible market participants have to meet the capacity obligation so that the eligible capacity is optimised as in the CM scenario and non-eligible capacity is optimised as in the EOM scenario while respecting the reliability standard set by the government and therefore taking into account the expected revenues in the CM.

Comparison with other policy interventions

In order to provide some context, we have also modelled other policy interventions in European electricity markets as well as the loop flows impact on available Net Transfer Capacity between Poland and neighbouring countries to compare their impact with the impact of the CM.

The objective is not to evaluate these policies, but to provide some elements of comparison with the effect of the Polish CM as regards the magnitude of their impacts. The other regulatory mechanisms that we have assessed are the following:

- **Reduced Loop flows,** assessing a situation of increased Polish Net Transfer Capacity with neighbouring countries given a situation where loop flows going through Poland in the common German-Austrian bidding zone are reduced (they can be a result of a range of policy measures that encourage market integration, TSO cooperation, and integration of grid development);

- **The Strategic Reserve in Germany**, including the forced inclusion of lignite plants in the reserve (the so-called Climate Reserve); and

- **The renewable energy sources (RES) support policy in Germany**, comparing a scenario with higher RES development, following the 2012 Renewable Energy Act (EEG) reform, to a development as anticipated before 2011;

These public interventions aim at different objectives and, as such, may not be comparable. However, they provide a benchmark to compare across a range of metrics: (a) whether the impact of the CM is significant; and (b) whether this impact is proportionate in light of its benefits and of the impact of other public interventions that characterise current European power markets.

Assessing whether the impact of the Polish CM is proportionate also requires taking into account its benefits. This study therefore estimates social welfare gains associated with the Polish CM. However, such a benefit assessment is not performed for the other policy interventions presented in section 5. The reader is therefore advised not to draw hasty conclusions on the public interventions considered in this study, which would not make sense without a dedicated cost-benefit analysis.

Assessment criteria

This report identifies the interactions between the CM and the electricity market, and quantifies the effects of these interactions in the short, medium and long term, using a range of criteria and indicators:

- **Security of supply criteria**: we evaluate the impact on security of supply in terms of capacity margin.

- **Energy efficiency criteria**: we evaluate the total consumer cost and the social surplus.

- **Available capacity criteria**: we evaluate the impact on the installed capacity (both on the supply side and on DSR).

- **Energy market impact criteria**: we evaluate the impact on the power price, as well as the impact on the total imports/exports between Poland and its neighbouring countries.

- **CO2 emissions criteria**: we evaluate the impact on CO_2 emissions both in Poland and in Europe.

2.4 DESCRIPTION OF THE POLISH CAPACITY MARKET

In 2016 the attainable capacity in the Polish Power System ('PPS') passed the historical level of 40GW. However, the capacity growth is mainly driven by renewable energy sources that, due to their operating characteristics and non-dispatchability, may not guarantee capacity availability at times of peak demand or when security of supply to end users is under threat. At the same time the share of conventional dispatchable sources in energy supply is decreasing steadily, while the significance of

these sources for assuring security of supply in the PPS, thus the need to maintain and develop them, is still the same.

To ensure continuity and stability of electricity supplies to all end users in Poland in mid- to long-term horizon, the Minister of Energy took the decision, at the beginning of 2016, to establish a capacity mechanism.

On 5 December 2016, on its website the Polish Government Legislation Centre published the Draft Act on the Capacity Market[14]. According to the justification of the Draft Act, the purpose of the Act is to prevent generation capacity shortage by remodeling the regulatory environment of the electricity market so as to create strong economic incentives encouraging the construction, maintenance and modernization of generating units and energy demand management on the end users side if necessary to meet the desired security of supply level.

The Draft Act is largely based on the document "*Functional Solutions of the Capacity Market*" [15] of 30 September 2016. These solutions constitute a modified version of the "*Draft Functional Solutions of the Capacity Market*", published by the Ministry of Energy on 4 July 2017. Both documents are preparatory policy documents with the preliminary assumptions of the capacity market design, which have been submitted on 6 July 2017 to the Polish parliament[16].

General principles

The main purpose of the Polish capacity market is to ensure electricity supply security to end users in mid- and long-term horizon. It aims to achieve a level of security of supply corresponding to a maximum of 3 hours of LOLE.

The Polish capacity market creates a source of revenue, in addition to that of the energy market and ancillary services. Capacities required to meet the security of supply criterion are contracted several years in advance. The Polish capacity market is a market-based mechanism aimed at guaranteeing

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[14]   Polish Government Legislation Centre (2016), Ustawa o rynku mocy – Projekt z dnia 30.11.2016 r. (Draft bill on the Capacity Market for the Polish power market).

[15]   Ministry of Energy (2016), Rozwiązania funkcjonalne rynku mocy (Capacity Market functional solutions).

[16]   Polish Government Legislation Centre (2017), Ustawa o rynku mocy – Projekt z dnia 06.07.2017 r. (Draft bill on the Capacity Market for the Polish power market).

the required level of security of electricity supplies while minimizing the costs to the economy as a whole.

The Polish capacity market is technology-neutral, thus creating level-playing field to all electricity production technologies and to DSR, with consideration of the degree to which individual technologies contribute to security of supply. The CM rewards the capacity units that provide capacity during system stress events that is at times when a risk of loss of continuity of supply is identified in the PPS.

The Polish capacity market design specificities

The Polish capacity market consists of a primary and a secondary market. The primary market consists of a main auction and additional centralised auctions. For a given delivery year the main auction is held during the 5th year before the delivery year, and additional auctions are held in each quarter of the year before the delivery year. The main auction concerns the whole delivery year, while the additional auctions cover each of the delivery quarters of the delivery year. The secondary market – which is not regulated *per se* – involves trading of capacity obligations between the capacity market participants.

Both main and additional auctions share the following features:

- **The product** on the capacity market is the net dispatchable capacity during delivery period along with the obligation to deliver it during System Stress Events within the delivery period.

- **Demand on the capacity market** is represented by a sloped capacity demand curve defined by the Ministry of Energy. This curve reflects dependence of capacity price on the volume of capacity procured. The main parameters of the demand curve are the capacity volume to be procured on the capacity market in a given auction – determined on basis of the forecasted peak capacity demand plus the required margin – and the market entry price by a new generating unit with lowest fixed operating expenses and capital expenses, which influence significantly the result of capacity auctions.

- **Cross-border participation in the capacity auction** originally was not taken into account directly[17]. To ensure electricity supply security in Poland, the units located in other systems were taken into consideration in the capacity market, by reduction of the calculated volume of demand on the main auction and the additional auction by the capabilities to cover the capacity demand using the cross-border interconnections in quantity not adversely impacting the security of supply in the Polish power system.

- **The capacity auction** is a Dutch auction with a single clearing price for all participants that won the auction (*pay-as-cleared*). The auction is held in a series of consecutive rounds until balance between capacity demand and supply is achieved. The auction consists of capacity providers submitting bids and the TSO is the sole buyer. Capacity Obligations and the auction clearing price are determined based on the capacity demand curve and supply curve established with the exit bids using the net welfare algorithm that ensures an optimal auction result from the point of view of the costs of the capacity market.

The costs of capacity market are covered by the end users who pay capacity charges as a part of their electricity supply tariffs. The capacity charge rates may be different for different groups of users. The capacity charge for consumers is proportional to household' s annual energy consumption.

To conclude, the actual level of support, as well as the functioning of Capacity Market will be regulated on an ongoing basis by the Minister of Energy who will determine the auction parameters – including demand for the available capacity, maximum offer prices, and number of rounds of auction – based of the proposal prepared by the TSO.

Timing of the Polish capacity market

As stated before, the Polish capacity market is a multi-year scheme that starts five years before the delivery year and ends one ahead of the delivery year. The general timeline of the mechanism is depicted in Figure 2-1 .

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17   This approach has been changed in the latest version of the Bill on the Capacity Market and the detailed rules on cross boarder participation are now directly addressed in Chapter 2 of the Bill, however this change does not affect the main results and conclusions of this report. Considering that foreign capacity providers as price takers, there would be no impact on capacity prices and generation mix. The only impact of allowing foreign participation in the Polish CM could be an increase in consumer costs to the benefit of interconnectors and/or foreign capacities.
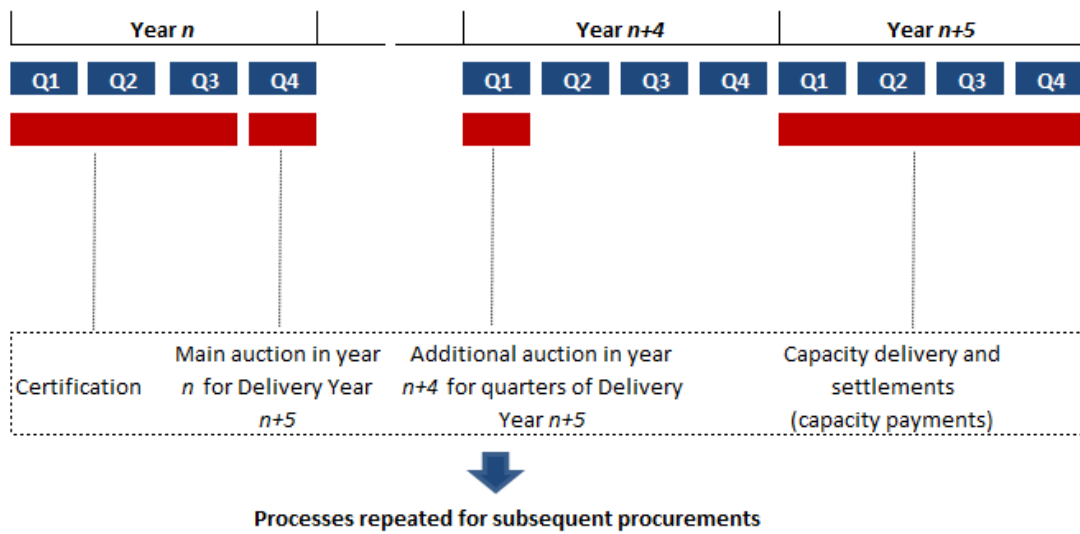
Figure 2-1: Detailed timeline of capacity market processes.

Source: Compass Lexecon's realisation based on Polish Ministry of Energy (2016), "Capacity Market functional solutions".

The first delivery period is expected in 2021. In that case, the period between the main auction and the delivery period will be shortened due to the approval of the rules of the Polish CM, expected at the end of 2017.

Potential impacts of the Polish capacity market

The Polish CM does not present specific rules likely to have a significant impact on the dispatch in the short term. First, it is based on the obligation to deliver appropriate volume of dispatchable capacity at System Stress Events. From a theoretical point of view, it could force generators (or DSR operators) to produce below their SRMC or to modify their bids. However, in practice, it is not likely to be the case as, during such stress events, market prices would likely be far above SRMC for all capacity providers (possibly hitting market cap) so that they would have participated in the market anyway. Second, it does not withdraw capacity from the market and therefore generation capacity in the market remains the same.

As regards longer-term impacts, the Polish CM aims at meeting a security of supply standard set by the Ministry of Energy. Thus, it will likely foster DSR development, avoid excessive mothballs or retirements, and secure timely investment if necessary in order to meet this criterion. As such, it may impact the long-term generation mix. However, it is calibrated based on the predefined security criteria LOLE, and overinvestment is avoided insofar as the contribution of neighbouring countries,

through interconnections, is taken into account.[18] Furthermore, DSR can participate in the Polish capacity mechanism on an equal footing, both explicitly to supply capacity. As such, the capacity mechanism is rather favourable to DSR and it is expected to stimulate DSR development.

To assess more precisely the long-term impact of the capacity market on the generation mix in particular, further quantitative work is required. This is the purpose of the next section.

2.5 STRUCTURE OF THE REPORT

This report is structured as follows:

- Section 3 quantifies the impacts of the Polish CM and compares the Polish CM with another capacity mechanism of strategic reserve;

- Section 4 quantifies the impact of an emissions cap on the Polish CM and its potential impacts on the electricity market;

- Section 5 compares the impacts of the Polish CM with the impacts of other policy interventions;

- Section 6 concludes on the key findings of our comparative analysis;

- Appendix A presents Compass Lexecon dispatch model;

- Appendix B describes Compass Lexecon capacity market model;

- Appendix C presents the key modelling assumptions in Poland and in neighbouring countries; and

- Appendix D presents reference sources used in this report

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[18]   Developments regarding cross-border participation are still ongoing.

3. Modelling of the impacts of the Polish capacity market

3.1 INTRODUCTION

The objective of this section is to quantify the impacts of the Polish CM on the energy markets and more generally on the European power systems.

We first describe our modelling approach and assumptions as well as the assessment criteria selected to analyse the Polish CM impacts. Then, we present the results of our simulations on the impact of the CM in Poland and in neighbouring states, which we assess according to the predefined evaluation criteria. We use the same methodology to assess the impacts of the EU emissions performance standard and other European policy interventions in Sections 4 and 5.

3.2 DESCRIPTION OF THE MODELLING APPROACH

Model description

To assess the impact of the Polish CM, we have modelled the European power system using our Compass Lexecon (CL) proprietary dispatch model coupled with a capacity market model, which we have developed internally. Both models are interlinked through an iterative optimisation process.

We assume perfect competition and no asymmetry of information for market participants, but we include some degree of risk aversion. Market participants are assumed to trust that energy regulators and public authorities will not intervene upon price spike occurrence.

European power market model

Compass Lexecon's European power market dispatch model covers the EU-28 countries as well as Switzerland, Norway, the Balkans and Turkey. Countries beyond this geographic scope are modelled at an aggregate level. The geographic scope of the model is shown in Figure 3-1. We are therefore able to capture the effect of the interconnections between the Polish energy market and neighbouring countries.

Figure 3-1: Geographic scope of Compass Lexecon's European power market model

Source: Compass Lexecon, 2017

The model, which is based on the well-established optimisation platform Plexos®, provides an hourly optimal dispatch[19], taking into account operational constraints. It allows for a realistic representation of European power markets since it considers each generation unit connected to the transmission grid, decentralised generation and renewable output's variability, specificities of hydro power and interconnectors as well as demand fluctuations. The model is finely calibrated to reproduce historical market prices.[20]

Capacity market model

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[19]   Our Plexos model is configured as an hourly optimisation model, but it is possible to increase or decrease the time frame, such as half-hour or 15 minutes. However, hourly modelling results can achieve a satisfying results within the scope of this study while increasing time frame would significantly increases calculation time during the optimisation process.

[20]   Compass Lexecon's European power market dispatch model is described in details in Appendix A, which also demonstrates the robustness of the modelling thanks to the back-casting exercise.

The capacity market model minimises the system cost while ensuring the reliability standard. It simulates the supply and demand curves and produces capacity prices defined as the minimum capacity price necessary to meet the capacity requirement set to reach a regulated reliability standard. For each year, we optimise market participants' operational, investment and retirement decisions based on their expected costs and revenues.

More precisely, the capacity market model "endogenises" economic decisions of market participants by ensuring that plants reach breakeven (based on their avoidable costs) either only with energy and ancillary services' revenues in the EOM or with energy and ancillary services' revenues plus capacity revenue as in the CM.[21]

Modelling approach to assess the capacity mix in EOM and CM designs

To determine the capacity mix in the EOM and CM designs, we perform iterations to converge toward a situation in which generators and DSR operators have positive net present value (NPV), based on their avoidable costs and market revenues, and where no additional investment would have a positive NPV. In other words, the capacity mix is determined so that:

- No existing plant has a negative NPV when considering its fixed operation and maintenance (FO&M) costs;

- No new build plant has a negative NPV when also considering investment costs; and

- If an additional capacity was built or not retired, its NPV would be negative.

The two market designs produce different optimal capacity mixes because they provide different revenue streams to market participants.

In an EOM, available capacity is driven by economic decisions of market participants based on their expected revenues in the energy market. It takes into account the current price cap in the day-ahead market and the revenues in other market segments (balancing and reserve markets). The EOM does not a priori guarantee that the reliability standard set by public authorities is met. Figure 3-2 summarises the optimisation process which is performed in our EOM modelling.

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[21]   Compass Lexecon's capacity market model is presented in details in Appendix B.
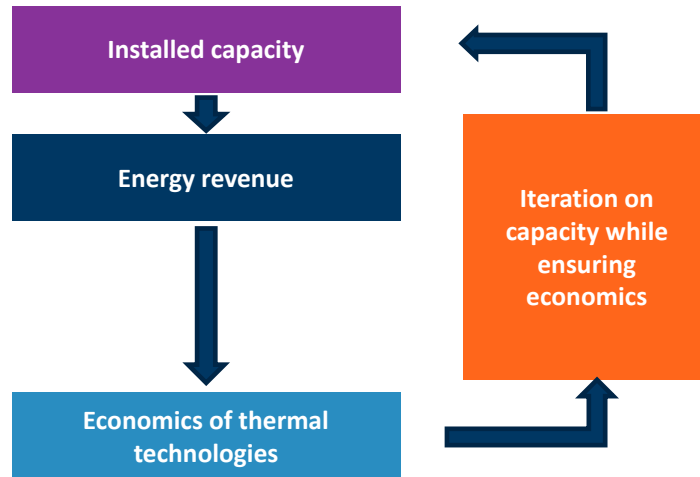
Figure 3-2: Modelling iterations in EOM design

Source: Compass Lexecon, 2017

In the CM, assuming that market conditions, such as demand and price formation, are equal to the EOM, market participants have to meet the capacity obligation defined to respect the reliability standard set by public authorities. Consequently, the available capacity is optimised taking into account the potential revenues in the CM in addition to other revenue streams that exist also in the EOM. The corresponding optimisation process operated in our modelling is presented in Figure 3-3.
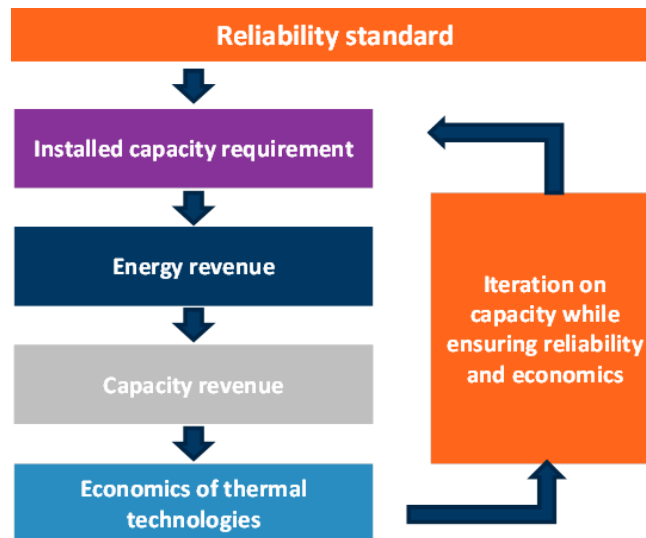
Figure 3-3: Modelling iterations in CM design

Source: Compass Lexecon, 2017

Main background assumptions

We evaluate the impact of the Polish CM based on several essential assumptions, which allow us to assess the capacity remuneration, revenue and generation mix at the equilibrium.

The set of forward looking assumptions used in the model are based on publicly available data (when possible), as well as on PSE's, International Energy Agency (IEA)'s and ENTSO-E's public power system outlook scenarios, validated by PKEE. More details are presented in 9.

- **Demand and evolution of must-run capacities,** such as hydro, wind and solar generation capacities are based on the PSE adequacy report 2017, which provides the most up to date vision of the Polish power system and is consistent with ENTSO-E MAF 2017 to be published this year. It is expected that two nuclear units of 1,400MW will come online in the medium term. As agreed with PKEE, the first unit becomes operational in 2030 while the second unit becomes operational in 2032.

- **Interconnection capacity** is based on the projection of PSE, which serves as a basis for ENTSO-E MAF 2016. Up to date, Poland has limited import capacity from Germany, Czech Republic and Slovakia due to the issue of loop flows in the German-Austrian bidding zone. Besides, it is also connected to Lithuania (300MW at the current level and 500MW by 2020) and Sweden (600MW). Our modelling geographic scale does not include Ukraine, the interconnection constraint of the Polish-Ukrainian line is not imposed. Interconnection capacity is expected to grow significantly in the medium and long -term mostly due to investments in internal grid and the phase shifters on the border with Germany which are to address the problem of loop flows.

- **Projections of commodity prices**, i.e. coal, gas, and oil prices are based on the projections of the New Policy (NP) scenarios of the World Energy Outlook (WEO) 2016 from the IEA. In addition, we benchmark the costs of lignite generation in Poland taking into account the difference in lignite prices based on the Booz&co study in order to reflect the specificity of the Polish lignite.

- **Projections of CO2 prices** are consistent with the NP scenario of the WEO 2016 up to 2030, while the long-run CO2 price evolution is obtained from our internal EU ETS model, which projects CO2 price increases from €33/tonne in 2030 to €60/tonne in 2040.

De-rating factors and de-rated capacity margin

The de-rated capacity margin is defined as the ratio between the additional de-rated capacity available (including DSR and interconnection capacities) above the net average cold spell peak demand (excluding auxiliary demand) The Polish regulator set the capacity target to procure the amount of capacity equals to the cold spell peak demand plus this margin in the capacity market in order to secure the Polish system, by ensuring the reliability standard of 3 hours of LOLE.

The proposal for the Polish CM relies extensively on the notion of de-rating. A de-rating factor is used as a factor reflecting the capacity available for each technology to meet the peak demand. The capacity eligible for participation in the capacity market is determined by applying the defined de-rating factors to net installed capacity of each generation type.

However, PSE has not yet published an official probabilistic analysis establishing the level of capacity necessary to achieve the adequacy target of 3 hours LOLE in different years, i.e. the relationship between the de-rated capacity margin to be maintained in the Polish capacity market and the number of LOLE. Likewise, PSE has not yet publish the de-rating factors that it eventually plans to use in the CM and which could be used to calculate the de-rated margin.

In order to set up a reasonable capacity target for the Polish CM, we apply the de-rating factors for each type of generation based on historical availability according to the European Network of Transmission System Operators for Electricity (ENTSO-E) data. The assumptions on de-rating factors are discussed and agreed with both PSE and PKEE, and consistent with other sources, such as ENTSO-E and Ofgem.

Table 3-1: Assumption of de-rating factors per generation type

Generation type	De-rating factor
BIOMASS	70%
CCGT	90%
COAL	90%
GAS	90%
GAS TURBINE	90%
LIGNITE	90%
OTHER BIOMASS	51%
OTHER CCGT	79%
OTHER COAL/LIGNITE	90%
OTHER COAL/OIL	60%
OTHER GAS	50%
OTHER WASTE	88%

Generation type	De-rating factor
SOLAR	0%
WIND OFFSHORE	0%
WIND ONSHORE	0%
NUCLEAR	91%
HYDRO	54%
CCGT NEW	95%
GAS TURBINE NEW	95%
COAL NEW	95%
DSR	40%
IMPORT PI	40%
IMPORT DC	94%

Source: Compass Lexecon, 2017 ·

Notes: The "OTHER" categories include CHP generation plants. IMPORT PI refers to import capacity from Germany, Czech Republic, and Slovakia to Poland. IMPORT DC refers to the DC import lines from Lithuania and Sweden to Poland.

We assume existing major thermal capacity to be de-rated at 90% and distinguish between main generation plants and CHP generation plants. Anticipating that new generation units of coal and CCGTs would be more available than existing thermal capacity, we apply a de-rating factor of 95% to new build coal and CCGT capacity. Given the current tight constraint on the Polish import capacity due to the problem of loop flows, which could be relieved over time, the listed de-rating factors of the import capacity are applied from 2022 onwards and available import capacity before that is considered to be lower.

Demand side response

As the old inefficient power units are phasing out and capacity shortages are expected during 2016-2018, up to date, PSE has launched public tenders for two DSR programs, one with fixed capacity availability price, second with variable activation price. In the long term, PSE evaluates the maximum of the DSR potential in Poland is 2,500MW beyond 2020, and the tender in 2016 procured 200MW of DSR capacity[22].

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[22]   Centrum Informacji o Rynku Energii (CIRE) (2017), Przetargi na usługi DSR coraz bliżej rozstrzygnięcia.

The CM is meant to trigger more DSR capacity to develop compared to an energy-only market, such that we distinguish DSR trajectories in the EOM, CM, and CM 550 scenarios. Starting from the current contracted level of 200MW in Poland in 2017, new DSR capacity will enter the market once the capacity revenue for new entrants exceeds the cost of entry of DSR capacity. We assume three different stages for the DSR development. The first 800MW can enter the market at the entry price of €30/kW. To develop additional 800MW DSR capacity, a trigger price of the capacity payment of €35/kW is needed and to reach the full DSR capacity potential of 2,500MW, the capacity price needs to exceed €40/kW. The incremental capacity per year is capped at 200MW and DSR capacity increases as long as it is profitable until reaching the maximum. Agreed by PKEE, in the EOM scenario, DSR is not competitive compared with new thermal entrants. As a starting point, DSR capacity is assumed to be stable in EOM, while it enters the market as long as the capacity price exceeds the cost of entry in the CM and CM 550 scenarios from 2021 onwards. Bearing in mind that capacity prices vary in the process of modelling iterations, DSR capacity is optimised altogether with existing and new coal and CCGT capacity at the equilibrium.

CHP capacity evolution

We consider CHP capacity as one of the modelling inputs. Data on CHP development included into model are based on the assumption that no specific support scheme for high efficient cogeneration would be further introduced on top of the existing support scheme, which is will be valid until the end of 2018[23]. Based on data from PSE, coal CHP capacity would be gradually substituted by gas CHP capacity. The resulting CHP total capacity would hence remain stable.

According to the long term energy policy up to 2030 (PEP 2030)[24] and the Sustainable Development Strategy[25] (published in 2017), support scheme is considered as an appropriate tool for CHP development. Based on that a new support scheme is expected to replace the existing one after 2018, CHP development could be further stimulated beyond our baseline assumption. However, modelling additional CHP development is beyond the scope of the study, and, in our opinion, as it

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[23] European Commission Press Release (September 2016), State aid: Commission approves Polish scheme to support high-efficiency cogeneration of heat and power.

[24] Ministry of Economy (2009), Polish Energy Policy until 2030 (PEP 2030); http://www.me.gov.pl/Energetyka/Polityka+energetyczna

[25] Ministry of Development (2017), National Sustainable Development Strategy (SOR); http://www.monitorpolski.gov.pl/mp/2017/260/1

would substitute the need for capacity of other generation types but it would not alter the need for the capacity market in Poland.
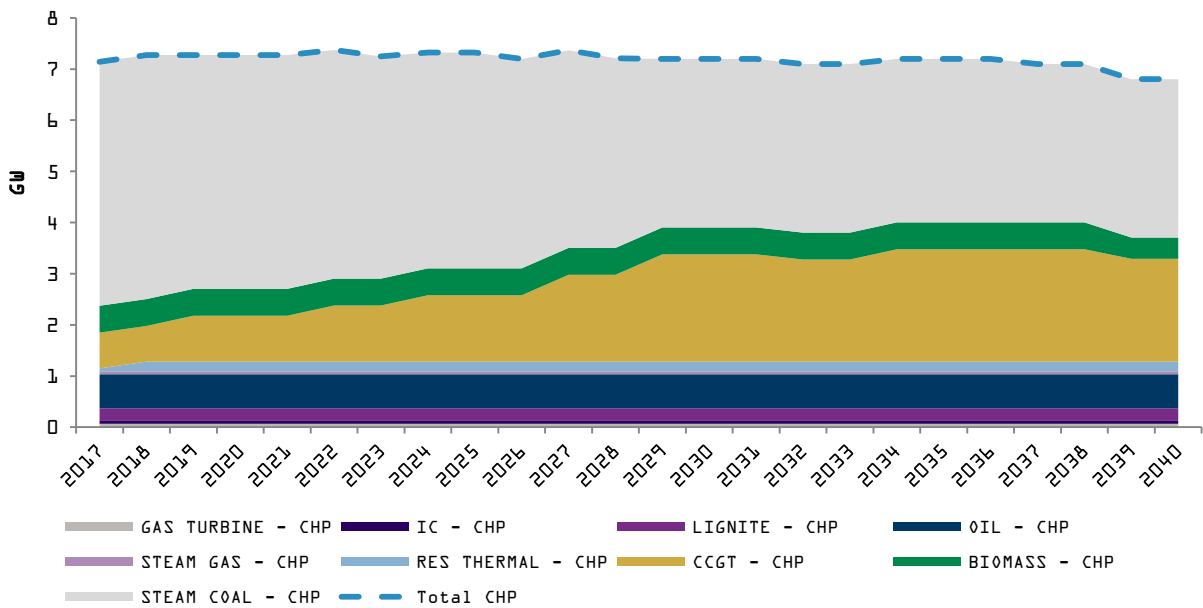
Figure 3-4: Assumption on CHP capacity evolution

Source: PSE, Compass Lexecon, 2017

NPV evaluation assumptions

The optimal generation mix is obtained by iterating the optimisation process while taking into account power plant operators' investment, reinvestment, operational, mothballing and decommissioning decisions, which are evaluated based on the Net Present Value (NPV) of cash flows over their expected amortisation period. Capital cost (CAPEX), variable and fixed operating and maintenance (VO&M and FO&M) costs, as well as economic lifetime for each generation type are provided by PSE and validated by PKEE.

According to PSE's view, while old thermal plants natural closures have been planned between 2017 and 2020, other existing coal and lignite plants have the choice to either decommission before 2021 or to reinvest in order to comply with the BAT conclusions adopted pursuant to the IED.

▪ The thermal plants that opt for reinvestment would take into account both energy revenue and capacity remuneration to be received after 2021 in order to recover their fixed costs, which includes both fixed O&M costs and annualised capital costs.

While most of the large operational plants should aim at reducing emissions level to comply with BAT conclusions, some would face higher reinvestment cost as additional retrofit CAPEX is required

to extend the operational lifetime. Table 3-2 presents the cost assumptions of the refurbished existing units according to the data that PSE provided.

Table 3-2: Reinvestment cost assumptions of refurbished existing units

Technology	CAPEX (€/kW)	Economic life (years)	Amortisation duration (years)	FO&M (€/kW)
BAT conclusions reinvestment	100	10	5	40
BAT conclusions + Retrofit CAPEX reinvestment	150	10	5	40

Source: PSE, 2017

Notes: Total CAPEX is presented. Amortisation duration corresponds to the duration of capacity contracts

In the CM scenario, new build thermal plants, such as coal, CCGT, and OCGT, enter the market in order to meet the requirement of the capacity reserve margin, while in the EOM scenario, new build thermal plants need to be profitable based on energy and ancillary revenue. In both scenarios, their corresponding revenue need to recover investment and fixed O&M costs. The cost assumptions of different types of new build capacity are summarized below.

Table 3-3: Investment cost assumptions of new units

Technology	CAPEX (€/kW)	Economic life (years)	Amortisation duration (years)	FO&M (€/kW)
CCGT	750	30	15	20
OCGT	550	30	15	15
Coal	1600	40	15	45
Lignite				45

Source: PSE, 2017

Notes: Total CAPEX is presented. Amortisation duration corresponds to the duration of capacity contracts.

Annualised CAPEX are calculated based on the WACC, which depends on generation types, the market design and amortisation duration. As investors expect to recover investment costs in the first years of operation, the amortisation duration is not equivalent to the life time of the generation plants. To replicate different levels of investment risk in the CM and EOM market designs, the WACC in the EOM design is 1% higher than in the CM design because of more volatile power prices in energy-only market and greater uncertainty of the energy revenue for power generators.

Table 3-4: Assumptions on WACC

Technology	WACC - CM	WACC - EOM	Annualized CAPEX (€/kW/year) - CM	Annualized CAPEX (€/kW/year) - EOM
CCGT	7%	8%	64	71
OCGT	7%	8%	44	49
Coal	8%	9%	134	149
BAT conclusions reinvestment	8%	9%	15	16
BAT conclusions + Retrofit CAPEX reinvestment	8%	9%	22	23

Source: PSE, 2017

Notes: Annualised CAPEX is obtained by annualising total CAPEX over economic lifetime subject to WACC for each generation type and in each scenario.

Capacity market bids

Figure 3-5 illustrates the biding strategies of the existing, refurbishing and new plants in the Polish CM. In the capacity market, power plants bid their "missing money", defined as the difference between their energy gross margin (energy revenue net of variable costs) plus ancillary services revenues, and the avoidable cost they would face to be online at time of delivery. As such:

- Existing plants only bid the difference between the energy gross margin, ancillary services revenues and their annual fixed O&M.

- Refurbishing plants bid the difference between the energy gross margin, ancillary services revenues and their annual fixed O&M plus the annualized refurbishing cost.

- New plants bid the difference between the energy gross margin, ancillary services revenues and their annual fixed O&M plus the annualized CAPEX.
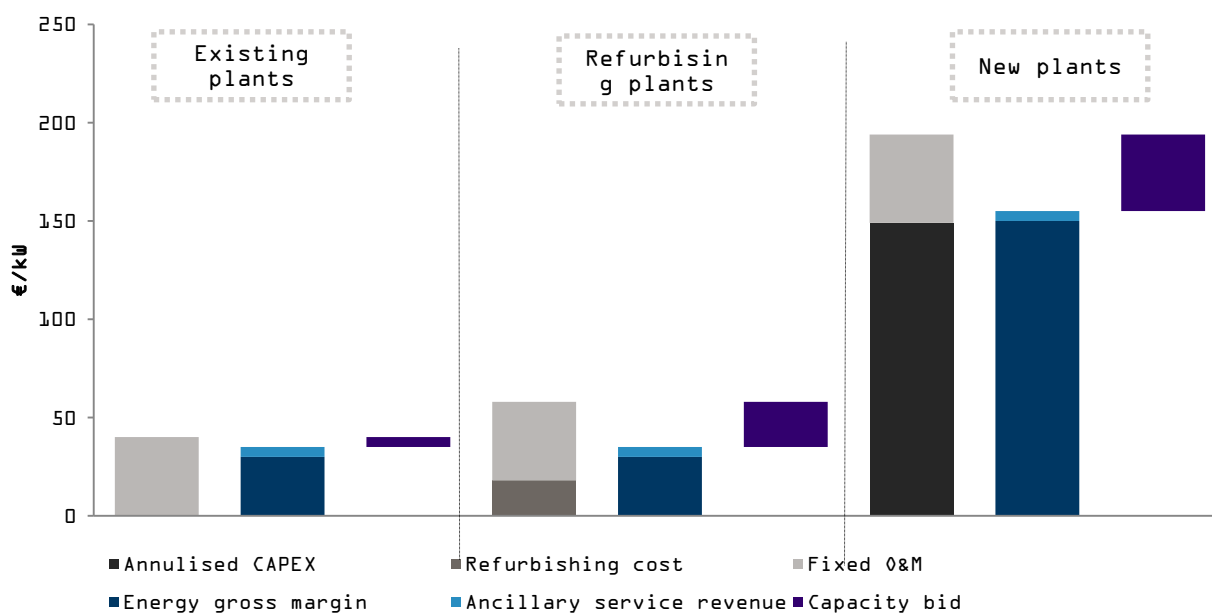
Figure 3-5: Capacity bid of existing, refurbishing, and new plants

Source: Compass Lexecon, 2017

Notes: Capacity bid is determined by the difference between fixed costs (CAPEX and O&M) and net revenues. The numbers in y-axis are indicative for the purpose of demonstrating the definition of capacity bids.

The capacity market takes the form of pay-as-clear pricing, according to which all successful capacity providers receive the uniform clearing price, which is assumed to cover investment expenditures for 15 years for new build generation units and five years for refurbished units. Hence, we assume that capacity bids of new and refurbished generation units would account for the length of the capacity payment contracts by bidding annualised missing money over the period of the capacity payment contract.

Value of loss of load (VOLL)

VOLL in theory is equal to the marginal consumer surplus associated with a unit increase in electricity supplied to rationed consumers when energy market is not cleared. The current price cap of €360/MWh in Poland is not based on VOLL and is expected to be removed after 2020. In order to capture the cost of the capacity mechanism in Poland, we need to assess the VOLL.

The Value of Loss of Load (VOLL) is provided by PKEE based on the estimation in the EY report[26], which is set at PLN76, 530/MWh, equivalent to €18000/MWh for Poland. In our modelling, the

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[26]   Ernst & Young (June 2017), Analizy w zakresie oszacowania kosztu niedostarczonej energii w KSE (Analysis on the estimation of the cost of unserved energy).

current price cap is replaced by €3,000/MWh beyond 2020, which is considerably lower than the suggested VOLL by PKEE.

3.3 ASSESSMENT CRITERIA

To assess the impact of the implementation of the Polish CM compared to an EOM design, the following criteria are analysed across both market designs:

- **Security of supply**: we evaluate the impact on security of supply in terms of capacity margin.

- **Energy efficiency criteria**: we evaluate the total consumer cost and the social surplus.

- **Available capacity criteria**: we evaluate the impact on the installed capacity.

- **Energy market impact criteria**: we evaluate the impact on the power price, as well as the impact on the total imports/exports between Poland and its neighbouring countries.

- **CO2 emissions criteria**: we evaluate the impact on CO2 emissions both in Poland and in its neighbouring countries.

This set of criteria covers the main areas of concern of the EC when assessing the impact of policy interventions in the energy sector. For each criterion, we discuss the impact of the CM in the short, medium and long-term.[27]

3.4 POLISH POWER SECTOR SCENARIOS

According the analysis of adequacy assessment of PSE, the reliability standard of 3 hours of LOLE corresponds to a de-rated capacity margin of 14%, which implies a growing need of capacity in the long term, shown in the figure below. This security of supply standard is standard in Europe compared to that in France, Belgium, and UK, which have a standard of 3 hours of LOLE.[28]

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[27]   Short-term only concerns the immediate effects on dispatch and bidding decisions, while medium-term regards to the expected effects in the several years to come. Long-term refers to the time horizon beyond five to seven years, typically from 2023 onwards.

[28]   Belgium also has an additional criterion: the LOLE shall remain below 20 hours for a statistically abnormal year, corresponding to the 95th percentile of the future states ELIA simulate.
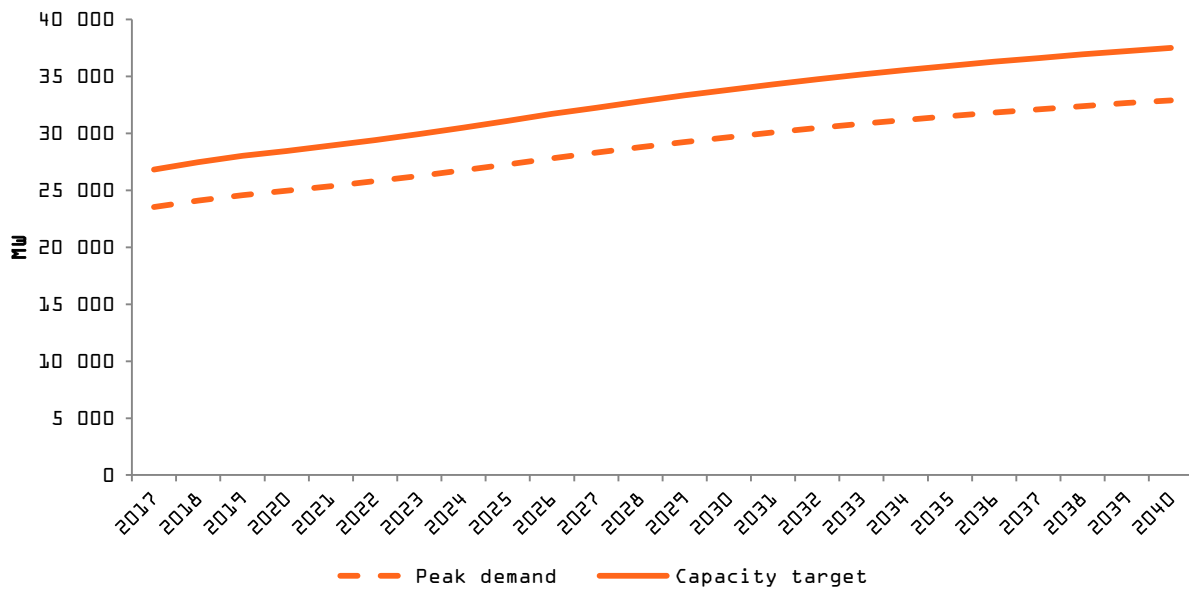
Figure 3-6: Evolution of capacity target to be secured to comply with the security of supply criteria

Source: PSE, Compass Lexecon, 2017

Notes: Capacity target is 14% higher than the projection of the Polish peak demand.

The adequacy assessment carried out with PSE shows that this corresponds to a capacity margin of about 14%, used to define the capacity target assuming standard de-rating factors presented previously. To ensure that the reliability standard is met in all years, a combination of existing plants refurbishments, new power plants constructions, demand side response development and new interconnection projects will be necessary. The development of each of these solutions will depend on their economics.

Considering the capacity outlook in Poland until 2021 presented in Figure 3-7, it appears that a significant number of plants face retirement risk in the near future. However, new build projects and interconnection capacity under construction are expected to maintain the system security.
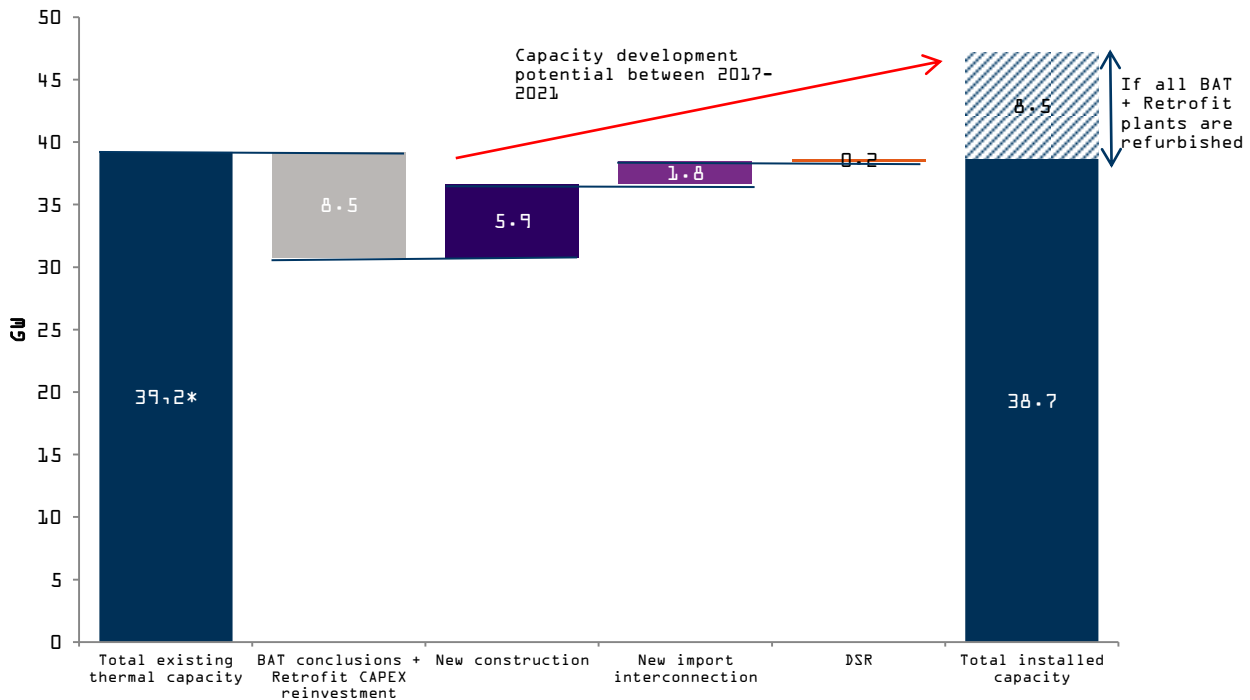
Figure 3-7: Potential development of thermal capacity and other new capacities in Poland by 2021 (GW)

Source: Compass Lexecon analysis based on PSE, PKEE and Platts data, 2017

Notes: *c20GW are subject to at least BAT conclusions reinvestment. Among them *8,5 GW face even higher reinvestment CAPEX (BAT + Retrofit). The chart focuses only on this capacity as it is the most at risk.*

More precisely, the following changes in the Polish generation capacity are expected to take place by 2021:

▪ c20GW of existing large coal and lignite plants are subject to at least BAT conclusions reinvestment[29];

▪ 8.5GW of existing capacity will face higher reinvestment CAPEX to comply with BAT conclusions and invest in additional retrofit CAPEX in order to carry on operations or to be closed[30];

▪ 5.9GW of new capacity will come online (4.0GW of new coal and lignite plants and 1.9GW of new gas plants);

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[29] Data provided by PKEE.

[30] Data provided by PSE.

- 1.8GW of new import interconnections will come online (+700MW on DE-PL, +450MW on CZ-PL, +450MW on SK-PL), in addition to the 200MW import capacity increase in 2020 between Lithuania and Poland; and

- Following the current cold reserve development, 200MW of DSR will be available on the market[31].

However, in the longer term, available generation capacity is no longer sufficient to meet the security of supply criterion in the absence of a capacity market.[32]

3.5 COMPARISON OF THE POLISH CM AND EOM DESIGNS

Impact on security of supply and on the generation mix

Impact on security of supply

Due to market failures, such as electricity prices signals not reflecting scarcity, EOM cannot ensure the security of supply at required level. In the contrary, one key long-term objective of capacity mechanisms is to ensure security of electricity supply. As such, they aim to protect consumers against the risk of power supply shortages by incentivising capacity providers to have (or develop) sufficient generation capacity in place. In Poland, security of supply is measured against a de-rated capacity margin target of 14%, implied by three hours of LOLE.

An appropriate CM design can motivate capacity providers to stay active in the generation market by ensuring them an additional remuneration from capacity certificates sale. This capacity remuneration aims at keeping them in business or at driving investments in new generation or DSR facilities to meet peak demand and, in the specific case of Poland, to compensate for the significant amount of conventional capacity decommissioned between 2020 and 2030. In contrast, in an EOM design, there is no guarantee that generators or DSR operators achieve sufficient revenues in the energy market in order to maintain sufficient available capacity to meet the reliability standard.

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[31]   The Polish TSO called a tender for two service options recently in March, 2017 – the guaranteed programme of 500MW and current programme with a volume to be defined.

[32]   These findings are directly related to the modelling approach. Assuming no perfect foresight or lower trust in the regulator not to intervene, would further the business case of new investments.

This intuition is confirmed by the modelling. As illustrated in Figure 3-8, the annual de-rated capacity margin under the Polish CM and EOM designs diverges significantly, especially in the long run.
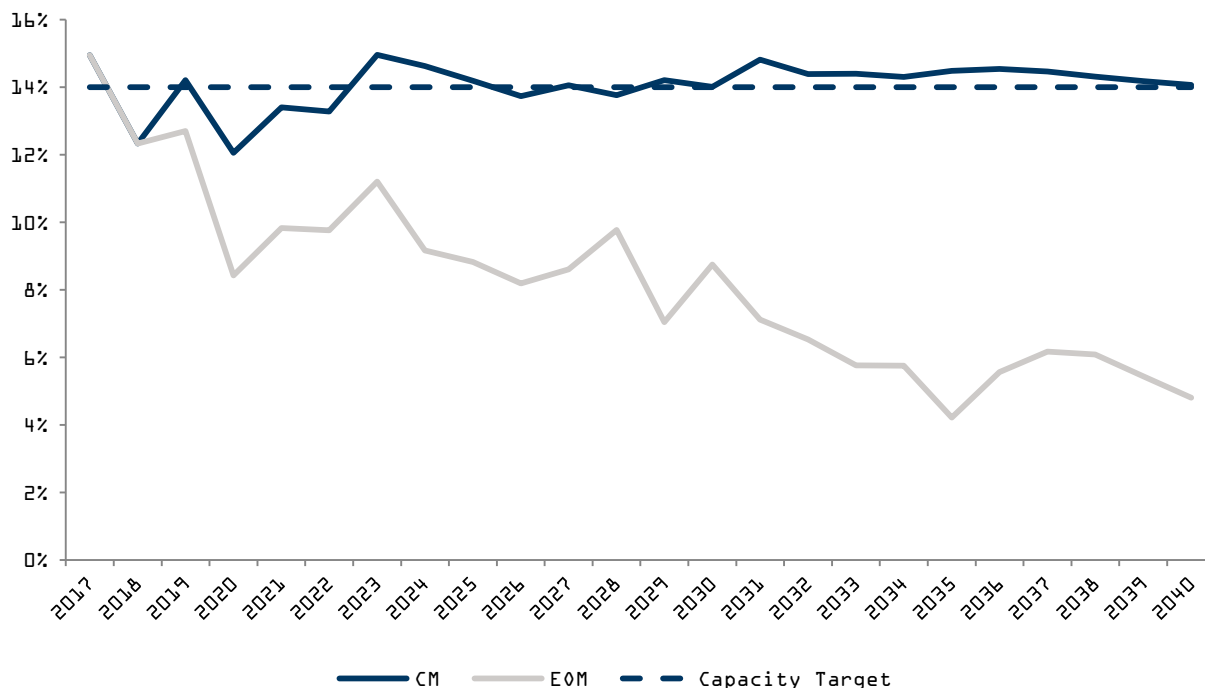
Figure 3-8: Annual de-rated capacity margin in the CM and EOM scenarios (%)

Source: Compass Lexecon, 2017

Notes: The de-rated capacity margin is defined as the ratio between the additional de-rated capacity available (including DSR and interconnection capacities) above the net average cold spell peak demand (excluding auxiliary demand).

The EOM cannot ensure the security of supply to be met at reliability standard, since market participants do not fully internalise the full value of security of supply. The annual de-rated capacity margin gradually decreases in the medium-term as more plants are mothballed or shut down and DSR is not developing due to the absence of sufficient remuneration. After 2018, it does not comply with the reliability standard. As a result, the de-rated capacity margin decreases to around 5% after 2035. Because the economic signal to trigger timely investments or reinvestment for refurbishment is not strong enough in the energy market, the development of DSR capacity is not possible, more existing plants are decommissioned before 2021 and new build investment starts from 2023 onwards. The profitability of existing and new build generation cannot be ensured while meeting the reliability standard of security of supply in the EOM scenario. The change in annual de-rated capacity margin over time also shows that the adequacy issue in Poland is not a temporary adequacy problem, but rather a long-term concern.

Conversely, under the CM scenario, the annual de-rated capacity margin remains around 14% above peak demand. By effectively incentivising market participants to keep plants running and to make

timely investments in capacity expansions, the Polish CM allows maintaining the capacity margin at the level of the reliability standard.[33]

Security of supply in Poland would be substantially deteriorated in the longer term if a CM was not introduced. From 2020 onwards, the capacity margin necessary to securely supply the Polish power system is not met in the EOM due to the closure of unprofitable plants. This results in high curtailment risk for consumers. In contrast, the CM allows meeting the reliability standard in all years.

Impact on generation mix

The Polish CM is designed to reinforce energy market signals so that sufficient capacity is available to meet demand in the long term and ensure that the de-rated capacity margin of 14% above peak demand is met. Compared to the EOM in which electricity prices do not necessarily reflect the true cost of security of supply in times of scarcity, it addresses this market failure by making additional capacity available and helps obtain a more optimal generation mix given the policy objectives.

Figure 3-9 illustrates the evolution of the Polish capacity mix under an EOM design.
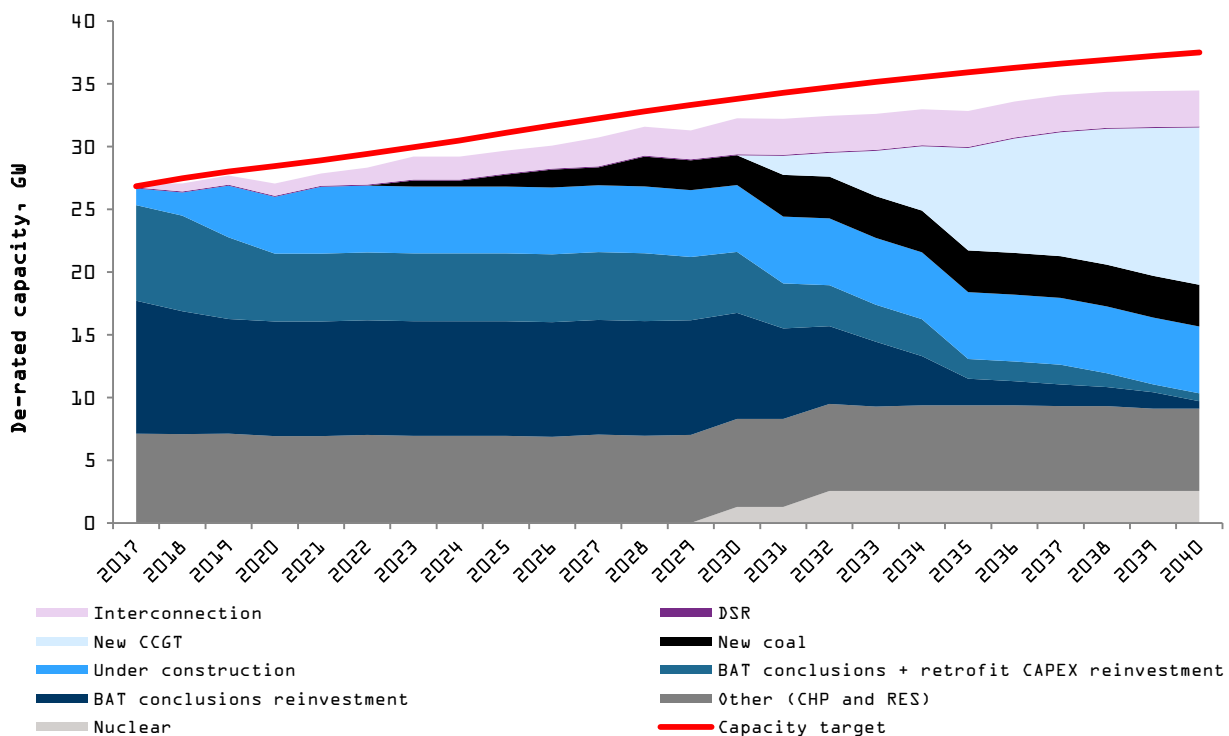
Figure 3-9: Evolution of the capacity mix compared to the capacity target in the EOM scenario (MW)

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[33]   Slight variations around the 3 hours can be observed. This is due to the indivisibility of investment, which cannot adapt to small variations of demand.

Source: Compass Lexecon, 2017

Notes: Capacity is de-rated with corresponding de-rating factors.

In the absence of a capacity market (EOM scenario), the short-term and long-term reliability standard is not met from 2018 onwards. The insufficient new investments in the Polish power system results from a combination of:

- **Low refurbishment investments:** Of the 8.5GW of capacity facing BAT conclusions + retrofit CAPEX reinvestment, about 6GW reinvest, and about 2.5GW existing plants close as it would not be economically favourable to remain in the market; and

- **Low new investments**: Given that new projects rely exclusively on energy revenues, new investments would require higher power prices to be economic, therefore lower capacity margins than necessary to respect the security of supply at reliability standard.

The investment level in EOM is achieved at the cost of endangering security of supply since more price spikes in the energy market are needed in order to cover investment and refurbishing costs.

In contrast, in the presence of a CM, the available capacity remains sufficient to meet the security of supply at the reliability standard over the whole modelling horizon, as shown in Figure 3-10.
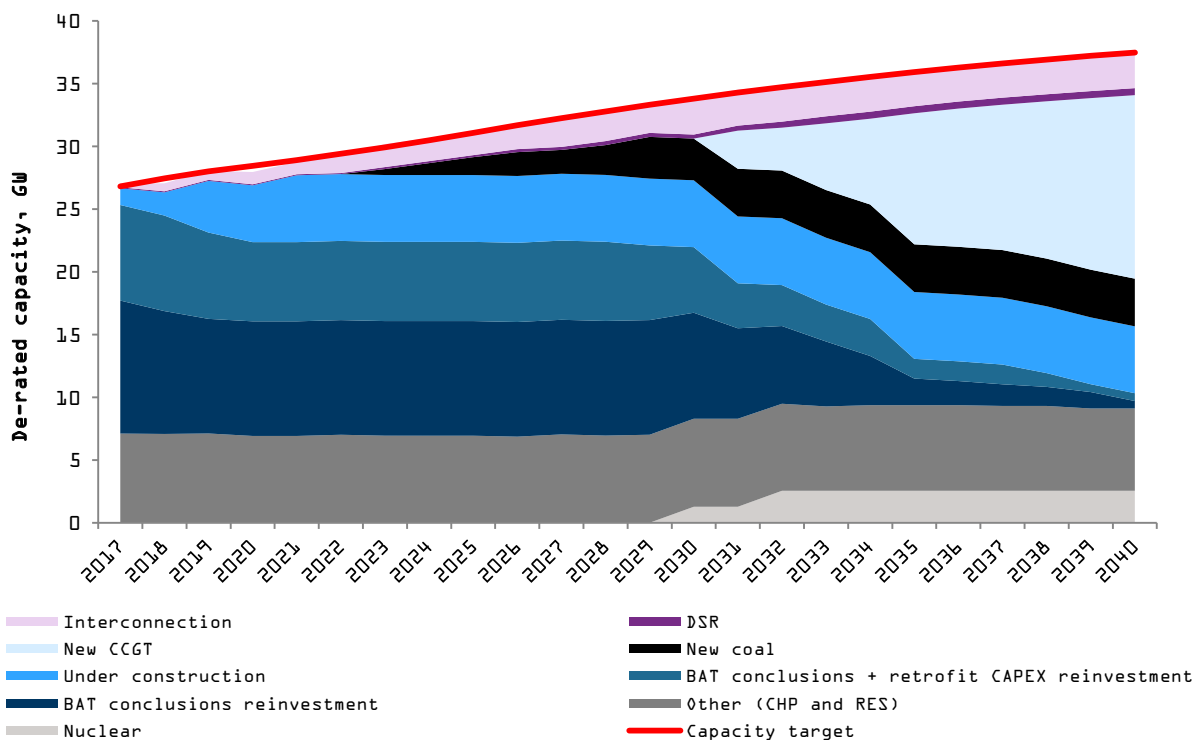
Figure 3-10: Evolution of the capacity mix compared to the capacity target in the CM scenario (MW)

Source: Compass Lexecon, 2017

Notes: Capacity is de-rated with corresponding de-rating factors.

Compared to an EOM design, new investments ensuring the secure supply of the Polish power system come from:

- **Higher refurbishment investments**: Because they anticipate the future capacity remuneration, an additional 1GW of existing plants decide to reinvest at the beginning of the 2020s to stay longer operational in the market.

- **Higher new investments**: The CM allows new build operators' investment costs to be compensated by capacity revenue in addition to energy and ancillary services revenues. The capacity revenue on the one hand reduces the risk of investment, and on the other hand ensures the economics of new build plants and the achievement of the reliability standard.

Figure 3-11 illustrates the difference in installed generation capacity between the CM and EOM scenarios. Installed capacity in EOM and CM is compared for every five-year period and the figure shows accumulated changes within the period.
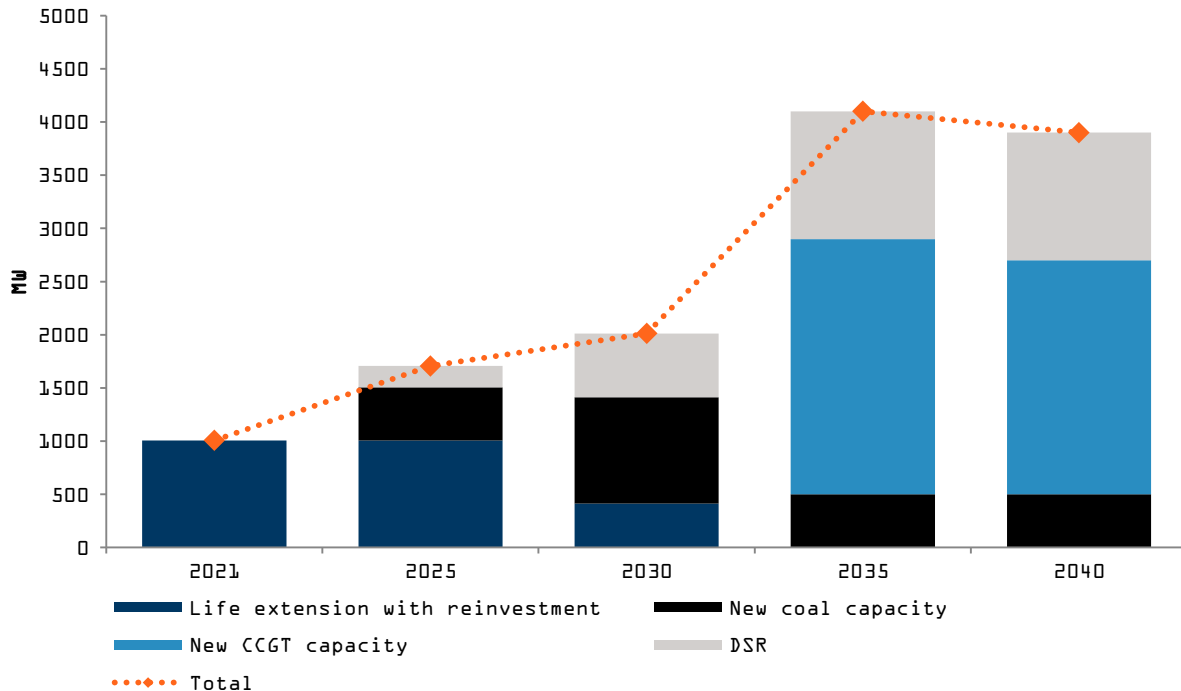
Figure 3-11: Difference in installed generation capacity between the CM and EOM scenarios (MW)
Source: Compass Lexecon, 2017

Compared to the EOM scenario, the CM maintains more generation capacity available to meet the security of supply at the reliability standard. In particular, the perspective of a capacity remuneration

that complements the lack of revenues in the energy market allows financing refurbishments of some existing coal plants to meet BAT conclusions + retrofit CAPEX and reduces decommissioning by 2021 by about 1GW.

In the longer run, the CM triggers more investments in new build capacities of 3,900MW:

- Before 2030, 500MW of additional coal plants are built;

- Between 2030 and 2040, more than 2,200MW of additional CCGTs are built; and

- Between 2023 and 2033, DSR further develops leading to an additional capacity of 1,200 MW in the CM scenario.

As the Polish CM aims at guaranteeing the adequacy between supply and demand, it has an impact on the available capacity mix. It helps selecting the most competitive technologies for all timeframes.

Sensitivity of reduced network constraint in an energy only market

It is worth noting that an increase in interconnection capacity would unlikely be a sufficient solution to the adequacy concerns in Poland in the EOM scenario. First, interconnection capacity may increase on a given border, but the neighbouring country may not have sufficient capacity margin to provide electricity to Poland at times of scarcity in Poland (risk of simultaneous scarcity). Secondly, increasing interconnection capacity could result in a significant increase in the amount of import flows to Poland (without changing Poland's net exporter position) given the current Polish import constraint, negatively affecting the incentives for reinvestment of existing capacity and investment in new capacity, further diminishing their profitability..

Belgium provides a natural example of a situation. The Belgian total transmission capacity is 3.5GW during the winter relative to a peak demand of 13.5GW in recent years. It has interconnection projects with the UK, France, and the Netherlands, which will increase the interconnection capacity by another 3GW by 2020[34]. Despite extensive interconnection capacity with respect to the peak demand, unprofitable market conditions leading to decreasing available thermal capacity and uncertainty around nuclear capacity put the Belgian security of supply under pressure and there is still a high risk of blackout. **Therefore, increased interconnection capacity will not tackle Polish adequacy problems in the long run.**

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[34] Elia (2015), Electricity security crisis in Belgium.

To support the above arguments, we run in parallel a sensitivity model of an EOM with increased interconnection capacity (hereafter the EOM LF scenario). We use the same interconnection capacity assumptions as in the Polish CM sensitivity of the reduced loop flows (the CM LF scenario) through Poland in the German-Austrian bidding zone, which will be described in more details in Section 5.

Overall, increased interconnection capacity does not solve the Polish adequacy problem. As shown in Figure 3-12, the de-rated capacity margin in the EOM LF scenario is even lower than in the EOM scenario after 2020. In the long run, they converge after 2035.
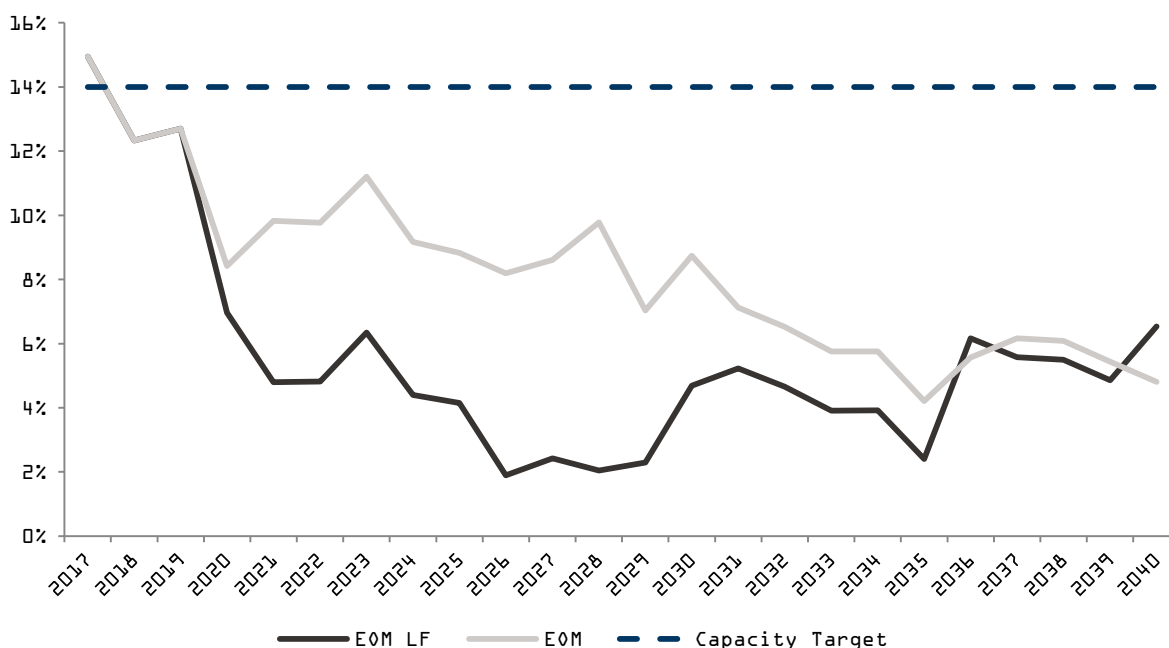
Figure 3-12: Annual de-rated capacity margin in the EOM LF and EOM scenarios (%)

Source: Compass Lexecon, 2017

Notes: The de-rated capacity margin is defined as the ratio between the additional de-rated capacity available (including DSR and interconnection capacities) above the net average cold spell peak demand (excluding auxiliary demand).As shown in Table 3-1, the additional interconnection capacity in the EOM LF scenario compared to the EOM is also de-rated at 40%.

Larger interconnection capacity negatively affects the investment incentives for reinvestment of existing capacity and investment in new capacity as more foreign capacity is available.

▪ As Poland is more dependent on power exchanges, running hours are reduced for the existing plants accompanied by a lower power price. Higher interconnection capacity up to the beginning of 2020s largely reduces the non-compliant plants' incentives for reinvestment anticipating poor profitability in the energy market.

- As a higher amount of existing plants are decommissioned, investment in new coal plants start still from 2023 onwards, but its development pace is slower compared to the EOM with limited interconnection capacity.

- Beyond 2030 when investment in CCGT plants becomes more competitive, because of higher decommissioning capacity and slower development of new build coal capacity, a higher amount of CCGTs is needed to fill the capacity gap.
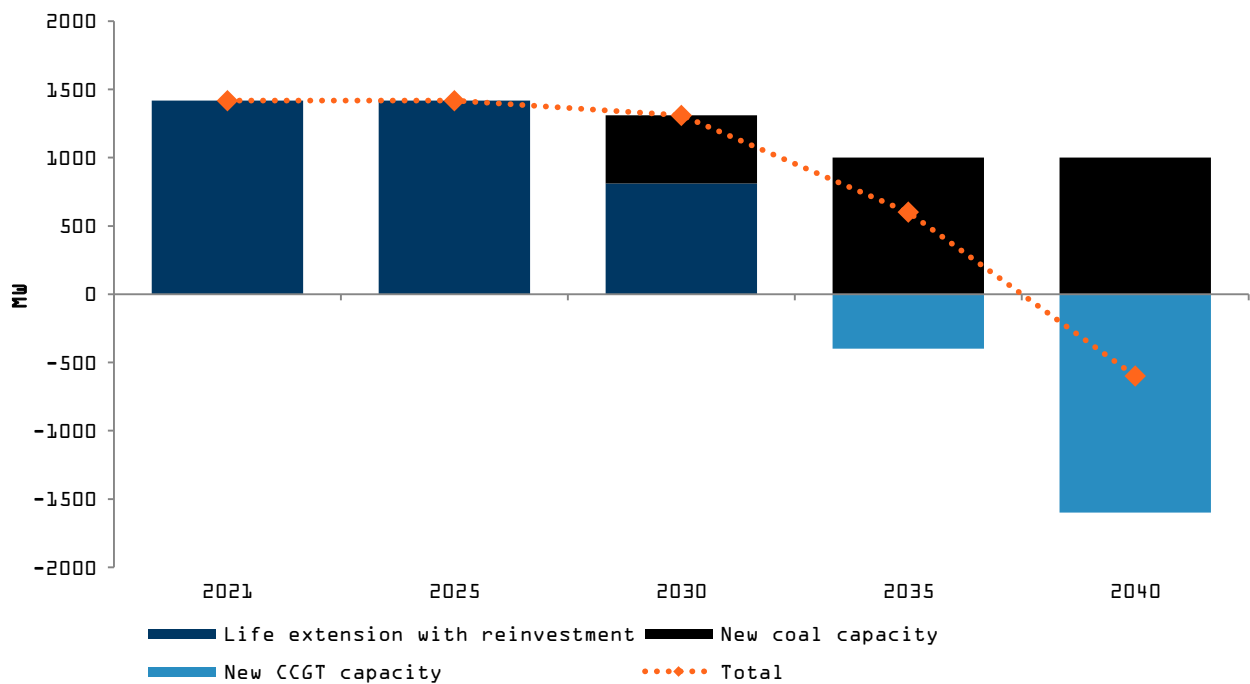
Figure 3-13: Difference in installed generation capacity between the EOM and EOM LF scenarios (MW)

Source: Compass Lexecon, 2017

Notes: The difference in capacity is calculated as EOM – EOM LF.

Impact on costs

Impact on capacity costs

The dynamic in terms of capacity investment under the CM scenario translates into the capacity price outlook presented in Figure 3-14. Eligible power plants are expected to receive capacity payments from 2021 onwards, i.e., when the Polish CM is implemented.
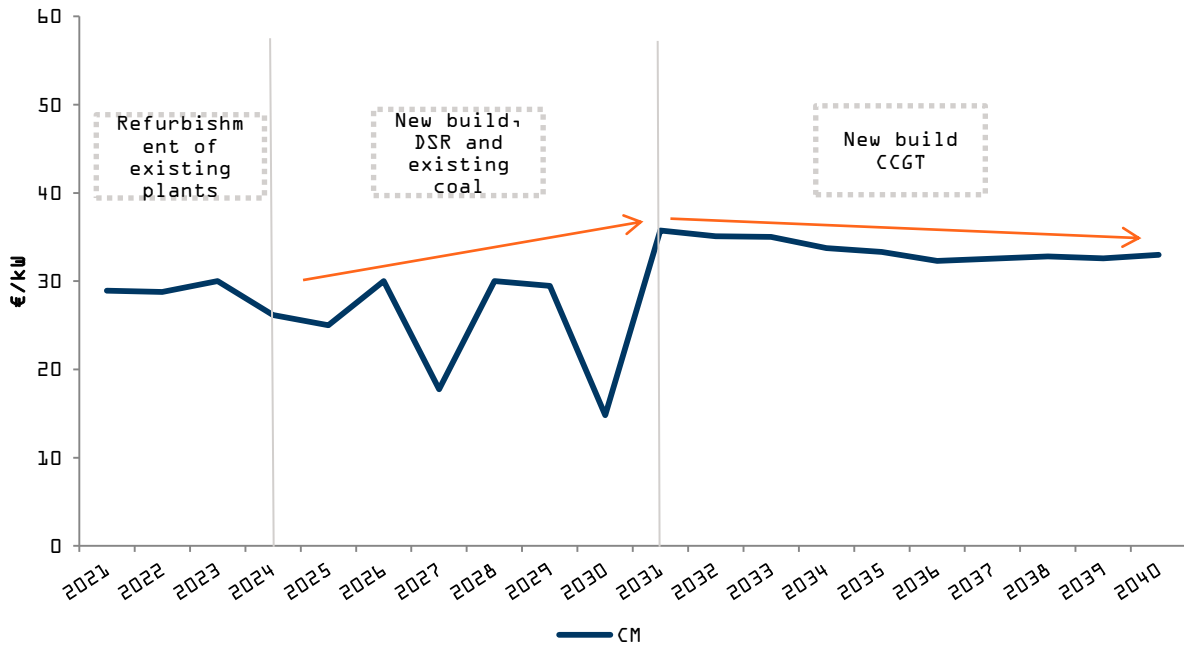
Figure 3-14: Capacity price in CM scenario (€$_{2016}$/kW)

Source: Compass Lexecon, 2017

The change in capacity price can be divided into three phases, which result from different generation technologies' competitiveness:

- Between 2021 and 2023, the capacity price is driven by the remuneration required by existing coal and lignite plants to comply with BAT conclusions and to invest in additional retrofit CAPEX. Existing capacity and planned projects are sufficient to meet the Polish capacity target until 2024.

- From 2024 onwards, new capacity is needed in order to secure the power system and coal is still the cheapest. The capacity price is therefore driven by the missing money of new coal plants when new capacity is constructed and of existing capacity if no new capacity comes online for a given year in the energy market up to 2031. In 2026 and 2028, DSR sets the capacity price. Bids increase over time until reaching CCGT bids.

- From 2031 onwards, new CCGT plants are more economic than new coal plants. Investment in new plants therefore shifts from coal to gas. New build CCGTs would become more competitive in the CM from 2031: from that date onwards, no more coal plants would be built. The capacity price slightly decreases from €36/kW to €33/kW by 2040, as the missing money of new gas plants in the energy market is reduced.

Based on our assumptions of commodity prices and construction costs of different technologies, new CCGTs become more competitive in CM and EOM from 2031 onwards: new CCGT capacity starts to develop and no new coal plants would be built post 2031. Alterative commodity or CO2 prices development or construction costs can result in a different investment pattern, but the evolution of CO2 is the main driver for investment to switch from coal to gas generation in 2031.

Impact on energy costs

The higher available generation capacity in the energy market leads to lower prices in the CM than in the EOM scenario, to the benefits of Polish consumers. The figure below shows the annual average power price outlook in the CM and EOM scenarios as well as the price differential between them.
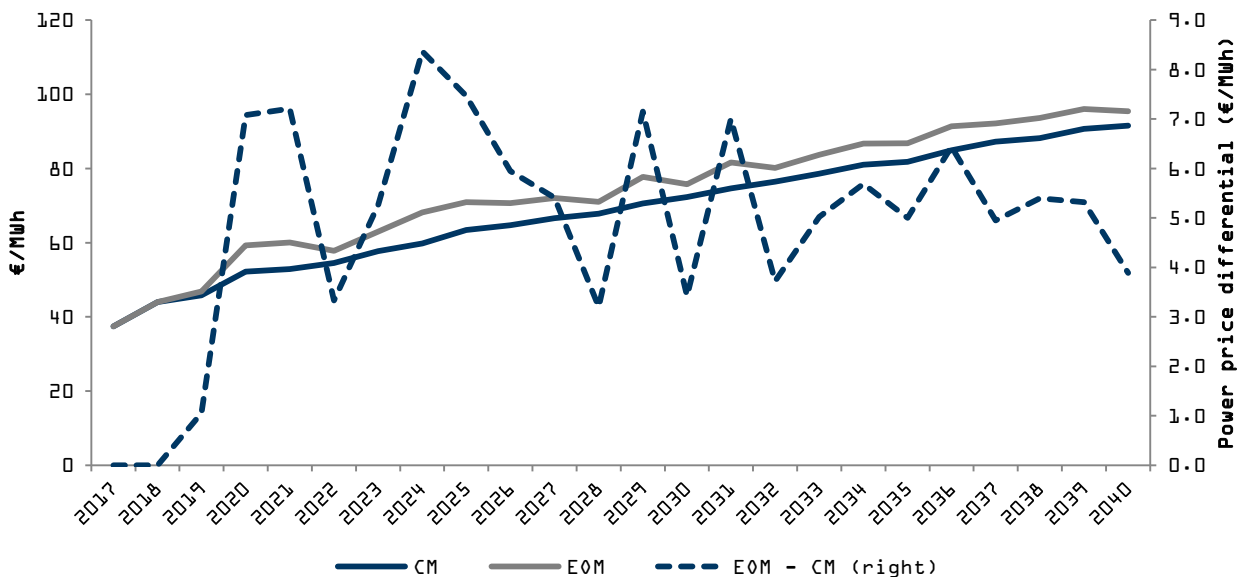
Figure 3-15: Annual average power prices in CM and EOM scenarios, and difference between EOM-CM (€2016/MWh)

Source: Compass Lexecon, 2017

Notes: The price difference is calculated as the EOM price minus the CM price. Its scale is based on the axis on the right.

In both scenarios, the power price outlook follows an upward trend, reflecting the increase of commodity prices (gas, coal and CO_2). However, EOM power prices increase at a faster rate than the CM power prices from 2020 onwards as a result of the decreasing capacity margin in the EOM. This situation also triggers more frequent price spikes and an increased volume of curtailment. Furthermore, the existence of a CM incentivises generators and demand-side response (DSR) operators to maximise their availability during winter, but it forces them neither to generate nor to modify their bids in the energy market.

In the long term, the power price differential stabilises at around €5/MWh, i.e. 6%, as a consequence of the stabilised capacity margin differential between the CM and EOM scenarios.

Higher average power prices under the EOM scenario are partly driven by an increased frequency of price spikes. Figure 3-16 illustrates the frequency of power prices in several price ranges in different years of the modelling horizon.
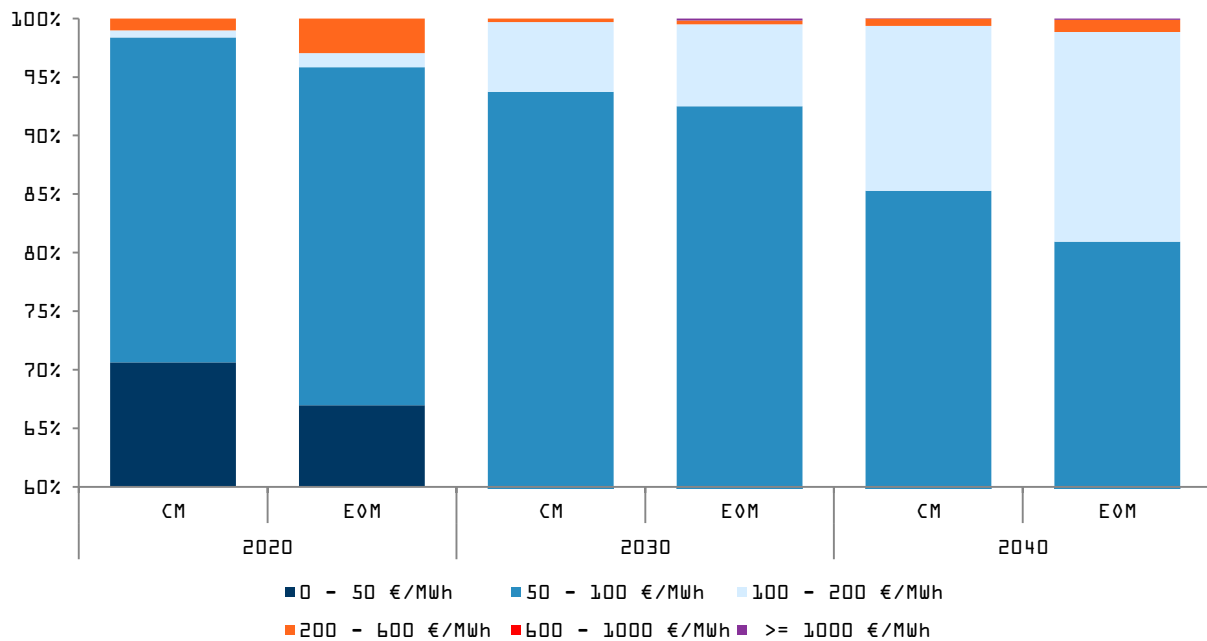
Figure 3-16: Frequency of price ranges in the CM and EOM scenarios in 2020, 2030 and 2040 (%)
Source: Compass Lexecon, 2017

While in 2020 power prices are in the €50-100/MWh range most of the time in both scenarios, price spikes above €100/MWh occur more frequently in the EOM than in the CM scenario already in 2020, 2030 and 2040. By 2040, power prices are above €100/MWh for 19% of the time under the EOM design against 15% in the CM scenario. They jump above €600/MWh twice as often. EOM prices in 2040 exceed €1,000/MWh during 10 hours.

Impact on total consumer costs

Another reason for the reduction of total costs for consumers is that financing costs for new investments are lower with a CM: since the CM helps secure more reliable revenues, it leads to a lower cost of capital and thereby reduces total costs. This is especially true for peaking plants that would run only a limited period of time during residual load extreme values.

All in all, the assessment of the costs and benefits for Polish consumers shows that the CM actually reduces total costs for them. Figure 3-17 shows the costs and savings to consumers introduced by the Polish CM compared to EOM.
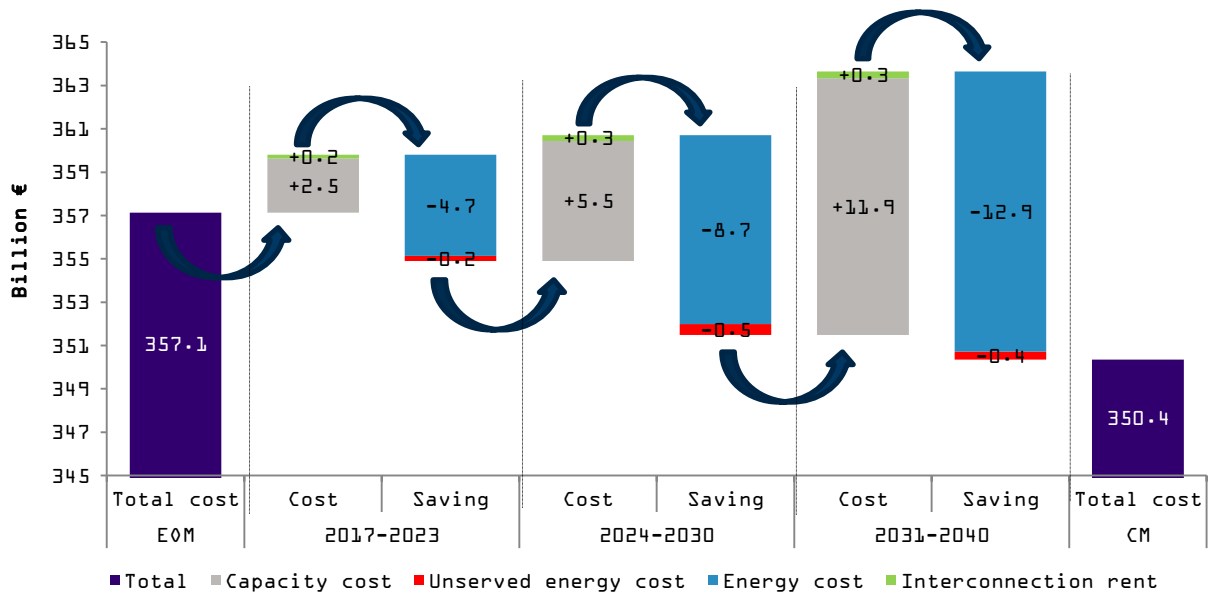
Figure 3-17: Comparison of costs to Polish consumers between the EOM and CM scenarios (billion €2016)

Source: Compass Lexecon, 2017

Notes: The figure compares the costs to Polish consumers in the EOM and in the CM and shows the variations between the two scenarios in three periods. A plus sign means an increase and a minus sign means a decrease in costs to consumers. We contribute the difference in interconnection rent between CM and EOM to consumer costs or savings because it is a result of the reduction in power prices and in financing and investment costs in the CM, which leads to lower congestion rent. This lower congestion rent for interconnectors introduces a cost for consumers. The cost to Polish consumers in the CM is lower than that in the EOM, representing a saving of the CM.

Overall costs and savings in the CM and EOM scenarios evolve overtime. They can be divided into three phases:

- Between 2017 and 2023, the CM leads to a small cost saving as the reduced loss of load offsets the cost of existing capacity refurbishment.

- Between 2024 and 2030, the CM leads to significant cost savings, offsetting the initial additional cost as the energy market benefits from the anticipated capacity requirement.

- From 2031 onwards, the CM benefits over the EOM are lower but remain positive on average as the CM benefits from lower unserved energy.

It is reasonable that the CM is temporarily as expensive as the EOM in the transitory medium-term period, because it brings forward the need of new investments to maintain security of supply. Costs are anticipated, but benefits are spread over a longer period. However, in the long term, the CM brings significant benefits to consumers by reducing the costs of unserved energy.

On average over the modelling horizon, the Polish CM compared to the EOM scenario reduces costs for Polish consumers by € 280 million per year and increases social welfare. First, lower curtailments of load and lower energy prices outweigh the additional capacity costs. Second, the CM reduces investment risk and therefore the cost of capital for investors.

Impact on social welfare

Social welfare is measure by the sum of consumer surplus, taking into account the variations of CM from EOM in unserved energy, energy and capacity costs, as well as interconnection rent for the Polish consumers, and capacity provider surplus, taking into account the variations in energy and capacity revenues as well as financing costs for generation and DSR units.

Energy and capacity revenues of the capacity providers and energy and capacity costs of consumers are a value transfer between capacity providers and consumers when calculating social costs. Financing costs are defined as the total cost borne by capacity providers that invest to develop new plants (or to refurbish existing plants), i.e., capital expenditures (CAPEX) and FO&M. In a CM design, capacity providers access funds at a lower cost of capital, which is associated with a less risky investment environment. The annualised financing costs for each generation unit are therefore lower than in an EOM. However, the total cost of CAPEX and FO&M is still higher in CM because more investment is made.

Overall, capacity providers in the CM scenario benefit from an increased capacity remuneration, which allows them to recover financing costs and partially compensates the reduced energy revenues due to lower power prices.

Figure 3-18 illustrates the additional social welfare, defined as the sum of consumer and capacity provider cost (or benefit), that is achieved in the CM scenario in comparison to the EOM design.
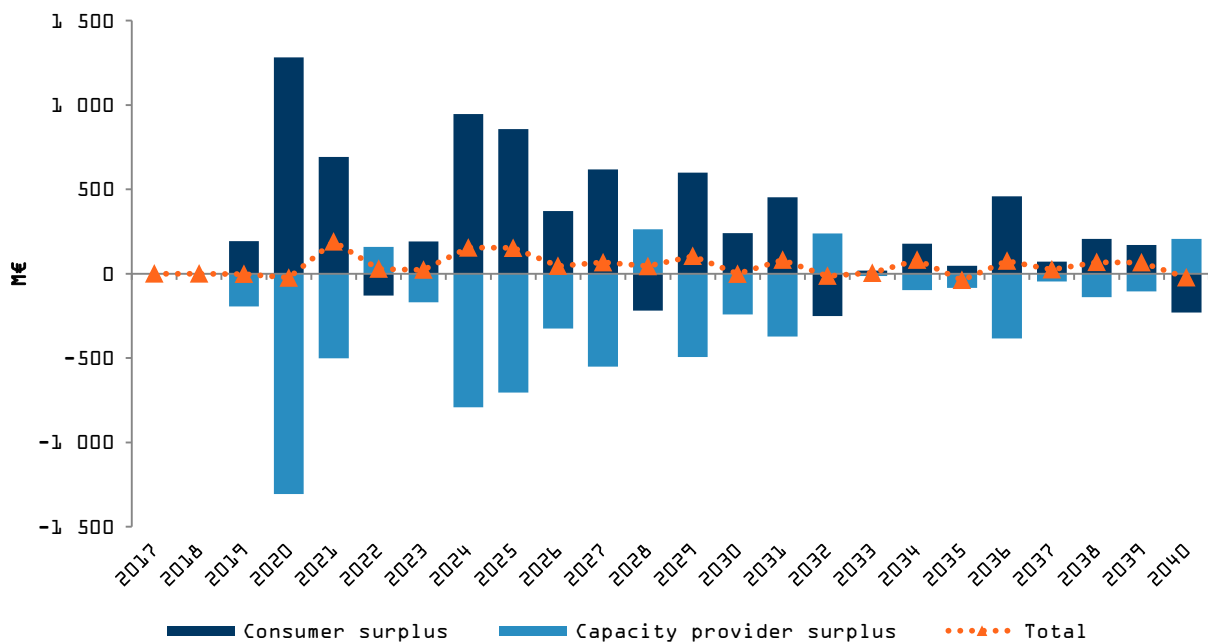
Figure 3-18: Additional social welfare (consumer and capacity provider surplus) in the CM scenario as compared to the EOM scenario (billion €$_{2016}$)

Source: Compass Lexecon, 2017

Notes: The figure presents the difference in surplus between CM and EOM. The consumer surplus corresponds to the net consumer cost or saving as presented in the previous figure. It takes into account unserved energy, energy, capacity costs and interconnection rent. The capacity provider surplus takes into account energy and capacity revenues as well as financing costs.

Overall, when summing up capacity provider surplus and consumer surplus, CM compared to the EOM scenario leads to additional social welfare of € 1 billion over the whole modelling horizon, i.e. € 46 million per year.

The CM aims to ensure that the reliability standard is met in all years, and is a least-cost measure for end consumers. Its impact is estimated in terms of costs and benefits for both consumers and capacity providers, resulting in an overall social welfare.

The total consumer cost includes the capacity cost, the energy cost, the unserved energy cost and the congestion rent (corresponding to revenues from interconnection to neighbouring countries).

The CM benefits generators and DSR operators which have more predictable revenues from capacity and reduced market risks and cost of capital.
Impact on the energy market functioning and on cross-border exchanges

The Polish CM is effectively designed not to alter market participants' bidding strategy and dispatch decisions in the short term. Polish capacity providers bid in the energy market on the basis

of their short-run marginal cost (SRMC) in the same way as they would do in the EOM. In both CM and EOM, the power price outlook follows an upward trend, reflecting the increase of commodity prices (gas, coal and CO2). However, EOM power prices increase at a faster rate than the CM power prices from 2020 onwards as a result of the decreasing capacity margin in the EOM. This situation also triggers more frequent price spikes and an increased volume of curtailment. Furthermore, the existence of a CM incentivises generators and demand-side response (DSR) operators to maximise their availability during winter, but it forces them neither to generate nor to modify their bids in the energy market.

Because of its impact on the evolution of the Polish generation mix and electricity prices, the implementation of the Polish CM has an impact on cross-border exchanges with neighbouring markets. The introduction of the CM increases the net export balance from Poland to other countries because the CM results in a lower Polish power price in the energy market and the Polish power price is lower with respect to neighbouring countries. While the Poland net exporter position remains, the net export flows from Poland in the CM scenario increase by 0.7TWh in 2020 and 6TWh in 2040 compared to the EOM scenario.

Breaking down the aggregated impact on net export flows from Poland, Figure 3-19 shows that the implementation of CM reinforces Poland's export position over time to all neighbouring countries.
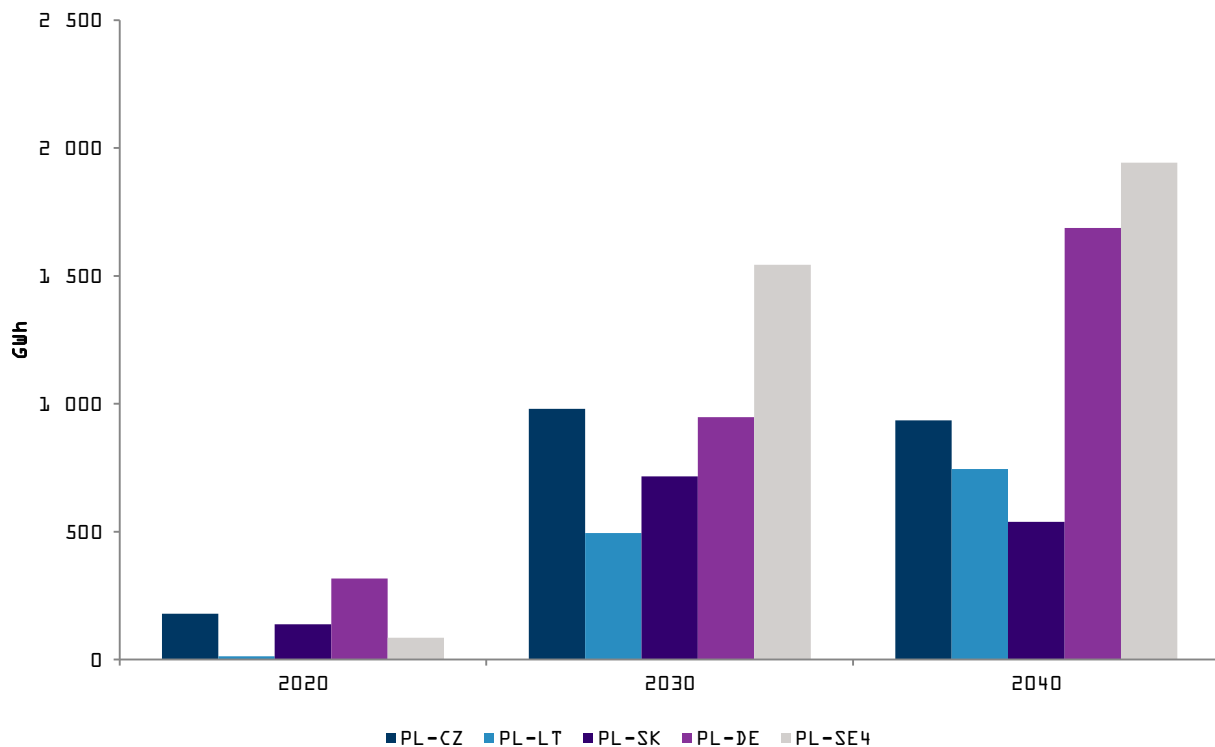
Figure 3-19: Net export delta from Poland to neighbouring countries between the CM and EOM scenarios in 2020, 2030 and 2040

Source: Compass Lexecon, 2017

The CM does not modify the behaviour and strategies of market players in the energy market and the short-term merit order. In the long term, it corrects the market failure where electricity prices are not reflecting the true cost of security of supply and helps to obtain the optimal available capacity given the policy determined reliability standard.

Impact on CO2 emissions

The result of generation mix indicates that coal capacity is expected to be marginally higher in the CM design than in EOM in the medium and long term. This results from two effects:

- Due to the perspective of capacity payments from 2021 onwards, several existing coal-fired plants stay on line, in contrast to EOM in which the lack of profitability leads them to be shut down; and

- More coal-fired plants are constructed from 2023 onwards to replace shutdown capacity and ensure that the reliability standard is met.

Consequently, a slightly higher level of CO2 is emitted from electricity generation under the CM scenario than in EOM from 2020 onwards, as illustrated in Figure 3-20 below.
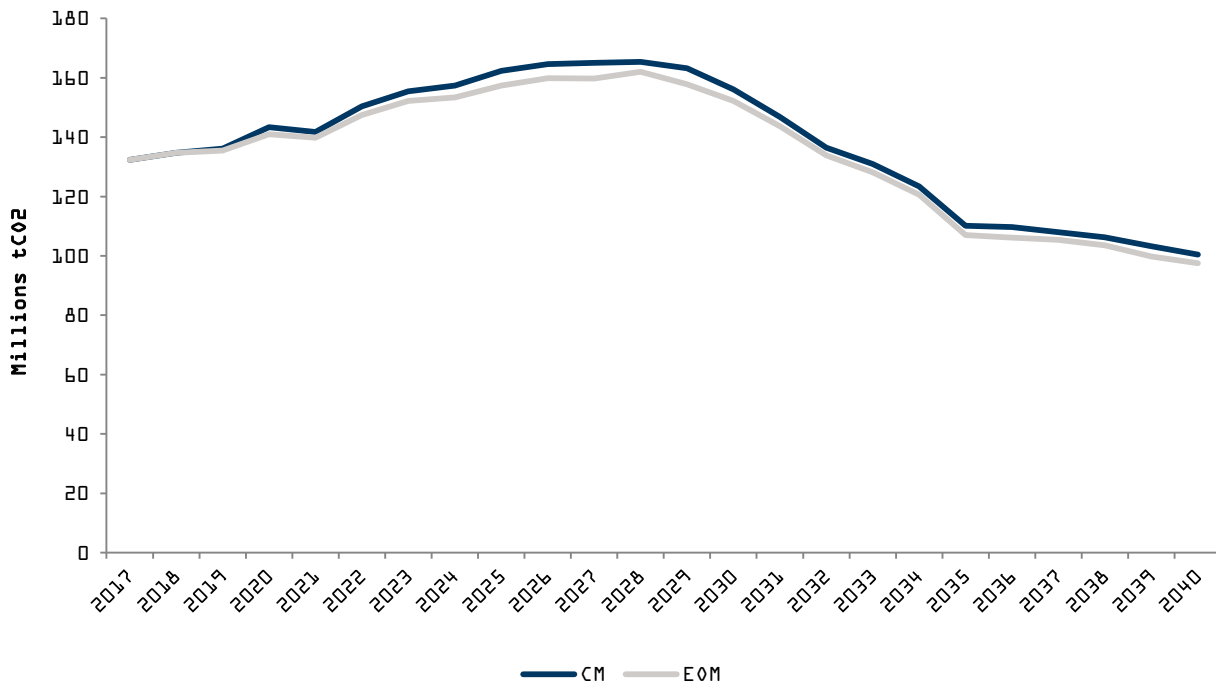
Figure 3-20: Polish CO_2 emissions from electricity generation in the CM and EOM scenarios

Source: Compass Lexecon, 2017

Until 2020, CO2 emissions from electricity generation average in Poland at 135 million tCO2 in both the CM and EOM scenarios. Afterwards, they increase at a higher pace in the CM, reaching 156 million tCO2 by 2030 compared to 152 million tCO2 in the EOM. A declining trend is observed in both scenarios in the 2030's. By 2035, emissions have reached 110 million tCO_2eq and 106MtCO2 under the CM and EOM scenarios, respectively.

Since it triggers a capacity addition to the Polish power market so as to ensure a 14% de-rated margin, the introduction of the Polish CM impacts neighbouring power markets which tend to import more under the CM scenario than in EOM. As a result, part of electricity volumes generated by neighbouring markets in EOM, as well as the corresponding CO2 emissions, is avoided in the CM design. However, the decrease does not offset the increase in Polish CO2 emissions. This effect is illustrated in

Figure 3-21 below. The EU wide CO2 emissions increase by 1-2 million tonnes.

All in all, the CM only slightly increases CO2 emissions from electricity generation compared to EOM design.
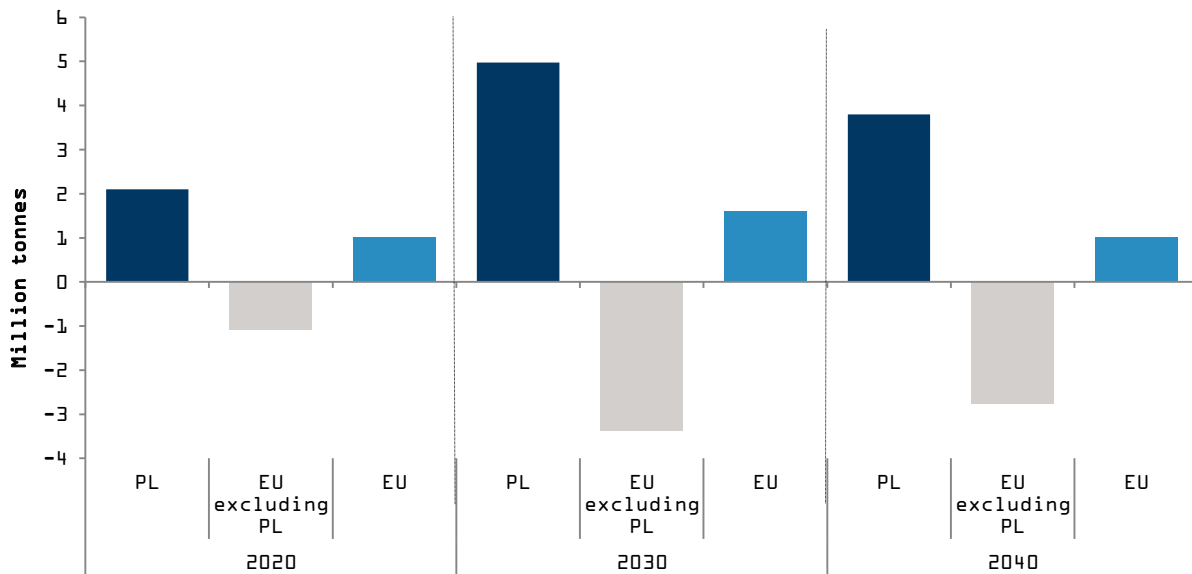
Figure 3-21: Difference in CO2 emissions from electricity generation between the CM and EOM scenarios in Poland, the rest of Europe and Europe

Source: Compass Lexecon, 2017

In 2030, about 5 additional million tCO_2 are emitted in Poland in the CM scenario in comparison to EOM, corresponding to 3% of the emissions in EOM. In the closest neighbouring countries (Germany, Czech Republic, Slovakia, and Lithuania), nearly 1 million CO_2eq is avoided from electricity generation.

3.6 MODELLING OF A POTENTIAL ALTERNATIVE CM: A POLISH STRATEGIC RESERVE

In its final report of the sector enquiry on capacity mechanisms published on 30 November 2016, the European Commission recommends introducing a strategic reserve when there is a temporary adequacy concern in a national power market.[35] Such strategic reserve should consist of a certain amount of capacity (generally power plants that are about to close) held outside the market and called upon in tense supply situations. As illustrated in Figure 3-22, a well-designed strategic reserve should therefore be activated after the market clearing and have limited, if any impact on the energy market.

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[35]   European Commission (2016), Final Report of the Sector Inquiry on Capacity Mechanisms, COM(2016) 752 final.
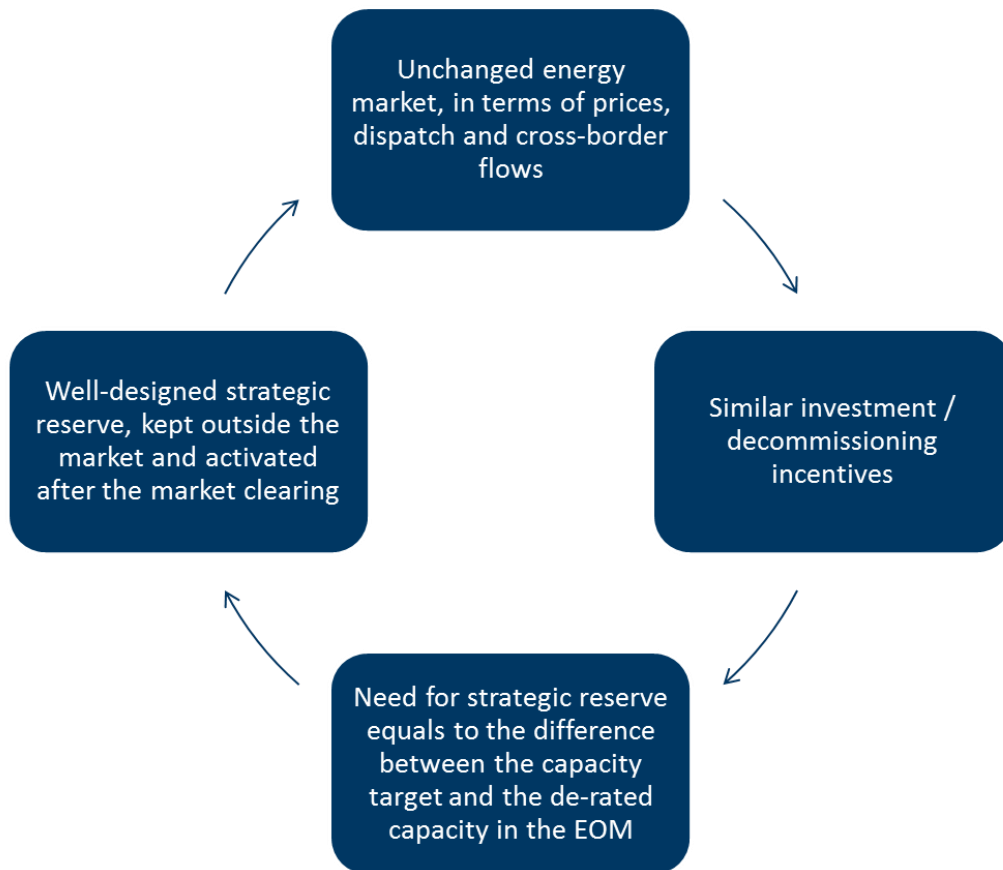
Figure 3-22: Impact of strategic reserve on the energy market

Source: Compass Lexecon, 2017

While this mechanism allows solving the adequacy concern for a few years, typically until enough new plants are built, the European Commission does not support strategic reserve as a way to tackle long-term adequacy issues or to stimulate new investments.

Volumes that would be required in different years are presented in Figure 3-23. As shown in the figure, there is a persistent capacity gap in the Polish EOM scenario. This implies that Poland would need a strategic reserve with between 1,000 and 4,000MW of capacity between 2021 and 2040. According to EC recommendations, a strategic reserve mechanism would therefore not be adapted in Poland.
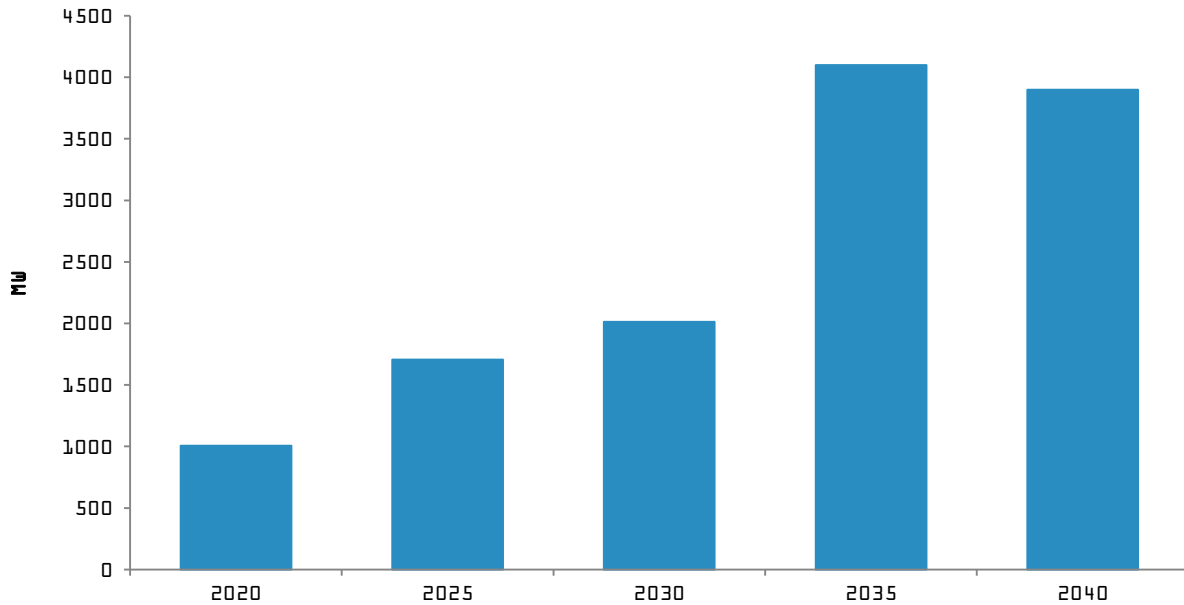
Figure 3-23: Volumes of the strategic reserve needed to meet security of supply criterion (MW)

Source: Compass Lexecon, 2017

Notes: The volume of the strategic reserve is defined by the difference in capacity between CM and EOM.

Furthermore, even though the capacity margin is not endangered between 2021 and 2023, capacity would still need to be contracted through the strategic reserve to enable coal and lignite plants to invest to comply with IED standards from 2021 onwards. This would further increase the incompatibility of this scheme with the Polish power market.

We model the strategic reserve in order to analyse its impact and quantify its costs for Polish consumers.

To perform this analysis, we have assumed that the strategic reserve would follow the best practices as identified by the EC in its Final Report of the Sector Inquiry on Capacity Mechanisms. In particular, in a well-designed strategic reserve, (i) there should not be incentives for plants that would remain in the market in an EOM to withdraw from the market and (ii) the Polish TSO would only activate the plants in the reserve after the clearing of the day-ahead market if there is not enough supply to satisfy all demand even at the price cap.

With respect to an EOM, the strategic reserve would have no impact on the day-ahead energy market (and very limited impact on intraday and balancing markets, if any) compared to the EOM. This also means that the incentives of power producers to maintain their plants in the market or to build new plants are unaltered and, as a result, capacity mix and energy prices in the market are unchanged.

Therefore, compared to the EOM, energy costs would be similar and the reserve's contracting and activation costs have to be put in balance with the value of the reduction in loss of load.

Yet, the strategic reserve in Poland would be made of existing coal plants that are about to close. These plants would bid their fixed operation and maintenance costs plus the reinvestment cost necessary to be compliant to run for at least 1,500 hours per year, resulting in high contracting costs, which would outweigh the benefits in lower loss of load.

As shown in Figure 3-24 comparing the costs and savings per year for Polish consumers between the Polish strategic reserve (SR) and the EOM, the contracting costs or capacity cost of the strategic reserve significantly overweigh the benefits of reduced unserved energy cost and **maintaining the Polish strategic reserve would introduce cost to consumers, amounting to € 1.5 billion over the period of 2021-2040, or equivalently € 77 million per year**.
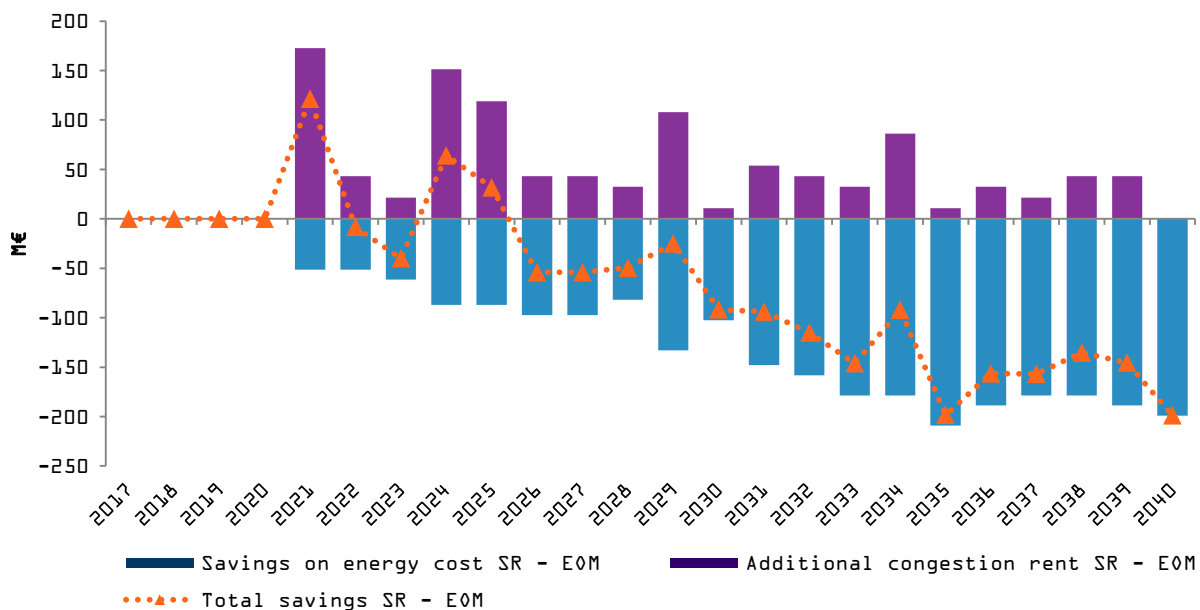
Figure 3-24: Comparison of costs per year to Polish consumers under the Polish strategic reserve (SR) and the EOM scenario (million €$_{2016}$)

Source: Compass Lexecon, 2017

Notes: The figure presents the difference in surplus between SR and EOM. The consumer surplus corresponds to the net consumer cost or saving. It takes into account unserved energy, energy, capacity costs and interconnection rent. The capacity provider surplus takes into account energy and capacity revenues as well as financing costs. Since the total savings are negative, they represent an incremental cost for consumers. As the strategic reserve does not have an impact on energy market dispatch, energy costs and interconnection rent are the same in both scenarios.

The costs of procuring strategic reserve are borne by consumer. Besides, the strategic reserve in Poland would be made of existing coal plants that are about to close. These plants would bid their FO&M costs plus the reinvestment cost necessary to be compliant to run for a maximum of 1,500

hours per year.[36] The strategic reserve is therefore expected to be less cost-efficient for Polish consumers as it leads to higher costs to meet the reliability standard compared to the CM. The evolution of costs and savings in both scenarios is presented in Figure 3-25.
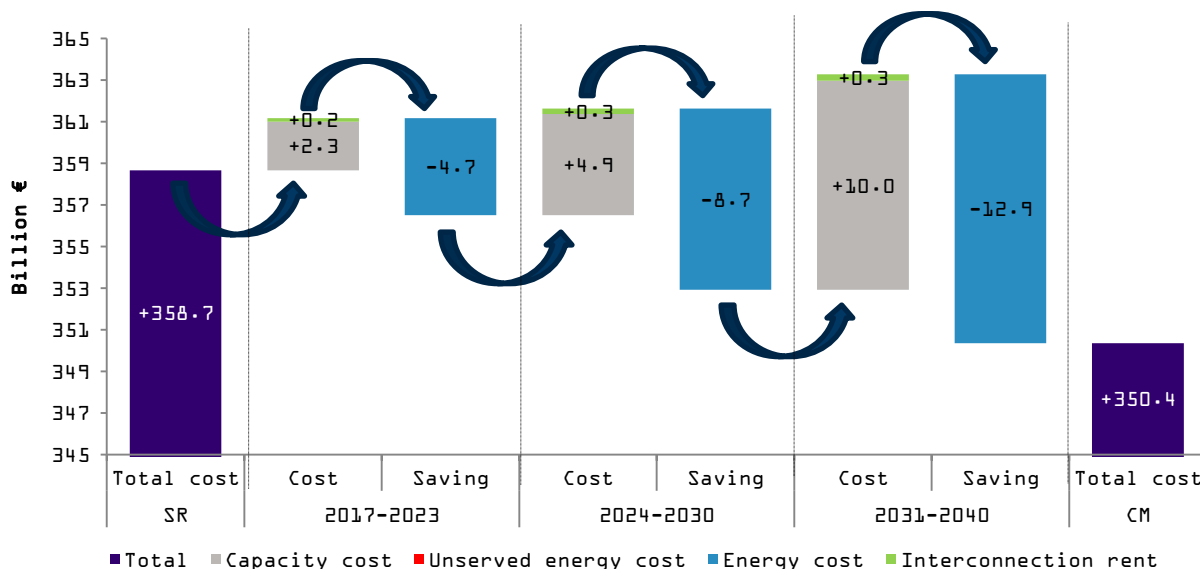
Figure 3-25: Comparison of costs to Polish consumers under the Polish strategic reserve and the CM scenario (billion €$_{2016}$)

Source: Compass Lexecon, 2017

Notes: SR refers to the scenario where the Polish strategic reserve is maintained. The figure compares the costs to Polish consumers in the SR and in the CM and shows the variations between the two scenarios in three periods. A plus sign means an increase and a minus sign means a decrease in costs to consumers. We contribute the difference in interconnection rent between CM and SR to consumer costs or savings because it is a result of the reduction in power prices and in financing and investment costs in the CM, which leads to lower congestion rent. This lower congestion rent for interconnectors introduces a cost for consumers. The cost to Polish consumers in the CM is lower than that in the SR, representing a saving of the CM

Overall costs and benefits under the Polish strategic reserve and the CM scenario evolve overtime. They and can be divided into three phases:

- Between 2017 and 2023, the CM leads to a small cost saving as the reduced loss of load offsets the cost of existing capacity refurbishment.

- Between 2024 and 2030, the CM leads to higher cost savings, more than offsetting the initial additional cost as the energy market benefits from the anticipated capacity requirement.

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[36]   Existing plants'   FO&M amount to €40/kW. Based on the PSE data, the annualised reinvestment cost required to make a plant operate under 1500 hrs/year derogation of the IED is €11/kW. Under this 1500hrs/yr derogation, power plants are subject to less stringent emission limits. (Annex V, part 1 of the IED)

▪ From 2031 onwards, the CM benefits over the EOM are lower but remain slightly positive on average as the CM benefits from lower financing costs.

The strategic reserve is therefore expected to be less cost-efficient for Polish consumers to meet the security of supply criterion. Overall, the CM leads to a total saving of over € 8 billion over 2017-2040 (assuming a VOLL at €18,000/MWh) corresponding to an average of € 350 million per year.

Considering social welfare, the CM also outperforms the Polish strategic reserve. The increased savings for consumers in the CM scenario as compared to the strategic reserve more than compensate the increase in capacity provider cost, which is higher in the CM scenario than in the strategic reserve.

Figure 3-26 illustrates the additional social welfare that is achieved in the CM scenario in comparison to the Polish strategic reserve.
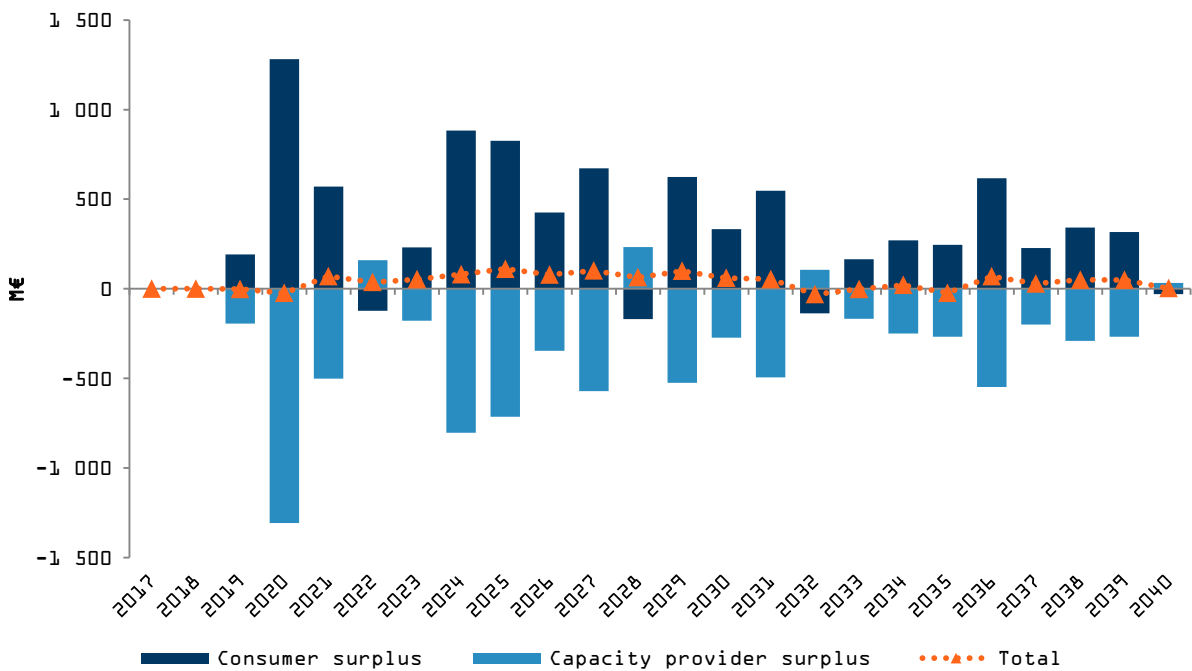
Figure 3-26: Additional social welfare per year (consumer and capacity provider surplus) in CM scenario as compared to Polish strategic reserve (million €$_{2016}$)

Source: Compass Lexecon, 2017

Notes: The figure presents the difference in surplus between the CM and the Polish SR scenarios. The consumer surplus corresponds to the net consumer cost or saving as presented in the previous figure. It takes into account unserved energy, energy, capacity costs and interconnection rent. The capacity provider surplus takes into account energy and capacity revenues as well as financing costs

Throughout the whole modelling horizon, the CM leads to a net gain of € 950 million, corresponding to an average of € 39 million per year.

4. Modelling of the impact of a 550gCO$_2$/kWh emissions cap on the Polish capacity market

4.1 INTRODUCTION

The objective of this section is to quantify the impacts of the introduction of the EU wide emission caps to the capacity market on the Polish energy markets and more generally on the European power systems.

We first describe the proposition of the introduction of an emission cap in capacity markets by the European Commission[37]. Then, we present the results of our simulations of the impact of the introduction of the EU wide emission caps in the Polish capacity market, according to the evaluation criteria that we have defined previously.

4.2 PROPOSED INTRODUCTION OF AN EMISSIONS CAP IN CAPACITY MECHANISMS

With a main focus on decarbonisation and further construction of a European internal energy market, the EC Electricity Market Regulation proposal[38] outlines the generation resources that are eligible for remuneration of capacity mechanisms in the legislative proposal of regulation on the Internal Market for Electricity that is expected to become effective early 2020.

The EC proposes to introduce an emissions performance standard (EPS) (550 EPS), which would ultimately exclude coal, lignite and some peaking plants emitting more than 550gCO2/kWhfrom participating in capacity mechanisms.
According to the proposal, existing generation capacity emitting 550gCO$_2$/kWh or more shall not be allowed to participate in the capacity mechanism five years after the entry into force of the 550 EPS and new generation capacity that does not meet the emission standard is excluded from capacity remuneration immediately after the implementation of the 550 EPS.

The 550 EPS would have a significant impact on the Polish power market, as a large amount of existing coal- and lignite-fired power plants is not able to meet the emission requirement. The

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[37] European Commission (2017), Clean Energy Package – Commission proposes new rules for consumer centred clean energy transition.

[38] European Commission (2016), COM(2016) 861 final/2, Proposal for a Regulation of the European Parliament and of the Council on the internal market for electricity (recast), Brussels, 23.2.2017

implementation of 550 EPS would imply exclusion for these plants from the participation in the capacity market in Poland and a reduction in incentives for investment in new coal and lignite plants.

4.3 POTENTIAL EFFECTS OF THE 550 EPS ON DECARBONISATION AND SECURITY OF SUPPLY

According to economy theory, it is best to address different market failures / externalities associated with security of supply or environmental issues via distinct policy instruments. It is therefore preferable to separate the policy measures intended for security of supply, such as capacity mechanisms, from the policy measures that target environmental issues and decarbonisation, such as EU cap-and-trade mechanism. **Using one tool (the EPS in capacity mechanism) for addressing both security of supply and decarbonisation will likely produce a less efficient outcome and increase the cost of achieving each of these policy objectives compared using distinct instruments, such as an unconstrained capacity mechanism and an adequate carbon price signal.**

In practice, the 550 EPS could increase the cost of guaranteeing security of supply in Poland whilst meeting the Polish decarbonisation targets, by deviating from the lowest-cost transition path towards decarbonisation of the Polish generation mix whilst maintaining security of supply. Indeed, the optimal exit time of coal plants needs to weigh in two effects, namely the environmental costs of operating coal plants, and the net benefits of maintaining those plants to ensure the security of supply. The modelling presented in this section provides more explanations of the underlying dynamics at play in the evolution of the Polish generation mix and quantifies this potential negative effect of the 550 EPS.

In addition, the 550 EPS overlaps with the EU ETS, possibly leading to inefficient outcome for EU decarbonisation unless the ETS is reformed. Indeed, the 550 EPS is unlikely to reduce emissions at the EU level unless the ETS cap is adjusted. The European Union's emissions 2020 and 2030 targets entail an annual cap on greenhouse gas emissions with a fixed number of allowances supplied in the ETS market each year. The carbon price at the market clearing equilibrium is achieved by balancing the supply and demand of the emission allowances. Preventing coal and lignite plants to participate in the capacity market, the 550 EPS would possibly force existing coal and lignite plants out of the energy market before the end of their economic lifetime; this implies a reduction in demand for allowances from the power sector if these plants are replaced by resources which emit less. At the new equilibrium, the EU wide emission level may not change significantly, as the increase in emissions from other sectors could offset the reduction in the power sector.

In addition, the potentially lower carbon prices that could result from the decreased demand for allowances could have side effects on investment decisions in the power sector as well as other sectors covered by the ETS. The complexity of the interference between the 550 EPS and the ETS therefore requires further research and discussion on the possible unintended consequences. As mentioned previously, economic theory indicates that overlapping policy measures and market mechanisms should be avoided or at least carefully engineered to avoid undermining the effectiveness of the EU ETS market and emissions reduction effort. **In order neutralize the negative effects on the ETS, any overlapping policy such as the 550 EPS should be associated with a re-adjustment of the ETS cap, and/or by the intake rate of the MSR and the cancellation of permits from the market.**

Finally, the 550 EPS could raise a number of issues with regard to security of energy supply in Poland and other countries beyond the electricity sector, by increasing significantly gas consumption and gas import dependency, and requiring significant investments in gas network infrastructure. The significant increase in consumption from gas plants would indeed require adequate investment to develop the gas network in the region.

The modelling presented in the rest of this section aims to provide some quantification of the potential effects of the 550 EPS implementation in Poland on the evolution of the Polish electricity system, and therefore on key indicators for both emissions and security of energy supplies.

4.4 DESCRIPTION OF THE MODELLING APPROACH

In order to model the effect of the 550 EPS on the Polish power market, we take into account the capacity obligation defined to respect the reliability standard in Poland and the capacity market design. We compare the assessment criteria between the following two scenarios:

- **CM Reference scenario**: the CM model as described previously. In the CM without the implementation of the 550 EPS, all market participants eligible to bid receive capacity payment. Therefore, their mothballing, operational, and investment decisions are made based on the expected future cash flows accounting for both energy and capacity revenues. As described above, in the optimisation, the capacity obligation defined to respect the reliability standard set by the government has to be met.
- **550 EPS scenario:** we consider ineligible coal or lignite plants to be treated in our model as in the EOM. Eligible plants would be treated as in the CM. Existing lignite and coal plants can receive a capacity payment up to 2024 according to the rule of the regulation, while new coal

and lignite plants will receive no capacity payment and have to rely on energy and ancillary service revenues to be economically viable. Optimization would take into account the economic profitability of thermal technologies and the reliability standard depending on the eligibility of the thermal plants.
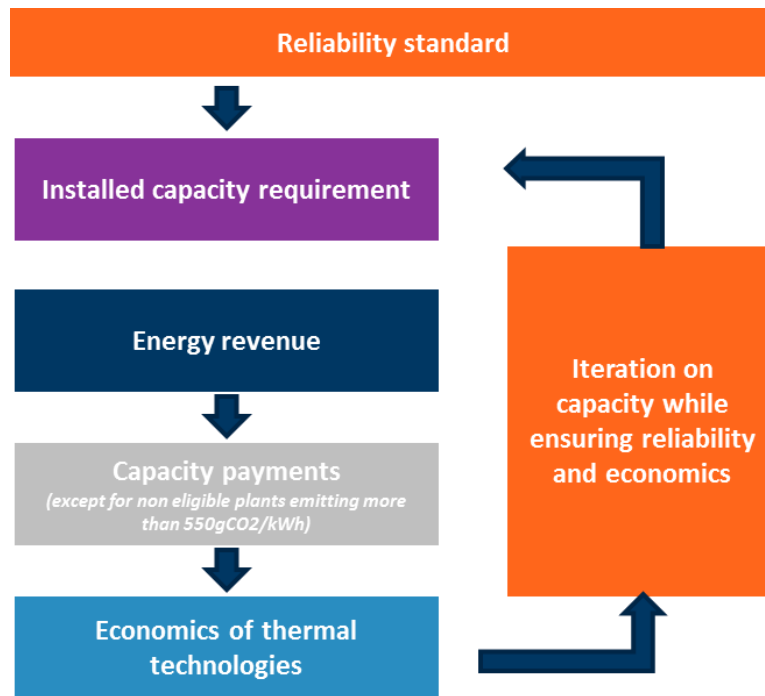
Figure 4-1: Modelling iterations in CM with 550 EPS design

Source: Compass Lexecon, 2017

More precisely, we iterate the modelling with the following constraints until the generation capacity mix equilibrium is reached:

- The net energy and ancillary services revenues of existing plants with no reinvestment plans for operating life extension need to cover their fixed operation and maintenance costs;

- The net energy and ancillary services revenues of existing plants that reinvest to comply with BAT conclusions and additional retrofit CAPEX need to cover both their fixed O&M costs and annualised capital costs; and

- The net energy and ancillary services revenues of new plants need to cover both fixed operation and maintenance costs and capital costs of investment.

4.5 COMPARISON OF THE POLISH CM WITH THE 550 EPS AND CM DESIGNS

Impact on security of supply and on the generation mix

Impact on security of supply

Since the Polish CM remunerates capacity providers to ensure a de-rated capacity margin of 14% above peak demand, capacity adequacy would be maintained and the reliability standard of 3 hours of LOLE is still met in the 550 EPS scenario.
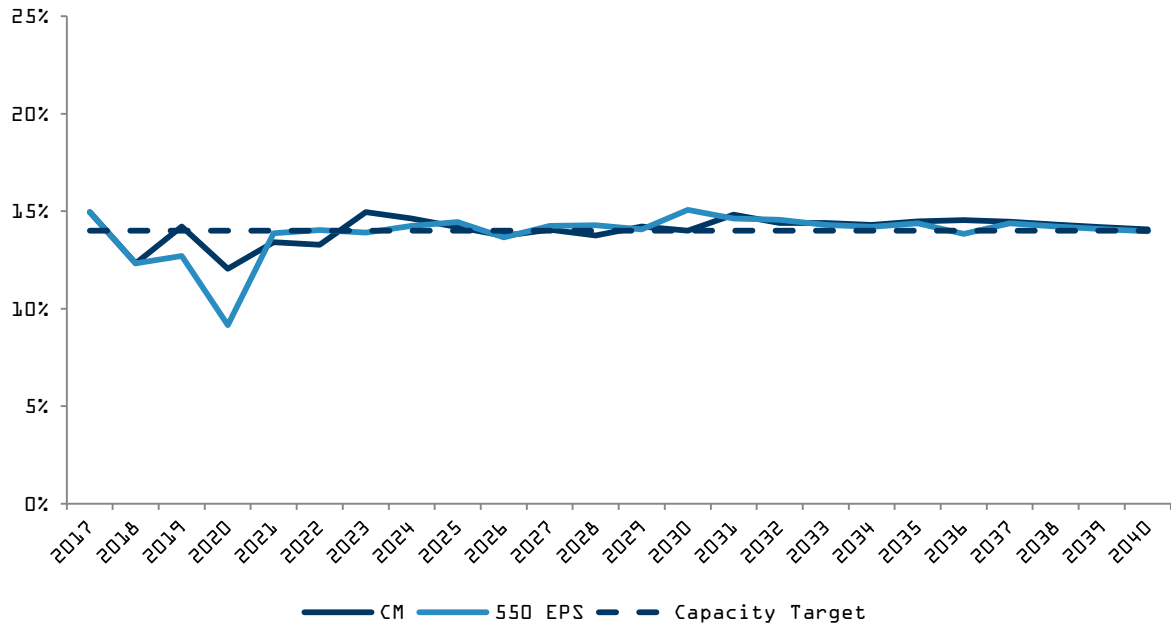
Figure 4-2: Annual de-rated capacity margin in the 550 EPS and CM scenarios (%)

Source: Compass Lexecon, 2017

Notes: The de-rated capacity margin is defined as the ratio between the additional de-rated capacity available (including DSR and interconnection capacities) above the net average cold spell peak demand (excluding auxiliary demand).

Impact on the generation mix

In Poland, generation technologies emitting more than 550gCO$_2$/kWh are mainly coal and lignite. The introduction of the 550 EPS as required by the EC would therefore have a direct impact on the generation capacity mix as compared to the envisaged CM design.

Anticipating the non-eligibility of the existing coal and lignite plants to receive capacity remuneration from 2024 onwards, some existing plants close before 2021 and investment in new build coal capacity is not profitable enough to be carried out as in the CM scenario since it would rely only on energy and ancillary revenues to recover investment and fixed O&M costs. New CCGT capacity is needed as early as 2021 to offset the early closure of existing coal plants and zero new build coal capacity.

The difference between the CM and 550 EPS scenarios in terms of installed generation capacity is shown in Figure 4-3.
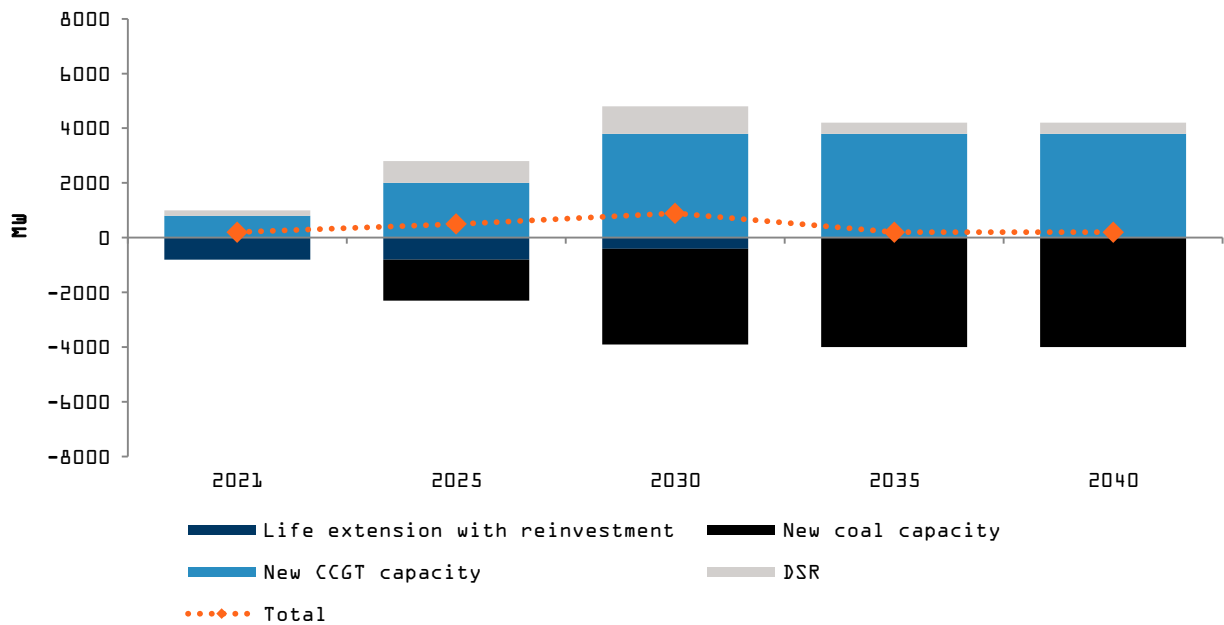
Figure 4-3: Difference in installed generation capacity between the 550 EPS and CM scenarios (MW)

Source: Compass Lexecon, 2017

Notes: The total capacity of 550 EPS is higher than CM because of higher DSR capacity in 550 EPS, which is de-rated at 40%.

In the medium to long term, 4GW of coal-fired capacity are not built by 2040 in the 550 EPS scenario in comparison to the envisaged CM design. They are replaced by an equivalent capacity of new CCGTs and DSR, which is developed earlier and reaches a slightly higher level, stimulated by higher capacity prices.

Impact on gas consumption

As a result of the introduction of the 550 EPS in the CM, Poland would build much more CCGTs before and during the 2030' s in the 550 EPS scenario than in the envisaged CM scenario. As shown in Figure 4-4, this would lead to a significant increase in the country' s gas consumption for electricity generation.
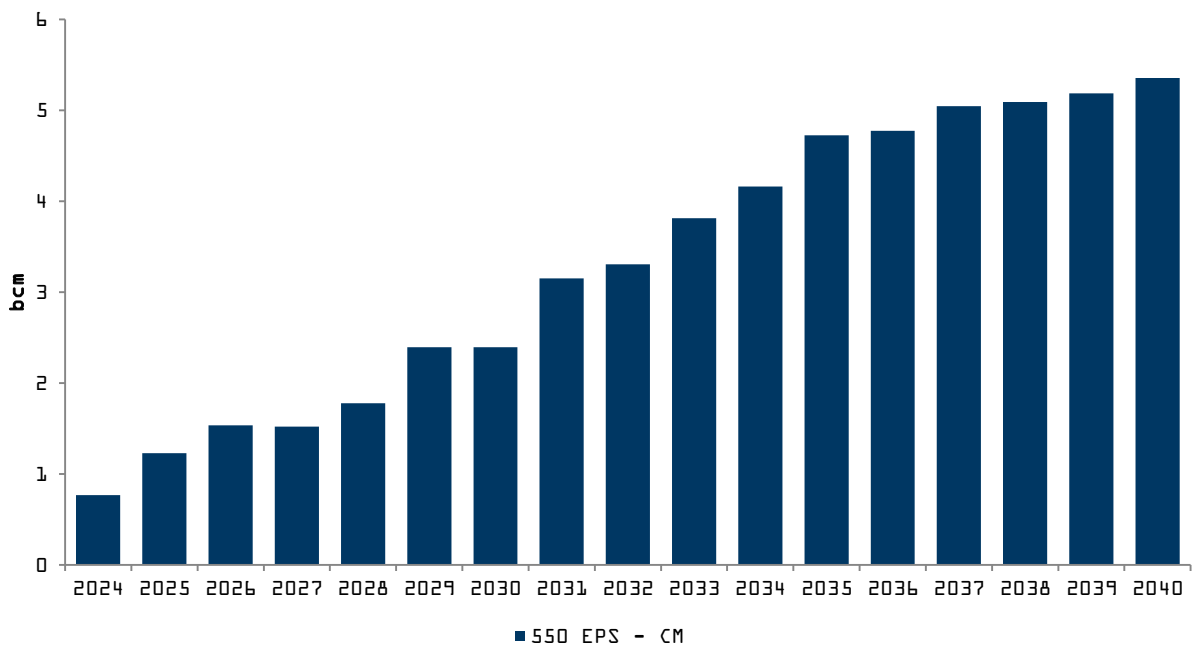
Figure 4-4: Additional gas consumption in the 550 EPS scenario compared to the CM scenario (bcm)

Source: Compass Lexecon, 2017

While in the 550 EPS scenario new CCGT plants are needed already in the short term to ensure that the capacity target is met. New CCGT plants are built from 2021 onwards. This is in contrast to the CM and EOM scenarios in which new CCGT plants are built from 2031 onwards, as soon as they become more economic than coal plants. The 550 EPS scenario leads to significantly higher demand for gas supply. Within the modelling horizon, gas consumption would be about 60bcm higher than in the CM scenario, amounting to a 70% increase.

The additional gas consumption would lead to higher gas imports to Poland, raising questions of necessary investments in the Polish gas network, the ability of the gas network to cope with such additional needs, and higher dependency on imports and the possible impact on gas security of supply. To put the questions into perspective:

▪ The current level of annual gas consumption in Poland is around 18bcm per year, while the development of a new CCGT plant in the CM scenario requires additional gas consumption of around 11bcm per year by 2040, equivalently a 60% increase of the current level.

▪ On top of that, the 550 EPS alone would introduce an additional increase of 5bcm per year 2040, an additional 30% increase compared to the current level.

The higher need for gas for electricity generation raises several questions and challenges. In particular, the Polish gas network in its current configuration may not be able to cope with such

additional need. The necessary investments to reinforce and extend the gas transmission infrastructure could have substantial cost implications for the Polish consumers which are not factored in our modelling exercise but would need to be taken into account in a complete cost benefit analysis. Furthermore, the additional gas need is likely to have an impact on the gas security of supply in Poland. In case no sufficient LNG infrastructure is developed in the country, it may increase its dependency on gas imports from large producing countries like Russia.

Impact on costs and welfare

Similarly to the CM and EOM scenarios, the 550 EPS' impact is estimated in terms of costs and benefits for both consumers and capacity providers, resulting in an overall lowered social welfare.

Impact on energy cost

The 550 EPS would require new CCGTs to enter the market to replace coal plants. As CCGTs have a higher SRMC – at least during the period of analysis – average power prices in the 550 EPS scenario are higher than in the CM scenario by about €1/MWh on average (Figure 4-5).
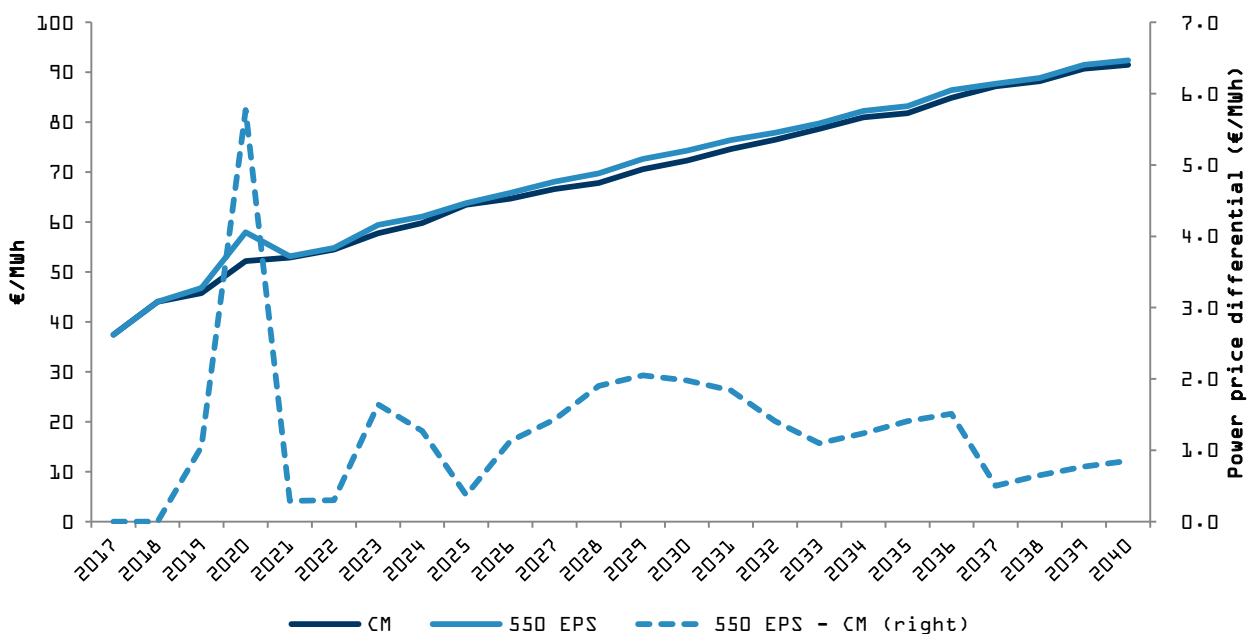
Figure 4-5: Annual average power prices in the CM and 550 EPS scenarios, and difference between 550 EPS and CM scenarios (€2016/MWh)

Source: Compass Lexecon, 2017

Notes: The price difference is calculated as the 550 EPS price minus the CM price. Its scale is based on the axis on the right.

As a result of the 550 EPS, the evolution of the capacity price in the 550 EPS scenario is mainly driven by the missing money from new build CCGT plants, as presented in Figure 4-6. Without capacity revenue, new coal plants are not built during the whole modelling horizon due to insufficient profitability and high market risks.
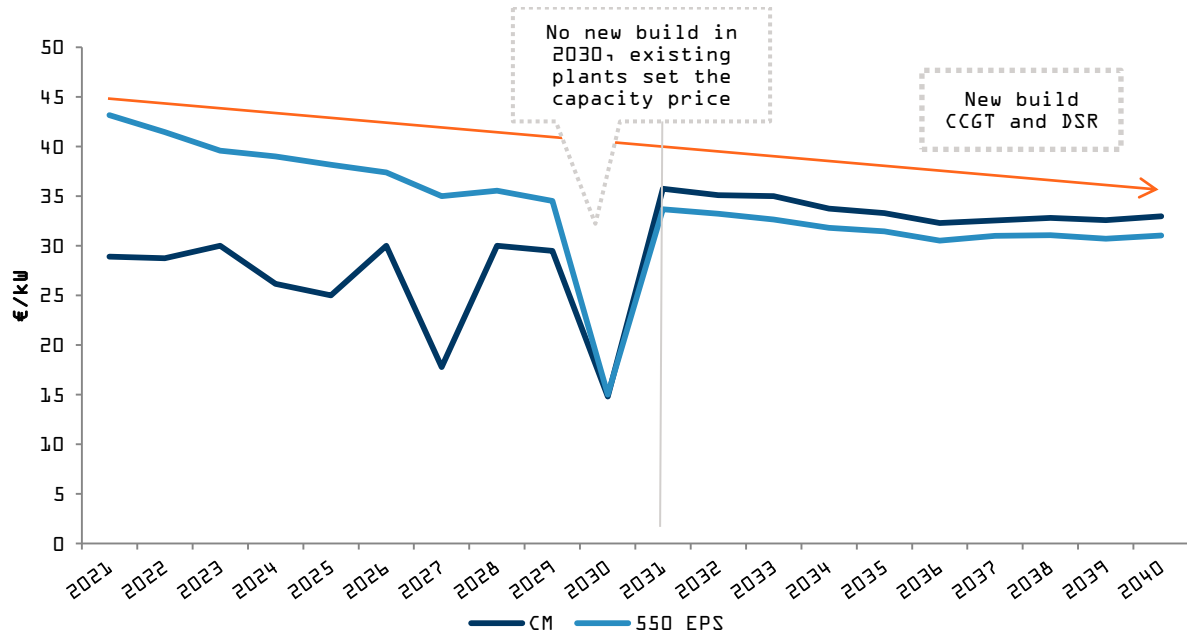
Figure 4-6: Capacity price in the 550 EPS scenario (€$_{2016}$/kW)

Source: Compass Lexecon, 2017

Up to 2030, the capacity price in the 550 EPS scenario is higher than in the CM scenario as a result of the larger investment costs of CCGT plants to be recovered through capacity revenues, compared to coal plants developed instead in the CM scenario. However, the increase in capacity prices in this period is compensated by the fact that from 2024, existing coal plants are no longer remunerated for capacity.

In the 2030s, the capacity price stabilises at a slightly lower level than in the CM as the price is set, in the CM and the 550 EPS scenarios, by CCGTs, but energy market's revenues of CCGTs are higher in the 550 EPS scenario due to higher energy prices.

Impact on total consumer costs

As shown in Figure 4-7, the 550 EPS increases costs for consumers despite the reduction in capacity costs due to the fact that all capacities no longer receive capacity payments. The introduction of the emission cap induces a net cost for Polish consumers of € 240 million over the period assuming a VOLL of € 18,000/MWh, i.e., € 10 million per year, as compared to the CM scenario.
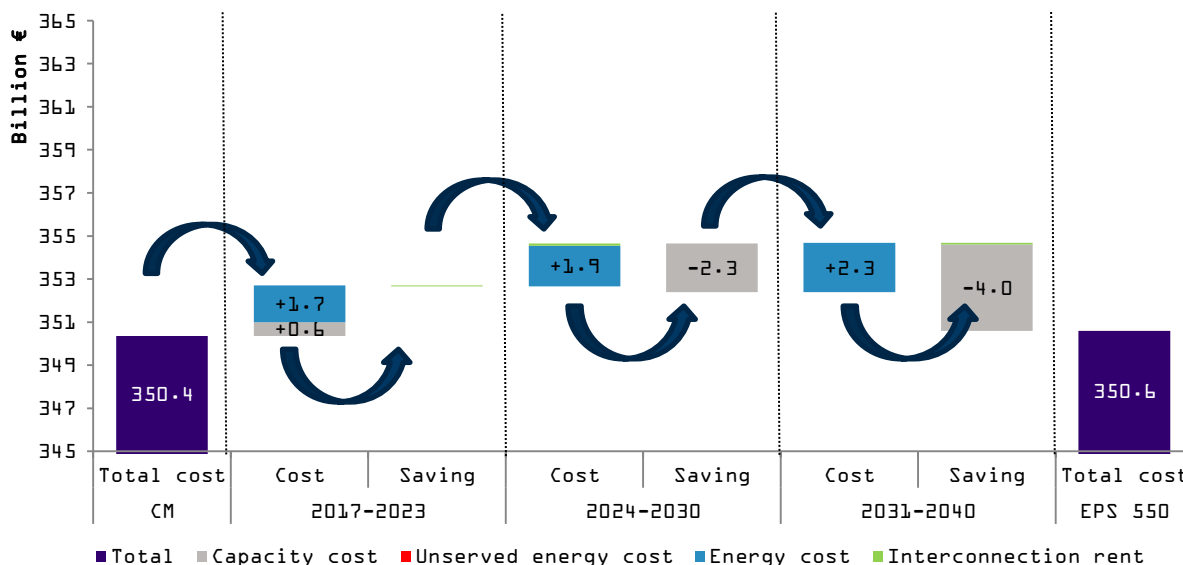
Figure 4-7: Comparison of costs to Polish consumers in the CM and the 550 EPS scenario (billion €$_{2016}$)

Source: Compass Lexecon, 2017

Notes: 550 EPS refers to the scenario of the implementation of 550 EPS on top of the CM. The figure compares the costs to Polish consumers in the SR and in the CM and shows the variations between the two scenarios in three periods. A plus sign means an increase and a minus sign means a decrease in costs to consumers. We attribute the difference in interconnection rent between CM and EPS 550 to consumer costs or savings because it is a result of the reduction in power prices and in financing and investment costs in the CM, which leads to lower congestion rent. This lower congestion rent for interconnectors introduces a cost for consumers. The cost to Polish consumers in the CM is lower than that in the EPS 550, representing a saving of the CM.

The introduction of an emission cap of 550gCO2/kWh in the CM results in less refurbishment of the existing plants and the construction of more CCGTs that completely replaces new coal plants, although these new coal plants would be more profitable before 2031 without this measure in the short to medium term.

- In the short term (2017-2024), the CM leads to a lower cost than the CM with the 550 EPS measure.

- In the medium term, (2024-2031), the CM leads to higher cost, decreasing to zero.

- In the long term (2032-onwards), the CM leads to higher cost than the 550 EPS partially offsetting the initial savings.

The consequences of introducing an emissions cap in the CM are small in terms of consumer costs as the reduction in capacity costs partly compensates the power price increase and the

difference in capacity prices. However, its implementation still induces a net cost for Polish consumers.

Impact on social welfare

Overall, CM outperforms 550 EPS in terms of social welfare, leading to a net gain of € 980 million between 2017 and 2040, or around € 40 million per year. Figure 4-8 presents the additional welfare created in the CM scenario compared to the 550 EPS scenario.
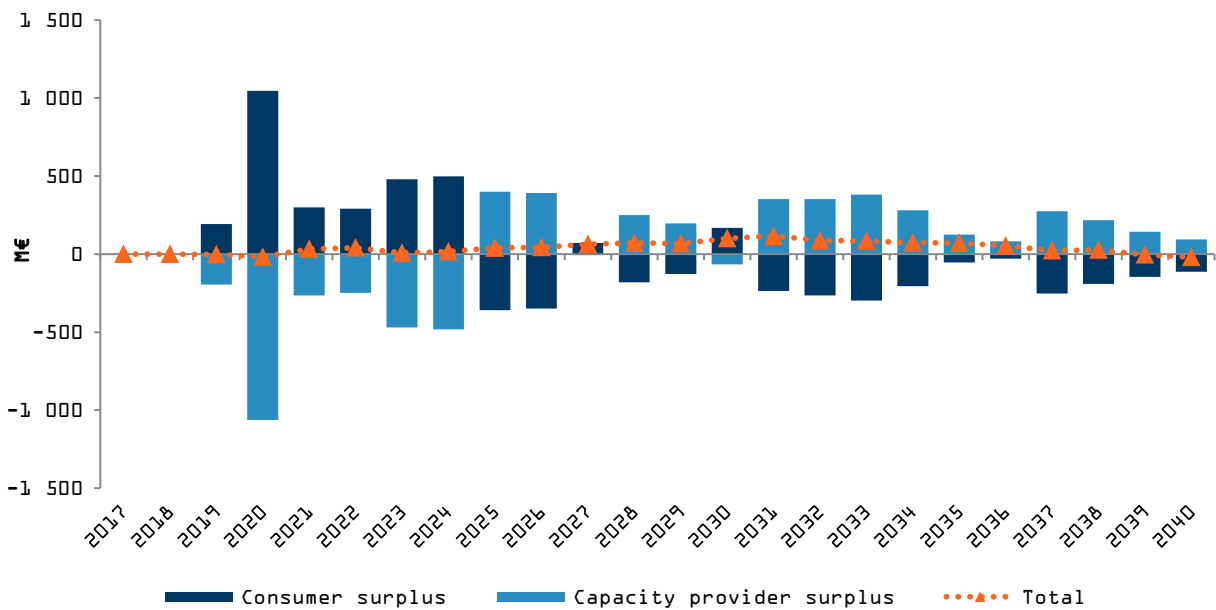
Figure 4-8: Additional social welfare (consumer and capacity provider surplus) in CM scenario as compared to 550 EPS (billion €$_{2016}$)

Source: Compass Lexecon, 2017

Notes: The figure presents the difference in surplus between the CM and EPS 550 scenarios. The consumer surplus corresponds to the net consumer cost or saving as presented in the previous figure. It takes into account unserved energy, energy, capacity costs and interconnection rent. The capacity provider surplus takes into account energy and capacity revenues as well as financing costs. The total additional social welfare in CM is mostly positive compared to 550 EPS, except for 2019-2020, and 2039-2040.

From 2024 onwards, the CM scenario leads to savings in terms of total social costs as both long-term consumers' and capacity providers' surplus become more significant than in the 550 EPS scenario. It has to be borne in mind that the assessment of consumer and social costs is done without considering the need of gas supply in Poland with the implementation of the EU 550 EPS.

In addition to the impact on consumer and social costs, the 550 EPS scenario increases the gas import dependency of Poland from other countries and triggers a displacement of potential domestic coal capacity with imported gas capacity. Consequently, significant investment would

have to be made in developing the gas network in the region in order to ensure security of supply of gas and continuous investment in CCGT plants.

Impact on the energy market functioning and on cross-border exchanges

As shown previously, the change in the generation mix induced by the introduction of the emissions cap of 550gCO2/kWh leads to an average increase of €1/MWh in energy market prices as compared to the CM scenario.

The introduction of the emissions cap of 550gCO2/kWh in the CM has a significant impact on the Polish net export flows in the long run, but its impact in the short and medium term is very limited. In the short and medium term, because the 550 EPS price is close to the EOM price, export balance in the 550 EPS scenario does not significantly defer from that in the EOM scenario. In the long run, more efficient generation and DSR assets are built and CCGTs become the baseload technology along with decommissioning of all existing coal and lignite plants in the Polish power market. The 550 EPS scenario significantly increases exports to neighbouring countries in the long run.

Impact on CO2 emissions and decarbonisation cost

The 550 EPS lowers the Polish domestic CO2 emissions related to electricity generation. However, it leads to a higher decarbonisation cost than in the CM scenario as carbon abatement is not carried out in the most efficient way.

Compared to CM and EOM, 550 EPS effectively reduces domestic CO2 emissions from electricity generation in Poland. As CCGT new builds gradually replace existing coal plants or substitute coal new build, the differential in domestic emissions from power generation is reduced by about 54 million tCO2 between 2020 and 2040 (a reduction of 39%), 11 million tCO2 higher than in CM and EOM – this is less than 10% of annual emissions in the PPS.
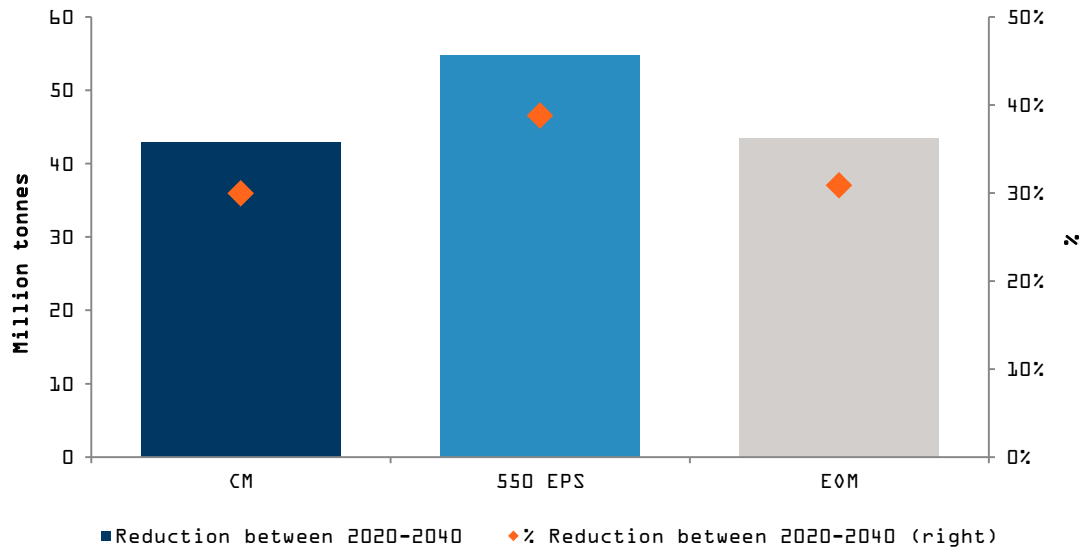
Figure 4-9: CO2 emission reduction from electricity generation in EOM, CM and 550 EPS scenarios between 2020 and 2040 (million tCO2)

Source: Compass Lexecon, 2017

However, assuming no change to the ETS cap or MSR, total emissions in Europe are not reduced through the Polish emissions cap as additional CO2 emission reductions[39] from its power system are offset by a lower decarbonisation effort in other sectors or countries (c.f. discussion earlier in this section).

The 550 EPS scenario therefore leads to decarbonisation at an implicit carbon cost higher than the ETS market price. The premium in the CO2 abatement costs in the 550 EPS scenario over the EU ETS price, as shown in Figure 4-10, is computed as the ratio of annual additional costs of 550 EPS over CM (total costs, i.e. difference in social surplus) over the saved CO2 emissions in the Polish power system between the 550 EPS and CM scenarios. Over the whole modelling period, the additional CO_2 abatement cost on top of the EU ETS is in the order of €5/tonne.

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[39]   Emissions are not reduced in comparative terms, with respect to the annual reduction of allowances in line the Linear Reduction Factor (LRF) defined by the European Commission. Assuming no change to the ETS cap or MSR is hypothetical. Further reforms of the EC in the EU ETS market are highly likely to reinforce the needed effort for emission reduction and to enhance the efficiency of the EU ETS market.
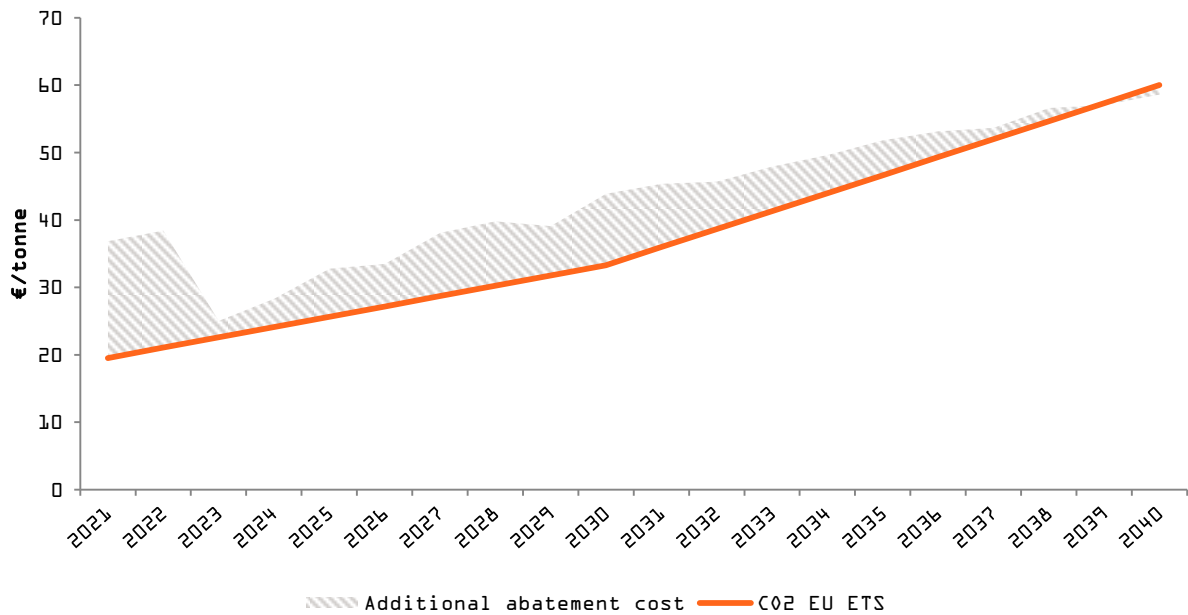
Figure 4-10: Additional CO_2 abatement costs on top of the EU ETS ($€_{2016}$/tCO_2)

Source: Compass Lexecon, 2017

Our quantification of the effects of the 550 EPS need to be compared with caution with those of the study done by E3M-Lab[40]. Indeed, the modelling approach and methodology differ significantly. The E3M-Lab study does not model the impact of a CM or 550 EPS, nor it assumes its existence, but it models instead the impact of a subsidy (Contract for Difference) limited to coal and lignite plants. However, the CM envisaged in Poland is not a subsidy specific to coal and lignite plants, but applies to all eligible technologies, including CCGTs, DSR etc. Conversely, the 550 EPS creates a difference of treatment which favours technologies other than coal and lignite, beyond the impact of the EU ETS, but this is not what the E3M-Lab study aims to assess.

As a result, the E3M-Lab study cannot be used as a basis to assess the efficiency of the 550 EPS and its findings should be compared with our study results with great care. Indeed, the coal/lignite subsidy assessed by E3M-Lab in Poland, Romania, Greece and Estonia would mainly displace gas-firing generation. The coal and lignite support would encourage investment in new build coal, resulting in different mix, price levels and significantly higher emission levels than those of the 550 EPS scenario of our study. As a result, the E3M-Lab study finds an increase in CO2 emissions by nearly 20% in the four countries modelled beyond 2030, in comparison to a 1% increase EU-wide in our results. Furthermore, the E3M-Lab study finds higher long-term electricity price by €2-5/MWh for consumers in 2030, whilst we find a moderate net cost impact on consumer

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[40]   E3M-Lab (June 2017), Modelling study contributing to the Impact Assessment of the European Commission of the Electricity Market Design Initiative.

prices as the reduction in capacity costs partly compensates the power price increase and the difference in capacity prices.

5. Comparison of the impact on the Polish capacity market with other public policies implemented in Europe

5.1 INTRODUCTION

The previous sections show that the CM achieves its objective of ensuring security of supply in Poland, while reducing the costs for consumers and enhancing social welfare. On the other hand, such benefits require the capacity mix to adapt, which results in higher exports and fewer price spikes (and less load shedding). In this section, we compare these impacts with those of other policy interventions, in order to put them into perspective and assess their relative magnitude. The objective of this section is to contribute to the European policy debate by providing quantitative estimates of the impacts of different policy interventions in electricity markets, but not to evaluate these policies with regard to their objectives.

As part of their national energy policy objectives and responsibilities, Member States put in place policies which can lead to changes in the volume of available capacity. These policy interventions are legitimate in order to achieve the national policy objectives (either for security of supply or support to specific technologies). CMs are one of these many public policy interventions which can be implemented by the Member States in the energy sector.

It is important to distinguish between an impact and a distortion when it comes to public policy interventions. The EC wants to avoid public policy interventions introducing distortions which could affect the internal electricity market, but there is often a lack of robust quantitative analysis. Policy interventions having an impact on energy markets are not equivalent to market distortion. In the contrary, these measures should lead to greater available capacity to achieve the goal of ensuring security of supply. Policies aiming to meet environmental objectives should lead to a higher share of renewable energy or decarbonisation. In both cases, it is logical that the changes of the generation mix and of demand management resulting from the governmental interventions would influence power markets, such as power prices.

In this comparative analysis, we have assessed the following three policy interventions:

- **Limited Loop flows**[41]: substantial unscheduled flows (loop flows) between Germany, Czech Republic and Slovakia going through Poland force system operators to reduce Net transfer capacities (NTC) available to cross-border trade in order to ensure transmission system stability and security. In the alternative case, we consider a scenario with limited loop flows, which allow available NTC to be higher from and to Poland, which could be facilitated by a range of policy measures that encourage market integration, TSO cooperation, and integration of grid development.

- **The German Strategic Reserve**: this is composed of a capacity reserve which targets security of supply and a climate reserve which aims to reduce CO2 emissions (up to 2.7 GW of lignite power to be retired from the energy market) while contributing to security of supply. In the counterfactual case, we assume that lignite plants are not retired and remain operational beyond the modelling horizon. We assume a perfect design for the capacity reserve, which thus does not affect the energy market and our focus is therefore on the impact of the climate reserve.

- **Policy support to renewable generation in Germany**: the Renewable Energy Act (EEG) came into force in 2012 to support a stronger growth of renewable energy sources (RES). In the counterfactual case, a lower RES development scenario is considered, based on the expected development of RES prior to the EEG.

It is worth noticing that the objectives pursued by the schemes vary and differ from the Polish CM. However, reducing network constraints, security of supply or decarbonisation are key policy objectives in the European energy strategy. The determination of its energy mix also remains a national prerogative in Europe. Any comparison of the effects should therefore be interpreted with caution, but the assessment in this section gives an interesting comparison to grasp what impact magnitude was deemed acceptable or not. Our modelling shows that the CM has a comparable or smaller impact on the electricity market than a range of other regulatory or policy interventions introduced in Europe.

5.2 PRESENTATION OF THE SCENARIOS FOR THE THREE POLICY SCHEMES

Loop flows in Poland

Presentation of the specific issue

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[41] Loop flows are not a policy intervention as such, but the result of various factors and measures.

Poland faces a specific issue of loop flows resulting from the unscheduled flows across the common German-Austrian bidding zone that mainly impacts Poland and Czech Republic.[42]

The substantial amount of loop flows in Poland is a consequence of the unbalanced demand and supply distribution in the common German-Austrian bidding zone: the most economical generation capacity is located in Northern and Western Germany while the consumption centre is located in Central and South-Eastern Germany as well as Austria. Imbalances between supply and load are often observed among others in the German-Austrian common bidding zone. These imbalances are exacerbated by the rapid growth of wind power generation in Northern Germany and solar PV in Southern Germany.

Furthermore, commercial transactions within Germany and between Germany and Austria are not subject to coordinated cross-border capacity allocation, since both countries are part of the same bidding zone. This market design therefore makes scheduled exchanges on the German-Austrian interconnection implicitly prioritised over other cross-border flows in the Central Eastern European (CEE) region.[43]

Commercial exchanges within the German-Austrian common bidding zone – both within Germany and between Germany and Austria – not only go through transmission lines internal to the bidding zone, but also through the transmission network of neighbouring bidding zones. Such a situation leads to unscheduled flows on the neighbouring, especially Polish and Czech, electric systems.

Figure 5-1 illustrates the paths and average volume of unscheduled flows in Central Eastern Europe (CEE) in 2015. Since the early 2010' s, there has been a strong and continuous increase in unscheduled flows in the Polish electric system, which increased by 53%, 127% and 38% at the German-Polish, Polish-Slovakian and Polish-Czech borders, between 2012 and 2015.

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[42] ACER/CEER Market Monitoring Report 2015

[43] Uncoordinated capacity allocation procedure on the German-Austrian border:
http://www.acer.europa.eu/Media/News/Pages/ACER-Opinion-No-09-2015.aspx
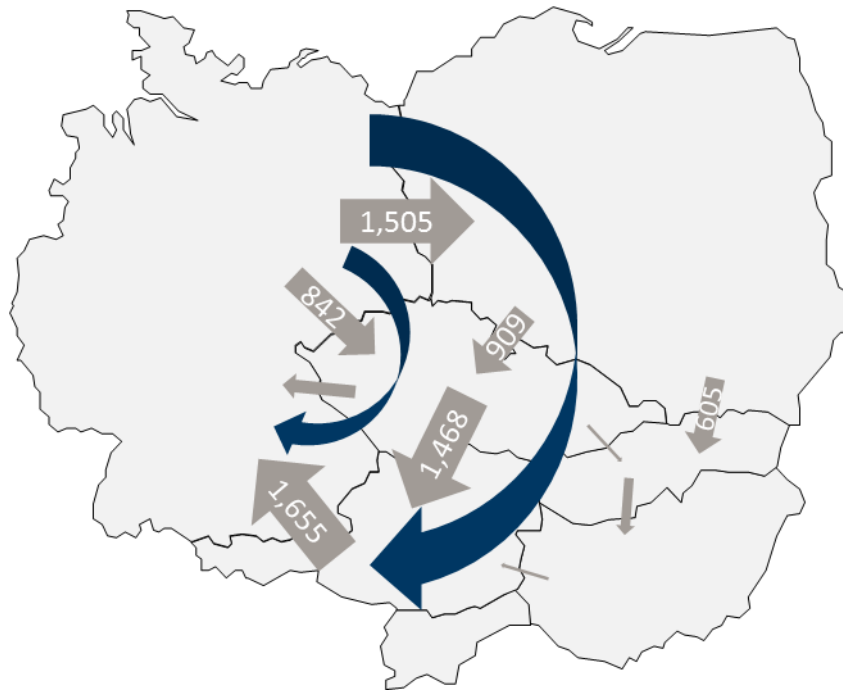
Figure 5-1: Average unscheduled flows in Central Eastern Europe in 2015 (MW)

Source: Compass Lexecon based on ACER/CEER Market Monitoring Report 2015 (p.31)

Notes: (1) Average unscheduled flows correspond to average hourly values; (2) The grey and dark blue arrows depict the commercial flows and major unscheduled flows, respectively; (3) Other values not presented in the figure are 39MW between Czech-Slovakia, 255MW between Slovakia-Hungary, 152MW between Hungary-Austria, 410MW between Czech-South Germany.

Since 2012, the Polish TSO significantly has reduced the NTC between Poland and its neighbouring countries. To account for the unscheduled flows and their uncertainty and avoid overloads and security issues, TSOs increase the de-rated capacity margin adapted to reduced total transfer capacity at a given interconnection, causing loss of social welfare at the regional level. For example, between 2012 and 2015, NTCs on the DE-PL border are usually set at 0MW to accommodate the unscheduled flows.
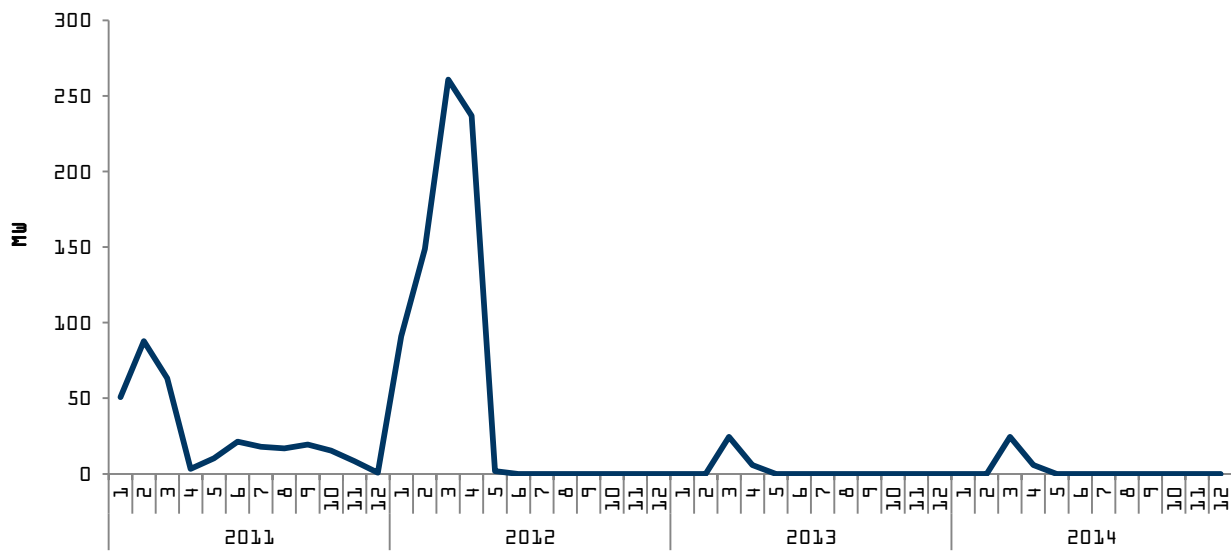
Figure 5-2: Change in average monthly net transfer capacity from Germany to Poland between 2012 and 2015

Source: Compass Lexecon based on ENTSO-E data

Notes: Average monthly net transfer capacities correspond to monthly averages of hourly values.

Several main factors could contribute to the increasing phenomenon of unscheduled flows on the Polish border:

- **Insufficient price signals**, which correspond to market prices not being able to correctly reflect the real-time physical situation of the grid infrastructure and to account for internal congestions within bidding zones;

- **Increased energy imbalances**, which result from the ongoing reconfiguration of supply and load in electric systems transiting to a low carbon economy; and

- **The impact of the increasing penetration of variable renewable energy sources** in Germany triggers congestion on internal lines of the common German-Austria bidding zone and therefore reinforces the phenomenon of unscheduled flows in the CEE region.

The factors identified above have primarily contributed to the increase in volume as well as to the volatility of unscheduled flows in the Polish electric system since the early 2010s.

For simplicity, we measure unscheduled flows as the difference between physical flows and schedules resulting from commercial trade. The figures below illustrate the change in average unscheduled flows at the two Polish borders mainly impacted by this phenomenon, i.e., the German-Polish and the Polish-Czech borders.
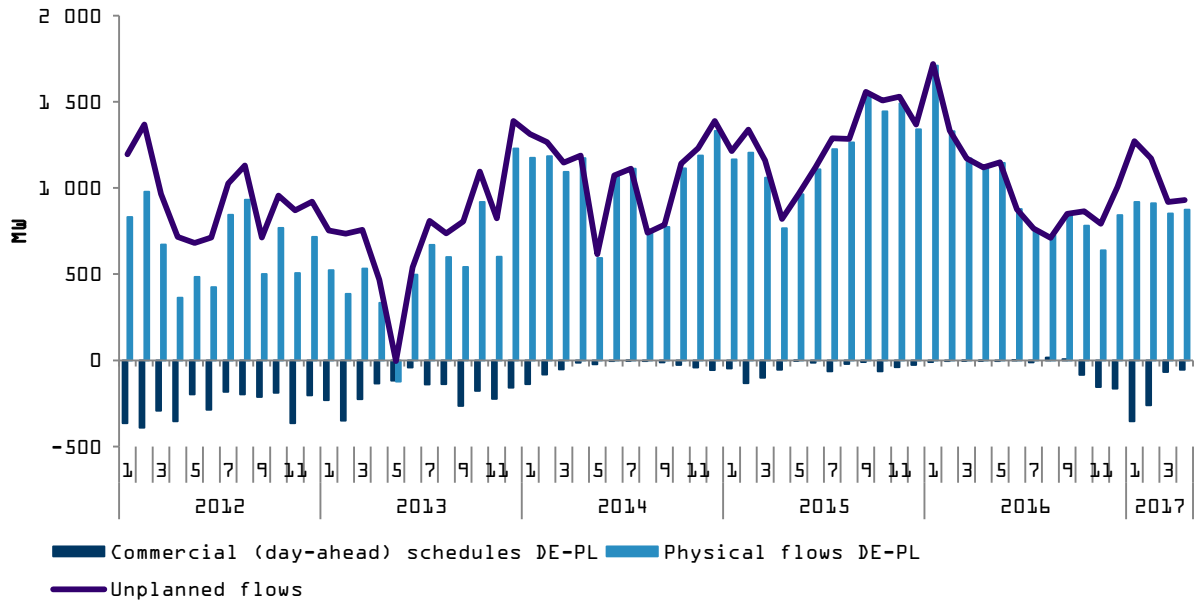
Figure 5-3: Change in average unscheduled flows on the German-Polish border between 2012 and April 2017

Source: Compass Lexecon based on ENTSO-E data

Notes: (1) Average volumes of unscheduled flows correspond to monthly averages of hourly values; (2) Positive values correspond to flows from Germany to Poland, while negative values correspond to flows from Poland to Germany.

On the German-Polish border, scheduled and physical flows go in opposite directions – Poland being a net exporter to Germany in all months of the period considered but experiencing substantial real-time physical flows from Germany. Furthermore, they strongly deviate in magnitude, peaking at the end of 2015 and beginning of 2016. In terms of absolute average flows over 2012-2017, unscheduled flows have been eight times higher than commercial transactions.
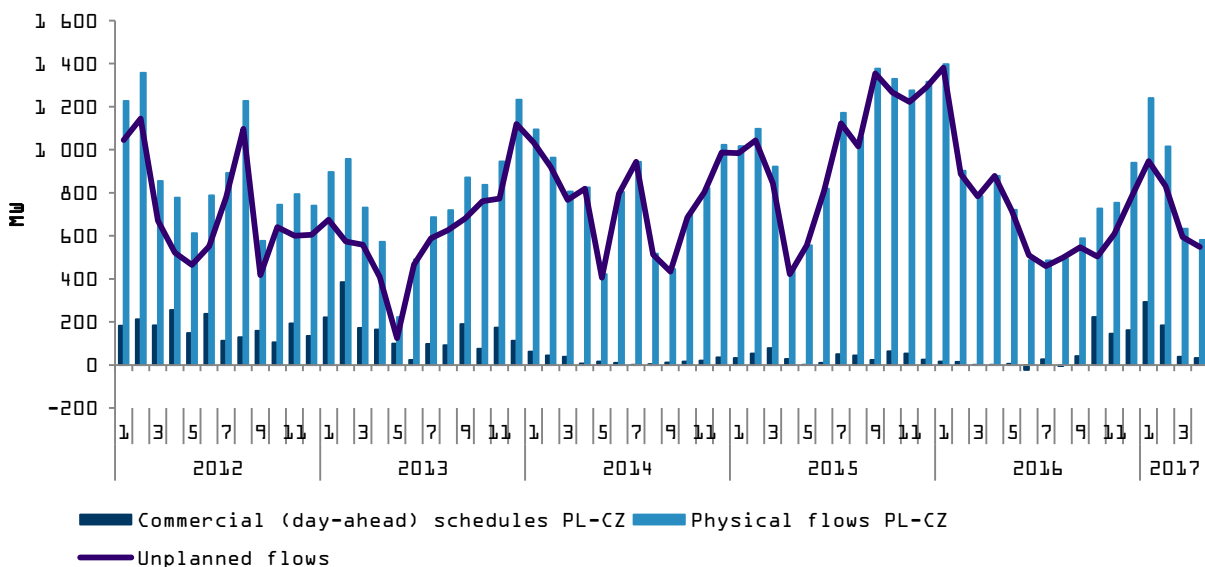
Figure 5-4: Change in average unscheduled flows on the Polish-Czech border between 2012 and April 2017

Source: Compass Lexecon based on ENTSO-E data

Notes: Average volumes of unscheduled flows correspond to monthly averages of hourly values.

In contrast, scheduled and physical flows on the Polish-Czech border go in the same direction, i.e., from Poland to Czech Republic. Similarly, they also strongly deviate in magnitude, with unscheduled flows about eight times higher than commercial transactions on absolute average over 2012-2017.

Modelling approach

Limiting loop flows resulting from network integration policy interventions in Poland would increase the NTC values between Poland and neighbouring countries, implying that enhanced price signals could better deal with congestion and allocate available transmission capacity in order to reduce energy imbalances and ensure security of supply.

We model unscheduled flows by adjusting net transfer capacity values in the model parameters.

▪ In the reference scenario (CM), we use maximum NTC values in 2015 which take into account the strong impact of unscheduled flows, in particular on the German-Polish interconnection lines. We assume that capacities are developed to match ENTSO-E MAF 2016 projections for 2020 and 2025.

▪ In the scenario with limited loop flows, in order to reflect increased NTCs, we estimate the historical average values[44] of unscheduled flows on the transmission lines in the direction of Germany-Poland and Poland-Czech Republic and increase the reference values by these amounts. For other borders and the opposite direction of these two lines, we evaluate Polish NTCs with reduced loop flows to be the maximum of NTC values in 2012, since the unscheduled flow phenomenon had not yet significantly affected the Polish system.

Table 5-1 and Table 5-2 list detailed NTC assumptions in the reference and alternative scenarios.

Table 5-1: NTCs in the reference scenario - CM (MW)

Border	2015	2020	2025	2030	2040

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[44]   Monthly data between 2012 and 2017 are provided by PSE.

Border	2015	2020	2025	2030	2040
PL-DE	1400	1600	1600	1600	1600
PL-CZ	600	800	800	800	800
PL-SK	600	600	600	600	600
PL-SE4	600	600	600	600	600
PL-LT	300	500	1000	1000	1000
DE-PL	0	200	900	900	900
CZ-PL	150	250	600	600	600
SK-PL	50	50	500	500	500
SE4-PL	600	600	600	1200	1200

Source: PSE, Compass Lexecon

Table 5-2: Additional NTCs in the reference scenario – Limited loop flows (MW)

Alternative	2015	2020	2025	2030	2040
PL-DE	+300	+300	+400	+400	+400
PL-CZ	+800	+800	+800	+800	+800
PL-SK	+50	+50	+50	+50	+50
PL-SE4	-	-	-	-	-
PL-LT	-	-	-	-	-
DE-PL	+1100	+1100	+1100	+1100	+1100
CZ-PL	+350	+350	+350	+350	+350
SK-PL	+450	+450	+450	+450	+450
SE4-PL	-	-	-	-	-

Source: PSE, Compass Lexecon

Notes: "- "means same NTCs in the reference scenario are kept. The amounts of increased NTCs with Germany and Czech Republic are estimated by the difference between commercial flows and physical flows based on the historical data provided by PSE.

The German strategic and climate reserve

Presentation of the mechanism

At the heart of the design of the future German power market proposed in the White Paper[45] published in July 2015, the Federal Ministry for Economic Affairs and Energy has decided to transform the power market into an "electricity market 2.0", which selects a different capacity remuneration mechanism than a capacity market.

The future power market will be backed up by a 4 to 5GW capacity reserve. The power plants that constitute this reserve do not participate in the electricity market. The strategic reserve will be made of two categories.

- **Climate reserve**: announced as a means to achieve the government's climate mitigation targets, up to 2.7GW of the strategic reserve will come specifically from lignite power plants, which would otherwise have been kept in the market and would have generated more and emitted CO2.
- **Capacity reserve**: the rest of the strategic reserve will be secured through an auction mechanism with the least costly offers to be accepted in order to construct a capacity reserve of 2GW. Due to poor profitability in the energy market, it is expected that these plants would have closed otherwise.

The legislation to implement the climate reserve was due for spring 2016, and the capacity reserve is scheduled to be implemented from 2018 onwards. A first lignite plant will be placed in the climate reserve in 2016, and the lignite capacity in the reserve will reach 2.7GW in 2019.

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[45]   BMWI (July 2015), White Paper: An electricity market for the Energy transition.
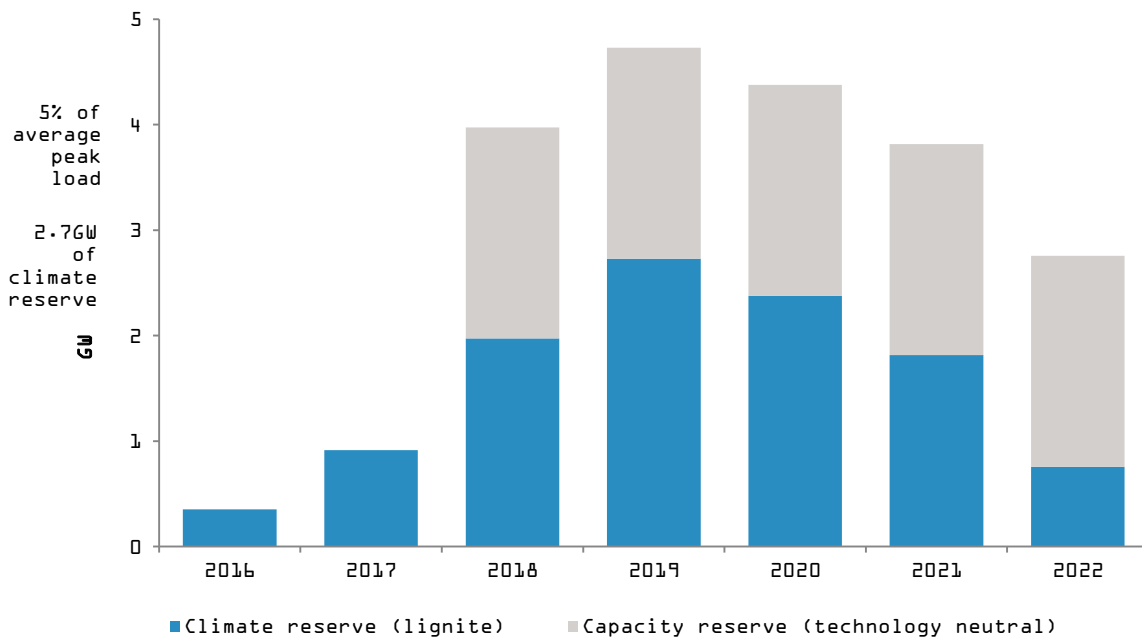
Figure 5-5: Germany's planned capacity and climate reserve evolution

Source: Platts and Compass Lexecon, 2016

Meanwhile, climate policies concerning coal and lignite plants in Germany and their specific consequences continue to be the subject of debates. Several studies conducted by Frontier Economics (2015) [46] recently compare three different options: the strategic reserve, a carbon levy, and promoting CHP. They consider that the strategic reserve and promotion of CHP can be less turbulent for the coal industry. In addition, the implementation of a carbon levy on old coal-fired power stations is currently under discussion at the German Ministry of Economics and Energy (BMWi). In order to achieve the national target of a CO2 reduction of 22 million tonnes by 2020, these studies reveal that all three proposals lead to a higher cost of emission abatement compared with simply buying and withholding emission certificates under the EU Emissions Trading Scheme, and that the carbon levy results in a higher cost for consumers. Therefore, uncertainty in the German climate policy has not been resolved at the moment and a fundamental decision is needed.

Modelling approach

The German Strategic Reserve is interesting because it is a CM that addresses security of supply issues, even though a component of the reserve, the climate reserve, also aims at reducing CO2 emissions. The amount of capacity that is moved out of the wholesale market is about 4.2GW per year, representing 5% of the level of peak demand in Germany.

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[46] Frontier Economics (2015), impact Assessment of Capacity Mechanisms. Report for the Federal Ministry for Economic Affairs and Energy (BMWI).

If a perfect strategic reserve is considered, the energy market should theoretically function equivalently to an energy-only market, as it is expected that the plants that are integrated in the reserve would have been closed otherwise and that the use of the reserve should not interfere with the energy market. According to the high-level description of the German capacity reserve by BMWi, these main criteria seem to be respected and the reserve is supposed to be used only in situations when the day-ahead market is expected not to clear. However, in practice, at least three issues may alter the functioning of the market:

▪ **Impact on intraday markets**: the activation of the reserve may not affect the day-ahead market because activation decisions are taken after the closure of the day-ahead market. However, once a part of the capacity in the strategic reserve is called into operation, this amount of generation will surely interfere with intraday trading and balancing. As a result, distortions may be created at the intraday and balancing stage. Acknowledging the limit of our model, we do not take into account the interactions between intraday and day-ahead markets.

▪ **Volume to be procured**: it is assumed that the volume to be procured is optimally chosen, meaning that: (a) only plants that are necessary to ensure security of supply are contracted and (b) an appropriate reserve capacity is procured, so that plants contracted in the reserve would not have remained in the market otherwise. If this assumption does not hold, the impact on the day-ahead market of the strategic reserve will not be negligible. In this case, we expect prices and volumes to be different from what we have modelled, and different from the theoretical EOM.

▪ **Climate reserve**: the climate reserve forces lignite plants to be placed in the reserve, although they might be profitable or at least more profitable than some other plants. From an economic point of view, putting less profitable plants into the reserve instead of lignite plants would be less costly. As a consequence, the climate reserve has a direct effect on the generation mix and merit order, as well as on total costs, compared to an actual EOM, because these lignite plants would have been kept in operation, but other, less economic, plants would probably have closed instead. When modelling the impact on the energy market, we have taken this aspect into account.

Our modelling approach distinguishes between the two categories of the strategic reserve: the capacity reserve and the climate reserve.

With respect to the capacity reserve, we consider a theoretical "perfect" market design based on the available information on the design of the strategic reserve, which assumes:

- The volumes contracted within the reserve should not exceed what is necessary and should not incentivise plants which are already covering their avoidable costs in the energy market to enter this reserve. Consequently, leaving aside the climate reserve's impact, the available capacity in the market is similar to that of an EOM in the case of a perfectly designed strategic reserve.

- The activation should not impact the wholesale prices and dispatch; the reserve is activated only if the day-ahead market does not clear and induces load curtailment without the activation of the reserve.

Such theoretical perfect market design for the capacity reserve should produce no impact on the energy market as compared to the EOM. It should not produce impact on the dispatch and the generation mix either, except when the reserve is activated to reduce loss of load.

However, in practice, the activation of the strategic reserve necessarily affects intraday and balancing markets' prices and flows, but these are not modelled in our simulations. As intraday markets develop and become more central in the market, these impacts may become substantial.

With respect to the 'climate aspect' of the reserve, we consider a theoretical climate reserve which assumes:

- The lignite plants forced into the reserve would have been economical to run in the market up to the end of their technical lifetime. The dispatch and prices are therefore impacted by the climate reserve;

- The activation of the lignite plants in the reserve has no impact on the wholesale prices and dispatch.

Such theoretical reserve should therefore have an impact on the wholesale prices and dispatch limited to the base-load nature of the plants forced into the reserve. Affordable base-load power would be replaced by more expensive base-load power.

However, in practice, given the ramp-up constraints of the lignite plants, the activation of the climate reserve would have additional impacts on the wholesale market during the activation period. But these are not modelled in our simulations.

The impact of the German strategic reserve including the climate reserve on European power markets has been modelled by comparing two scenarios:

- In the reference case, the climate reserve is assumed to be implemented as announced in the latest energy bill draft. 2.7GW of lignite plants are progressively taken out of the power market and maintained operational from 2016 to 2023, and then closed. It is then projected that similar efforts will be made in the future to reduce the lignite generation throughout the entire modelling horizon.

- In the counterfactual sensitivity modelling, existing lignite plants are kept operational beyond the modelling horizon in an energy market without the climate reserve.

Policy support to renewable generation in Germany

Presentation of the mechanism

In 2000, the first Renewable Energy Act (EEG) came in force in Germany. The purpose of the law was "to facilitate the sustainable development of energy supply, particularly for the sake of protecting the climate and the environment, to reduce the costs of energy supply to the national economy (also by incorporating external long-term effects), to conserve fossil fuels and to further promote the development of technologies for the generation of electricity from renewable energy sources" .[47]

The act introduces financial support to renewable plants for a period of 20 years following the year that the plant comes into operation.

The act has since then been revised several times. In 2011, the German government decided to stimulate the RES development, through the "Energiewende" (energy turnaround) concept. This led to the 2012 revision of the EEG[48], which also intended to further encourage direct marketing. The 2012 EEG provided the option to producers of renewable power to receive a market electricity price plus a market premium. In the 2014 Revision[49], the EEG sets targets of up to 45 percent of total generation to come from renewables by 2025 and to 60 percent by 2035. Total new renewable build

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[47]   White Paper of BMWI, An electricity market for the Energy transition, July 2015.

[48]   BMWI (2012), Renewable Energy Act 2012 (EEG 2012).

[49]   BMWI (2014), Renewable Energy Act 2014 (EEG 2014).

is subject to annual capacity limits by technology. In 2017[50], the EEG-remuneration shall no longer be set by the state but determined mainly by the market. Tenders will be distinctive for each technology (onshore wind, PV, offshore wind, biomass, etc.).

As a result, government support for renewables prompted a strong growth of wind, solar and biomass. In 2015, Germany had an installed capacity of 41GW of wind, 39GW of solar PV and 8GW of biomass. Between 2011 and 2015, Germany built around 10GW of onshore wind and 14GW of solar PV.
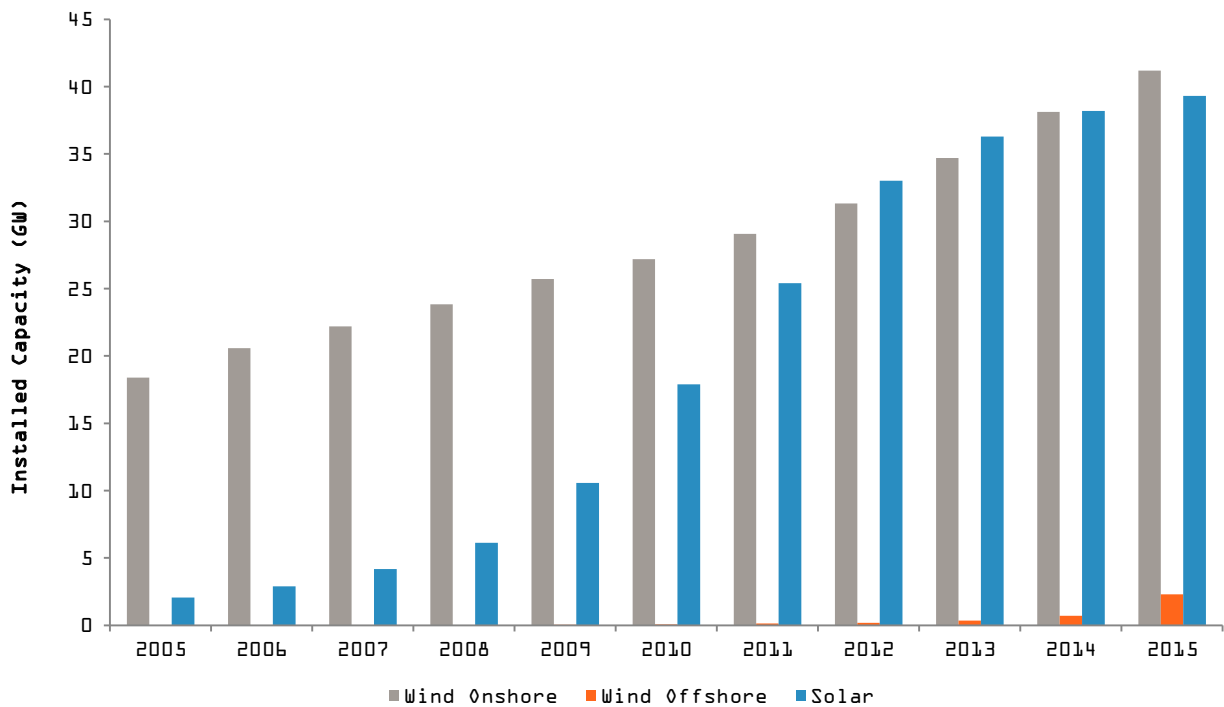
Figure 5-6: Installed renewable capacity in Germany between 2005 and 2015 (GW)
Source: ENTSO-E and Compass Lexecon, 2017

Modelling approach

The policy support to renewable generation in Germany impact on European power market has been modelled by comparing two scenarios:

▪ In the reference case, the policy support led to a high level of renewable development between 2011 and 2015. The development of new renewable capacity is then projected to fall between ENTSO-E and BNetzA (the German energy regulator) projections.

<p>50   BMWI (2017), Renewable Energy Act 2017 (EEG 2017).</p>

- In the counterfactual scenario we assume a lower policy support to renewable generation and that such a lower support would have led to a growth of renewable capacity as in the conservative scenario of ENTSO-E System Outlook and Adequacy Forecast 2011-2025. This represents the projection of the renewable capacity before the support to renewable increased in 2011.

Figure 5-7 below shows the renewable development in both cases.
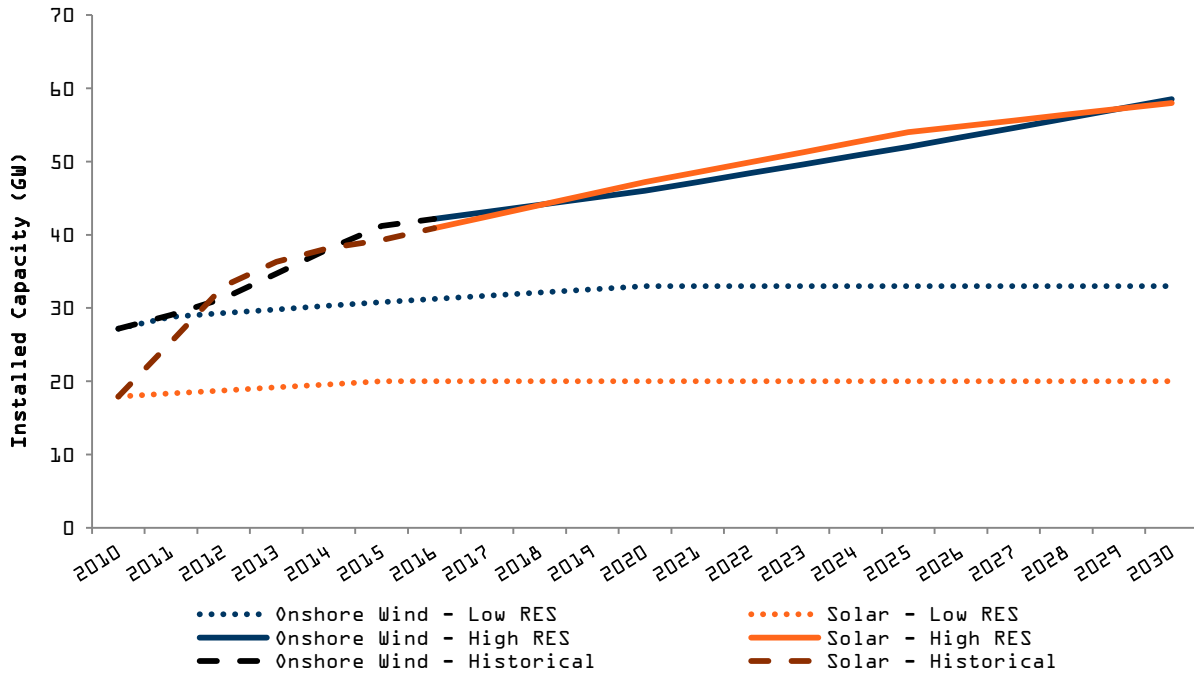
Figure 5-7: Renewable capacity development with and without renewable support

Source: Compass Lexecon, 2017

5.3 ASSESSMENT OF THE IMPACTS OF THE THREE INTERVENTIONS

Impact on security of supply and generation mix

The different public policy interventions modelled have varying objectives. Consequently, their impact on the available generation mix is difficult to compare. We can however observe that the modifications of the available capacity in Germany induced by some of the other policy interventions modelled are much more significant than the changes driven by the Polish CM. Figure 5-8 illustrates the change in available capacity in Germany by 2030 and 2040 triggered by each intervention in comparison to its counterfactual scenario.
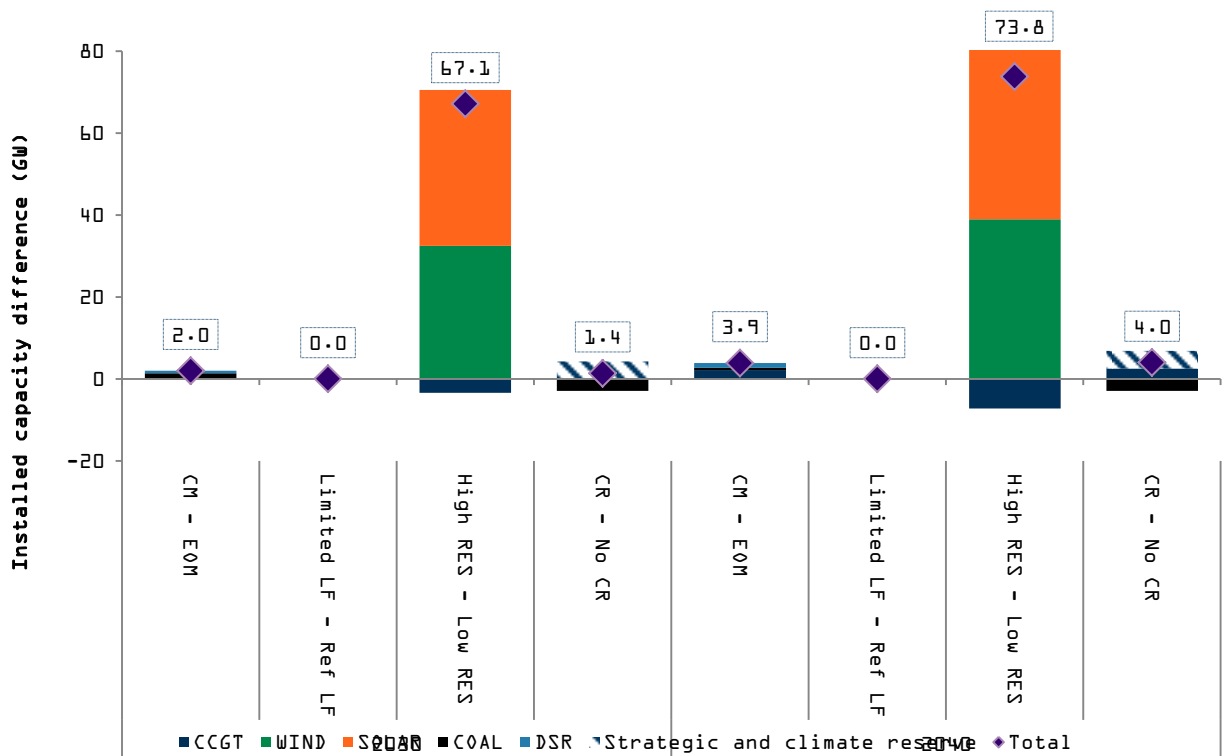
Figure 5-8: Impact on available capacity of the CM and other policy intervention compared to the counterfactual scenario (GW)

Source: Compass Lexecon, 2017

Notes: (1) The figure shows the difference in installed capacity between the assessed scenario and the reference scenario in Germany. CM – EOM is the capacity difference in Poland between the CM and EOM scenarios. Limited LF – Ref LF is the capacity difference in Poland between the scenarios with limited loop flows and with higher loop flows in Poland as in the CM. High RES – Low RES is the capacity difference in Germany between the high RES development as in the CM and the slow RES development. CR – No CR is the capacity difference in Germany between the scenario with the climate reserve and the scenario in which the climate reserve is not implemented; (2) In the limited loop flows sensitivity, while the German mix has not been re-optimized, the polish mix has been re-optimized.

The policy intervention with the strongest impact is the German RES policy support. Under this scenario, an additional capacity of 67GW by 2030 and 74GW by 2040 is available in Germany compared to the situation with no support.

By 2030, the amount of additional capacity driven by the Polish CM is comparable to the German strategic reserve. The effect of reduced loop flows is quantified while keeping the same generation mix. Hence, there is no change in available capacity in this sensitivity analysis.

Overall, modifications of the available capacity induced by German renewables support are much more significant than the changes driven by the Polish CM.

Impact on energy market functioning and cross-border flows

Since the different public policy interventions have an impact on countries' generation mix and consequent dispatch, their introduction modifies wholesale power prices in comparison to a situation where they are not implemented. Figure 5-9 illustrates the percentage change in prices in key countries under different interventions.
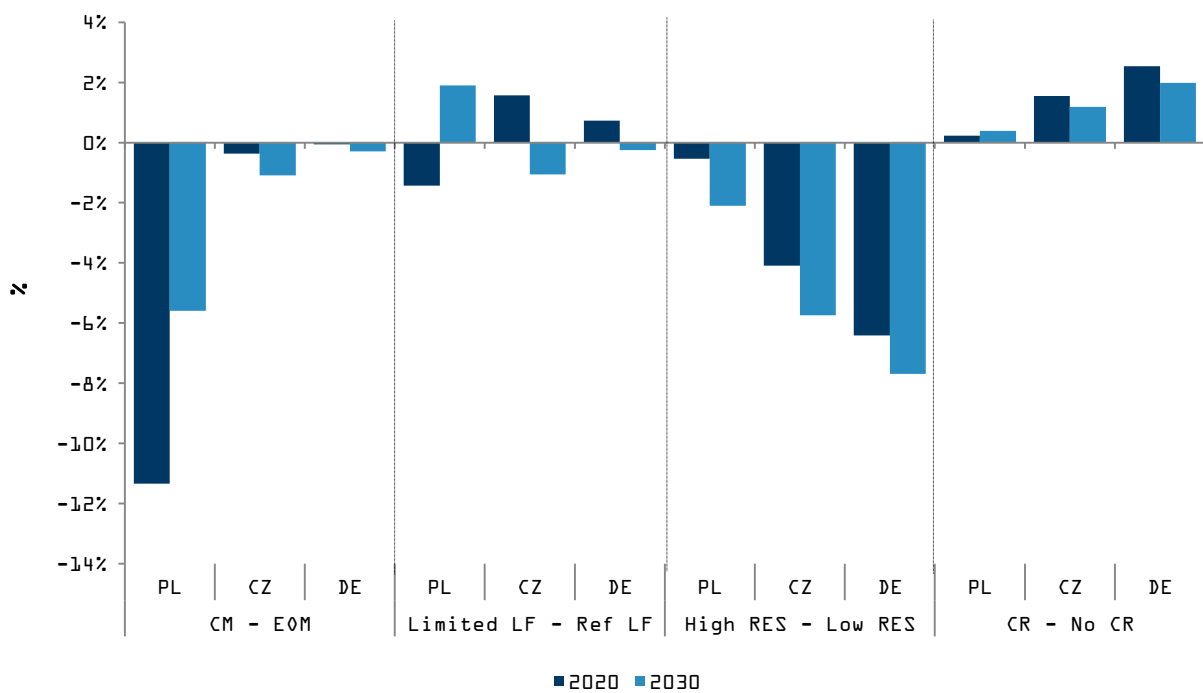
Figure 5-9: Percentage change in power prices in Poland, Czech Republic and Germany under the different interventions by 2020 and 2030 (%)
Source: Compass Lexecon, 2017

The introduction of the Polish CM has an impact on Polish wholesale power prices, corresponding to a 6% decrease by 2030 compared to the EOM scenario. However, its impact on Czech Republic and Germany is very limited in comparison to other interventions.

The German RES policy support has the strongest overall impact on prices, leading to a decrease by 2030 of 8%, 6% and 2% in Germany, Czech and Polish power prices, respectively. In contrast, introducing the German Climate Reserve only slightly increases prices by 2030 in all countries compared to a situation where the Climate Reserve is not in place. The situation with Limited loop flows has a variable impact on power prices, leading to a 2% increase by 2030 in Polish power prices but decreasing Czech and German prices by 1% and 0%, respectively. The increased interconnection availability increases both import and export flows of Poland. At the aggregated level, the impact of Limited loop flows on power prices depends on relative change in interexchange between Poland and neighbouring countries.

In addition to their impact on wholesale power prices, public policy interventions result in different cross-border flows, compared to a scenario without their introduction. In 2030, the Polish CM modifies cross-border flows by about 4TWh, whilst some other policy interventions have a greater impact on cross-border flows: the Limited loop flows allow Poland to increase exports to neighbouring countries by 5TWh, while the German Climate Reserve decreases exports by 18TWh and the RES support increases net export by 64TWh respectively.

Public policy interventions may drive electricity prices upwards or downwards, but the impact in absolute terms on power prices of the Polish CM in the long run is not greater than some other policies modelled. The Polish CM has an impact on cross-border flows because the domestic available capacity is modified to maintain security of supply. However, this impact is more limited than other policy interventions.

Impact on CO2 emissions

As analysed above, coal capacity in Poland is expected to be higher in the CM design than in EOM in the medium and long term due to the perspective of capacity payments from 2021 onwards and new coal plants' construction from 2023 to replace shutdown capacity to ensure the reliability standard.

A slightly higher level of CO2 is emitted from electricity generation in Poland in the CM scenario than in the EOM scenario, as illustrated in Figure 5-10 for 2030. However, since it triggers capacity addition to the Polish power market, the introduction of the Polish CM impacts neighbouring power markets that tend to import more under the CM scenario than in EOM. As a result, a small share of electricity volumes generated by neighbouring markets in EOM, as well as the corresponding CO2

emissions, is avoided in the CM design. Furthermore as discussed in Section 4, there is little change in CO_2 emissions at the EU level.
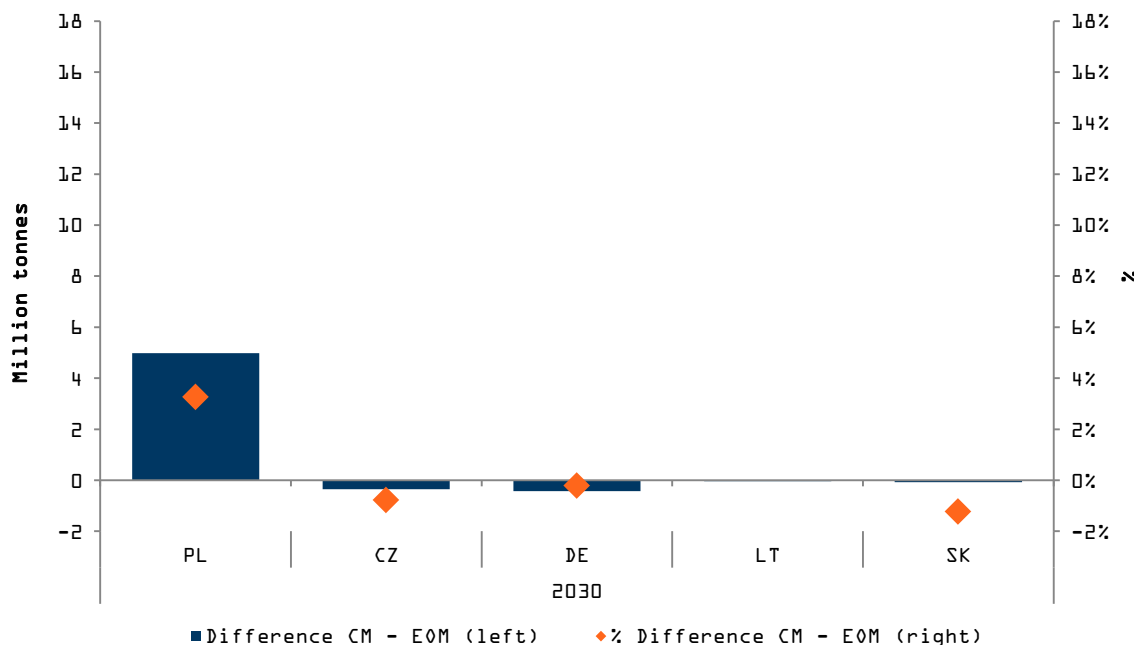
Figure 5-10: Difference in CO_2 emissions between Polish CM and EOM scenarios in 2030 (million tonnes)

Source: Compass Lexecon, 2017

Notes: PL: Poland; CZ: Czech Republic; DE: Germany; LT: Lithuania; SK: Slovakia

Overall, the Polish CM only slightly increases domestic emissions from electricity generation. Compared to the EOM, CO_2 emissions are 3% higher in the CM by 2030. Its impact on neighbouring countries' emissions is relatively small. By 2030, emissions are 1%, 0%, 6% and 1% lower than in the EOM in Czech Republic, Germany, Lithuania and Slovakia, respectively.

The domestic impact of the Polish CM is lower than the impact of loop flows (LF) in Poland, the German CR, as well as High RES in absolute terms, as illustrated in Table 5-3.

Table 5-3: Difference in CO_2 emissions between the CM scenario and the LF, CR and High RES scenarios in 2030 (million tCO2 and %).

Scenarios	PL	CZ	DE	LT	SK
Difference CM - EOM	5.0	-0.3	-0.4	-0.0	-0.1
% Difference CM - EOM	3%	-1%	0%	-6%	-1%
Difference Limited LF - Ref LF	6.9	-0.5	0.0	0.0	-0.2
% Difference Limited LF - Ref	4%	-1%	0%	2%	-3%

Scenarios	PL	CZ	DE	LT	SK
LF					
Difference CR - No CR	1.7	0.4	-11.6	0.0	0.1
% Difference CR - No CR	1%	1%	-6%	2%	2%
Difference High RES - Low RES	-8.7	-1.6	-16.6	-0.1	-0.4
% Difference High RES - Low RES	-6%	-4%	-8%	-13%	-7%

Source: PSE, Compass Lexecon

Notes: For each comparison, the first line presents the difference in CO2 emissions in absolute terms and the second line presents the difference in CO2 emissions in percentage.

By 2030, a situation with limited LF leads to an increase in Polish domestic CO2 emissions of 4% as compared with the case of Ref LF. It has a limited impact on neighbouring countries' emissions, which decrease in Czech Republic and Slovakia by 1 and 3%, are stable in Germany and increase in Lithuania by 2%. In the long run, limited LF would slightly enhance Poland's net export balance, which requires support from higher domestic generation.

In the case the German climate reserve (CR) is implemented, less coal and lignite plants stay online in Germany, resulting in a decrease in domestic CO2 emissions of 6% by 2030. Conversely upon German CR implementation, Polish, Czech, Lithuanian and Slovakian CO2 emission increases slightly by 1%-2% in 2030.

Of all policy interventions analysed, the German support to renewables has the most substantial impact on CO2 emissions both in Germany and its neighbouring countries. By 2030, the Germany policy support to renewables allows avoiding more than 16 million tCO2 in Germany alone as compared to a situation with low renewable development. Its impact on neighbouring countries is also significant due to higher power flows from Germany. In Poland, more than 8 million tCO2 are avoided by 2030. This is also the case for Czech Republic, Lithuania and Slovakia (1.6, 0.1 and 0.4 million tCO2 avoided, respectively).

The Polish CM has a marginal impact on CO2 emissions in Poland and its neighbouring countries. Policy interventions aiming at decarbonising the generation mix reduce CO2 emissions, but other interventions may increase emissions.

Impact on overall cost

Similarly to the Polish CM, the German Strategic Reserve aims at ensuring security of supply. It includes a specific measure to close lignite plants, which additionally contributes to decarbonisation. The costs arising from these two goals presented in Figure 5-11.
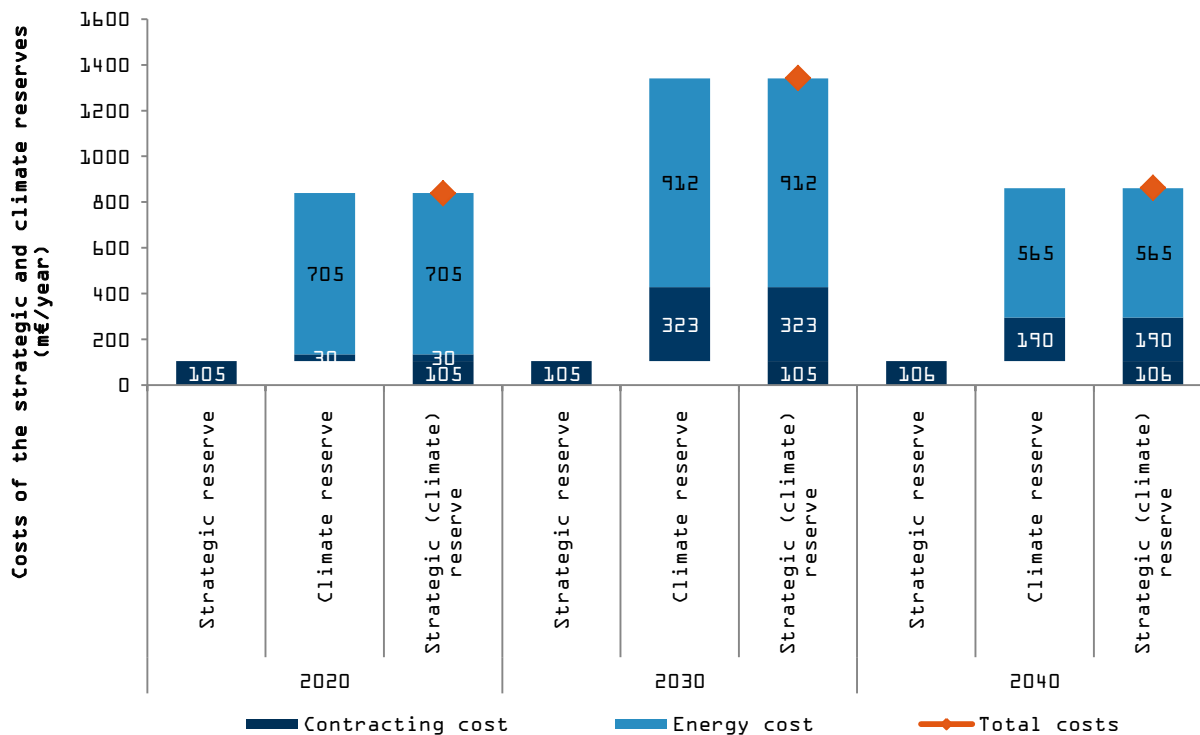
Figure 5-11: Breakdown of the impact of the German Strategic Reserve on customers cost in 2020, 2030 and 2040 (€m/year)
Source: Compass Lexecon, 2017

On average, the Polish CM reduces consumer costs. This is mainly due to its contribution to reducing load shedding and energy costs. In contrast, the German Strategic Reserve (SR) could increase net costs for consumers by € 800-1,300 million per year. The specific measure to close lignite plants, which additionally contributes to decarbonisation, incurs additional cost to maintain the capacity in the reserve. In the long run, most of the net cost for consumers is due to the 'climate aspect' of the strategic reserve.

Without this distortion in the constitution of the reserve, a perfect strategic reserve would still introduce a net cost in the first years of implementation. But over the period 2018-2030, it would be a zero-sum gain for end consumers.

The German Strategic Reserve introduces additional costs for consumers of around € 800-1,300 million per year, mostly due to the Climate Reserve.

6. Conclusions

6.1 IMPACTS OF THE POLISH CM COMPARED TO AN EOM

To assess in detail the impact of the Polish CM, we have modelled the European power system using our dispatch model, with or without the introduction of a CM in Poland. This has allowed simulating energy prices, dispatch and flows in Poland and in Europe, on an hourly basis, as well as investment, mothball and closure decisions, with and without the introduction of the CM in Poland.

This report is prepared based on the issue of draft bill on 5 December 2016 and before the issue of the latest version of the Bill, which has been submitted to the lower chamber of the Polish Parliament on 6 July 2017. The changes between the two versions of the Bill do not significantly change the results and conclusions of this report.

We have analysed the impact of the CM, by contrast to a theoretical EOM with a price cap at €360/MWh up to 2020 and at €3,000/MWh afterwards, with regard to several criteria:

- **Security of supply**. The introduction of the CM guarantees that the reliability standard is met, maintaining the de-rated capacity margin above the expected Polish peak demand around 14%, equivalent to 3 hours LOLE per year. Conversely, in the EOM, the security of supply becomes pressing from 2018 onwards and the de-rated capacity margin deteriorates to 5% in the long run.

- **Impact on the energy mix**. In order to maintain security of supply at the desired reliability standard, the CM helps bring in additional capacity compared to the EOM. In the short to medium term, based on our cost assumptions, it encourages more existing plants to reinvest in order to comply with BAT conclusions and invest in retrofit CAPEX, and fosters development of demand-side response. It is only from 2031 that the CM allows more CCGT generation capacity in the market when investment in CCGTs becomes more cost-competitive compared to investment in coal plants. In the long run, around additional 3.9GW are built, including 0.5GW of new build coal, 2.2GW of new build gas and 1.2GW of DSR.

- **Economic efficiency**. The CM is economically efficient to address security of supply issues, as it increases social welfare by more than € 46 million per year over the period 2017-2040. These gains are partly enabled by a reduction of financing costs for capacity providers, especially peak capacity providers, who may secure part of their revenues in the CM. Moreover, contrary to what is usually expected, end consumers are the main beneficiaries of the economic surplus

introduced by the CM, as the CM reduces consumer costs by € 280 million per year between 2017 and 2040, as a result of the reduction of loss of load expectation and reduction of energy costs.

- **Impact on the energy market**. The Polish CM does not affect generators' bidding and dispatch strategies, as it is based on availability, such that there is no short-term impact of the CM on the energy market and the only potential impact would result from additional capacity in the future. In the medium term, the impact on prices is limited as additional DSR is called upon only in extreme situations. The long term price gap between EOM and CM is about €5/MWh or 6%, and this is concentrated on peak hours, where the system is tight. As a consequence, the net export balance increases by up to 6TWh.

- **Impact on CO2 emissions**. The CM slightly increases CO2 emissions in Poland, because of higher domestic generation. This increase is partially compensated by a decrease in neighbouring countries. The EU wide CO2 emissions increase slightly.

As an alternative mechanism to ensure the reliability standard of security of supply, the strategic reserve is not sufficient to address Polish structural adequacy concerns as Poland is facing long-term adequacy issues. Furthermore, the strategic reserve is not a cost-efficient way to ensure security of supply in the long term.

Compared to the Polish CM, the strategic reserve is expected to be less cost-efficient for Polish consumers to meet the security of supply at the reliability standard. Overall, the CM outperforms the Polish strategic reserve, leading to a savings for consumers of € 350 million per year and an increase in social welfare of € 39 million per year on average.

6.2 IMPACTS OF THE 550 EPS COMPARED TO THE CM

The EC suggests introducing an emission cap in CMs which would prevent generation capacity emitting more than 550gCO2/kWh from participating in CMs. The implementation of the 550 EPS would have a significant impact on decommissioning and investment incentives of coal and lignite plants. In this context, we have assessed the impact of the 550 EPS scenario, by contrast to the CM scenario, with regard to the similar criteria:

- **Security of supply**. The CM with 550 EPS still maintains security of supply at the level of reliability standard. The de-rated capacity margin remains around 14%.

- **Impact on the energy mix**. Anticipating the non-eligibility of the coal plants to receive capacity remuneration from 2024 onwards, more existing plants close before 2021 and no new build coal capacity is built due to insufficient profitability. In the long term, 4GW of coal plants are not built in the 550 EPS scenario as compared to the CM, replaced by 3.8GW of new CCGT plants as well as by 0.4GW of DSR capacity in addition to the CM scenario, which are developed earlier stimulated by higher capacity prices. The consequence of this significant CCGT capacity increase is an increase in gas consumption, gas important dependency and gas network upgrade requirements. Over the outlook period, the 550 EPS increases Polish gas consumption by 60 bcm, a 70% increase compared to the CM scenario.

- **Economic efficiency**. Despite the reduction of capacity payment to coal/lignite plant operators, the 550 EPS slightly increases costs for the Polish consumers compared to a technology-neutral CM. It increases consumer costs by € 10 million per year and has a negative impact of € 40 million per year in terms of social welfare.

- **Impact on the energy market**. The change in the generation mix caused by the introduction of the 550 EPS leads to an average increase of about €1/MWh in energy market prices as compared to the CM scenario.

- **Impact on CO2 emissions**. Compared to CM and EOM, the 550 EPS effectively reduces domestic CO_2 emissions from electricity generation in Poland, as CCGT new build gradually replaces existing coal plants or substitute coal new build. However, in the absence of any change in the ETS cap, the 550 EPS does not reduce overall emissions in Europe, and leads to an additional abatement cost of €5/tCO2 above the EU ETS price on average over the outlook period.

6.3 COMPARISON OF THE IMPACTS OF THE POLISH CM COMPARED TO OTHER POLICY INTERVENTIONS

Following the same methodological approach, we have assessed the impact of other policy interventions in Europe, namely:

- Limited loop flows through Poland in the German-Austrian common bidding zone;

- The Strategic Reserve planned in Germany, including the forced inclusion of lignite plants in the reserve (so-called Climate Reserve);

- The RES support policy in Germany;

The comparison with other mechanisms aims to put things into perspective, in order to assess whether the impact of the CM is significant or not compared to other public interventions. These other mechanisms often have different objectives: reducing network constraint, decarbonisation, and development of RES. Any comparison of the effects should therefore be interpreted with caution, but the assessment gives an interesting comparison to grasp what could be deemed proportionate or not.

We have analysed the impact of these interventions and compared them to the CM's impact, with regard to the same criteria:

- **Impact on the energy mix**. Policy interventions generally have a much stronger impact on the generation mix than the CM. RES support in Germany can lead to change in the installed capacity of more than 70GW by 2040, while the CM impact is between 2-4GW in the medium to long term. The impact of the German strategic reserve, taking into account capacity put in reserve, is comparable, between 1-4GW.

- **Economic efficiency**. The impact of the strategic reserve in terms of consumer costs is different to the Polish CM. Indeed, the strategic reserve increases consumer costs by around € 800-1300 million, while the CM is beneficial for consumers in terms of costs. This increase in costs is mainly due to the climate aspect of the reserve: without this distortion in the constitution of the reserve, the strategic reserve would still have induced a net cost in the first years of implementation but, over the period 2018-2030, it would have been a zero-sum gain for end consumers.

- **Impact on the energy market**. Public interventions may drive electricity prices upwards (e.g. the German climate reserve) or downwards (RES support), but the impact of the CM in absolute terms on power prices is not greater than the other policies modelled. In the long run, while the CM does not modify Polish power prices by more than 6% on average, whilst the RES support policy can decrease the German price by 8%. Furthermore, the impact of the CM on prices is limited mostly during peak hours. As a consequence, the impact on cross-border trade is reduced compared to other interventions, especially RES support.

- **Impact on CO2 emissions**. The CM has a relatively small impact on CO2 emissions. Policies that target decarbonisation and RES development have a significant downward impact on CO2 emissions.[51]

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[51]   However, we have not assessed the downward impact of RES development on CO2 prices, which may limit the reduction of CO2 emissions.

7. Appendix A – Description of Compass Lexecon's European power markets dispatch model

7.1 INTRODUCTION

This section presents Compass Lexecon's European power markets dispatch model, which was used to support the impact assessment of the Polish CM and other public policy interventions. It successively describes:

- The modelling platform;

- The geographic scope of the model;

- The European power plants database;

- The European power market assumptions;

- The price setting mechanism;

- The renewable power generation modelling approach; and

- The back-casting calibration exercise.

7.2 MODELLING PLATFORM

The European power markets dispatch model developed by Compass Lexecon is implemented in the commercial modelling platform Plexos® Integrated Energy Model. This modelling platform is most commonly used in the European electricity industry by utilities, regulators and transmission system operators. Plexos® allows finding solutions quickly using advanced optimisation procedures taking into account of a large number of variables and complex constraints of transmission network and power plants. It also provides a flexible and user-friendly interface allowing testing multiple scenarios, to perform stochastic sampling and optimisation, and to present the results in a graphical form.

7.3   GEOGRAPHIC SCOPE OF THE MODEL

Compass Lexecon's European power markets dispatch model covers the EU-28 countries as well as Switzerland, Norway, the Balkans and Turkey. Countries beyond this geographic scope are modelled at an aggregate level. The geographic scope of the model is shown below in Figure 7-1.

Figure 7-1: Compass Lexecon's European power markets model geographic scope

Source: Compass Lexecon

7.4   EUROPEAN AND THE POLISH POWER PLANTS DATABASE

Based on Platts data, Compass Lexecon has developed a European power plants database. The database contains technical specificities of all thermal European plants and is used as the basis of the power dispatch model. The database is regularly updated to include the latest announcements from plants operators, utilities and regulators.

The database is completed by a range of scenarios on decommissioning dates for existing plants, commissioning dates for current and future projects, and projection on renewable developments.

The Polish power plant database is additionally refined with data provided by PSE, including detailed plant lists, technical parameters, such as generation types, net capacity, minimum stable levels, forced outrage and maintenance rates, and fuel charges, capacities of must-run generation etc. For

major Polish thermal plants, we have updated decommissioning and commissioning dates based on the most up-to-date information of PSE. These data have been communicated with and validated by PKEE. We identify the plants in the Polish existing capacity that need to reinvest to comply with BAT conclusions according to the vision of PSE, but this plant list only serves as a departing point of our modelling iterations.

7.5 EUROPEAN POWER MARKET ASSUMPTIONS

Compass Lexecon's European power markets model runs on a set of key inputs developed in-house. A consistent set of assumptions based on public data as well as on Compass Lexecon's European expertise is used to model power price outlooks. The power dispatch model uses:

- **Demand projections**. Compass Lexecon's long-term power demand projections in European countries are derived from a combination of GDP growth, policy effectiveness, and the expected technological change. In the reference case, uptake of energy efficiency measures drives electricity demand lower, but electrification of the transport and heat sectors (together with GDP growth) offsets this reduction.

- **Supply projections**. Supply projections are based on climate and energy policies and technology development cost. In particular, future capacity mix scenarios in European countries are based on the existing thermal plants retirement or mothballing economic modelling based on released publication, energy policies and regulations (the IED, replacing the LCPD; and BAT conclusions adopted pursuant to the IED), existing low carbon technologies retirement or life extension based on current and future energy policies, new thermal plant capacity scenarios based on economic modelling and new low carbon technologies scenarios based on future energy policies.

- **Commodity price projections**. Commodity prices are one of the main determinants of the SRMC of most power generators, and thus a primary driver of wholesale power prices. We have developed internal scenarios based on publicly and privately released data from IEA's World Energy Outlook and EIA's Annual Energy outlook projections. Commodity price projections are regularly reviewed to account for latest changes in energy markets regulation.

- **Interconnection projections**. Based on the ENTSO-E data and Compass Lexecon's expertise on European power market, a transmission database referencing historic NTCs and future interconnection projects has been created.

Each scenario is internally consistent and represents a plausible combination of assumptions on the considered variables.

7.6 PRICE SETTING MECHANISM

This model uses a detailed bottom-up methodology: the supply from flexible thermal power plants is modelled individually to meet the demand net of the supply of must-run renewable generators. The dispatch is determined to minimise the costs of generation in the North-West Europe while satisfying the unit commitment constraints of generators as well as the flow constraints over the European transmission network. The model uses the zonal transmission network representation that matches with the price zones currently implemented in Europe and the commercial transmission boundaries.

The model calculates the price in each price zone as the marginal value of energy delivered in that zone based on the simulated bids of flexible generators. In reality, these bids closely follow the estimated short-run variable cost of power generation. Therefore, the estimated clearing prices correspond to the marginal cost of electricity. Such estimation of electricity prices based on the marginal cost is reasonable when the capacity margin above the demand is high and there is high competition between generators to serve the demand.

However, when demand in an area reaches the levels close to the generating and import capacity, generators have less competitive pressure to bid at the SRMC level. In such cases, the clearing price is set above the marginal cost of the most expensive running unit. Such prices allow the marginal units to cover the variable cost of production and further contribute to covering their fixed costs.

A dedicated model to reflect this bidding behaviour, referred as to the "Fixed-cost recovery mechanism" has been developed. This model calculates the mark-ups of the generators' bids over the marginal cost depending on the capacity margin.

7.7 RENEWABLE POWER GENERATION MODELLING APPROACH

Given the impact of renewable variability on future power system, we have developed specific methodologies to represent and forecast wind and solar production and model hydro flexible generation. The model also includes pumped storage explicit modelling and has the flexibility to model on-site storage. The renewable power forecast methodologies are completed by an in-depth understanding of the economic impact of renewable production on power prices.

Wind power

Following extensive analysis on the impact of wind variability on future power systems, for multiple clients such as TSOs, interconnection operators and European utilities, a specific wind model – the "CL Hybrid wind model" – has been developed. It combines:

- Wind manufacturers theoretical power curve applied on historic re-calibrated wind speed data collected from weather stations across Europe; and

- Historic wind power production.

This combined methodology strengthens the wind modelling capability as it goes beyond wind turbine manufacturers' data and uses historic technical performances at the heart of the "wind speed to power converter" algorithm. The methodology is derived from research papers on the statistical difference between theoretical wind power output and realised output.

Solar power

Besides using historic solar production, a dedicated methodology to model the impact of future technical improvements, such as capturing diffuse solar irradiation, has been developed.

As for wind modelling, we collect irradiation data from weather stations scattered around Europe and convert the irradiation values into power values by using a statistical analysis on the relationship between average solar irradiation and national solar production. This relationship captures the inverter efficiency and diffusion coefficient.

Wind and solar bids in wholesale market

To capture the fatal characteristic of renewable generation, the wind and solar production are modelled as must-run generation. Existing and under construction sites are allowed to bid negatively up to their renewable incentives level, creating occasionally negative prices.

Following work on the negative price impact and regulation, the model was adapted to include a number of wind and solar sites vintages in order to accurately model the level down to which renewable plants will bid before being curtailed. This acknowledges that overtime renewable generation will be merchant-only and will not have external incentives to create negative prices.

Nordic and Alps hydro modelling

The model specifically focuses on an explicit modelling of the production flexibility of the Nordic and the Alps hydro reservoirs. Hydro production is one of the main determinants of the electricity prices in the Nordic region and one of the main sources of flexibility in the Alps. The hydro model is

designed to dynamically replicate the seasonal optimization performed by those producers. The modelling is based on two elements:

- Hydro constraints, such as reservoir maximum levels and weekly natural inflows have been calibrated following extensive research on historic and future hydro data; and

- Given the calibrated constraints, our dispatch model includes a state-of-the-art algorithm designed to calculate the "water value", i.e. the value of water held in storage. It then uses the water value of the hydro plants in the short-run optimisation.

This detailed approach further improves the dispatch model robustness, providing additional flexibility to the European power system.

Figure 7-2 presents the weekly inputs fed into the model (with a focus on Norway) while Figure 7-3 presents a result from our European power dispatch model compared to historic production values (with a focus on Sweden).
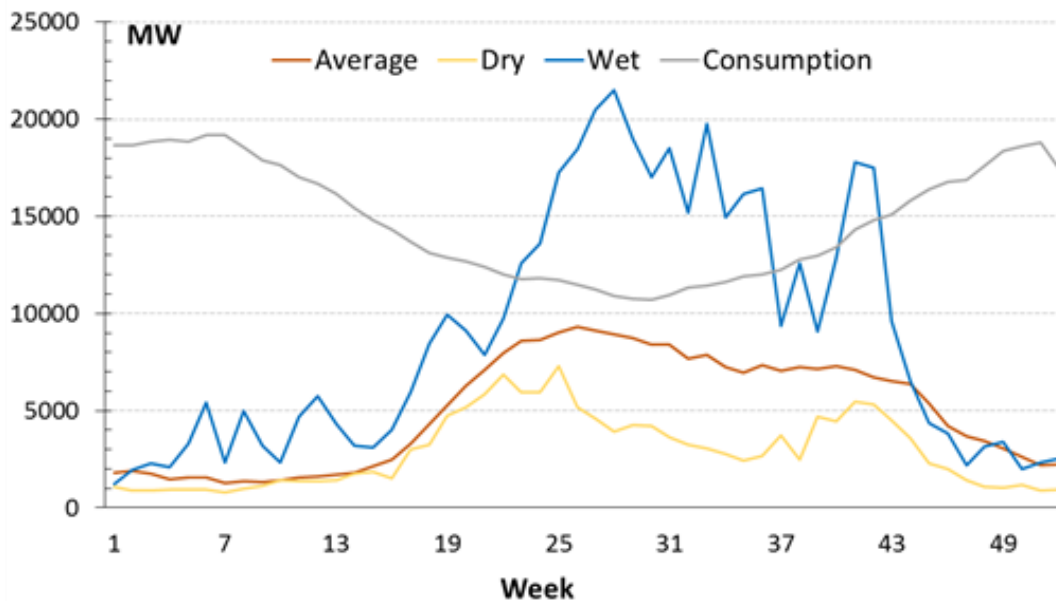

Figure 7-2: Compass Lexecon's Norwegian hydro model input

Source: Stattnet, Compass Lexecon's European hourly dispatch model calibration
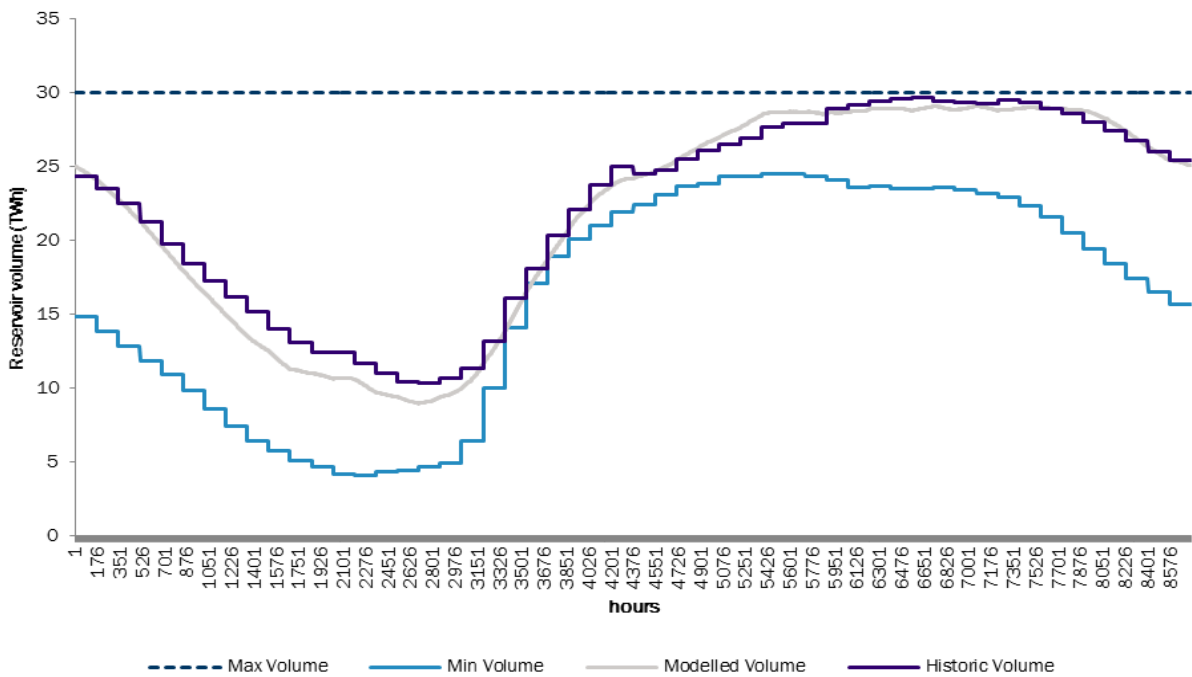
Figure 7-3: Compass Lexecon's Swedish hydro modelling results

Source: Compass Lexecon's European hourly dispatch model calibration

Pumped storage

Pumped storage facilities are the main source of storage on the European power systems. Our model includes a specific add-on to correctly account for this source of flexibility. It optimises its pumping and dispatch schedule on a weekly basis.

7.8   BACK-CASTING CALIBRATION

The model has been calibrated with respect to the historical price profiles observed in a number of European countries. Back-casting is a process by which we use our model to determine prices over a historic period and then compare to the actual prices observed over the same historic period. The closer the modelled results to the actual results the greater comfort we can draw that our model will produce reliable forecasts over the future.

For example, Figure 7-4 below shows the results of the back-casting calibration of the prices calculated by the model against the realized prices in 2012 in Germany and Figure 7-5 below shows the results of the back-casting calibration of the price duration curve in 2015 in Poland.

The high precision of the hourly price profiles is achieved through a realistic representation of the dynamic constraints of thermal plants and an accurate calculation of the demand net of the must-run production from renewable and distributed generation.
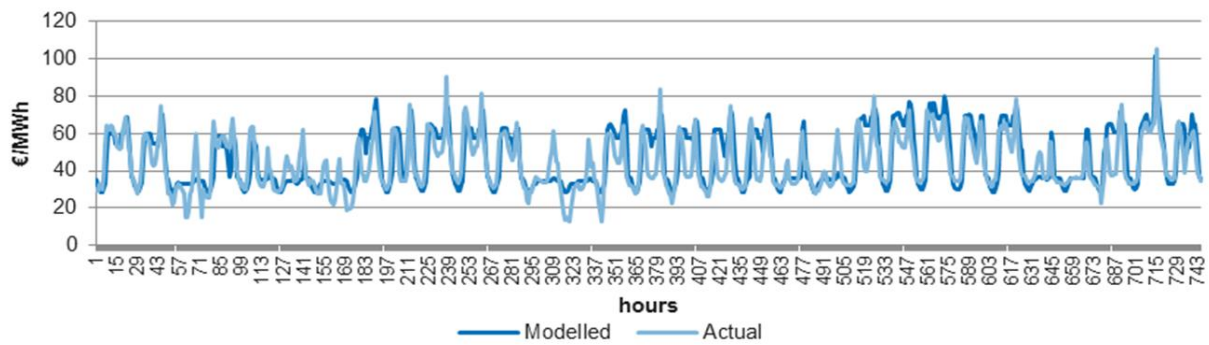
Figure 7-4: Back-casting calibration – German hourly prices, October 2012

Source: Compass Lexecon's European hourly dispatch model calibration
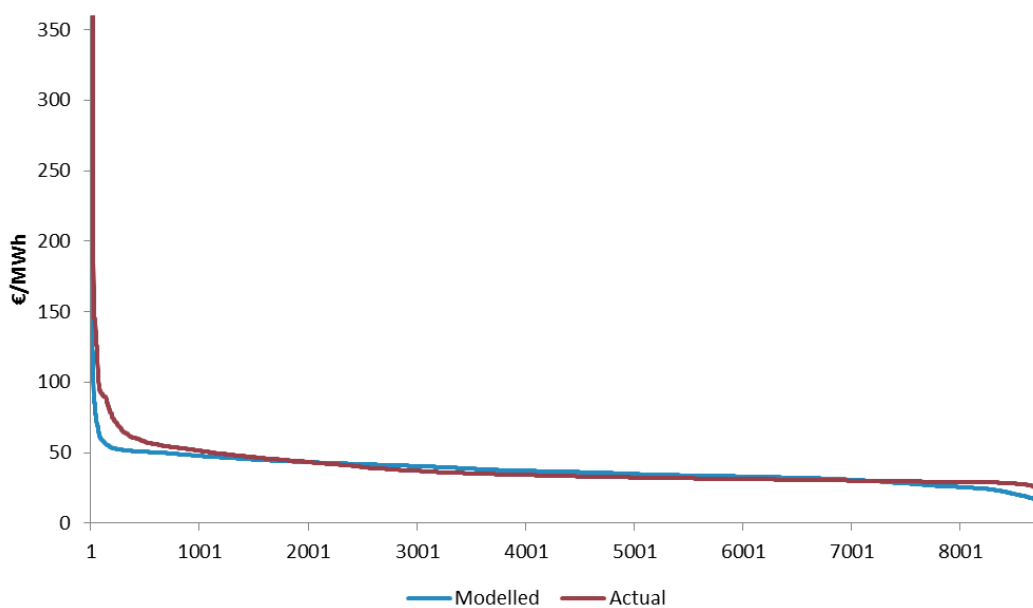
Figure 7-5: Back-casting calibration – Polish price duration curve, 2015

Source: Compass Lexecon's European hourly dispatch model calibration

8. Appendix B – Description of the capacity market model

8.1 INTRODUCTION

This section presents Compass Lexecon's capacity market model, which has been developed to forecast future capacity prices based on an inter-temporal optimisation of decisions to mothball, retire or invest in generation units. It is integrated with the European power markets dispatch model over the entire modelling horizon.

The section successively describes:

- The modelling assumptions;

- The interactions with Compass Lexecon's capacity market model; and

- The capacity market bids' modelling approach.

8.2   MODELLING ASSUMPTIONS

Perfect competition

Capacity certificate trades are modelled through an annual trade which computes the annual capacity price as the intersection of the supply curve and the demand curve. Compass Lexecon's capacity market model assumes perfect competition and information between market participants. It minimises the system cost while ensuring the security of supply/reliability standard.

Inter-temporal optimisation

Compass Lexecon's capacity market model simulates the recurrent annual capacity certificate trades over several years. Since the decision to retire, invest or mothball units depends on the expectation of the future income over the next years, this decision is made based on a multi-period strategy taking into account the inter-temporal constraints. The capacity market model has been set up to run over a number of future periods (2017- 2040).

8.3   INTERACTION WITH EUROPEAN POWER MARKETS DISPATCH MODEL

Capacity market offers that are based on the "missing money" depend on the plants' revenues expected in the energy and ancillary services markets. Plants' energy market revenues are fed to the capacity market model from the European power markets dispatch model developed in Plexos®. Depending on the decision to retire or invest, the capacity mix evolves, which is reflected in a further iteration of the power market model.

This interaction is illustrated in Figure 8-1 below.
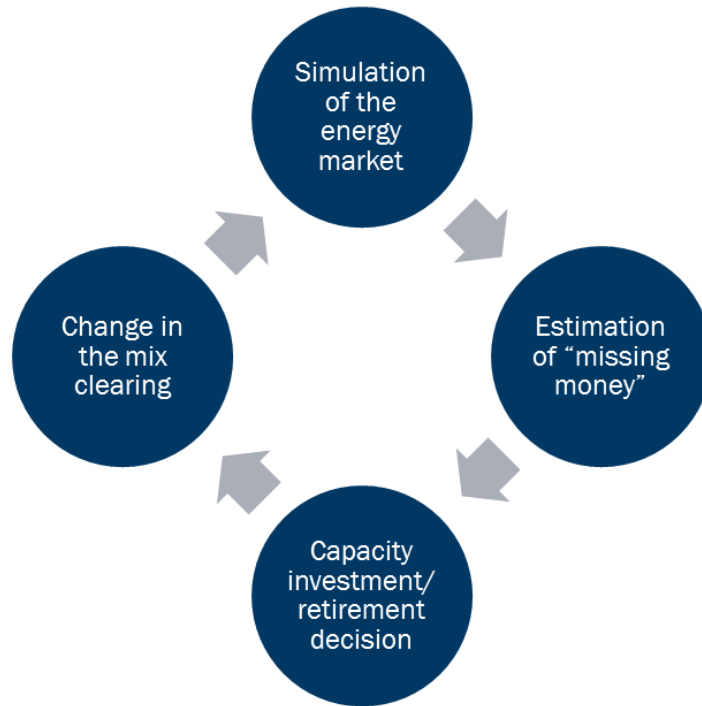
Figure 8-1: Interaction between energy and capacity markets models

Source: Compass Lexecon, 2017

8.4   CAPACITY MARKET BIDS

A competitive bid in a capacity market should reflect the plant's "missing money", i.e., the part of the avoidable fixed cost not covered by the expected energy and ancillary services revenues. Figure 8-2 below shows the competitive capacity bid of existing and new units.
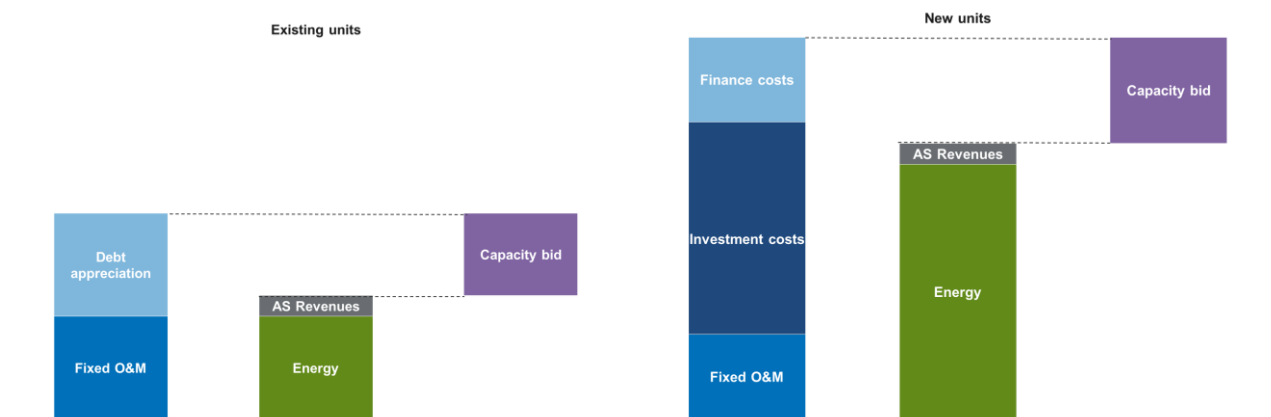
Figure 8-2: Competitive capacity bid from existing and new units

Source: Compass Lexecon, 2017

For existing units, the avoidable cost of being a capacity resource is represented by:

- **Fixed annual operating and maintenance expenses**; and

- **Debt depreciation** (equity cost is assumed to be sunk cost).

The competitive capacity bid corresponds to the difference between the two cost items and the sum of energy and ancillary revenues
For new units, the avoidable cost of being a capacity resource is represented by:

- **Fixed annual operating and maintenance expenses;**

- **Annualised investment costs;** and

- **Financing costs**.

The competitive capacity bid of existing units corresponds to the difference between the three cost items and the sum of energy and ancillary revenues.

Investments in power plants are financed through both equity and debt. For existing plants, the equity part of the investment often represents a sunk cost. However, remaining debt is often recoverable in case a plant is sold and thus represents avoidable cost of being a capacity resource. Therefore, remaining debt can represent a substantial part of the capacity bid of existing plants. Its share in the bid depends on a number of factors:

- Debt-to-equity ratio; and

- Debt depreciation schedule and amount of the remaining debt in a given year, the weight of the debt being higher in newer plants.

Ideally, capacity bids together with energy and ancillary revenues could allow generation units to additionally recover the amount of debt that they need to repay. Given the uncertainty about the debt share of the capacity bid, a special sensitivity analysis is conducted for this parameter. Figure 8-3 illustrates the share of the debt depreciation schedule and cost split of a thermal plant project after its construction. We assume that debt depreciation linearly decreases from the first year of operation until the year it is cleared. Therefore, the total annual cost of a thermal plant project includes fixed O&M costs and an annually decreasing cost of debt repayment. While we do not explicitly consider debt depreciation in the capacity bid calculation in this report, adding this element introduces higher uncertainty and draws an upper bound of the capacity bid.
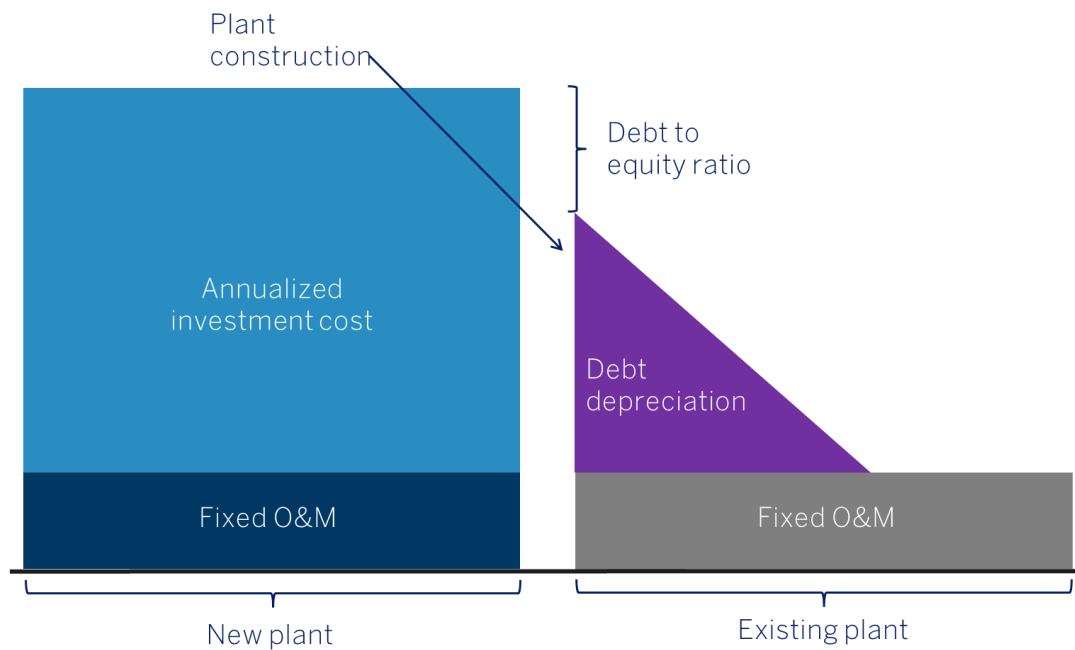
Figure 8-3: Capacity market offer of new and existing plants

Source: Compass Lexecon, 2017

9. Appendix C – Description of key modelling assumptions

9.1 INTRODUCTION

This section describes the key scenario modelling assumptions. We use publicly available third-party data sources whenever it is possible to construct the core assumptions, such as IEA, ENTSO-E, various national TSOs, etc. We cross check the consistency of these assumptions with databases provided by PSE and PKEE, as well as with our internal modelling assumptions in our European dispatch model. These core assumptions include:

- Exchange rates;

- The power demand outlook;

- The commodity prices outlook (gas, coal, lignite and CO2 prices); and

- The capacity mix outlook, including operational constraints, in particular the production of renewable energy and the decommissioning/additions of thermal power plants.

9.2 EXCHANGE RATES

The exchange rate assumptions used in the modelling, presented in below, are based on IEA WEO 2016.

Table 9-1: Exchange rate assumptions

	2017	2020	2030	2040
USD/EUR	1.114	1.12	1.12	1.12
GPB/EUR	0.85	0.86	0.80	0.80

Source: Compass Lexecon based on IEA WEO2016

9.3 POWER DEMAND OUTLOOK

Our power demand outlook is built based on the baseline scenario of PSE' s latest adequacy outlook for Poland. Table 9-2 describes the change in annual and peak demand in Poland throughout 2030.

Table 9-2: Annual and peak demand assumptions

	2016	2020	2025	2030
Annual demand (TWh)	151.5	163.1	181.6	200.9
Peak demand (GW)	23.2	25.0	27.3	29.7

Source: PSE 2016 adequacy outlook

The Polish electricity demand is expected to grow at an annual rate of 2.4% between 2016 and 2025 and of 2.3% between 2025 and 2030. Beyond this horizon, we extend the increasing trend of the Polish power demand up to 2040 at an annual growth rate of 1.4%.

Similarly, the Polish peak demand increases from 23.2GW in 2016 to 29.7GW in 2030 at an average growth rate of 1.6%. Beyond that scope, we assume that it increases at a rate of 1.0% throughout 2040.

Figure 9-1 shows the historic and forecasted energy intensity outlook over 2016-2040. Energy intensity in Poland is expected to decrease gradually.
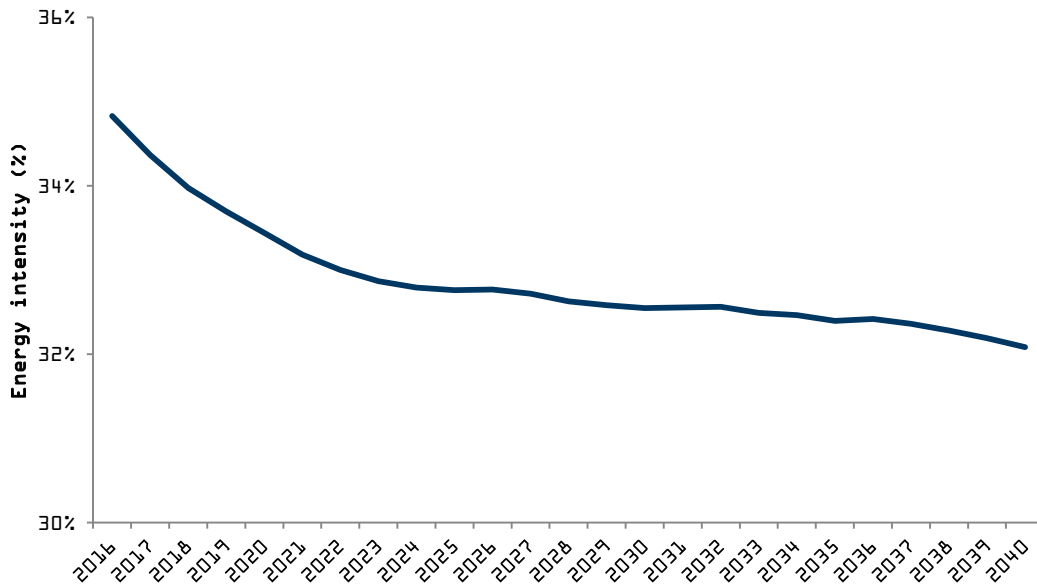
Figure 9-1: Energy intensity in Poland, 2016-2040

Source: PSE, European Commission and Compass Lexecon

9.4   COMMODITY PRICE OUTLOOK

Commodity prices are the main determinant of electricity generation short-run marginal costs (SRMC) and thus a primary driver of wholesale power prices. In the following paragraphs, we give an overview of the historic development of oil, coal, gas and CO2 prices and of our commodity price outlook.

Coal

We assume that the global coal market will increase to the long-term equilibrium of the WEO 2016 New Policy scenario by 2030 from the current level. This is driven by the worldwide rebound of coal demand driven by the political uncertainty around further worldwide green policies such as the COP21 Paris agreement. Figure 9-2 presents our outlook.
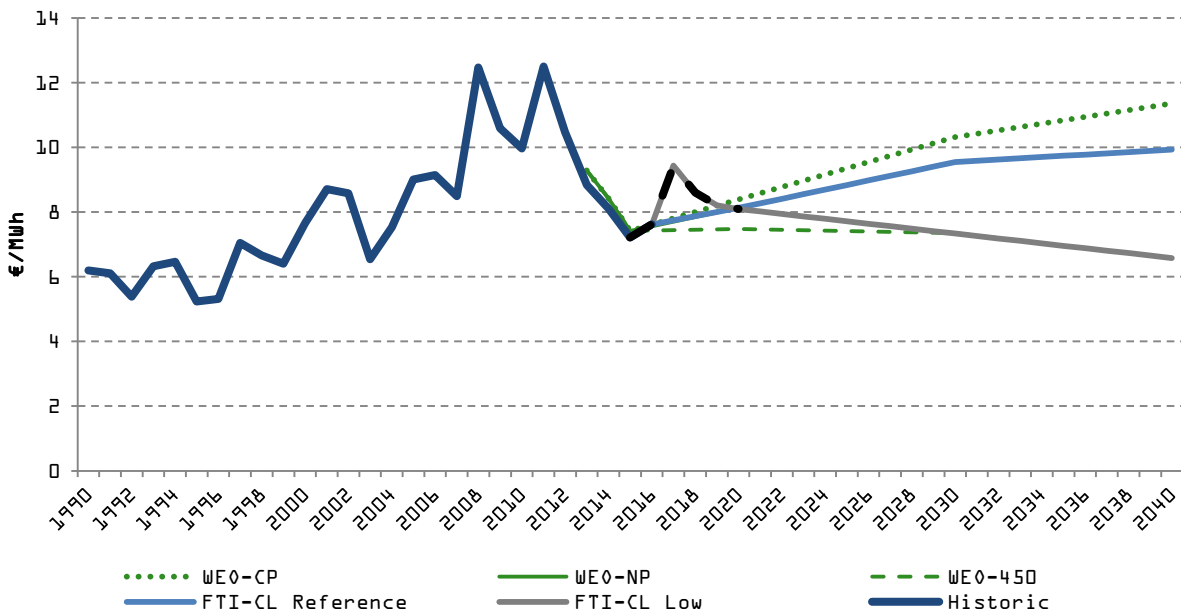
Figure 9-2: International coal price outlook (€/MWh, 2016 real prices)

Source: Compass Lexecon based on IEA WEO 2016

Lignite

While mining costs are relatively comparable between lignite producing countries (Germany and Eastern Europe), the calorific value of the extracted lignite has a significant impact on the cost per GJ, leading to significant variations between these countries. We benchmark the costs of lignite generation taking into account the difference of lignite prices based on the Booz&co study. [52]

Figure 9-3 presents the difference of full lignite costs in Poland, Germany, Bulgaria, Romania, Serbia, Czech Republic, Turkey, Greece and other Balkan countries, which have sizable lignite production and lignite generation capacity. In 2012, the full lignite costs in Poland are €2.0/GJ (€7.2/MWh), in the middle of the full lignite cost spectrum.

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[52]   Booz&co., 2012. Understanding lignite generation costs in Europe. Available at https://www.dei.gr/documents2/investors/meleth%20booz/understanding%20lignite%20generation%20costs%20in%20europe.pdf
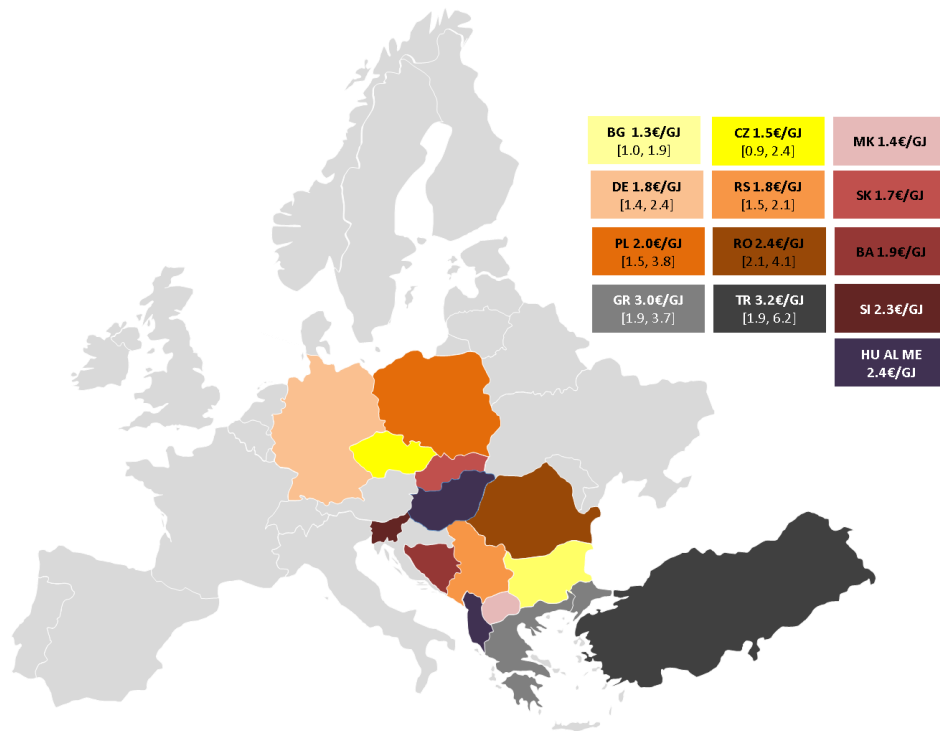
Figure 9-3: 2012 full lignite costs in lignite producing countries (€/GJ)

Sources: Compass Lexecon analysis based on Booz&co

In our reference scenario, we index the Polish market lignite price evolution on the evolution of coal prices.

Natural gas

European gas prices reached €11/MWh August 2016, their 5-years minimum. Since then, they increased back to c. €20/MWh in Q4 16 / Q1 17 (nearly doubling in 6-months' time), before reaching their current level of €17/MWh. Despite the high volatility of European gas prices over the last couple of years, reflecting the numerous uncertainties in the European and global gas markets, the fundamentals of the market indicate that European gas equilibrium prices is around €17/MWh in the short to medium term, subject to Liquefied Natural Gas market surplus in the next few years.

We assume that European gas markets will steadily rebalance towards the long-term equilibrium of IEA WEO 2016 New Policy scenario. This is driven by the increased use of gas in the power sector to replace aging coal and nuclear plant. This increasing demand is partially met by increased LNG supply from the US. Figure 9-4 presents our outlook.
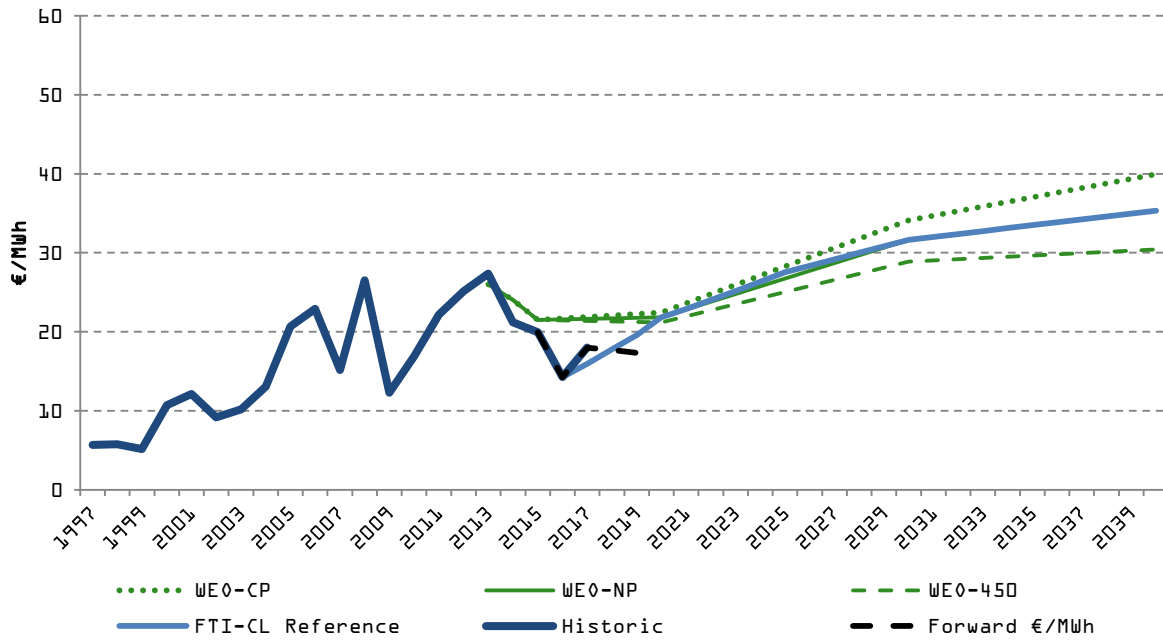
Figure 9-4: European natural gas price outlook (€/MWh, 2016 real prices)

Source: Compass Lexecon based on IEA WEO 2016

CO2

The EU ETS currently suffers from a surplus of emission allowances, such that the quota prices are at their lowest level. A reform of the ETS for the 4th phase post 2020 is currently in discussion.

We assume that the evolution of the CO_2 price is consistent with the NP scenario of the WEO 2016 up to 2030 and the long-run CO_2 price up to 2040 follows the projection of our internal EU ETS model, which projects the CO_2 price increases from €33/tonne in 2030 (WEO NP) to €60/tonne in 2040.

Figure 9-5 presents our outlook.
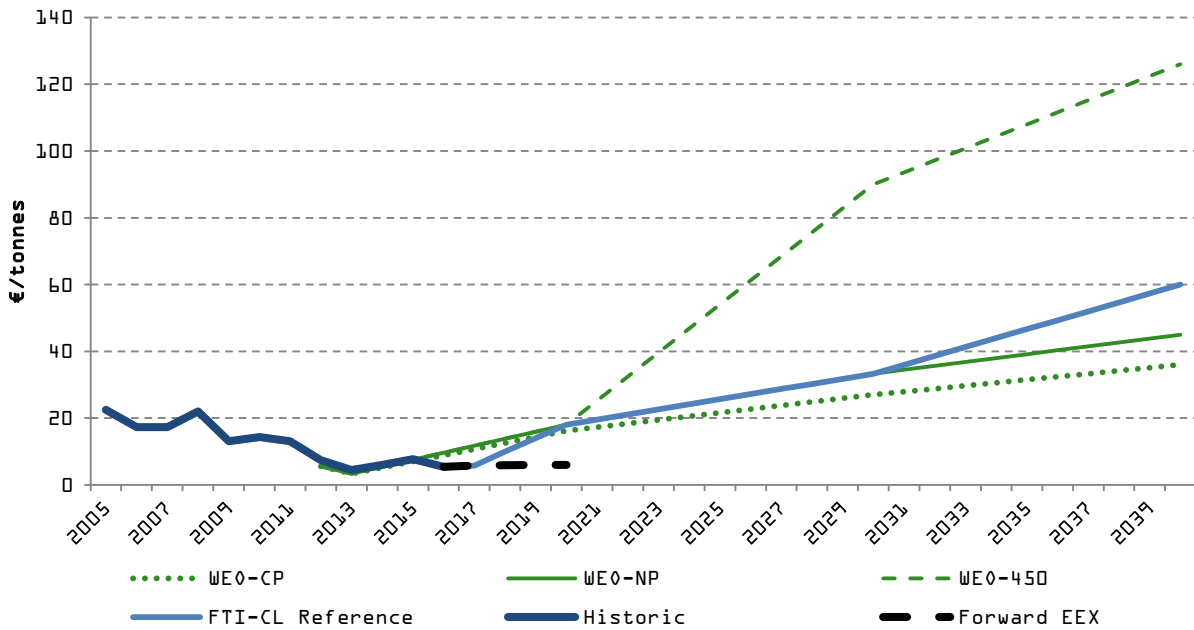
Figure 9-5: EU ETS CO2 certificate price (€/tonne, 2016 real prices)

Source: Compass Lexecon based on IEA WEO 2016

9.5 CAPACITY MIX OUTLOOK

The Polish generation mix is dominated by lignite and coal generation, accounting for more than 70% of the power generation. The thermal generation mix is expected to undergo substantial changes in the coming years as old thermal plants constitute the majority of the Polish thermal generation capacity.

More specifically, the European IED sets minimum standards for emissions of SO2, NOx and dust to the air from large combustion plants with a thermal rating equal to or greater than 50MW. With stricter emission standards and an ageing fleet, it is estimated that more than 4GW of capacity will retire in Poland by 2020.

At the current stage, Poland does not have nuclear power, but plans to construct a nuclear power plant that will come into operation in the medium term. As validated with PKEE, we assume that Poland will construct two nuclear units of 1,400MW with the first unit commissioned at the earliest in 2030.

While assumptions on thermal capacities are based on various sources, such as Platts European database, ENTSO-E, and different national TSOs' data, we keep the evolution of future must-run capacities, such as nuclear, hydro, wind and solar power, in line with PSE's and PKEE's views. Table 9-3 presents our must-run capacity outlook for Poland.

Table 9-3: Must-run capacity in Poland, 2020, 2025 and 2030 (MW)

Must-run capacity (MW)	2020	2025	2030
NUCLEAR	0	0	1,400
HYDRO	2,345	2,345	2,345
WIND ONSHORE	7,050	8,000	9,080
WIND OFFSHORE	0	1,000	2,010
NUCLEAR	350	600	2,400

Source: Compass Lexecon based on PSE and PKEE

Figure 9-6 shows the evolution of the Polish de-rated capacity mix against the peak demand over 2016-2030.
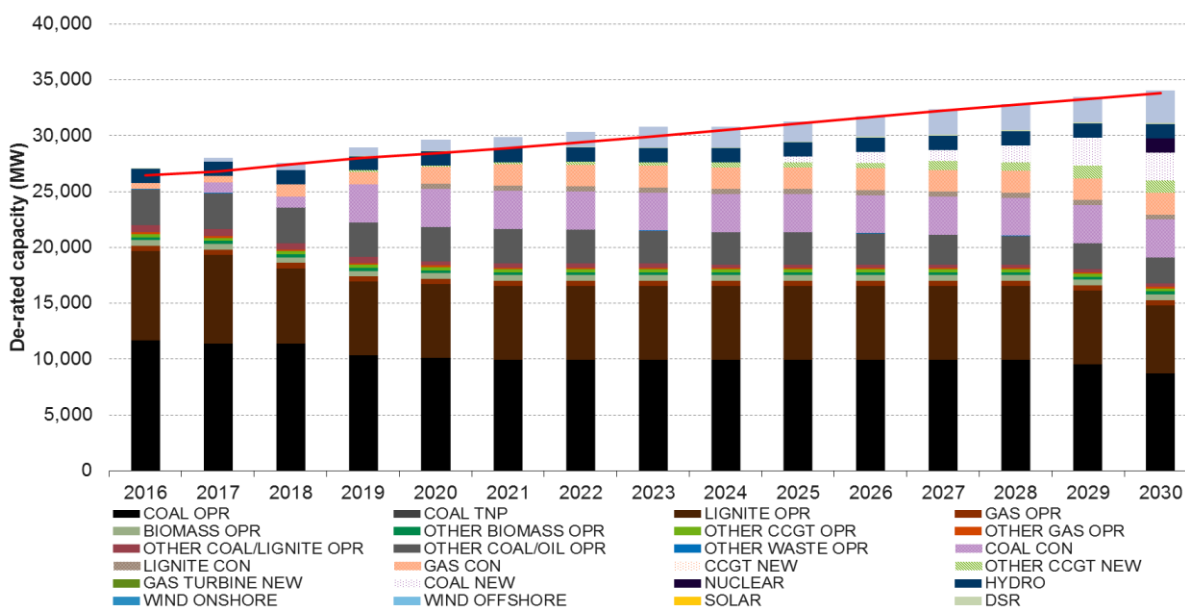

Figure 9-6: Evolution of the Polish capacity mix, 2016-2030

Source: Compass Lexecon based on PSE and PKEE

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