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Techno-economic Analysis of an Instrument Mix to Decarbonize the Electricity Sector

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Techno-economic Analysis of an Instrument Mix to Decarbonize the Electricity Sector

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The current progress of global power sectors is "insufficient (...) to fulfill its critical role as a leading force in the decarbonization of economies around the world."

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"Meta-studies can then utilize the policy mix concept as an integrating analytical framework to synthesize these partial contributions (...)."

Rogge and Reichardt 2016

"(…) science-policy interactions are neither static, linear nor one-directional (…)."

Turnheim et al. 2020

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Diese Arbeit ist während meiner Zeit als wissenschaftliche Mitarbeiterin am IER entstanden. Es war eine spannende und sicherlich einmalige Zeit, in der ich unzählige neue Erfahrungen sammeln und tolle Menschen kennenlernen konnte.

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Abstract

The policy landscape for mitigating climate change is becoming increasingly complex, and so its analysis. This thesis contributes to addressing this task by assessing the three core instruments for decarbonizing the power sector (carbon pricing, renewable energy support, and coal phase-out), as well as their interactions based on three techno-economic criteria (economic, technological, and distributional effects on the generation side). This topic is particularly relevant due to several reasons: On the one hand, the power sector is a central sector in order to be able to achieve the reduction targets in other sectors as well. Second, the instrument and policy mix analysis is becoming more important, as mitigation targets are regularly revised, each requiring an iterative reconciliation between target setting and instrument mix suitability.

A particular focus of this thesis is on the interactions of the European Emissions Trading Scheme (EU ETS) with additional measures addressing the same emission source ("overlapping policies"). A detailed summary of the literature on this topic shows that a perfectly functioning ETS is superior to other instruments from a cost-effectiveness perspective. Hence, introducing an instrument in parallel to the ETS is only justified if it serves to address a market failure, improves the design of the ETS, or if serving other objectives than cost-effectiveness.

Other literature on instrument mix analysis identifies a need for research in communicating complex results to policymakers and evaluating more than two instruments. This thesis contributes to these research gaps with three individually completed analyses. The linear, system-cost-optimizing electricity market model E2M2 is used, suitably simplified for the particular research questions. This approach enables the identification of energy economic coherences, which are graphically represented for an improved communication to decision makers and are complemented by a high-resolution case study in two of the analyses.

The first of the analyses looks at economic effects of a coal phase-out that operates in parallel with the EU ETS. Results show that - in the presence of very poor intertemporal efficiency - the introduction of this additional instrument can lead to lower abatement costs. At the same time, it becomes clear that empirical analyses whether this inefficiency actually exists in the real ETS market are lacking. Thus, the empirical basis would first have to be improved in order to assess whether the introduction of an "overlapping policy" is justified from an economic point of view.

In the second analysis of this thesis, a screening curves model is applied to show the short-term effects of the three instruments on market prices and contribution margins of individual technologies. Results show that the effects of the individual instruments on electricity prices overlap in the mix and the stringency of the individual instruments determines which effect dominates. Technology-specific contribution margins of biomass and gas combined cycle (CC) plants increase in the medium term due to high carbon prices and the coal phase-out, but in the long term the contribution margins of all technologies fall below their initial levels.

In the third analysis, the long-term profitability of the technologies is investigated in an iterative approach, accounting for insufficient scarcity prices in the real market. Results show that in the short term, shifts in the system can occur so that newly invested wind turbines and gas CC plants can recover their full costs without scarcity prices. However, in a further decarbonized system, net present values are strongly negative. Thus, to incentivize sufficient investment, it is necessary to ensure that scarcity prices of sufficient magnitude credibly materialize or that fixed costs are recovered by other means.

The individual results of the analyses suggest two key recommendations for the design of a policy mix in the power sector: first, the number of policy instruments should be kept as low as possible. Second, the design and evaluation of an instrument mix should be guided by its theoretically optimal outcome.

Among other important design principles, the following three steps can be derived for the conceptualization of a decision on "overlapping policies":

1. The basis for the decision must be a careful empirical analysis of whether a market failure exists and to what extent.

2. The possibility of remedying the market failure(s) by adapting existing instruments should be examined.

3. If this is not possible, the new measure should be designed to address the market failure(s) precisely, cause minimal undesirable side-effects or inefficiencies and take into account interactions with the existing mix of instruments.

The results of this work have shown that the empirical basis for the first two steps was insufficient, at least for the introduction of a coal phase-out in the German power sector.

However, careful application of these three steps in future can help ensure that the policy mix for decarbonizing the power sector is better suited to achieve the reduction targets in the power sector as efficiently as possible. Finally, ensuring a holistic policy mix analysis requires not only the consideration of multiple instruments, criteria, and policy mix characteristics, but also the synthesis of results from different scientific disciplines, which must then be communicable to policymakers in an understandable way. This remains a massive task with a very large need for research, but its accomplishment will be crucial for a successful transformation, not only of the power sector.

Kurzfassung

Die Politiklandschaft zur Bekämpfung des Klimawandels wird zunehmend komplexer und damit auch ihre Analyse. Diese Arbeit liefert einen Beitrag zur Bewältigung dieser Aufgabe, indem die drei Kerninstrumente zur Dekarbonsierung des Stromsektors (CO_2-Bepreisung, Förderung von erneuerbaren Energien und Kohleausstieg), sowie deren Wechselwirkungen anhand von drei techno-ökonomischen Kriterien (ökonomische, technologische und Verteilungseffekte auf der Erzeugungsseite) bewertet werden. Die besondere Relevanz des Themas hat mehrere Gründe: Zum einen ist der Stromsektor ein zentraler Sektor um auch die Minderungsziele in anderen Sektoren erreichen zu können. Zum anderen wird die Instrumenten- und Politikmixanalyse zunehmend komplexer, aber auch wichtiger, da Minderungsziele regelmäßig überarbeitet werden, was jeweils einen iterativen Abgleich zwischen Zielsetzung und Eignung des Instrumentenmix erfordert.

Ein besonderer Fokus dieser Arbeit liegt auf den Wechselwirkungen des Europäischen Emissionshandelssystems (EU ETS) mit zusätzlichen Maßnahmen, welche die gleiche Emissionsquelle adressieren („overlapping policies“). In einer ausführlichen Zusammenfassung der Literatur dazu wird deutlich, dass ein perfekt funktionierendes ETS anderen Instrumenten aus Perspektive der Kosteneffizienz überlegen ist. Die Einführung eines Instruments parallel zum ETS ist nur dann gerechtfertigt, wenn es der Behebung eines Marktversagens dient, das Design des ETS verbessert oder wenn andere Ziele als die Kosteneffizienz im Vordergrund stehen.

In der übrigen Literatur zur Instrumentenmixanalyse wird vor allem Forschungsbedarf bei der Kommunikation von komplexen Ergebnissen an die Politik und der Evaluierung von mehr als zwei Instrumenten gesehen. Diese Arbeit liefert einen Beitrag zu diesen Forschungslücken mit drei individuell abgeschlossenen Analysen. Dabei kommt das lineare, systemkostenoptimierende Strommarktmodell E2M2 zum Einsatz, das für die jeweilige Fragestellung geeignet vereinfacht wird. Diese Vorgehensweise ermöglicht die Darstellung von energiewirtschaftliche Zusammenhängen, welche für eine verbesserte Kommunikation an Entscheidungsträger grafisch dargestellt und in zwei der Analysen von einer hochaufgelösten Fallstudie ergänzt werden.

Die erste der Analysen beschäftigt sich mit ökonomischen Effekten eines Kohleausstiegs, der parallel zum EU ETS wirkt. Ergebnisse zeigen, dass die Einführung eines zusätzlichen Instruments bei sehr schlechter intertemporaler Effizienz zu geringeren Vermeidungskosten führen kann. Zugleich wird deutlich, dass empirische Analysen dazu fehlen, in welchem Ausmaß diese Ineffizienz im realen ETS-Markt tatsächlich vorhanden ist. Es müsste also zuerst

die empirische Basis verbessert werden, um beurteilen zu können, ob die Einführung einer „overlapping policy“ aus ökonomischer Sicht gerechtfertigt ist.

In der zweiten Analyse dieser Arbeit wird ein Screening Curves Modell angewandt, um die kurzfristigen Effekte der drei Instrumente auf Marktpreise und Deckungsbeiträge einzelner Technologien aufzuzeigen. Ergebnisse zeigen, dass sich die Effekte der einzelnen Instrumente auf die Strompreise im Mix überlagern und die Stringenz der einzelnen Instrumente entscheidet, welcher Effekt dominiert. Technologie-spezifische Deckungsbeiträge von Biomasse und Gas GuD steigen mittelfristig aufgrund von hohen CO_2-Preisen und dem Kohleausstieg, langfristig liegen aber die Deckungsbeiträge aller Technologien unterhalb ihres Ausgangsniveaus.

In der dritten Analyse wird die langfristige Rentabilität der Technologien in einem iterativen Ansatz untersucht, unter der Annahme von unzureichenden Knappheitspreisen im realen Markt. Ergebnisse zeigen, dass kurzfristig Verschiebungen im System stattfinden können, sodass neu investierte Windenergieanlagen und Gas GuD-Anlagen ihre Vollkosten ohne Knappheitspreise decken können. In einem weiter dekarbonisierten System sind die NPVs jedoch stark negativ. Um ausreichende Investitionen anzureizen muss also sichergestellt werden, dass Knappheitspreise in ausreichender Höhe glaubwürdig zustande kommen oder dass die Fixkosten auf andere Weise gedeckt werden.

Die Einzelergebnisse der Analysen lassen zwei zentrale Empfehlungen für die Gestaltung eines Politikmixes im Stromsektor zu: Erstens sollte die Anzahl an Politikinstrumenten so gering wie möglich gehalten werden. Und zweitens sollte sich die Gestaltung und die Bewertung eines Instrumentenmix an dessen theoretisch optimalem Ergebnis orientieren.

Neben weiteren wichtigen Gestaltungsschwerpunkten lassen sich daraus folgende drei Schritte für die Konzeptionalisierung einer Entscheidung über „overlapping policies“ ableiten:

1. Basis für die Entscheidung muss eine sorgfältige empirische Analyse sein, ob ein Marktversagen vorliegt und in welchem Ausmaß.
2. Die Möglichkeit, das/die Marktversagen durch Anpassung bestehender Instrumente zu beheben sollte geprüft werden.
3. Ist dies nicht der Fall, sollte die neue Maßnahme so gestaltet werden, dass das/die Marktversagen präzise adressiert werden, minimale unerwünschte Nebeneffekte bzw. Ineffizienzen verursacht werden und Wechselwirkungen mit dem bestehenden Instrumentenmix berücksichtigt werden.

Die Ergebnisse diese Arbeit haben gezeigt, dass die empirische Basis für die ersten beiden Schritte zumindest bei der Einführung eines Kohleausstiegs im deutschen Stromsektor unzureichend war.

Die sorgfältige Anwendung dieser drei Schritte kann jedoch dazu beitragen, dass der Politikmix zur Dekarbonisierung des Stromsektors in Zukunft besser geeignet ist, die Klimaziele im Stromsektor so effizient wie möglich zu erreichen. Um schließlich eine ganzheitliche Politikmixanalyse zu gewährleisten, bedarf es nicht nur der Berücksichtigung mehrere Instrumente, Kriterien und Politikmix Charakteristika, sondern auch der Synthese von Ergebnissen aus verschiedenen wissenschaftlichen Disziplinen, die dann verständlich an die Politik kommunizierbar sein müssen. Dies bleibt eine gewaltige Aufgabe mit sehr großem Forschungsbedarf, deren Bewältigung jedoch für eine erfolgreiche Transformation - nicht nur des Stromsektors - von entscheidender Bedeutung sein wird.

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Abbreviations

AMC	Average Specific Mitigation Cost
CC	Combined Cycle
CCS	Carbon Capture and Storage
CEM	Capacity Expansion Model
CHP	Combined Heat and Power
COP	Conference of the Parties
DSM	Demand-side Management
E2M2	European Electricity Market Model
EEG	Erneuerbare Energien Gesetz
ERAA	European Resource Adequacy Assessment
ETS	Emission Trading System
EVA	Economic Viability Assessment
GHG	Greenhouse Gas
GuD	Gas und Dampf
MGA	Modelling to Generate Alternatives
MSR	Market Stability Reserve
NDCs	Nationally Determined Contributions
O&M/OaM	Operating and Maintenance
OC	Open Cycle
PDC	Price Duration Curve
PV	Photovoltaic
RLDC	Residual Load Duration Curve
SCM	Screening Curves Model
UCM	Unit Commitment Model
UNFCCC	United Nations Framework Convention on Climate Change
WACC	Weighted Average Cost of Capital
VRE	Variable Renewable Energy

1 Introduction

1.1 Climate Change Mitigation, Policy and the Importance of the Electricity Sector

In 1992, more than 30 years ago, the United Nations Framework Convention on Climate Change (UNFCCC) was adopted in Rio de Janeiro (UNFCCC 1992). Under this framework, numerous UN Climate Change Conferences (Conference of the Parties = COP) have been held, in which efforts to limit greenhouse gas emissions and the associated global warming are coordinated at the global level. One important milestone of these conferences was the Paris Agreement from 2015 in which Parties finally agreed on "Holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels (...)." (UNFCCC 2015). This is to be achieved through so-called Nationally Determined Contributions (NDCs), in which countries set and regularly revise their national reduction targets.

For this purpose, a 5-year cycle was defined in the Paris Agreement, in which NDCs shall be revised and resubmitted. A "global stock take" in which the progress in achieving the goals set in the Paris Agreement is monitored and reflected back to the parties shall thereby serve as a basis (UNFCCC 2015). An initial version of the NDCs had been submitted by all Parties to the Paris Agreement, and as of the end of July 2021 (before COP26), 113 of these Parties had also renewed their NDCs for the first time (UNFCCC 2021). However, NDC targets still result in an emission gap to reach the 2°C target. Furthermore, it is also not certain whether the targets set in the NDCs will actually be achieved, since "Policies implemented by the end of 2020 (...) are projected to result in higher global GHG emissions than those implied by NDCs." (IPCC 2022). Thus, major further efforts are required worldwide if the targets set in the Paris Agreement shall be achieved.

For this to succeed, the targets defined at the global level must be translated into policy measures. Accordingly, it is expected that policy measures at various regional levels will also need to be adapted on a recurring basis and, in particular, each time the NDCs are revised. This represents a major task for policymakers, in that existing measures will have to be revised regularly, adapted, checked for consistency and effectiveness, and additional measures may have to be defined or old ones to be terminated. An informative graphical representation of this cycle can be found, for example, in UBA 2018, Fig. 1.

Beyond the global level, targets are also defined for smaller geographic entities (such as countries, federal states, cities or even companies) or at sectoral levels. The achievement of these targets is often linked to corresponding policy measures.

Consequently, today it is not individual policy instruments that are used to combat climate change, but rather a variety of measures that act in different ways and at different levels and can also influence each other (both supporting and inhibiting). In existing literature, this combination of measures is often referred to as an instrument mix. A policy mix[1], on the other hand, is a broader term that can also include the associated policy-making process and policy strategy.

Summarizing the above means that several aspects contribute to the complexity of a policy mix: First, a temporal component, namely that targets are modified and tightened over time, requiring new policy interventions. Second, a regional/sectoral component, according to which targets and corresponding measures are defined at different policy levels and with different coverage. In addition, a mix of instruments is always embedded in an overarching policy strategy and its realization depends on respective local policy-making processes.

In addition, however, there are fundamental reasons why a combination of several instruments may, under certain conditions, be better suited to achieving a set goal than one instrument alone (e.g. IEA 2011; Sorrell and Sijm 2003).

The finding that there is already a multi-dimensional policy mix to combat climate change in place today - combined with the planned regular revision of targets under the UNFCCC - suggests that the policy mix will continue to become more complex rather than simpler in the future.

In achieving the ambitious GHG targets, the electricity sector has a key role to play for several reasons. While significant reductions have been achieved in this sector in many countries in the past, electricity sector emissions globally still have a very high share of total emissions. The power sectors were responsible for 23% of global GHG emissions in 2019 (IPCC 2022, TS-24) and even reached an all-time high in 2021 with an increase of emission by about 7% (after declining in 2019 and 2020 due to the pandemic situation (IEA 2022)). IEA 2022 consequently summarizes the current progress of global power sectors as "insufficient (...) to fulfill its critical role as a leading force in the decarbonization of economies around the world."

Second, decarbonization of other sectors is expected to be associated with electrification of end-use applications, and thus with increased electricity demand (e.g. Williams et al. 2012). Thus, the emissions intensity of electricity generation must decrease even more rapidly to achieve net reductions for power sectors.

Another aspect that makes the power sector relevant as a subject of policy mix analysis is that the power sector usually is a highly regulated sector. As a result, it was possible to implement

[1] A further distinction of these terms can be found in Section 1.2.

policy measures to reduce emissions at an early stage. In Germany, for example, the feed-in of renewable energy was promoted as early as 30 years ago under the Electricity Feed-In Act (the forerunner of today's Renewable Energy Sources Act, EEG). Since then, numerous instruments have been added, resulting in the complex and comprehensive policy mix that can be found today (Rogge and Reichardt 2016). The electricity sector therefore shows a lot of experience in terms of implementation and evaluation of policies, as well as a good database.

1.2 Policy Mixes, Instrument Mixes and Their Evaluation

The ex-ante and ex-post evaluation of policy instruments has long been subject to research and a wide range of literature exists on this subject. In order to facilitate the classification of this work into literature, the interrelations of policymaking and policy evaluation are presented schematically below and the literature on this complex of topics is structured afterwards.

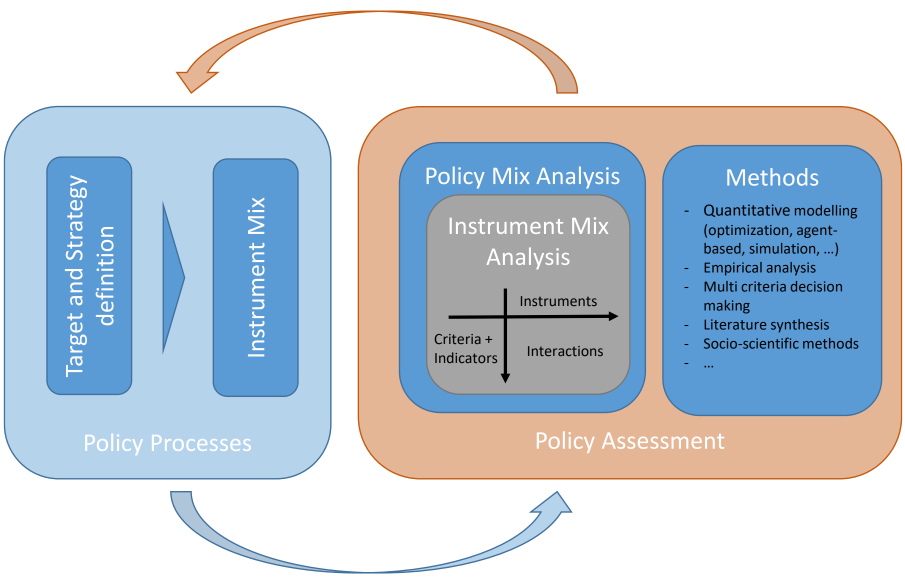

Figure 1-1. *Schematic relationships between policymaking and assessment of policy mixes*

Figure 1-1 represents the linkages between policymaking and evaluation as relevant for this thesis: There is a continuous feedback loop between policy definition and implementation on one side and a scientific policy evaluation on the other side. On the evaluation side, instrument mix analysis deals with the evaluation of several policy instruments according to one or more evaluation criteria and is thus a core component of policy assessment. A so-called policy mix analysis represents a more holistic approach and can additionally consider the policy-making process, strategic objectives as well as special characteristics of policy mixes in the assessment (adapted from Rogge and Reichardt 2016). In the definition of terms in Rogge and Reichardt

2016, a policy instrument is defined as a concrete measure that is used to achieve an overarching goal. Examples are the EEG in Germany or the Emissions Trading Scheme on the European level. A policy mix, on the other hand, is understood as a comprehensive concept and policy instruments or a mix of instruments always represent only one component of it. Compared to an instrument mix analysis, a comprehensive policy mix analysis also takes into account, for example, processes in policy-making, political strategies and special characteristics of policy mixes such as consistency and credibility. Such a policy mix analysis is interdisciplinary and numerous methods from different research disciplines are required. Examples will be provided in the literature summary that follows in the next paragraphs.

Once a policy assessment has been performed, results and recommendations shall be fed back to policymakers in order to provide feedback whether intended targets can or have been reached with the chosen policy mix. Where appropriate, results shall be incorporated in terms of adjustments, extensions, or terminations of existing policies. The importance of this iterative relationship between policy implementation and assessment is already referred to in Walker 2000 and applied to policies in energy transitions in Castrejon-Campos et al. 2020.

These relationships can be compared to a technical control loop in which a set point is specified by the political target definition. The achievement of this set point is then regularly measured by policy analysis and any deviations are reflected back to policymakers. This is the only way to enable policymakers to react to any deviations and take appropriate countermeasures within the related policy or instrument mix. The complexity of this "political control loop" is increased by the fact that usually more than one objective is defined at the political level, numerous instruments exist which might influence each other in terms of effectiveness and rapidly changing framework conditions.

Within the research area of policy evaluation concerning the decarbonization of electricity sectors, different strands of literature exist: Within the area of instrument and instrument mix analysis, one strand of literature focuses on the evaluation of individual instruments. These are evaluated using different methods in relation to different criteria in order to provide feedback to policymakers on the performance of a particular instrument (e.g. Laing et al. 2013 or Del Río 2012). Another strand of literature is concerned with the comparison between two instruments (in terms of one or more criteria), as a decision support for policymakers choosing between two alternative measures (e.g. Ekins and Baker 2001). In addition, there is literature that deals with a so-called mix of instruments, i.e. the interactions between two or more instruments. The focus in this literature is often on whether the instruments under consideration support or inhibit each other with respect to a specific policy objective, or whether they do not influence each other at all[2]. However, the interactions of more than two instruments are also examined in a few studies with regard to a selected set of criteria (e.g. Axsen et al. 2020 or Bertram et al. 2015). Multiple instruments related to more than one criterion are assessed in the literature by using multi-criteria decision making (overview in Pohekar and Ramachandran 2004 and Wang et al. 2009) or applying a systematic literature review (Peñasco et al. 2021 or van den Bergh et al. 2021).

While instrument (mix) analysis has a longer history in literature, the conceptualization of policy mix analysis has been added to this line of research more recently with the idea of developing more overarching approaches to analyze and evaluate policy mixes holistically (Flanagan et al. 2011). A central concept in this regard has been proposed in the context of innovation policy by Rogge and Reichardt 2016.

However, several aspects contribute to the fact, that the assessment of instrument mixes as well as policy mixes show a high degree of complexity[3]: One is the fact that a policy mix emerges and changes over time and policy instruments are added, changed or terminated. Second, policy objectives and measures are defined in different policy domains and at different political and geographic levels. Interactions can arise in all of these dimensions (Rogge and Reichardt 2016). In addition, the power sector is confronted with particularly rapidly changing framework conditions. These include, among others, highly volatile energy prices, carbon prices, energy demands, as well as rapidly changing political objectives and related measures (e.g. Castrejon-Campos et al. 2020).[4] Although work is ongoing to address this complexity (Borozan 2022, Castrejon-Campos et al. 2020, Kosow et al. 2022, Schmidt and Sewerin 2019 and Corradini et al. 2018), there is a huge task remaining until a regular, effective and integrated feedback loop between the policy/instrument assessment and the policy making side can be established.

This thesis classifies in the literature of instrument mix analysis. In the course of the work, three core instruments for the decarbonization of the power sector and their interactions with respect to their techno-economic criteria are analyzed. The need for such a systematic instrument mix analysis especially with regard to more than two instruments is highlighted e.g. by van den Bergh et al. 2021. This analysis thus provides a building block for a higher-level policy mix analysis, as proposed by Rogge and Reichardt 2016. The methodology adopted in

[2] For example, interactions of the ETS with a promotion of renewable energies are discussed in detail, summarized e.g. in del Río González 2007 or Lindberg 2019.

[3] An approach to determine the size and complexity of a policy mix is proposed in Limberg et al. 2022.

[4] Already during the period of preparation of this thesis, central assumptions for the power sector have changed. For example, in the first publication, a coal phase-out in Germany was still one of three scenarios; at the time of publication of the last paper, the coal phase-out was already one of the basic assumptions.

this thesis is a two-step approach, in which a simplified model experiment is applied first to highlight energy-economic coherences. Subsequently, a case study is conducted to quantify the effects. To the author's knowledge, this approach has not been used before in the context of a systematic instrument mix analysis.

A complete picture of research gaps and the corresponding contribution of this thesis is summarized in Chapter 1.4 and the methodology is described in detail in Chapter 1.5. First, however, the following Chapter 1.3 starts with the theory of combining instruments with an ETS and then outlines the selection of instruments and evaluation criteria for this work.

1.3 Decarbonizing Instruments in the Electricity Sector: Theory and Evaluation Criteria

The first part of this section provides a brief overview of the economic theory on externalities as well as a short introduction to the history of the EU ETS as a central instrument of European climate policy. Subsequently, other instruments for decarbonization of the power sector are classified and the instruments and evaluation criteria analyzed in this paper are outlined. Finally, the discussion of interactions between the EU ETS and other instruments is summarized from literature.

GHG emissions represent a negative externality, which means that the polluter of the emissions does not directly bear the costs of their consequential damages. In the case of GHG emissions, this is of particular relevance, as GHGs have a global impact compared to other emissions and can cause very high costs (Stern 2007, 310 f.). In theory, there are approaches how such externalities can be internalized, i.e. how the costs can be imposed on the polluter through price signals, which at the same time provides an incentive for the emitter to avoid them. With regard to the design of such internalization, two approaches are discussed in particular: A tax on emissions (Pigou 1920) or the trade of emission rights (Coase 1960). Both approaches are considered cost-effective in theory because, under optimal market conditions, they lead to a full internalization of externalities (Ekins and Baker 2001). For this to happen, however, all conditions of a perfect market must be met, including in particular complete information, a known market price and no transaction costs (see e.g. Stoft 2002, S. 53).

In European climate policy, the 2000s saw the opening up of a policy previously dominated by command and control instruments to a broader range of instruments that also included market-based approaches (Yamin 2005). Proponents of market-based approaches criticized above all the poorer cost efficiency of command and control mechanisms compared to market-based approaches (Ekins and Baker 2001). Several aspects[5] eventually led to the establishment of an emissions trading system in the EU and the introduction of the EU ETS as an instrument that is superior in terms of cost-effectiveness (Goulder and Parry 2008). The Green Paper published by the European Commission that was aimed at supporting the introduction of the EU ETS summarizes well these considerations: "Emissions trading […], will help reduce the cost to the Community of respecting its commitments. Together with other polices and measures, emissions trading will be an integral and major part of the Community's implementation strategy." (COM 2000)

The EU ETS still represents a central instrument for reducing GHG emissions in the European energy industry, as became evident most recently with the announcement of the "Fit for 55" package (Council of the EU 12/18/2022).

In addition to the EU ETS, numerous other instruments have an influence on the decarbonization of the power sector. Some of these are instruments that existed prior to the introduction of the ETS, such as the EEG, but some are additional measures introduced alongside. The interactions of these instruments with the ETS will be discussed later in this chapter. In the following, the instruments are first described and classified.

Various classifications of policy instruments can be found in literature, from environmental policy (Wietschel et al. 2002) or from climate policy (Barker and Crawford-Brown 2014; Stern 2007), where the classification is made at different levels in each case. Among others, instruments can thereby be distinguished by mechanism of action, by regional coverage, by executive body, or by whether the instruments are applied on the supply or demand side. Since no definition of instruments was found in the literature that explicitly refers to the decarbonization of the power sector, an own definition is developed in the following. For this purpose, it seems important to first identify all instruments that actually have an impact on the decarbonization of the power sector (but do not necessarily have this as an explicit goal). For this purpose, it is helpful to start from the possibilities of emission reduction in power generation. These are listed in Wietschel 1995, among others, and can be described as follows: CO_2 emissions arise from the combustion of fossil fuels and thus in the electricity sector on the generation side, i.e., from the generation of electrical energy by thermal power plants. Consequently, one mitigation option consists of reducing electricity demand, which means that less electricity has to be generated and thus fewer emissions are emitted. Corresponding energy savings on the demand side can be realized through increased efficiencies or

[5] Among other things, one could refer to first practical experiences with emission trading systems from the USA, flexible mechanisms were mentioned in the Kyoto Protocol for the first time as enablers to meet its targets and the proposal of an EU-wide CO_2 tax had failed before (see Convery 2009).

substitutional measures. Alternatively, a reduction can be achieved by emitting fewer emissions during electricity generation, which can be achieved either by switching to generation technologies with lower CO_2 intensity or by increasing the efficiency of the generation technologies currently in use.

In order to obtain a comprehensive list of measures that have an impact on the above mentioned mitigation options, inputs from several publications (Blechinger and Shah 2011; IPCC 2001; Peñasco et al. 2021; Barker and Crawford-Brown 2014) were combined. The resulting list of instruments is then structured along their extent of influence on the decarbonizing the power sector in Figure 1-2 (suggested among others in Rogge and Reichardt 2016). Instruments are therefore divided into core instruments (instruments with direct or significant impact on emission reductions), high impact instruments, and supporting instruments. The last category describes measures that influence emission reductions rather indirectly or that are used to compensate for possible adverse side-effects (for a definition, see e.g. Ürge-Vorsatz et al. 2014) of the first two instrument categories.

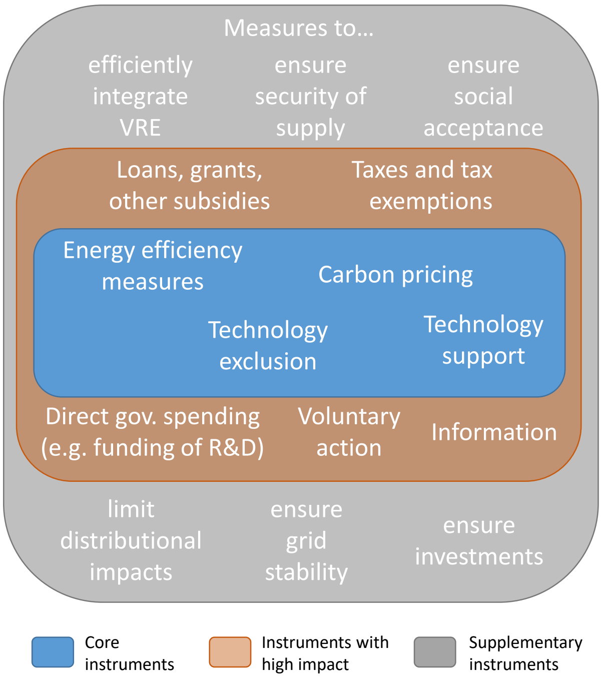

Figure 1-2. *Political instruments and their extent of impact on decarbonization of the electricity sector*

In Figure 1-3 the core instruments identified this way are assigned to possible abatement measures in the power sector and thus also to the generation and/or demand side. For this thesis, one example of each core instrument on the supply side is explored, with reference to the German electricity sector:

- The EU ETS as an example for CO_2 pricing in a market-based approach,
- the EEG as an example of support for low-emitting or renewable technologies based on feed-in tariffs and
- the coal phase-out as an example for the exclusion of a technology based on a regulatory measure.

Thus, with the three core instruments for decarbonization of the power sector, three different approaches of instruments are covered (market-based, feed-in tariff and regulatory), but at the same time the number of instruments remain manageable to draw concrete conclusions from the instrument mix analysis.

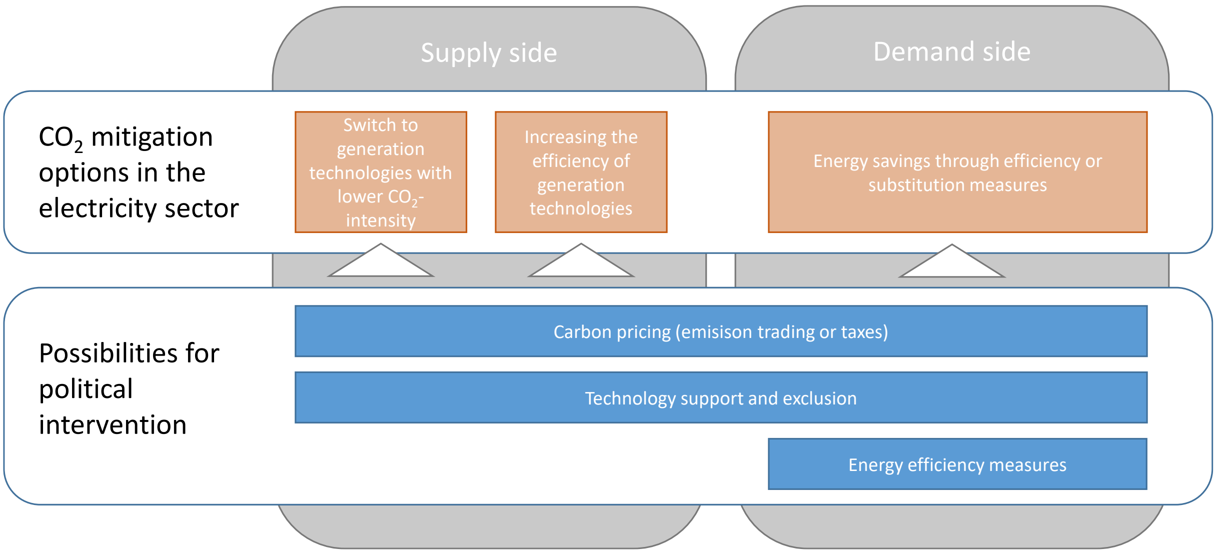

Figure 1-3. *Possibilities for political intervention to mitigate emissions in electricity sectors*[6]

After the definition of the instruments, the techno-economic evaluation criteria applied in this work are explained in the following: Criteria for evaluating policy instruments and their interactions are also defined very differently in the literature and are highly dependent on the policy area under consideration. However, within the field of energy transition policies, many sources refer at least to similar high-level evaluation criteria. Those are namely environmental, technical, economic and social outcomes of policy instruments. Table 1-1 summarizes three relevant sources that apply those criteria slightly different.

Out of these three sources, Peñasco et al. 2021 is the most relevant for this work, since their focus lies specifically on decarbonizing instruments for the energy sector. Moreover, they make a very clear distinction between criteria per se and indicators that can be used to evaluate these criteria. Their basic structuring is used for the list of evaluation criteria in this thesis. However, some insights from specific literature on the power sector are incorporated:

[6] Own illustration with input from Wietschel 1995 and Barker and Crawford-Brown 2014.

Security of supply is added as one very important indicator and technological effectiveness is renamed to technological effects. The latter follows the consideration that technological effectiveness can be evaluated e.g. in case of a technology support instrument but is difficult to be evaluated in case of a technology-open instrument such as the ETS. Moreover, the focus of this thesis is on the evaluation of techno-economic criteria. For the evaluation of the criteria investments and social effects, other methods such as social-scientific methods, are much more suitable, so that a synthesis of results from different research areas would make sense here in order to achieve a more complete instrument mix analysis. However, the results on the criteria considered here can provide helpful inputs for the evaluation of the remaining criteria. For example, findings on the criteria of distributional effects and cost-related effects are relevant for assessing social acceptance, and results on the use of technology (investments) provide input for assessing effects on innovation and employment. Table 1-1 summarizes the categories that are applied in the three publications discussed above and shows the structure of techno-economic criteria and indicators that emerges for this thesis.

Table 1-1. *Evaluation criteria for policy instruments*

<table>
<tr><th>Peñasco et al. 2021</th><th>Wang et al. 2009</th><th>Oikonomou and Jepma 2008</th></tr>
<tr><td>Environmental effectiveness</td><td>Environmental aspects</td><td rowspan="2">Effectiveness</td></tr>
<tr><td>Technological effectiveness</td><td>Technical aspects</td></tr>
<tr><td rowspan="2">Cost-related outcomes</td><td rowspan="3">Economic aspects</td><td>Efficiency</td></tr>
<tr><td>Impact on energy and market prices</td></tr>
<tr><td>Innovation outcomes</td><td>Innovation</td></tr>
<tr><td>Distributional outcomes</td><td rowspan="3">Social aspects</td><td rowspan="3">Impacts on society</td></tr>
<tr><td>Competitiveness</td></tr>
<tr><td>Other social outcomes</td></tr>
</table>

<table>
<tr><th colspan="2">Used in this thesis</th></tr>
<tr><th>Criteria</th><th>Indicators</th></tr>
<tr><td>Environmental effectiveness</td><td>Emission reductions [€/tCO₂]</td></tr>
<tr><td>Cost-related effects</td><td>Reduction cost [€/tCO₂], total cost [€]</td></tr>
<tr><td>Technological effects</td><td>Optimal technology mix/investments [MW], security of supply</td></tr>
<tr><td>Distributional effects</td><td>Electricity prices [€/MWh], producer margins and NPVs</td></tr>
<tr><td>(Innovation)</td><td>-</td></tr>
<tr><td>(Social effects)</td><td>-</td></tr>
</table>

After defining the instruments under consideration and their evaluation criteria, the following section revisits the discussion on interactions between an ETS and complementary measures. According to the theory discussed above, an emissions trading system is superior to other instruments with respect to the criterion of cost-effectiveness. Moreover, the fix quantity restriction (cap) on emissions implies, that additional instruments affecting the same emission source no longer have an emission-reducing effect. For example, if emissions were reduced by a VRE subsidy and allowances were "freed up" as a result, these could be used by other emitters since the absolute cap remains constant.[7] In addition, emission reductions through complementary measures could lower the carbon price and thus even negatively influence the efficiency of the ETS (Sijm 2005). The extreme conclusion from these considerations is that all instruments addressing emissions already covered by an ETS (often called "overlapping policies" in literature) may be redundant or even counterproductive (compare e.g. Görlach 2014). However, this conclusion is based on two important assumptions: First, the ETS market is operating perfectly (e.g. with perfect information of all actors) and second, the goal of cost efficiency is the only or dominant policy objective. Questioning these assumptions, some literature exists that supports the existence of additional instruments besides the ETS under certain conditions. Lecuyer and Quirion 2013 for example find, that it can be beneficial to implement an additional instrument when uncertainties are taken into account. Lehmann and Gawel 2013 find restrictions to technology development and adoption to be the most important reason to apply a VRE support scheme in parallel. Görlach 2014 highlights the difficulty to adequately trigger long-term innovation and investment decisions within an ETS. This complete discussion is summarized very well in Sijm 2005 in three broader aspects that may justify additional action besides the ETS, namely "(1) improving the design of the EU ETS, (2) correcting for market failures, and (3) meeting other policy objectives besides CO_2 efficiency."

Finally, a relevant design element of the EU ETS with regard to interactions between overlapping policies is the Market Stability Reserve (MSR). The MSR is a dynamic, quantity-based adjustment mechanism of the EU ETS that causes allowances to be withdrawn from the market and transferred to a reserve as soon as a threshold of allowances in circulation is exceeded. From there, allowances can be cancelled under certain conditions or returned to the market (see e.g. Perino 2018 for a good summary).

The instrument was introduced with the objectives of reducing the historically grown surplus of allowances, making the system more resilient to unexpected demand shocks (European Commission 2014), stimulating long-term investments in low-carbon technologies and strengthening synergies with overlapping policies (Perino and Willner 2016). However, whether the MSR actually meets (and can meet) these objectives is controversial. Even the answer to the question of whether overlapping policies in combination with the MSR have an impact on cumulative emissions in the ETS is unclear (Bruninx et al. 2020; Perino 2018; Rosendahl 2019; Perino and Willner 2016).

[7] This effect is also called waterbed effect in literature, e.g. defined by Flachsland et al. 2020 as "unilateral emission reductions that are either ineffective as cumulative EU-wide emissions remain unchanged, or that even lead to an increase in cumulative emissions".

After having outlined the theory of ETS and overlapping instruments, as well as the instruments and criteria applied in this thesis, the following section turns on the specific research questions for this work.

1.4 Research Question and Concept

Following the discussion from the last section, the specific research questions for this work can be summarized as:

1. How should the combination of the three core policy instruments carbon pricing, support of variable renewable energy (VRE) and coal phase-out be evaluated with respect to the criteria of cost-related, technological and distributional effects on the generation side?
2. What are the resulting recommendations for the design of the policy mix in the power sector?

In order to answer these questions, this thesis is structured into three main sections, each of which has been published in a paper as a self-contained individual analysis. The answer to these two questions runs through all three papers.

The first paper of this thesis (Chapter 2) focuses on cost-related effects of carbon pricing and a simultaneous coal phase-out. Therefore, interactions between an ETS and overlapping instruments are examined. A literature research shows how political targets are translated into restrictions in energy system models. The effects of an overlapping instrument on total system cost and mitigation costs are demonstrated in a generic mitigation cost curve as well as in several specific scenarios.

The focus of the second paper (Chapter 3) is on distributional effects of the three instruments carbon pricing, support of VRE and coal phase-out (individually and in combination) by considering the indicators of electricity prices and contribution margins. A simplified screening curves model is set up to explain implications of instruments targeting the decarbonization of electricity generation. Again, a detailed case study on the German electricity sector supports this simplified demonstration.

While investments and thus security of supply are taken as given in the first two analyses, the third analysis (Chapter 4) examines whether investments would actually be made under non-optimal market conditions. Specifically, this means that a market situation without scarcity prices is simulated by combining an investment and a dispatch model. An iterative consideration of asset profitability under these conditions allows to evaluate changes in the optimal technology composition and implications for the level of security of supply. In summary, the focus of Chapter 4 lies on technical and distributional effects by considering the indicators of profitability of investments (NPVs), the optimal technology mix and security of supply.

Summarizing the foci of the three papers implies that all of them contribute some part to answering the first research question. Figure 1-4 additionally shows how the individual papers integrate into the matrix of instruments and techno-economic evaluation criteria (that have been introduced as part of Figure 1-1). The dashed blue line represents the fact that the first paper only deals with two of the instruments, but conclusions from this analysis can be transferred to the existence of other instruments besides carbon pricing (discussion in Section 5.1).

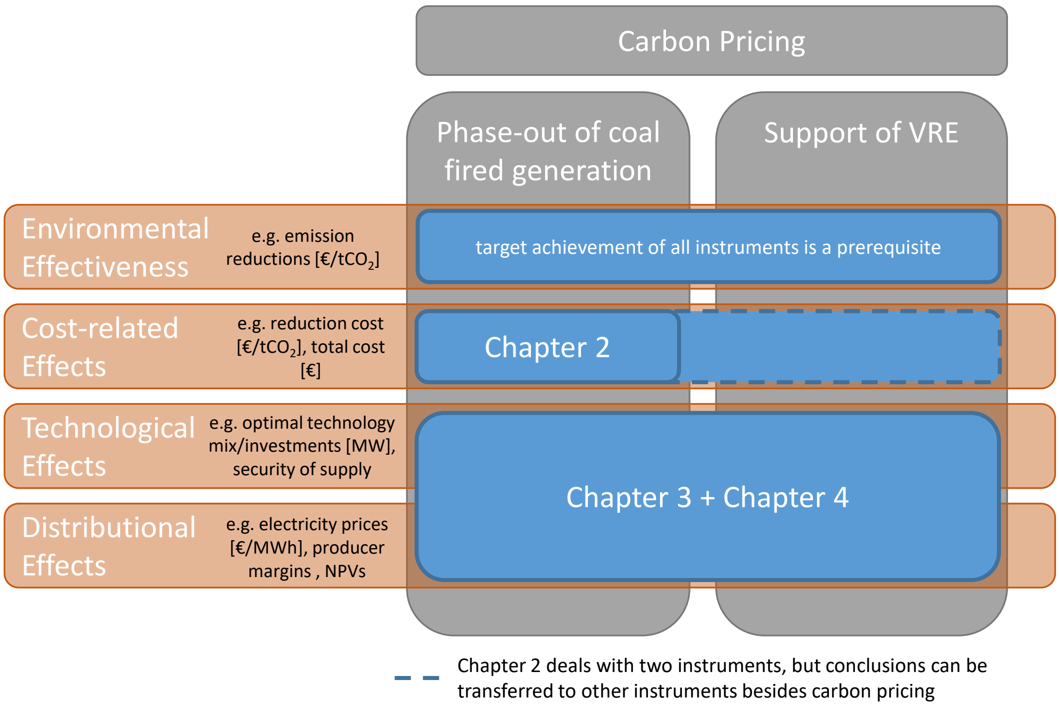

Figure 1-4. *Structure of the thesis and integration in the techno-economic instrument evaluation framework.*

Part of this work is the evaluation according to the blue marked criteria in Figure 1-4. The evaluation of the criterion environmental effectiveness does not provide much insight (or is trivial) with the chosen methodological approach, because the goals are exogenously given to the model and are thus fulfilled in all calculations for all instruments.

Answers to the second research question are part of the discussion sections of each paper as well as the synthesis in Section 5.2.

1.5 Methodology

Regarding the methodology of instrument mix analysis, three specific research gaps can be identified from literature:

First, explanations in Chapter 1.2 have outlined, that holistic policy mix analyses are essential to provide regular feedback to policymakers. This is the only way to ensure that the existing policy mix is suitable to achieve politically desired goals. The interactions within a policy mix can be very complex and so can their analysis, but this has only been conceptualized in the literature in recent years. Among other conclusions, van den Bergh et al. 2021 identify a need for research in this area on the evaluation of the combination of more than two instruments and the derivation of recommendations for action that are as concrete as possible (see Chapter 1.2 for details).

Second, this complexity in evaluation and, more importantly, the use of different methods also poses a challenge for communicating results and findings to relevant decision makers or the public. In this regard, the design and development of policy mixes exemplifies how communication between research and policy has become an increasingly challenging issue in recent years. E.g. Turnheim et al. 2020 call in this context for “more thorough evaluations of relevant policy support mechanisms”, to increase efforts to merge currently fragmented research results and thus to work on an improved communication from the research community towards decision-makers. In addition, they suggest supporting general research findings with concrete case studies and graphical representations.

Third, studies on energy transformation research are usually calculated with very complex and high-resolution models, but often only few scenarios are considered. Such scenarios run the risk of quickly becoming obsolete as framework conditions change. DeCarolis 2011 supports this thesis by stating that single, very detailed scenarios (and thus a lack of consideration of uncertainties) can even lead to the cognitive limitation of possible solution scopes. Among others, Fodstad et al. 2022 therefore call for a greater consideration of uncertainty within energy transformation studies and corresponding modeling exercises.

In summary, the three areas in which research needs exist are

1. the consideration of high uncertainties in energy transformation scenarios,
2. the communication of complex results of transformation research to policy
3. and the evaluation of policy instruments beyond the comparison of two single instruments.

The work in this thesis addresses parts of all three of these research gaps:

1. The consideration of high uncertainties is tackled by the application of highly abstracted model setups and scenarios (sometimes called “model experiments”, see below in this chapter). The explanation of energy-economic coherences thus provided, aims to convey an understanding of interrelationships rather than purely quantitative scenario results. This understanding enables a better and faster estimation of the

effect of changing framework conditions and thus an improved handling of uncertainties.

2. Appropriate communication formats are used to generate this understanding and to communicate the results of the model experiments in a sustainable manner: Results and interrelations will be first presented graphically and then supported by a specific case study. This way of presentation intends to simplify the communication of energy-economic coherences towards decision-makers with regard to the interactions of several policy instruments in the electricity sector.
3. Interactions of three core instruments contributing to the decarbonization of electricity sectors will be analyzed systematically. The individual analyses will focus on one or more of the techno-economic criteria used to evaluate political instruments with a particular focus on overlapping instruments with the EU ETS. The synthesis of the results can provide a building block for a more holistic policy mix analysis.

For all three analyses of this thesis, the fundamental linear optimization model "European Electricity Market Model" (E2M2) is applied in different configurations. The model is based on the fundamental equations of Sun 2013 and has since been frequently applied and methodologically extended. In its basic configuration, it maps the European day-ahead electricity market in high temporal resolution (hourly) and optimizes power plant capacity expansion and dispatch simultaneously. In the objective function, the system costs (consisting of investment costs, fixed operating costs and variable costs) are minimized. In addition to meeting the exogenously specified electricity demand, numerous technical and economic restrictions are set in the model, such as the start-up and shut-down behavior of conventional power plants or restrictions on the use of storage facilities. Where case studies are calculated in this thesis, the regional focus is set on the German electricity sector, so that a simplified version of the model with only one market area is used here. Output variables of the model are typically hourly resolved dispatch time series (if required also by power plant unit), capacity expansions and removals, electricity and carbon prices, as well as emissions. The configurations of E2M2 applied in the three individual analyses can be found in the following Table 1-2 and in the respective methodological chapters of the publications.

Table 1-2. *Overview of E2M2 configurations for the three case studies*

	Paper 1 (Chapter 2)	Paper 2 (Chapter 3)	Paper 3 (Chapter 4)
Regional scope	Germany	Germany	Germany
Scenarios	BAU,CAP,CP,CAP+CP,BUDGET	BAU,EE,CP,CO2,MIX	-
Uncertainty handling	deterministic	deterministic	deterministic
Time resolution	2 hours	1 hour	2 hours
Existing technologies	34 groups	33 groups, 125 single plants	12 groups
New technologies	20	20	8
CO_2 restriction	cap and budget	cap	cap
Foresight	annual	annual	annual, perfect
Desinvest	no	no	yes

Furthermore, the implementation of the policy instruments focused in this thesis in the linear optimization model E2M2 is explained in the following.

1. Emissions trading

   An emissions trading system is a quantity-based instrument, according to which the amount of emissions is limited by the politically defined cap and the corresponding quantity of allowances issued. This can be implemented in an optimization model by introducing an upper bound on emissions. As in an optimally designed ETS, abatement options are then realized in order of increasing abatement costs. This way of implementing an ETS in a linear optimization model provides the possibility to evaluate the carbon price that would occur in the trading of allowances in a perfect market (Fais 2014, ch. 4.2). In the context of this thesis, the ETS is modeled in this way. Interfaces and feedbacks with other ETS sectors and the non-ETS sector are simplified by assuming fixed emission quantities, which seems justifiable due to the otherwise simplified model assumptions.

2. Promotion of variable renewable energies

   The design of renewable energy support varies across countries and regions and can therefore also be modeled in different ways (see Fais 2014, ch. 4.3 for details). Within the three analyses of this thesis, it is modeled by a minimum capacity investment level (lower bound), which is specified exogenously for the technologies concerned. Minimum investment levels are taken from the targets of the relevant regulation (e.g. EEG 2017). Thus, it is assumed that the subsidy works exactly as intended. The corresponding technologies are added to the system at least to the specified extent and are available for generation, even if this does not correspond to the optimal solution without this restriction. However, if it represents the optimal solution in terms of system costs (i.e. if these technologies become economically viable at a certain point of time), additional capacity can be added beyond this minimum requirement.

The model used in the third paper (Chapter 4) contains a methodological advancement that allows to decommission generation capacity before the end of its lifetime. Here, a subsidy for renewable energies is taken into account in that these technologies cannot be retired before the end of their subsidy period (e.g. 20 years).

3. Coal phase-out

   A coal phase-out can also be modeled in different ways depending on its design (lifetime limitation, limitation of residual emission quantities, tradable certificates, etc.). In this work, it is modeled by overriding the average expected lifetime of existing hard coal or lignite power plants by an exogenously specified retirement date, after which plants are no longer available for generation. New investment in coal-fired power plants is excluded altogether. This type of modeling thus represents only an intervention in the model's input data and not in the model structure, as is the case with the first two policy instruments.

With the above mentioned model outputs under minimization of system costs, linear optimization models are fundamentally important for the evaluation of policy instruments in the energy system. Many (but not all) of the evaluation criteria can thereby be answered consistently with one methodological approach and the results can additionally form a basis for the evaluation of numerous other criteria. Consequently, this approach has frequently been used to evaluate policy instruments (e.g. DeCarolis 2011). However, one important issue arises with regard to the meaningfulness of the results: These models are often very large models, due to their high temporal and regional resolution and the very detailed mapping of technical and economic restrictions, combined with a simultaneously long time horizon. This "as close to reality as possible" modeling is useful to be able to draw quantitative conclusions from firmly defined scenarios. However, the complexity and the strong dependence of results from chosen input parameters makes it difficult to draw more general conclusions about power sector coherences (DeCarolis 2011) or to e.g. isolate effects of individual political measures.

To compensate for this shortcoming, a two-step approach is chosen in the three individual analyses of this work: In the first step, a highly simplified model is used to enable a schematic representation of cause-effect relationships. The need for and benefit of such strongly simplified model runs are also described in the literature. For example, Gils et al. 2019 advocate model experiments with "strongly reduced systems" with regards to future model comparisons. In fact, model experiments have recently been used in the energy industry environment, mainly in the context of large-scale model comparisons (Berendes et al. 2022; Gils et al. 2022; van Ouwerkerk et al. 2022). Model experiments are also referred to as stylized/reduced test cases, systems or scenarios in literature.

In this work technologies of existing and new power plants or the temporal resolution are strongly reduced or the emission abatement cost curve is strongly simplified for the model experiments. The simplification of the problem achieved in this way enables, above all, a good graphical representation of the cause-effect relationships in the case of political interventions in the system.

However, due to their low level of detail, those models are not capable to provide reliable quantitative results. So in two of the three individual analyses, a case study is then conducted in the second step, which is calculated with the higher temporal and technical resolution of E2M2 and under more detailed scenario assumptions. This two-step approach is also mentioned in literature as valuable for improving communication between transition research and policy (Turnheim et al. 2020).

This two-step methodological approach is applied in three distinct analyses in the following chapters: The first analysis (Chapter 2) investigates the impact of political goals besides an emission target on total and average mitigation cost. The second analysis (Chapter 3) answers the question on how a coal-phase out redistributes costs and profits when carbon pricing and VRE support is already in place. Finally, Chapter 4 deals with the question of profitability of generating assets under insufficient scarcity pricing.

2 Impacts of Complementing Goals besides Emission Targets on CO_2 Mitigation Cost: A Model-based Analysis

Authors: Annika Gillich, Lukasz Brodecki, Kai Hufendiek

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Author contributions:

The following Table 2-1 shows the contributions of the author and co-authors to this paper, using the "CRediT author statement" system (Elsevier 2019). At that time, Lukasz Brodecki was an employee at the Institute for Energy Economics and Rational Energy Use. He performed the second case study in the paper with the energy system model TIMES Pan-EU. Conceptualization was done in several joint discussions, leaded by Annika Gillich. Kai Hufendiek moreover provided the resources, did the funding acquisition and reviewed the submitted manuscript.

Table 2-1. *Author contributions first paper*

	Annika Gillich	Lukasz Brodecki	Kai Hufendiek
Conceptualization	x	x	x
Methodology	x	x	
Software	x	x	
Validation	x	x	
Formal Analysis	x	x	
Investigation	x	x	
Resources			x
Data Curation	x	x	
Writing – Original Draft	x		
Writing – Review & Editing		x	x
Visualization	x	x	
Project Administration	x	x	
Funding Acquisition			x

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Impacts of complementing goals besides emission targets on CO_2 mitigation cost: A model-based analysis

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ABSTRACT

Global temperature responses to the stock of greenhouse gases (GHG) in the atmosphere, rather than to the flow. However, Nationally Determined Contributions as submitted under the Paris Agreement, suggest that a large share of policies still focusses on year-specific GHG targets, which do not full comply with the stock problem. A literature review performed for this paper supports that those politically set caps are taken over by energy system models.

However, due to a higher flexibility in the choice of mitigation options, a time-spanning carbon budget can achieve the same cumulated emission reduction than year-specific caps - but at lower average mitigation cost. In this paper we demonstrate in a first step that the introduction of a second policy besides year-specific caps can lead – counterintuitively – to lower average mitigation cost than a cap alone. The reason is that the second policy induces a mitigation pathway, that approaches the carbon budget solution. In a second step, reasons behind this effect are demonstrated in a generic mitigation cost curve analysis. The application of two models with different regional and thematic foci emphasizes that this is not a case-specific effect, but can occur under various circumstances.

We conclude that using a scenario with a budget constraint on GHG emissions more frequently - in addition to widespread cap or price scenarios - supports policy-makers to identify pathways at lowest mitigation cost. As a second benefit, the generic demonstration of mitigation cost curves in this paper helps modellers to gain a better understanding of model results under various political constraints.

1. Introduction

The implementation of ambitious greenhouse gas (GHG) reduction goals, as agreed in Paris, is going to result in additional power system costs. However, it should be a target for policy makers to keep this increase of power system costs to a minimum when complying with those targets. Hence, defining a proper policy framework and selecting appropriate instruments for inducing the GHG abatement pathway with least marginal abatement cost becomes crucial.

Looking at the Nationally Determined Contributions (NDCs), submitted under the Paris Agreement, it becomes obvious that GHG targets are often defined as a proportional reduction target of emissions for predefined milestone years [1]. Also Millar et al. [2] come to the conclusion that the majority of policies is still based on fixed targets for certain milestone years. However, it is proven that the increase in temperatures relates directly to the cumulative amount of emissions and that a carbon budget provides a better guide to long-term effects on warming than emission targets set for certain years (summary of studies e.g. in Ref. [3]). But additionally, and this is the focus of this paper, setting a time-transcending carbon budget will allow for more flexibility in the selection of mitigation options and therefore allow to reach the same cumulated emission reduction at lower system cost than with year-specific caps or prices (e.g. shown in Refs. [4,5]).

In order to emphasise this point, we have evaluated 117 publications[1] in the area of energy system modelling with various regional and thematic foci, including peer-reviewed as well as grey literature. Fig. 1 shows the distribution of CO_2 restrictions used in those publications. It becomes obvious, that the majority of the scenario analyses considers a minimum share or capacity of renewables, 33% consider a CO_2 price or cap in their scenarios, while only 2% of the reviewed publications use a CO_2 budget as a constraint. The model foresight is often not mentioned explicitly in literature.

The goal of this paper is to illustrate how the selection of CO_2-constraints impacts model results and which approach should be used in order to derive sound policy recommendations from the assessment of mitigation pathways in energy system models. To achieve this, we show in a first step that through the implementation of political goals, introduced in parallel to a cap (or price) on CO_2, lower average specific CO_2

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[1] A list of these publications can be provided by the corresponding author upon request.

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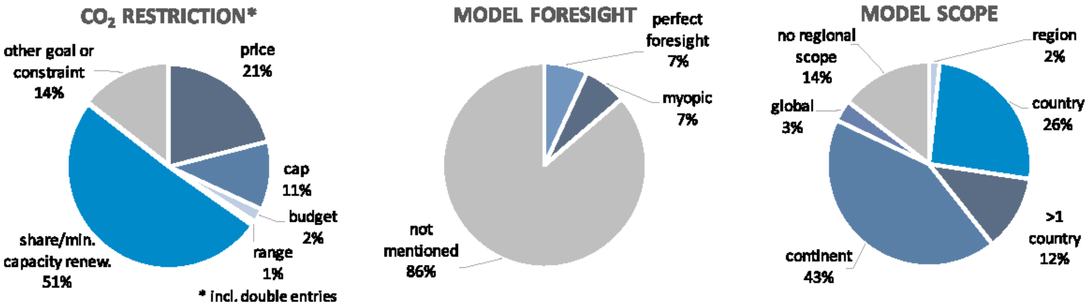

Fig. 1. CO_2 constraints used in literature.

mitigation costs can be reached. This is done in two modelling examples with a description of models, scenarios and results in section 2 and 3. In a second step, we explain the reasons behind this effect in section 4.

2. Modelling approach and scenario definition

To demonstrate the above mentioned effect, we apply two cases and use two energy system models, both based on linear programming with an objective function of minimizing the overall system cost. These system costs consist of costs that occur from the fulfilment of energy demands, i.e. major components are fuel cost, other variable cost for plant operation, fix plant cost, plant investment cost and transmission cost. Consequently, we do not consider the complete social cost of carbon in this paper and cannot draw any conclusions in this direction. Following the definition of e.g. Ref. [6], costs in this paper represent capacity cost and energy cost only, but do not include environmental cost or damage cost.

By using two independent energy system models we provide a basis for robust argumentation regarding the mentioned effect. Furthermore, this approach allows us to identify two different causes and thus leads to additional insight on how to avoid such distortion. While the first case considers the total energy system of a medium sized municipality in southern Germany [7,8], modelled with TIMES Local, the second case deals with the entire German power sector, modelled with E2M2. We use two model applications with different sectoral and regional foci to emphasise that the observed effect is not an isolated case, but can occur when considering various research questions concerning the energy sector. Despite the different regional coverage, we implement four comparable scenarios and compare the results of both models regarding their level of emission reduction and their specific CO_2 mitigation costs. Fig. 2 summarizes the approach in this paper: the three scenarios BASE, CAP and BUDGET are run with comparable restrictions on CO_2 in both models, a fourth scenario is specific for the respective case. The four scenarios are first compared for each case separately and afterwards underlying effects are discussed in a generic way for both cases.

As a reference, from which emission reductions and reduction costs are calculated, a BASE scenario is calculated in both cases, to determine the resulting energy system without any constraints regarding CO_2 emission reductions or similar limitations. The second scenario includes a CO_2 cap for each of the model years. The overall goal in TIMES Local is a

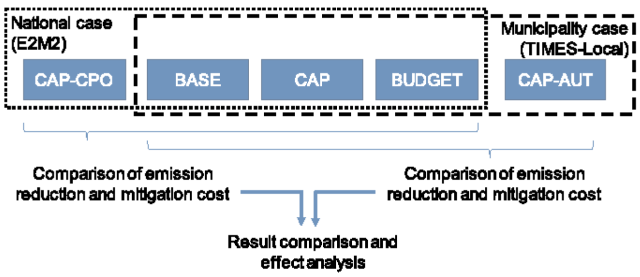

Fig. 2. Modelling approach using E2M2 and TIMES Local.

reduction of CO_2 emissions by 90% in 2050 compared to 1990. In E2M2, CO_2 targets are defined in line with [9] through a projection of 2030 goals until 2050, resulting in a reduction of 95.5% compared to 1990 levels for the electricity sector. For years in between the base year and the milestone years 2030/2050, goals are interpolated and defined as an upper bound in the models. The third common scenario is called BUDGET where only an overall CO_2 budget for the time horizon between the base year and 2050 is implemented and no year-specific CO_2 caps are defined. Instead, the sum of the yearly upper bounds from the CAP scenario is implemented as one upper bound over the entire modelling period. To ensure comparability of the resulting circumstances in 2050 (same CO_2 levels) between all CO_2 limiting scenarios, solely for 2050, emissions in BUDGET are limited to the same level as in the CAP scenarios. The fourth scenario is defined differently for the two cases and is characterized by the same year-specific caps on CO_2 emissions as in the CAP scenario but including an additional restriction. This scenario is used to demonstrate that introducing a second policy besides a year-specific cap, can – counterintuitively – reduce average mitigation cost, because the mitigation path moves more towards the solution of the BUDGET scenario. In the municipality case, this extra constraint targets a minimum degree of energy self-sufficiency (autarky) of 75% over the whole modelled region by 2050. In other words, 75% of the primary energy used in 2050 must be generated locally. Again, this goal is linearly interpolated from the base year for each of the time steps until 2050 (scenario CAP-AUT). In the national case, the additional constraint beside the year-specific CO_2 caps, targets an early phase-out of lignite and hard coal power plants in Germany (scenario CAP-CPO). Whenever something applies to both scenarios, these two scenarios are also referred to as CAP + 2nd in the following text. A summary of scenario definitions is listed in Table 1.

No further changes are implemented between the scenarios for both models. In the next section, the two models and most relevant model settings are briefly introduced.

2.1. The integrated MARKAL-EFOM system (TIMES) scenario framework

The basis of the approach is a municipality case applying the model TIMES Local, a linear optimization model based on the model generator TIMES. An energy system is mapped in bottom-up technological detail as a network of processes (e.g. power plant types, transport technologies), goods (energy sources, materials) and the resulting emissions in the form of a reference energy system aggregated in one node. Objective of the model is an integral expansion and deployment planning of the energy system under the premise of cost minimization while considering boundary conditions (e.g. technology availability) [10,11]. TIMES Local is an application which focuses on the processes relevant for a municipality or district model.

For the application in this paper, the model has perfect foresight over the whole modelling period from 2010 to 2050, which is divided into 5-year steps. All scenarios are calculated with an hourly time resolution for five typical weeks (representing the four seasons plus one peak week and weighted over the year, adding up to 840 representative time slices per period. Reference year for weather data and generation

Table 1
Description of scenarios used in both models.

Scenario	Description	CO_2-Restriction
BASE	reference scenario for calculation of emission reduction and cost increase	none
CAP	scenario BASE with additional cap on CO_2 emissions	year-specific upper bound
CAP-CPO/CAP-AUT	scenario CAP with additional restriction on coal capacities (CPO)/level of self-sufficiency (AUT)	year-specific upper bound + 2nd constraint
BUDGET	reference scenario for time integral cost-optimal solution	budget until 2050 + 2050 upper bound

profiles is the year 2011.

Key figures of the considered municipality for the year 2012 are: final energy demand of 563 GWh, emissions of 159 tCO_2, approx. 22000 inhabitants and a yearly electricity demand of 3300 kWh per household. More details about the use case can be found in Ref. [8].

2.2. European electricity market model (E2M2) scenario framework

The electricity market model E2M2 is a bottom-up techno-economic model using linear or mixed-integer optimization. Objective function of the model is the minimization of overall power system costs, with the main components investment costs, costs for fuel, emission cost and variable as well as fix costs for operation and maintenance.

Scenarios for this paper are run with a 2-hourly time resolution using one representative year for every five years over the total for the period from 2015 until 2050. The model has perfect foresight over the whole modelling period and the year 2006 is used as reference year for renewable generation profiles and electricity demand profiles. Regional coverage is Germany as one node and electricity imports and exports from/to neighbouring countries are given as a model-exogenous assumption. Heat demand and production is not modelled separately, but considered as a must-run (minimum production constraint) for combined heat and power plants. Existing power plants are phased out after reaching their technology-based technical lifetime.

$$\textit{Average specific mitigation cost (AMC)} = \frac{\sum_{t=1}^{T} \frac{SC_t^{Scenario} - SC_t^{BASE}}{(1+i)^t}}{\sum_{t=1}^{T} \frac{e_t^{BASE} - e_t^{Scenario}}{(1+i)^t}}$$

with SC_t: *yearly system cost*; e_t: *yearly* CO_2 *emissions*; $(1+i)^t$: *discount factor*. (1)

A more extensive description of both models is provided in Appendix.

3. Results

3.1. Municipality case with autarky level

The results of the scenarios calculated for the municipality case presented in this section show the influence of the scenario definition on the optimization for CO_2 mitigation pathways. Fig. 3 (left) summarizes the total discounted system cost for the modelled region and the time horizon. The pathway with lowest system cost, due to lack of CO_2 emission related constraints, is the BASE scenario, which will from now on be used as the reference for the following scenarios. The lack of fixed intermediate goals for the single milestone years offers the BUDGET scenario a higher level of flexibility compared to CAP and thus leading to minimum system cost under consideration of CO_2 targets. The CAP + AUT scenario has the highest system cost induced by the technical requirement of the additionally defined self-sufficiency bounds. The necessity of increased local generation at higher costs combined with higher investments lead to extra expenditures amounting to 34 Million €$_{2010}$ for the modelled region, distributed over the time horizon. Those results are in line with optimization theory: applying a higher number of restrictions to the same problem results in equal or higher cost. To demonstrate the impacts of the modelled scenarios regarding CO_2 mitigation goals, Fig. 3 (right) presents overall emission reductions relative to the BASE scenario. This shows that CAP and BUDGET feature the same emission mitigation (654 kt) over the time horizon. The mitigation in the CAP + AUT scenario surpasses this value by an additional 170 kt CO_2 reduction. This occurs due to the desired degree of self-sufficiency resulting in a higher use of technologies based on locally available renewables hence further decreasing overall emissions.

On the secondary axis in Fig. 3 (right), average specific mitigation cost for CO_2, calculated over the total time horizon, are shown. These are calculated as the quotient of the delta between the system costs compared to BASE and the delta of total CO_2 emissions also compared to BASE, which results in the following definition of AMC:

The numerator in this case corresponds to the delta of the objective function values in the cost minimization models. In order to make mitigation cost between years comparable, emissions are discounted with the same factor as the system costs. Discounting of both, costs and emission reductions, also makes sure that the discounted sum of costs is put into relation to the discounted sum of benefits, following the discussion e.g. in Refs. [12,13] and as also referenced by the IPCC in Ref. [14]. However the actual level of the discount rate continues to be a matter of disagreement.

As explained above, since the BUDGET scenario contains the largest solution space, it represents the optimal point for mitigating the defined CO_2 amount (654 kt CO_2). Hence, the resulting average specific mitigation cost (AMC) must also be the lowest. The CAP scenario leads to

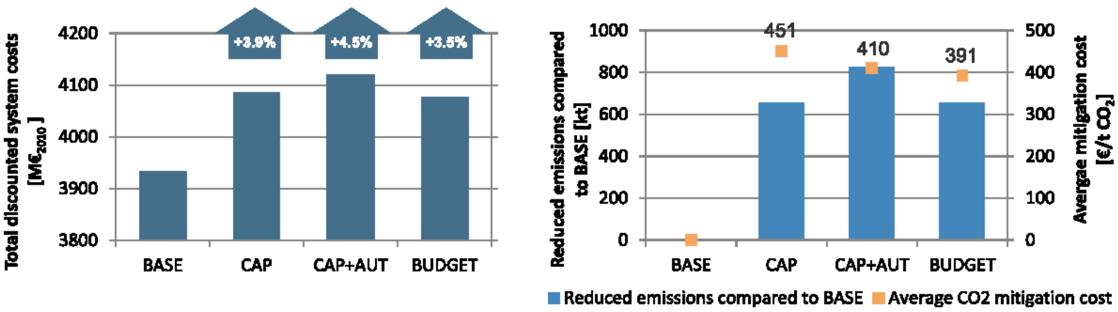

Fig. 3. Discounted system costs (left), CO_2 mitigation and average mitigation cost compared to BASE (right) for the municipality case.

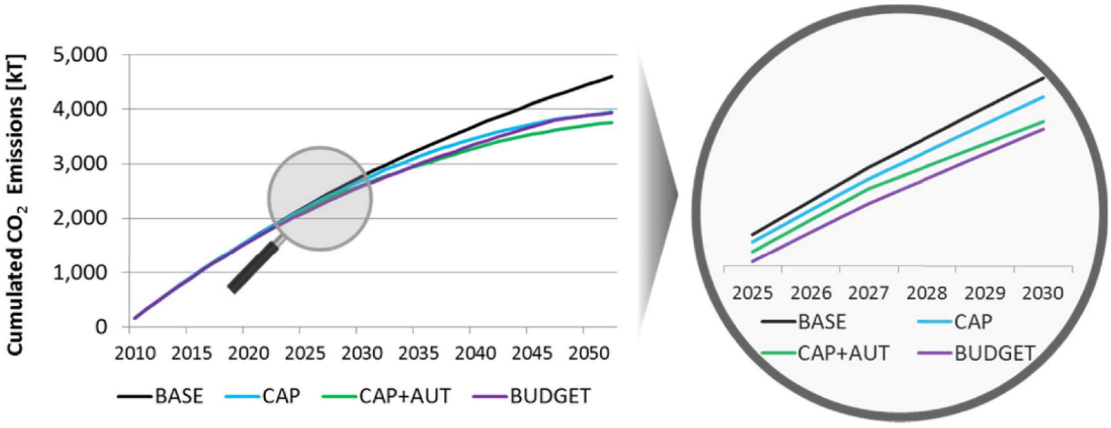

Fig. 4. Cumulated CO_2 emissions for the municipality case.

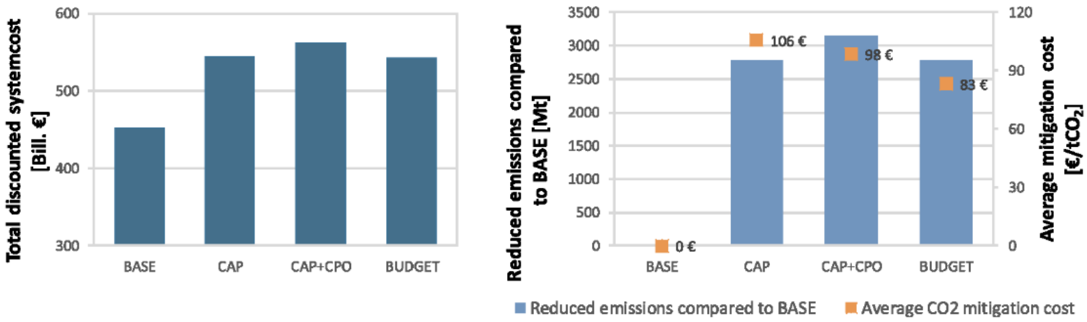

Fig. 5. Discounted system costs (left), CO_2 mitigation and average mitigation cost compared to BASE (right) for the national case.

6% higher mitigation cost compared to BUDGET. It is important to note, that the CAP + AUT scenario also leads to higher AMC in comparison to BUDGET. However, with 410 €/t CO_2, the value is also below the CAP case although the solution space for this scenario is the smallest.

How this distortion of AMC in a system can occur is shown in Fig. 4 with a cumulated CO_2 emissions curve for the region and their development for the four scenarios. While BUDGET leads to the cost optimal pathway for CO_2 mitigation the CAP + AUT curve follows it for certain model years more closely than the CAP curve. In the excerpt, it can be seen that CAP has a larger gap to BUDGET than the CAP + AUT scenario. The reason for lower AMC is the additional 2nd constraint where, in this case the demanded level of self-sufficiency "pushes" the CAP curve into the direction of the BUDGET and thus implicitly (but rather not deliberately) leading to lower AMC. Furthermore, the BUDGET and CAP curve converge in the years 2045 and 2050, thus leading to equal overall CO_2 mitigation in comparison to the BASE case. The demanding self-sufficiency level leads to lower cumulated emissions, thus the green curve lies below the other curves in 2050.

3.2. National case with coal phase-out

As described above, four comparable scenarios are been calculated for the national German electricity system with E2M2. The second constraint, besides a cap on emissions, in this case, is a regulatory phase-out of coal-fired power plants until 2045 (scenario CAP + CPO).[2]

[2] The German government has in the meantime published a plan for the national coal phase-out, which recommends an earlier phase-out, namely until 2038 at the latest [19]. Our scenario CAP-CPO is not adapted, since a different phase-out year or path of coal power plants will not change the key messages of this paper.

Fig. 5 shows the total system costs of the four scenarios on the left. The same effect as discussed in the previous section can be observed: scenario BASE shows the lowest system costs, CAP and BUDGET reach the same cumulated emission reduction (right), but in BUDGET it can be reached at lower AMC and at lower system costs. However, although CAP + CPO shows higher system costs compared to CAP, higher emission reductions can be reached at slightly lower AMC (98 € compared to 106 €, see Fig. 5, right).

When looking at year-specific emission levels and the power mix, it becomes obvious that both, BUDGET and CAP + CPO lead to a high fuel-switch from coal to gas during the first years. The coal phase-out as a 2nd constraint approximates the BUDGET solution regarding the implementation of CO_2 mitigation options.

4. Analysis and origin of effect

In order to further elaborate on the above observed effect, it is useful to demonstrate mitigation options in a generic CO_2 mitigation cost curve as shown in Fig. 6, which is valid for both cases discussed above. Compared to the model runs, we have made the following

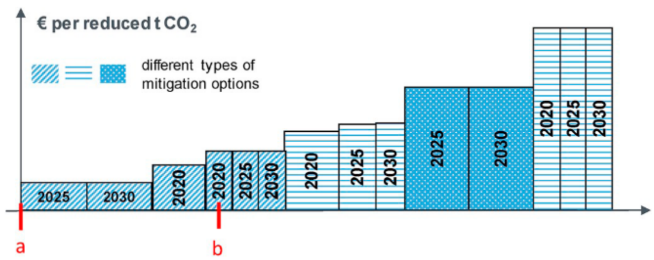

Fig. 6. Generic time-integral CO_2 mitigation cost curve as given in BUDGET.

simplifying assumptions:

- all cost assumptions (fuel, operation and maintenance, investment, etc.) are assumed to be constant over time,
- discount rate is assumed to be 0% and
- newly invested plants have a lifetime of 1 year, in which only the annuity of the invest costs occur (or in other words: investment decisions in one year have no impact on mitigation options for the following years).

These simplifications allow us to demonstrate the time-integral mitigation curve as one single curve and therefore explain the mechanisms behind the above outlined results as isolated as possible. With increasing model complexity, the number of variants of the total mitigation curves over the full time horizon increases.

The three different patterns of the bars represent different types of mitigation options. Those could, for example, be fuel-switching from coal to gas or the replacement of existing generation units by units with lower specific emissions.

The same mitigation option can be available in more than one year of the considered time horizon, which is demonstrated by the year assigned to each bar in Fig. 6. For reasons of simplification, the years 2020, 2025 and 2030 are considered only. However, it is important to point out, that not all mitigation options are available in all years, which can be explained with an easy example: Since new investments in coal-fired generation will unlikely be made under ambitious CO_2 reduction levels, fuel switching from coal to gas as a mitigation option is mainly available in early years as long as existing coal plants are still in operation and have not reached their technical lifetime yet. Since all scenarios are run with perfect foresight over the whole modelling period, the model "sees" the entire time-integral mitigation cost curve, i.e. including mitigation options for all years. However, there is a difference amongst the scenarios, upon which mitigation options can be used to fulfil the respective CO_2 restriction. Since the budget restriction limits the sum of emissions over the entire period, the model will implement the cheapest mitigation options first, i.e. choose options starting from point "a" and implement all options from left to right until point "b" is reached (distance between "a" and "b" in Fig. 6 represents reduction of BUDGET compared to BASE). This is independent of the year in which this mitigation takes place.

The CAP scenario, however, faces year-specific restrictions of emissions. In order to comply with this restriction, the model can only choose mitigation options that are effective in this specific year. Instead of a time-integral mitigation curve, the model is limited to year-specific mitigation curves that include only mitigation options that are effective in the respective year. This is shown in Fig. 7 by three separate curves for the years 2020, 2025 and 2030. Required reductions through the cap are demonstrated by the mitigation levels "c", "d" and "e", which increase over time. The level of AMC for the respective year is marked on the y-axis.

Since the model's objective function requires minimization of system cost, the model will not reduce more emissions than required by the cap, as long as mitigation cost is above zero. This means that in the year 2020 for example, the model will reduce emissions exactly until level "c", but not beyond. As shown in Fig. 7, the model has to implement more expensive mitigation options in 2030 than in 2020, in order to reach the year-specific mitigation level. This might be the case, because level "e" is higher than "c", but also because the mitigation cost curve in 2030 is steeper than the one in 2020. Comparing the cost of mitigation options throughout the years, one can see, that relatively cheap mitigation options in 2020 (to the right of level "c"), remain unused in the CAP scenario while relatively expensive mitigation options are implemented, in order to comply with the cap in 2030. In the BUDGET scenario, those cheap mitigation options would be implemented first, which results in lower overall AMC in the BUDGET scenario compared to CAP.

Complementing effects of the 2nd constraints will be discussed in the following.

4.1. Cause 1: early use of low cost mitigation options

Based on the above analysis, the effect of an early coal phase-out as a 2nd constraint can be easily explained. While a linear cap leads to emission reductions to the levels "d", "e" and "f" in Fig. 7, the coal phase-out forces the implementation of mitigation measures in the early years beyond the level required by the cap. Thus, it moves the reduction level from "c" to "c*". Since those early mitigation options are cheaper relative to implemented mitigation options in later years, AMC across all years can be lowered with their implementation ($AMC_{2020,CAP+2nd} < AMC_{2025,CAP}$ and $AMC_{2030,CAP}$). Thus, the additional reduction caused by the second constraint at comparably low cost can lead to a decrease in overall AMC – despite higher absolute system cost.

4.2. Cause 2: innovation of low emission technologies

Sudden changes in the structure of the mitigation curve, e.g. through modelled innovation processes, can also lead to a reduction of overall AMC, as it is the case in our municipality example. This can happen in case a technology appears in a certain year, enabling a mitigation option with lower AMC than those that are available up to that point. In Fig. 8, this is demonstrated by the mitigation option with relatively low cost, that becomes available in 2025 and 2030. Both, CAP and CAP + 2nd make use of this option, but the second constraint enforces an increased use of this new option if and only if that option offers an additional benefit to fulfil the 2nd constraint. In our case this option is the investment into highly efficient photovoltaic, which leads to a decrease in emissions and also an increased self-sufficiency level. The usage of this option increases the reduction level from "d" to "d*"

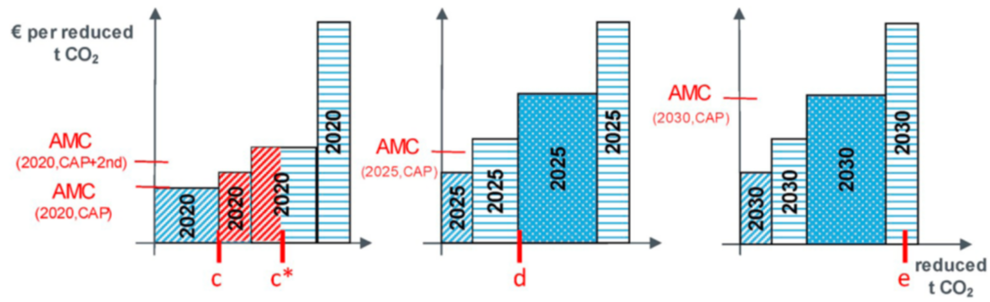

Fig. 7. Year-specific CO_2 mitigation cost curves as in CAP and additional mitigation through the second constraint (red shaded area). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

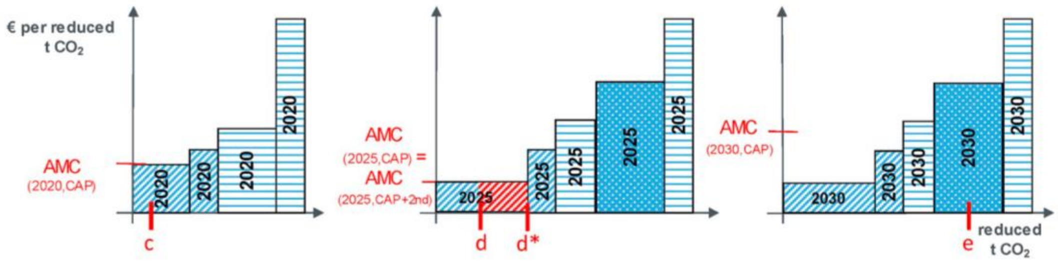

Fig. 8. Additional mitigation through the second constraint caused by innovation of low emission technologies.

in 2025 (see red shaded area in Fig. 8). Again, the introduction of the second constraint lowers the AMC compared to the CAP scenario.

5. Discussion

Our research shows that the mathematical definition of model constraints plays a crucial role in energy system analysis and the evaluation of CO_2 mitigation pathways, as the definition of year-specific CO_2 constraints only might result in overlooking solutions with lower AMC. This effect is shown exemplarily with a CO_2 cap, but can also appear when using others, such as a minimum renewable target. Since a renewable target is limited to certain technologies, and therefore limits the flexibility of choosing mitigation options even more than a CO_2 cap, it can be expected that this effect will increase. Coming back to the results of the literature review in Fig. 1, this means that even more than 80% of considered publications use such year-specific targets but do not compare the results with a time-integral budget scenario.

Moreover, it might be a surprising result for modellers to achieve lower AMC through the implementation of an additional constraint. No general answer to when this effect appears can be given, as it depends on specific model settings. However, it was shown that it can happen in two different models for two different research cases, implying that this is not a single case. The explanation of causes behind this effect can help modellers who experience the same issue to better interpret their model results. Whether this effect occurs, depend on model type, time horizon and technology parameterization. In our analysis, the global discount rate has a large influence on whether the CAP + 2nd scenario leads to a rise or reduction of AMC compared to CAP. It is important to note that the CAP + 2nd scenario always leads to higher absolute system costs and also to higher AMC than the BUDGET scenario.

Moreover, the restriction level of the 2nd constraint is highly relevant, since very stringent supplementary goals may lead to disproportionate higher system costs. It can be said that the two explained causes above are catalysts for this distortion but do not necessarily lead to it.

To ensure a cost optimal solution for a scenario with climate goals regarding both absolute system cost as well as AMC, a scenario with a budget restriction should be calculated complementary to a cap scenario. This ensures the identification of possible solutions with lower AMC and guarantees to find minimum cost solutions. The BUDGET setting refers to an instrument with a time integral emission market. This seems to be the optimal instrument in a theoretical framework, where all information along the time scale is available for all market players right from the beginning. However, if this is an instrument that can be implemented and will work efficiently in the real world, is subject to a different discussion.

Furthermore, due to the limited time horizon of every model, a single cap constraint for the final period must be defined also in the budget scenario. If not, the starting point for the time period beyond the model horizon is not comparable, since the final reduction level is not the same (even though total emitted CO_2 is identical). Moreover, even if the same final emission reduction level is achieved, the resulting energy system can look different and therefore have a different remaining potential for emission reductions. A qualitative analysis of this residual potential could be conducted via a sensitivity analysis with varying emission targets for the final time period. To decrease such deviation policy instruments targeting technologies with low lock-in effects can be chosen.

Further analyses should examine the robustness of the results regarding sensitivity of the models for technology parameterization. Also, research should be conducted for non-perfect-foresight models since, e.g. with myopic optimization such effects may play a bigger role than in integral models runs.

6. Conclusion

In a review of recent energy system studies we have shown that year-specific CO_2 caps or prices are often used in energy system models, even though this is not completely representing the carbon stock problem. The scenario comparison for two separate cases - one on a municipality level and the other on national scale - shows that these model constraints can lead to an inadvertent reduction of possible solutions for mitigation pathways. In both of the examples additional goals such as a regulatory phase-out of coal power plants and a minimum level of self-sufficiency lead to lower average specific mitigation costs compared to a scenario with a year-specific cap only. This effect might occur under various circumstances and might be a counterintuitive result for modellers. The explanation of two possible causes in a generic cost curve can help modellers to better understand results under several political constraints. Based on these causes, we conclude that it is recommended to calculate a scenario with a CO_2 budget constraint and perfect foresight in comparison to a cap. As shown in the literature review, the majority of contemporary energy system analyses does not compare their results to such a scenario.

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Appendix

TIMES model description

The reference energy system of TIMES Local takes into account the sectors of public electricity and heat supply, households, commerce, trade, services, transport and industry. The entire energy supply chain is covered, from primary energy to final energy to useful energy, and technologies are in competition to meet demands.

Energy service demands such as heating, hot water, cooling, mobility and lighting as well as their development over the time horizon are defined based on statistical data. Investments into technology capacities and storages as well as their dispatch are decided endogenously and are part of the optimization results.

Various research questions can be answered through the definition of user constraints, e.g. the cost-optimal implementation of autarky targets under compliance with technical and economic restrictions. Input parameters for the optimization are usually existing power plants, development of energy demands and prices, parameter for technologies and primary energy carriers. Those parameters include e.g. potentials for heat pumps, heating networks or the availability of biomass. Output of the model is, amongst others, the composition of cost-optimal technologies regarding type and capacity as well as the required energy supply per primary energy carrier.

For the municipality application, important characteristics are e.g. building sizes and related dimensions of facilities for heat provision. For this purpose, the private household sector is disaggregated in different types of buildings characterized by their demand for light, warm water, heating, cooking and remaining demand for e.g. electric appliances. The provision of living space is separated in existing buildings, new buildings and investment options such as refurbishment measures for existing buildings.

More detailed descriptions of the TIMES Local model including current developments can be found in Refs. [7,15].

E2M2 model description

The electricity market model E2M2 is focused on the power sector, with an objective function of minimizing overall power system cost. The level and profile of power (and optionally heat) demand is given as input parameter, while the model identifies the cost-optimal solution to cover this demand, given all other technical and economical restrictions. Power plant dispatch as well as power plant investment decisions are thereby taken endogenously, using linear or mixed-integer optimization. The model code is written in GAMS and data is managed in Microsoft Access.

The model structure and the data management allows for a high choice of model settings, e.g. regarding timely and regional resolution or the model's foresight period.

With a maximum timely resolution of 8760 h per year and the possibility to run scenarios on a plant level, the model is particularly suitable to represent fluctuations in generation from renewable power plants, dispatch of storages and hourly power prices. Model runs can be performed with either no installed capacities ("green field") or considering existing power plants on a plant level and with regional allocation. Existing plants as well as possibilities for new investments are characterized by economic parameters (e.g. specific investment cost, fix and variable operation and maintenance cost, ramp-up cost) as well as technical parameters for different generation technologies. Required reserve capacity is provided cost-optimally by spinning and non-spinning reserve power plants.

Exogenous input parameter for E2M2 are e.g. primary energy prices, CO_2-prices or upper bounds, power and heat load profiles, generation profiles for fluctuating renewables, technical and economic parameter for existing power plants as well as for new investments and cross-border transmission capacities. Endogenously determined parameters on the other hand are dispatch of power plants and storages, capacity additions, power prices (based on marginal generation cost), emissions, fuel usage as well as all costs related to the satisfaction of the power (and heat) demand.

A detailed description of basic model equations and recent extensions can be found in Refs. [16–18].

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3 Extended Policy Mix in the Power Sector: How a Coal Phase-out Redistributes Costs and Profits among Power Plants

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Author contributions:

The following Table 3-1 shows the contributions of the author and co-authors to this paper, using the "CRediT author statement" system (Elsevier 2019). At that time, Nikolai Klempp was an employee at the Institute for Energy Economics and Rational Energy Use. Conceptualization was done in several joint discussions, leaded by Annika Gillich. Kai Hufendiek and Nikolai Klempp performed the review and editing of the manuscript. Kai Hufendiek moreover provided the resources and did the funding acquisition.

Table 3-1. *Author contributions second paper*

	Annika Gillich	Kai Hufendiek	Nikolai Klempp
Conceptualization	x	x	x
Methodology	x		
Software	x		
Validation	x		
Formal Analysis	x		
Investigation	x		
Data Curation	x		
Writing – Original Draft	x		
Writing – Review & Editing		x	x
Visualization	x		
Funding Acquisition		x	

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Extended policy mix in the power sector: How a coal phase-out redistributes costs and profits among power plants

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ABSTRACT

With the phase-out of coal power plants, the existing mix of instruments aimed at decarbonising electricity sectors is getting more complex. This paper contributes to its understanding by highlighting the impact of coal phase-out, CO_2-price and increasing capacity of variable renewable energies on contribution margins of power plants. By visualizing these three instruments in a brownfield screening curves model (SCM), their fundamental effects on plant operation, electricity price and margins become apparent at a glance. Moreover, the SCM allows to derive generic statements about winners and losers on the supply side. Results are then quantified within a case study for Germany using the power sector model E2M2. The high resolution regarding time and generation system permits a realistic simulation of electricity prices and thus of margins at plant level.

We conclude that 1) margins between technologies and plants within the same technology vary significantly, in extreme cases by 9.5 times (period 2020–2050). And 2) the impact of a coal phase-out declines when the other two policies become more stringent. E.g. for an old lignite plant, a coal phase-out in a moderate political environment causes a loss in margin of 47%, whereas the loss is only 16% in an ambitious environment.

1. Introduction

The power sector is one of the most regulated sectors and several political instruments have been implemented in the past in order to reduce the carbon intensity of electricity production (overview e.g. in Rogge and Reichardt, 2016). Nevertheless, there are reasons why the electricity sector is still in the focus of the political debate: In some countries the power sector is - despite some achievements - still the biggest source of GHG emissions (e.g. UBA, 2019; Ciupageanu et al., 2017; KOBiZE, 2019). Additionally, ambitious emission reduction targets require that heat and transport sectors must also be strongly decarbonized. Due to the increasing electrification of these two sectors, the electricity sector will consequently play a central role here (Williams et al., 2012). This outlines the relevance of further political interventions in order to achieve rapid and high reductions in the electricity sector. As one additional measure, many European countries have now announced an exit from coal-fired power generation within the next few years or an exit is at least under discussion (Europe beyond coal, 2018).

However, the phase-out of coal-fired power plants and its interactions with other political instruments have hardly been investigated in literature to date (see section 2.1). It is explicitly not the aim of this study to identify an optimal policy mix, but rather to explain and quantify effects of existing instruments individually and in combination. This paper contributes to closing this research gap in two ways: On the one hand, the effects of a coal phase-out on the energy sector are shown in a simple generic model and a graphical representation. This contributes to a better understanding of direct and indirect implications of the instrument on an electricity system. In addition, the effects of a coal phase-out are compared to those of a CO_2 price and an increasing capacity of variable renewable energies (VRE), so that differences become clear at a glance. Especially in such a complex instrument landscape as in the power sector, this understanding is essential to enable the coal phase-out to unfold its desired effect quickly and effectively. On the other hand, this paper focuses in particular on the aspect of contribution margins of power plant operators, which can provide indications for the design of compensation payments. The payment of appropriate compensations can, first, achieve a higher acceptance of the coal phase-out instrument on the side of producers and consumers and second, help to design the coal phase-out as cost-effective as possible. Accordingly, this paper contributes to a successful implementation of the coal phase-out and thus to a fast and effective decarbonisation of the

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key sector of power generation.

The applied methodology is a simple screening curves model which serves to illustrate effects of the three instruments CO_2 price, increasing capacity of VRE and coal phase-out on electricity price, operation and contribution margins. In contrast to the frequent use of a screening curves model for cost-optimal capacity planning (greenfield), a brownfield approach is chosen here, assuming an existing, not necessarily cost-optimal generation system. A brownfield approach is applied as this corresponds to the situation that politicians actually face when designing a coal phase-out and thus more helpful suggestions can be derived for its practical implementation. The subsequent use of an energy system model provides indications on how strong those previously identified effects can be in the case of the German energy sector. A high resolution on the generation side is chosen in the model in order to derive results on plant level. These results can directly be linked to the discussion on compensation payments, since those are usually also made on plant level.

The paper is structured as follows: A separate section is devoted to the literature review and the distinction in section 2. In section 3, the methodological procedure is explained, both models and their interrelationship are introduced. Effects of the instruments in the screening curves model are described and presented graphically in section 4. A quantification of those effects is then made as an example for the German electricity sector in section 5. Finally, results are summarized and implications for policy makers are discussed.

2. Literature review and distinction

This section first provides a literature review of the three policy instruments considered here and their interactions. This is followed by a classification into the current discussion on the topic of policy mix and an explanation of how the term distributional effects is used. The section concludes with a brief summary on how this screening curves model integrates into existing literature.

2.1. Political instruments and interactions

So far, literature on the effects of a coal phase-out mainly consists of nationally focused studies with different emphasis. A comprehensive analysis for Germany, including proposals for the political implementation of the phase-out, is provided e.g. in Agora Energiewende (2016) and in WWF Deutschland (2017). A focus on security of supply is set in Energy Brainpool (2017). Climate Analytics (2017), for example, is devoted to the European perspective and the connection between the targets of the Paris Agreement and coal-fired power generation in Europe.

In addition, there is some scientific literature dealing with a more general approach to a coal phase-out. With a focus on Germany again, Heinrichs and Markewitz (2015) show that a coal phase-out can reduce emissions but increase total system costs. In Heinrichs and Markewitz (2017), a comparison between a politically induced coal phase-out and one that is induced by a CO_2 restriction is performed, with the latter found to receive the same emission reduction at lower cost. Jotzo and Mazouz (2015) propose a market-based mechanism for the phase-out of lignite with a view to the Australian electricity sector, whereby compensation payments are determined by a tender procedure. Yilmaz et al., (2016) state, that a coal phase-out in Germany, in contrast to the UK, has a significant impact on electricity import, export and wholesale prices.

While very detailed literature is available on the interactions between the two instruments CO_2 price/emissions trading system and VRE support (overview e.g. in González, 2007), the combination of these instruments with a coal phase-out has received only little attention so far. To the authors knowledge, this combination of the three instruments has only been studied by Bertram et al., (2015), with the conclusion that the additional implementation of a coal phase-out can reduce both, efficiency losses and distributional effects.

2.2. Policy mix and distributional effects

It is obvious, that interactions of policies become more complex with the introduction of one more instrument and therefore require careful evaluation. While the estimation of the additional emission reduction by a coal phase-out can still be modelled comparatively well, the ex-ante estimation of all side effects (distribution effects, electricity price effects, security of supply etc.) in such a policy mix is a great challenge. However, the aim of policy should be to identify these side effects as early as possible so that - in case unwanted effects are expected - appropriate countermeasures can be taken in good time. This paper contributes to this by systematically analysing and highlighting one effect in particular, namely the distribution effects between technologies and power plants caused by above mentioned three instruments. A different field of literature deals with approaches for a holistic analysis of policy mixes (see e.g. Rogge and Reichardt, 2016), where the research issue addresses a general framework for policy mix analysis. In contrast, this paper deals with three specific instruments and one evaluation criterion only and can therefore only provide one building block for the holistic approach by outlining partial cause-effect relationships.

The term distributional effects is defined and applied differently in literature. In principle, distributional effects can occur between different groups of actors, in the electricity sector in particular between the main groups of generators, end customers, the state (which receives tax revenues as a regulator) and grid operators. Distributional effects, however, can also be considered at different aggregation levels, as for example end customers can be disaggregated into different end customer groups. This enables analyzing distributional effects within one of these main actor groups, e.g. their different levels of burden caused by an increase in electricity prices. E.g. Hirth and Ueckerdt (2013) show that renewables support moves rents from producers to consumers, and a CO_2 price shifts rents from consumers and emitting producers to clean producers. In distinction to them, this paper considers distributional effects as shifts of costs and revenues on a more disaggregated level: between different technologies of a countries power plant portfolio on one hand and between different power plants of the same technology in a second step.

2.3. Screening curves

The concept of screening curves is particularly suitable for clarifying interactions in the electricity sector by means of a clear graphic representation. For this reason, it has been applied in energy system modelling over a long period of time. A broad description of the basic concept of screening curves can e.g. be found in Stoft (2002) and Loud (1988). In literature, the concept of screening curves is often applied to derive cost-optimal compositions of power plant portfolios and as well as their cost-optimal dispatch (e.g. in Belderbos and Delarue, 2015). Compared to the basic form, many extensions have recently been developed: Green (2005) shows basic principles of price formation in electricity markets by means of screening curves. Steffen and Weber (2013) use screening curves to derive the optimal storage capacity in an energy system. Some publications also deal with the representation of demand side management in screening curves: Koomey et al., (1990) illustrate the decision between demand and supply side investments; Hill et al., (1992) integrate demand side measures graphically to compare it to supply side investments and Cepeda and Saguan (2016) look at long-term effects of demand response policies. Another direction of research is the consideration of operating restrictions such as start-up and shut-down costs or minimum downtimes: Jonghe et al., (2011) look at the impact of ramp-rates, transmission capacities und storage through a comparison of screening curve results with those of a linear optimization model; Staffell and Green (2016) show the impact of start-up costs by their graphical representation in screening curves; Batlle and Rodilla (2013) as well as Zhang et al., (2015) incorporate a representation of the cycling

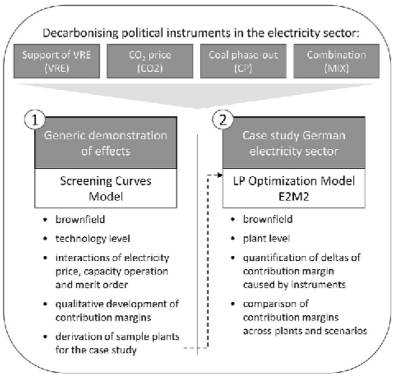

Fig. 1. Methodology used in this paper to derive effects of instruments on contribution margins.

costs in a traditional screening curves model. The provision of reserve capacity and ancillary services is discussed in Olsina et al., (2006) and Zhang and Baldick (2015).

In addition to these extensions of the screening curves, the approach was also used in literature to discuss effects of political interventions. Green (2005) deals with the effects of an emissions trading system on capacity planning in electricity systems. Kennedy (2005), Lamont (2008) and Ritzenhofen et al., (2016) consider the effects of a high share of VRE, with the latter also focusing on the different designs of renewable energy support. To the authors' knowledge, the mix of more than one instrument has so far been investigated by Hirth and Ueckerdt (2013) with the two instruments of renewable energy support and a CO_2 price, just as a coal phase-out has not yet been the subject of analysis with screening curves. Methodologically, these publications frequently combine screening curves with a second model, often with a LP or MIP optimization model (as applied in this paper), but also with a heuristic or system dynamics model.

Previous studies often consider a cost-optimal capacity planning, i.e. the decision on the cost-optimal composition of a power plant portfolio in a green-field approach. However, this cost-optimal composition is rarely found in reality, since 1) investment decisions are taken under uncertainty about future cost and load conditions and 2) the change of framework conditions by political intervention can turn a cost-optimal generation system into a non-optimal one. Power plants achieve a comparatively long operating life, i.e. an investment decision once taken, leads to high sunk costs and barriers for a flexible adaptation of the system to changing conditions. These factors lead to the situation that an existing generation system usually does not correspond to the cost optimal one under the actual cost and load situation. Zhang and Baldick (2017) and Güner (2018), among others, are working on the mapping of existing power plants in a screening curves model and are developing their own algorithm for deciding on the addition of the most cost-effective technology, taking the existing power plants into account. Hirth and Ueckerdt (2013) assume a cost-optimal generation system (called long term equilibrium) and show the effects on it in a short term equilibrium, in which the dispatch adapts cost-optimally to the changed framework conditions, but the generation system structure does not yet. In contrast to these publications and the frequently used SCM green-field approach, a brown-field approach is chosen in this publication. This means, that a not (necessarily) cost-optimal existing generation system is assumed and the redistributions occurring as a result of political intervention in this existing generation system are investigated. The effects of different compositions of the generation system are also discussed, so that they can also be transferred to a different generation mix.

3. Methodology

3.1. Framework

The methodology of the paper consists of two steps in which different models are used to examine effects of three policy instruments that contribute to the decarbonisation of the electricity sector: a CO_2 price (scenario "CO2"), the support of VRE ("VRE") and the politically induced shutdown of coal-fired power plants ("CP") before the end of their technical lifetime. These three instruments and their impact on power plants contribution margins are first derived by a generic brownfield screening curves model (SCM). Within the SCM, a generic existing power plant portfolio is modelled, on which the three instruments act. The model is intentionally kept straightforward in order to show the mechanisms of the instruments as clearly as possible and outline their substantial effects on electricity generation, capacity operation, merit order, electricity price and contribution margins. The analysis in the SCM also serves to derive criteria for the identification of strong winners and losers amongst power plants, which are then applied to select the sample power plants in the case study.

Advantages of the analysis in SCM are the derivation of statements that are as generally valid as possible and can moreover be well visualized. On the other hand, the representation of the power sector is also greatly simplified and thus neglects some variables that may have a major influence on the system and the statements made here.[1]

In order to account for these aspects anyway, scenarios are calculated in the high-resolution electricity market model E2M2 in a second step. Statements from SCM are thereby validated and quantified in a case study for the German electricity sector. The above mentioned influencing variables are taken into account in these model runs. The result of the case study is the development of contribution margins for the selected sample power plants under each of the different instruments separately (scenarios "CO2", "VER" and "CP") as well as under the combination of these instruments in the scenario "MIX". The two steps of the applied methodology are summarized in Fig. 1.

3.2. Screening curves model

The screening curves model (SCM) that is applied in this paper is used to derive basic mechanisms of policy instruments. For a better understanding and traceability, model equations and assumptions are kept to the minimum that is required to answer the relevant research issue and are introduced in the following.

As the model is based on a brownfield approach, there is an existing set of power plants that can be operated to cover the load. This set of power plants has evolved historically and therefore does not necessarily correspond to the cost-optimal power plant set for this load situation. However, existing power plants are dispatched cost-optimally. It is assumed that sufficient capacities are available to cover the load, i.e. the model represents a pure optimization of resource deployment planning and not an optimization of the capacity planning. In the nomenclature of Hirth and Ueckerdt (2013) the initial configuration represents a short term equilibrium. In Table 1 and following, the model is described with all variables and equations as well as basic assumptions.

The objective function of the model minimizes total costs, which corresponds to the variable costs in a complete brownfield approach (only existing plants, no new investments), see equation (1). It is assumed that the fixed costs of existing power plants cannot be influenced, which means that they are not taken into account in the objective

[1] These include in particular: the retirement forecast of the existing power plant portfolio, cost-optimal new investments, start-up, shutdown and ramping costs, non-constant fuel costs and power plant availability, the application of storage facilities, electricity exchange with neighbouring countries as well as the provision of capacity to ensure security of supply.

Table 1
Definition of sets, parameters and variables used in the screening curves model.

$I:=\{1,\dots,j\}$	set of technologies
$T:=\{1,\dots,k\}$	set of time steps in the considered period [h]
p_i	installed capacity of technology $i\epsilon I$ [MW]
c_i	variable costs of technology $i\epsilon I$ [€/MWh$_{el}$] and $c_1 > c_2 > \dots > c_j$
$q_i(t)$	energy generated by technology $i\epsilon I$ in time step $t\epsilon T$ [MWh$_{el}$]
$d(t)$	energy demand in time step $t\epsilon T$ [MWh$_{el}$]
C_{total}	total costs [€]

function either. The first constraint represents the coverage of demand in each time step, shown in equation (2). Energy produced by technology i in time step t must not be greater than the installed capacity of this technology, see equation (3).

Accordingly, the optimization problem formulates as follows:

$$min\ C_{total} = \sum_{i=1}^{j}\sum_{t=1}^{k} q_i(t)*c_i\ ,\ \{q_i(t)\ with\ i\in I,\ t\in T\} \tag{1}$$

$$s.d.\ \sum_{i=1}^{j} q_i(t) = d(t) \qquad \forall t\in T \tag{2}$$

$$q_i(t) \le p_i \qquad \forall i\in I \tag{3}$$

$$q_i(t) \ge 0 \qquad \forall t\in T\ . \tag{4}$$

Ideal competition is assumed and therefore the electricity price is based on marginal costs, i.e. the price duration curve $PDC(t)$ results from the marginal costs of the most expensive technology, whose production quantity at the respective time step t is greater than 0. Accordingly, the price duration curve is defined as

$$PDC(t) := \max_{\{i\ \in\ I:\ q_i(t)>0\}} c_i(t) \qquad \forall t\in T \tag{5}$$

and the load duration curve is defined as

$$LDC(t) := d(t) \qquad \forall t\in T\ . \tag{6}$$

Furthermore, the energy produced by a technology over the total considered time period sums up to

$$Q_i(t) := \sum_{t=1}^{k} q_i(t) \qquad \forall i\in I, \tag{7}$$

which is also referred to as the operation of a technology in the further text.

Focus of this paper is the examination of contribution margins of the power plant operators in particular. It is assumed that the producers can sell the electricity at any time at the marginal cost price prevailing on the market. Since the price always corresponds to the marginal cost of the most expensive producing technology, and this price can be achieved for all producing technologies, the contribution margins equal 0 for the marginal technology/technologies and are greater than 0 for all other producing technologies respectively. Specific contribution margins are therefore defined as

$$CM_i(t) := \frac{(PDC(t)-c_i)*q_i(t)}{p_i},\ \ \forall i\in I,\ t\in T : PDC(t) > c_i\ . \tag{8}$$

The sum of the hourly specific contribution margins over the whole considered time period results in the definition of the yearly specific contribution margins

$$CM_i := \frac{\sum_{t=1}^{k}\left((PDC(t)-c_i)*q_i(t)\right)}{p_i},\ \ \forall i\in I,\ t\in T : PDC(t) > c_i\ . \tag{9}$$

Specific contribution margins always refer to the generation capacity in MW.

For the application of the model in this paper, we consider seven different thermal technologies, including assumptions about fuel costs, emission factors, variable operating and maintenance (O&M) costs and efficiencies. These seven technologies are considered to exhibit the same installed capacity, which cumulatively corresponds to the maximum load. The fact that the installed capacity in a real generation system is higher than the maximum load, can be neglected here, since excess capacities would not operate in this simplified model and would therefore always have a margin of zero. All other assumptions for these technologies are listed in Table 2. The values result from a combination of several sources: emission factors of the fuels are taken from IPCC (2006), O&M costs as well as efficiencies from Schröder et al. (2013) and fuel costs from VIK (2018). However, as not all necessary assumptions for nuclear energy are available in these sources, NEI (2018) is also used for nuclear energy data only. Costs are always related to the reference year 2015 and expressed in €.

The applied load duration curve corresponds to the standardized residual load profile for Germany in 2015. Thus, existing VRE plants are considered by deducting their production from the load curve (load profile and VRE production profiles both from ENTSO-E 2019). A generic maximum load of 50 MW is assumed and a temporal resolution of 100 h is chosen for this application. Fig. 2 shows the graphical representation of the screening curves for this model including contribution margins and other variables, parameters and functions.

3.3. *European electricity market model (E2M2)*

The second model used in this paper is the electricity market model E2M2, which is a bottom-up techno-economic model using linear or mixed-integer optimization. It was developed at the Institute of Energy Economics and Rational Energy Use, University of Stuttgart. Objective function of the model is the minimization of power system costs, with the main components of investment costs, fuel costs, emission cost and variable as well as fix costs for O&M. The level and profile of power demand is given as input parameter, while the model identifies the cost-optimal solution to cover this demand, given all other technical and economical restrictions. Power plant dispatch as well as power plant investment decisions are taken endogenously by the model. The model code is written in GAMS and data is managed in Microsoft Access. A detailed description of basic model equations and recent extensions can be found in Sun (2013); Bothor et al., (2015); Fleischer (2019). The model has recently been validated for the historic year 2015 with regards to the key figures weighted average electricity price, emissions, installed capacity, cumulated yearly production as well as hourly dispatch. For the validated year 2015, cumulated yearly generation for each primary energy deviates less than 0.7% (in relation to total generation) from empirical data. Emissions differ by 2.5% and the weighted average yearly electricity price by 1%. In the weeks with the highest load and the lowest residual load, the model achieves very good results in terms of hourly dispatch per energy carrier.

For the application in this paper, the model foresight is limited to the current year that is to be optimized (myopic foresight) and renewable generation profiles and electricity demand profiles are based on empirical technology-specific generation curves. Regional coverage is Germany as one node and electricity imports and exports from/to neighbouring countries are given as a model-exogenous assumption. Existing power plants are phased out after reaching their technology-based technical duration of life.

Contribution margins highly depend on the level and pattern of the electricity price. We therefore consider a focus on the two parameters timely resolution and plant disaggregation as most relevant. In order to account for daily, weekly and seasonal price patterns, we use a 2 hourly time resolution in our model runs with one representative year for every five years over the total period from 2015 until 2050. The largest approx. 150 thermal power plants in Germany are represented on plant

Table 2
Technical and economic assumptions for the screening curves model.

Technology	Fuel cost[$€_{2015}$/Mwh$_{th}$]	Emissionfactor [t/MWh$_{th}$]	Variable O&M costs [$€_{2015}$/Mwh$_{el}$]	Efficiency [%]	Share of inst. capacity [%]
Hard coal, IGCC	9,42	0,341	8,6	49%	equally distributed
Lignite	8,22	0,364	6,4	43%	
Nuclear	6,28	0	4,5	33%	
Natural gas, combined cycle	22,33	0,202	4,3	60%	
Natural gas, gas turbine	22,33	0,202	3,2	39%	
Oil, steam turbine	31,49	0,264	3,2	41%	
Biomass pellet	40,00	0	0,0	46%	

level, smaller ones are summarized in groups based on the plants age, primary energy and technology.

Additionally, we pay special attention to ensure that the price generated in the model actually only corresponds to the marginal dispatch costs. As usual, we derive the electricity price from the model by using the dual variable of the demand restriction (see e.g. Remme, 2006). However, in order to make sure that the price represents the marginal dispatch costs only, and e.g. is not distorted by costs for investment, two sequential model runs are performed: The first model run allows for endogenous investment, while in the second model run, the cost-optimal generation mix of the first model run is given as exogenous parameter. New investments are not allowed in the second model run. This way, we ensure that the price of electricity is in line with the price that would arise under the current market framework of an energy-only market.

4. Results in the screening curves model

In this section, we first discuss the impact of the three policy instruments on the electricity generation system, in particular on merit order, technology operation and electricity price. With this background, changes in contribution margins are derived in section 4.2. Finally, effects on contribution margins of the three instruments in combination are considered.

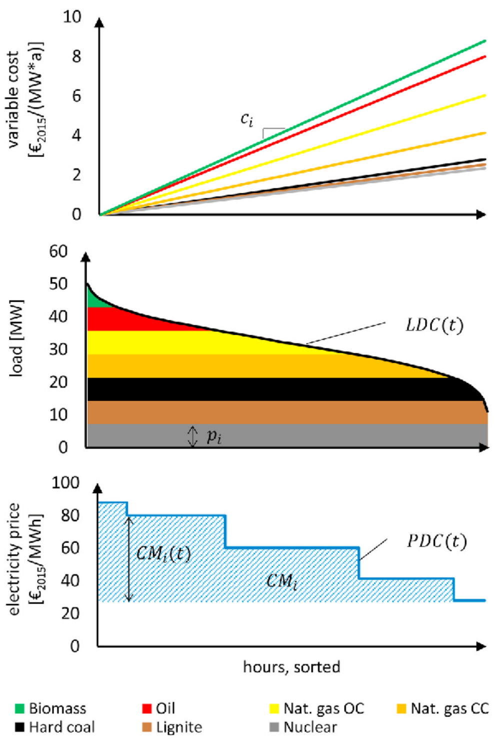

Fig. 2. Visualization of the screening curves model.

4.1. *Representation of policy instruments*

In the following, impacts of a CO_2 price and the addition of VRE capacity on the electricity system are only summarized shortly, since those can be found in literature already (e.g. Green, 2005; Hirth and Ueckerdt, 2013).

A CO_2 price changes the merit order from a pure sorting according to fuel and variable O&M costs (at a CO_2 price of 0€) to a sorting according to emission factor (at a sufficiently high CO_2 price), thus affecting the level of operation of all technologies. The price duration curve rises to varying degrees (black line in bottom Fig. 3a) for hours in which emitting technologies are price-setting. The average volume-weighted electricity price thus rises (orange line in Fig. 3a).

The addition of VRE capacity causes a shift downwards of the residual load curve, with its exact course highly depending on the respective VRE generation profiles.[2] Consequently, full load hours of existing power plants are significantly reduced and the number of hours with an electricity price of zero increases. The average volume-weighted electricity price decreases accordingly (orange line in Fig. 3b).

The third instrument considered comprises the phase-out of coal power plants. In principle, switching off a technology leads to a “gap” in the merit order and, in the simplified model considered here, the load can no longer be covered. The production must therefore be replaced by another technology. This fact fundamentally distinguishes the representation of a coal phase-out in the SCM from the other instruments: in order to cover the load, additional capacity must be added.

Fig. 3c shows an example of the replacement of lignite and hard coal by open cycle gas turbines.[3] This results in the following change for the remaining technologies:

- The operation of technologies with lower marginal costs than those of the switched-off and the replacing technology does not change (in this case nuclear power).
- Technologies with higher marginal costs than those of the one switched-off but lower than those of the replacing technology slide downwards in the merit order, thus increasing their operation (here combined cycle natural gas).
- The operation of technologies with higher marginal costs than those of the switched-off and the replacing technology does not change (here oil and biomass).

When replaced by a technology with lower marginal costs, the effect is similar, except that the operation of the technologies “in between”

[2] In our SCM, the ratio between PV, wind onshore and offshore was chosen according to (BMWi 2017).

[3] OC gas turbines are chosen here exemplarily as a technology with higher marginal cost - a cost-optimal selection of replacing technologies is part of the optimization in E2M2 model runs.

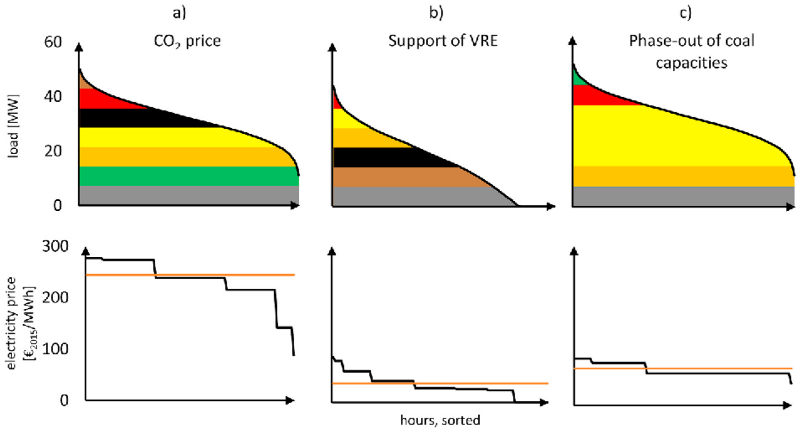

Fig. 3. Screening curves for the three isolated instruments CO_2 price, support of VRE and coal phase-out.

does not increase, but decreases.

If the replacing technology is one with similar marginal costs as the one that is switched off, i.e. it is sorted in the same place in the merit order, the operation of the other technologies does not change.

The phase-out also impacts the price duration curve - at least as long as either the switched off or the replacing technology (or both) is or was price-setting in any hour. In our example in Fig. 3c, replacement by a single and more expensive technology flattens the curve and slightly increases the average volume-weighted electricity price.

In theory, however, there is a second effect on the price curve: the switch-off creates a shortage, which creates the incentive for market entry, i.e. for new investments in generation capacities. For taking a positive investment decision, the investor must be able to reward his full costs on the market. The result is a scarcity price that is higher than the marginal cost prices previously considered. Hirth and Ueckerdt (2013) amongst others, have also looked on the derivation of this scarcity premium and conclude that this scarcity premium in a long-term equilibrium, i.e. with a cost-optimal power plant portfolio, leads to the fixed costs of all technologies being covered exactly and the profit (not the contribution margin) for all technologies becoming zero. However, this statement cannot be applied to the case under consideration here: it cannot be assumed that the existing generation system is designed to be cost-optimal, nor is the replacement technology selected according to cost-optimal criteria. Although a scarcity premium resulting from market entry shall cover the fixed costs of the new technology, for existing power plants there may be both, an over- and under-recovery of the fixed costs and thus an additional profit or loss.

Implications of a coal phase-out can vary greatly depending on the composition of the power plant portfolio: it is obvious, that the higher the installed capacity of the coal-fired power plants, the greater the impact on price curve and operation of the remaining plants. Additionally, the described effect is more severe when technologies with a load in the flat area of the LDC are switched off than when technologies in the steep area of the LDC are switched off.

4.2. *Contribution margins under different policy instruments*

The contribution margin per MWh for all technologies results from the delta between the marginal costs of the price-setting technology and those of the technology under consideration. For hours in which the technology under consideration is price-setting, the contribution margin is zero.

As described above, the merit order changes with increasing CO_2 price and sorts itself according to the emission factors [t CO_2/MWh_{el}].

Above a certain CO_2 price, that technology with the highest emission factor shows the highest variable cost and thus a contribution margin of zero. For technologies with a low emission factor, on the other hand, the operation rate can increase and the delta to the marginal costs of emission-intensive technologies increases, thus positively influencing the contribution margin. Above a sufficiently high CO_2 price, the contribution margin of all technologies increases - except for the technology with the highest emission factor, whose contribution margin falls to zero. For all other technologies, the margin can even rise above the level at a CO_2 price of 0€ (see Fig. 4a).

As described above, the addition of VRE leads to a lower operation of existing technologies, to a lower PDC and thus to a lower average electricity price. Consequently, margins of all technologies also decrease: while marginal costs of technologies remain constant, the utilisation rate and the PDC and thus also the contribution margins decrease (Fig. 4b).

Fig. 4c shows the development of margins in the coal-phase out case, where coal is linearly reduced and step by step replaced by OC natural gas. It becomes obvious, that margins per MW for technologies in the lower range of the merit order (here nuclear, hard coal, lignite and natural gas CC) increase with decreasing coal capacities. This is due to above explained two reasons: First, the average electricity price increases since coal is replaced by a technology with higher marginal cost. And second, some technologies face a higher operation of capacities due to a shift downwards in the merit order. Both applies also to coal power plants, that initially remain in the system, which is why the margin per MW also increases for remaining hard coal and lignite power plants, before it drops to zero. The gain for coal in our example reaches approx. +20% for hard coal and lignite, but can differ significantly depending on the composition of the technology portfolio. In our example, coal technologies show an operation rate of almost 100%, even before coal capacities are reduced. In case coal technologies are running at a lower operation rate before the shutdown starts, the above described second effect will result in a much higher increase in margins.

We have not considered margins for VRE so far. However, it applies for all three instruments that the contribution margins for VRE also change with the electricity price. In contrast to controllable power plants, however, the operation does not change - as long as no curtailment takes place. The extent of the change in contribution margin varies, however, since plants can only generate a contribution margin in hours in which they produce, which - in the case of fluctuating renewables - does not necessarily coincide with the hours of the higher/lower electricity price.

So far, effects of the instruments have been considered at the technology level, i.e. it has been assumed that all power plants of a technology are identical in efficiency and variable costs. In fact, there are

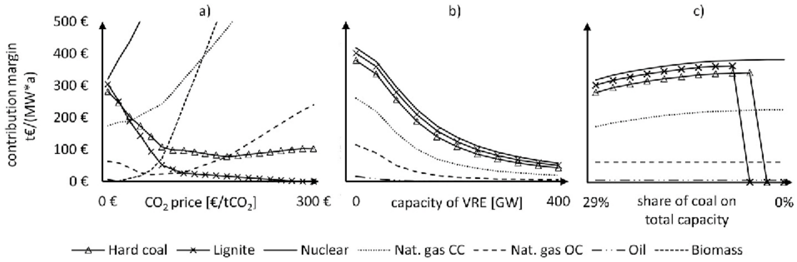

Fig. 4. Change of contribution margins under the three instruments.

considerable differences within a technology for existing power plants, above all in terms of efficiency, which can lead to very different contribution margins between plants. However, conclusions made above remain also valid when considering individual power plants, which will be explained in the following:

- Regarding a CO_2 price, the difference is that there is not one specific CO_2 price at which a technology change in the merit order takes place, but there will be a price range within which technologies can be mixed. It is not the most emission-intensive technology, but the most emission-intensive power plant, whose contribution margin falls to zero above a certain CO_2 price, contribution margins of all other power plants rise again.
- Transferring the support of VRE capacity to a plant level means that power plants with the highest absolute contribution margin losses are those that were previously operating at full capacity, i.e. those with lowest marginal costs. However, since the merit order does not change, these power plants will still have a higher contribution margin than others, even with high shares of VRE. The operation of the most expensive power plants drops to zero, as they are no longer needed to cover the load, even if the peak load is only slightly lower.
- A sequential shutdown of power plants is comparable to the results on technology level: power plants that are shut down early, loose their entire contribution margins immediately, while power plants that are shut down late, can generate contribution margins for a longer period of time; additionally, these plants can also benefit longer by the general price increase - in case coal is replaced by a more expensive technology. The switch-off sequence of the power plants within a technology thus leads to considerable differences of the contribution margins of individual power plants.

4.3. Combination of instruments

Now we face the situation, that many countries already have a support program for VRE in place and are taking part in the EU-ETS, have some other kind of emission trading system or a CO_2 price in place. The coal phase out is now introduced additionally as a third major instrument and compensation payments to coal power plants are under discussion. Therefore, special attention is paid to this order of instrument implementation and to the development of margins of coal and lignite power plants in particular.

Under the combination of the first two instruments, support of VRE and increasing CO_2 price, lignite contribution margins for lignite generation decline. This is in line with the findings for the individual instruments above, since lignite is the most emission-intensive technology in our SCM model and therefore faces the highest loss in contribution margins by a CO_2 price. The support of VRE leads to a decline for all technologies and therefore enhances the loss of lignite margins (see Fig. 5b).

The same effect can be observed for hard coal, thus up to a CO_2 price of approx. 175€ only in our example (see Fig. 5a). This is due to the fact that hard coal is not the most emission-intensive technology here and therefore faces increasing rents above a certain CO_2 price level through the increasing spread of marginal cost between lignite and hard coal.

If a coal phase-out is introduced as a third instrument in addition, it becomes obvious, that the effect on contribution margins is lower the more stringent the other two instruments are: A coal power plant that operates in a system with no VRE and a CO_2 price of zero faces higher absolute losses when it is shut down than a coal power plant operating in a system with 200 GW VRE and under a CO_2 price of 100€, because the margin before the shutdown was much higher. It should be mentioned that this conclusion can change for hard coal under very high CO_2 prices (here > 175€) and very low share of VRE, although this is a special case that is unlikely to occur.

Similar conclusions - but with regard to emission reductions - have been drawn in literature before, e.g. from Yilmaz et al., (2016), who state that the effect of a coal phase-out on emission reductions is lower in an environment with high CO_2 prices and high VRE capacities. Also Jonghe et al. (2009) conclude that the effect of one of the instruments VRE support and CO_2 price on emission reductions is lower the more stringent the other instrument is.

The case study in the next part of this paper demonstrates the extent, that those differences in contribution margins can reach between individual power plants.

5. Case study: The German electricity sector

5.1. Scenarios and data

Scenarios for the case study have been chosen in such a way that the effects of the three instruments discussed above can be analysed as isolated as possible. For this, a BAU (business as usual) scenario is calculated with a moderate expansion of VRE (172 GW in 2050) and a moderate CO_2 price development (linear increase to 75€/tCO_2 in 2050). Compared to the BAU scenario, only one parameter is changed in the scenarios CO2, VRE and CP: increased CO_2 price development to 150€/tCO_2 until 2050 in "CO2", increased expansion of VRE to 395 GW in "VRE" and a shutdown of lignite and hard coal power plants up to and including 2035 in "CP". The scenario CO2-VRE corresponds to the combination of scenarios VRE and CO2 and MIX to the combination of all three instruments. A phase-out of nuclear power plants is implemented in all scenarios.

Technical data for existing power plants in Germany are taken predominantly from BNetzA (2019a) and BNetzA (2019b). Efficiencies for thermal power plants are implemented on a plant level, taken from Open Power System Data (2018), where available. In case efficiencies were not available, they have been estimated based on a plants primary energy, age and technology.

Based on this data, sample plants for the comparison of contribution margins are selected. For both energy sources, lignite and hard coal, a plant with a comparatively low efficiency was chosen as "old power plant". Sorting of plants by efficiency largely corresponds jto sorting by year of commissioning, so that an old power plant corresponds to a comparatively inefficient power plant in almost all cases. However, the

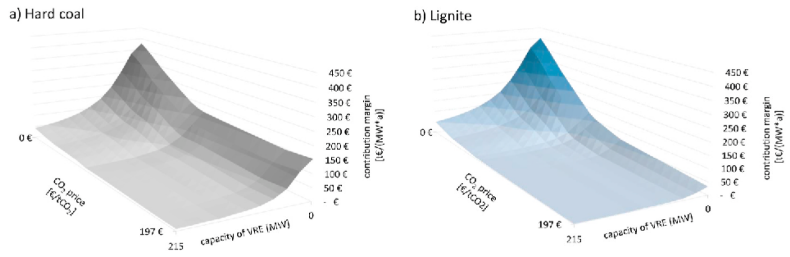

Fig. 5. Contribution margins under a combination of the two instruments support of VRE and CO_2 price.

requirement for the sample plant was also an expected operation beyond 2025, otherwise the effects of the instruments on contribution margins are too low for analysis. The "new power plant" was chosen for its comparatively high efficiency and consequently has a much longer expected remaining time in operation.

For the calculation of yearly contribution margins per plant, model results are inserted into equation (9) above. The consideration of the timely resolution of 2 h and the more detailed representation of variable costs, consisting of fuel cost, CO_2 cost, variable cost for O&M and cost for plant start-up, shut-down and ramping, results in the equation

$$CM_i = 2 * \frac{\sum_{t=1}^{4380} \left(PDC(t) - \left(c_{i,Fuel} + c_{i,CO2} + c_{i,OaM} + c_{i,Startup} \right) \right) * q_i(t)}{p_i} . \quad (10)$$

5.2. *Results and discussion on technology level*

For an overview of scenario results it can be referred to Figure A.1 and Figure A.2 in Appendix A, where emission trends and the development of the generation mix are listed for all scenarios. However, since the focus of our analysis are contribution margins of technologies and power plants, these results are not discussed further here.

The change in contribution margins at technology level in the case study corresponds to the results of the SCM: In the CO2 scenario, contribution margins of low-emitting/non-emitting technologies are significantly higher than in BAU, while contribution margins of emission-intensive technologies are significantly lower. In scenario VRE, contribution margins of all technologies are below BAU, with losses increasing as the amount of installed VRE increases.

In the CP scenario, it shows that the cost-optimal replacement of switched-off coal capacities - as assumed in the SCM - are largely gas-fired power plants, i.e. a technology with higher marginal costs. Due to these higher marginal costs, the electricity price rises and most technologies can benefit from a slightly higher contribution margin than in BAU. Moreover, effects explained in the SCM for hard coal and lignite technologies can be observed in CP: the remaining share of coal technologies profits from a higher electricity price and from a higher operation, so that – compared to BAU - the contribution margin per remaining MW is significantly higher in the first years.

However, by combining all three instruments in scenario MIX, it becomes obvious that the effects of the CO_2 price and the support of VRE dominate over those of the coal phase-out: contribution margins for coal-fired power plants decline over the entire period, even though the losses through CO2 and VRE are slightly weakened by CP.

The proportional change in contribution margins in scenario MIX is given in Fig. 6. It becomes obvious that the effect of the higher CO_2 price dominates in the first few years, i.e. emission-intensive technologies lose contribution margin and low-emission technologies benefit. In the long term, however, the effect of VRE support dominates and all technologies face declining margins. With scenario assumptions chosen here, the increase of margins reaches 58% for natural gas between 2020 and 2025, while coal margins decline by 42% (lignite) and 34% (hard coal) in the same period.

5.3. *Results and discussion on individual plant level*

Beyond the results of the SCM, E2M2 allows for analysing results on a power plant level, enabling the different contribution margins within a technology to be evaluated. As explained earlier, we pay special attention to coal and lignite power plants here, since their contribution margins play a special role in the current discussion about compensation payments.

The first core finding is, that - independent from the scenario – expected contribution margins between power plants of the same technology vary greatly. Fig. 7 shows the differences of cumulated contribution margins (real values per MW) over the period from 2020 to 2050 between old and new coal power plants. Within the BAU scenario for example, a new power plant can expect a cumulated contribution margin that is approx. 9.5 times as high as the one for an old power plant. One reason of course is the higher efficiency of the new plant. This means that the new power plant is placed further ahead in the merit order, has a higher operation and a higher spread between the electricity price and its own marginal cost. On the other hand, the remaining technical lifetime of the new plant is significantly longer, which means that this power plant can generate a contribution margin over a longer period of time. For a better understanding of the cumulated values, it can be referred to the development of the contribution margins over the years in Figure B.1 in Appendix B.

The second central finding is that effects of a coal phase-out on contribution margins are much smaller in the case of a high CO_2 price and a strong increase of VRE capacities than in the case of a moderate CO_2 price and a moderate VRE development. Fig. 8 shows the change in the contribution margin as an example for an old lignite-fired power plant. It becomes clear that a coal phase-out in a system with a low CO_2 price and moderate VRE expansion (BAU) has a strong impact on the contribution margin of -47% for this specific plant. In contrast, a high

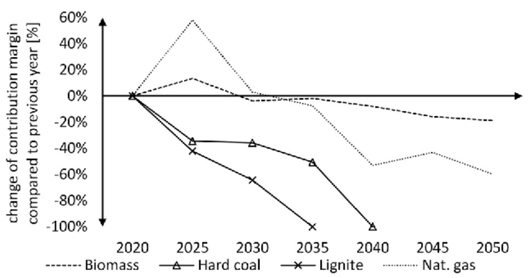

Fig. 6. Course of contribution margins at technology level in scenario MIX.

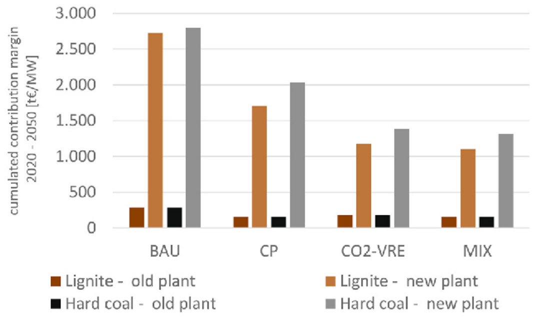

Fig. 7. Cumulated contribution margins for sample old and new coal power plants.

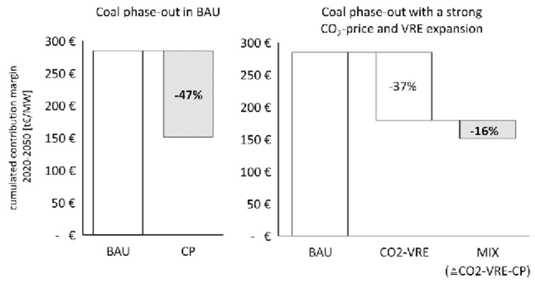

Fig. 8. Impact of policy instruments on contribution margins of an old lignite plant.

CO_2 price and a strong VRE expansion already leads to a loss of contribution margin of 37%, so that a coal exit in such a political environment reduces the contribution margin only by additional 16%. This effect also occurs in the case of the new lignite-fired power plant, as well as for the old and new hard-coal power plants, where a coal phase-out in an ambitious political environment reduces contribution margins only by approx. 5%. This result follows the finding in the SCM in section 4: the more stringent the other two instruments are, the smaller the impact of a coal phase-out on contribution margins will be.

As discussed in the methodology section, E2M2 focuses on the electricity sector, which means that interdependencies with other sectors are neglected. Additionally, the results do not consider the effect that national or sectoral GHG mitigation measures targeting emissions that are already covered by the ETS, can lead to decreasing ETS CO_2 prices. Therefore, it should be subject to further research to examine the topic of this paper in an energy system model, covering all ETS sectors and countries.

A further limitation of our results is that above shown contribution margins include only revenues generated by the sale of electricity. This means that additional revenues e.g. from a possible CHP remuneration or from option premiums are not taken into account. The contribution margins here should therefore be regarded rather as a "contribution margin share" from the pure sale of electricity.

6. Conclusion and policy implications

This study examines the effects of a coal phase-out on the energy sector, especially in combination with the existing instruments increasing capacity of variable renewable energies (VRE) and a CO_2-price. Background is that many European countries have announced the implementation of a coal phase-out, but interactions of this with existing instruments have not yet been studied very detailed. A focus is set on contribution margins of power plant operators and their development under the influence of the three instruments. Thus, the study provides indications for the determination of compensation payments, which is a critical issue when designing a coal phase-out. Methodically, a screening curves model with a brownfield approach is used to demonstrate the effects of the three instruments on capacity operation, electricity prices and contribution margins. In a subsequent case study, the electricity sector model E2M2 with a high power plant resolution is used, so that conclusions can be drawn about the extent of expected and lost contribution margins on a power plant level.

The results of this paper permit two important conclusions: 1) Contribution margins between technologies and also plants within one technology can vary greatly and 2) Impact of a coal phase-out on contribution margins declines when the other two policies become more stringent. In the case of the scenarios calculated in this paper, the difference in cumulated contribution margin in the period 2020 to 2050 between old and new power plants can be up to 9.5 times. The influence of a coal phase-out on the cumulative contribution margin in real values of a power plant can be between 5 and 47%, depending on the extent of the renewable energy expansion and the level of the CO_2 price. Of course, these values apply only to the example power plants selected here and under the scenario assumptions taken here. However, the more general conclusions drawn initially on the basis of the screening curves model can also be applied to other scenario conditions and electricity systems. The extent of the effects depends, among other things, strongly on the composition of the power plant portfolio, the share of coal in the installed capacity and the planned coal phase-out sequence and speed.

Hence there are several relevant parameters that can influence the level of contribution margins. If compensation payments are fixed by negotiation between the parties involved, an implicit assumption must be made about the development of those influencing factors. However, if the development then turns out to be different than assumed, there is a risk that compensation payments will be too low or that the effects of other instruments will be unintentionally offset.

This in turn leads to the consideration, that a once fixed compensation per decommissioned MW of lignite or coal capacity would hardly equal the actual amount of contribution margin losses. Such a model could create strong winners and losers among power plants and thus create windfall effects for some operators and excessive costs for the taxpayer on the other hand. Rather, a compensation model should be found in which technology, power plant age and efficiency as well as the development of existing policy instruments can be taken into account.

One possibility to take these influencing factors into account, is to link the compensation to certain parameters, such as the CO_2 price, the installed capacity of VRE or the expected lifetime of power plants. However, such a compensation system would be complex and politically not easy to communicate. Another possibility is to apply a more market-based approach, which would encourage the concerned players to consider their expectations about the development of the political framework conditions and thus their own profit expectations.

One conceivable option is a competitive bidding process in which the parties concerned submit a bid as to what price they are prepared to shut down their power plant. If these auctions take place repeatedly over a longer period of time, bidders could also take changes in the political framework into account.

Another market-based approach that has already been discussed, concerns the issue of electricity generation rights or emission rights in the amount of a previously determined residual budget. These rights are then traded between operators of the concerned power plants only, resulting in a price that also reflects the profit expectations of the traders. Here, too, the price would adapt to changing conditions with the additional advantage of a defined residual amount of electricity or emissions. The elaboration of a detailed proposal of such a system should be subject to further research.

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CRediT authorship contribution statement

Annika Gillich: Conceptualization, Data curation, Formal analysis, Investigation, Methodology, Resources, Software, Validation, Visualization, Writing - original draft. **Kai Hufendiek:** Funding acquisition, Writing - review & editing, Supervision. **Nikolai Klempp:** Funding acquisition, Writing - review & editing, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A

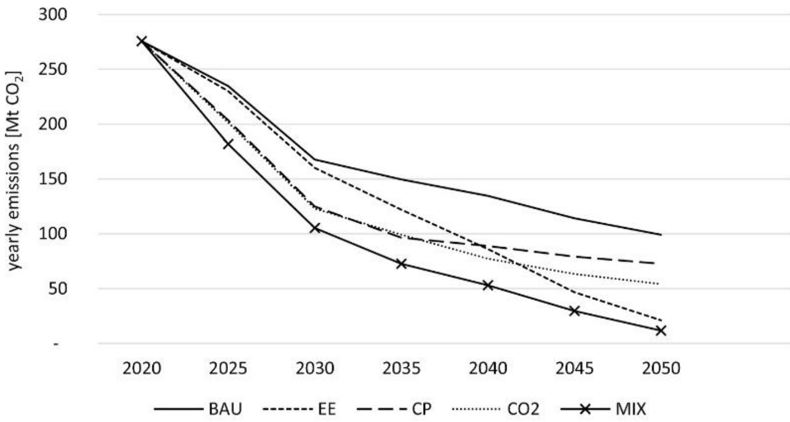

Fig. A.1. Results of the case study scenarios – emission trends.

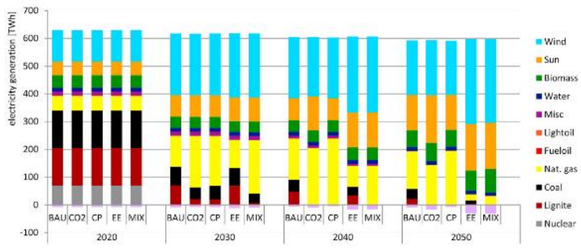

Fig. A.2. Results of the case study scenarios – energy mix for selected years.

Appendix B

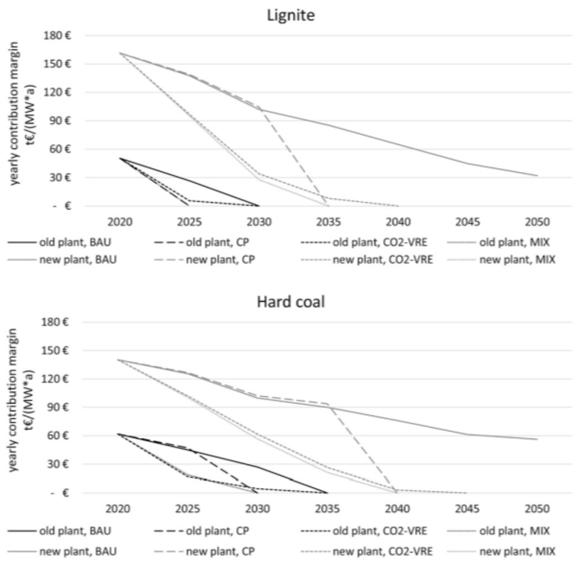

Fig. B.1. Development of contribution margins for sample lignite and hard coal power plants.

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4 Asset Profitability in the Electricity Sector: An Iterative Approach in a Linear Optimization Model

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Author contributions:

The following Table 4-1 shows the contributions of the author and co-authors to this paper, using the "CRediT author statement" system (Elsevier 2019). Conceptualization was done in several joint discussions, leaded by Annika Gillich. Kai Hufendiek performed the review and editing of the manuscript, provided the resources and did the funding acquisition.

Table 4-1. *Author contributions third paper*

	Annika Gillich	Kai Hufendiek
Conceptualization	x	x
Methodology	x	
Software	x	
Validation	x	
Formal Analysis	x	
Investigation	x	
Data Curation	x	
Writing – Original Draft	x	
Writing – Review & Editing		x
Visualization	x	

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Article

Asset Profitability in the Electricity Sector: An Iterative Approach in a Linear Optimization Model

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Abstract: In a competitive electricity market, generation capacities can exactly cover their full costs. However, the real market deviates from this ideal in some aspects. One is the concern of non-existent or insufficient scarcity prices. We present an iterative method in a linear optimization model to investigate the profitability of assets in the absence of scarcity prices and how the system changes when this risk is incorporated into investors' expectations. Therefore, we use a two-step optimization of capacity planning and unit commitment. Iteratively, mark-ups at the height of uncovered costs are added to investment costs. This typically leads to a system with better investment profitability while keeping the system cost increase low. The methodology is applied to a simplified brownfield generation system, targeting CO_2-free power generation within 25 years. In a model with annual foresight of actors, iterations result in a generation system with significantly lower (or even no) uncovered costs for new investments within ten or fewer iterations. Our example case with full foresight shows that early-added gas (combined cycle) and wind onshore capacities are able to recover their full costs over a lifetime, even without scarcity prices. However, the contribution margin gap remains high, especially for storage and biomass.

Keywords: electricity market modelling; power sector; asset profitability; optimization; iterative method; scarcity prices

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1. Introduction and Relevance

Electricity generation as part of the energy system plays a key role in the way to a greenhouse gas (GHG)-neutral energy system. Although significant reductions have already been achieved in this sector in recent years, there is still significant transformation needed to achieve GHG-neutral electricity production. Therefore, for example, many countries have lately decided to phase out their coal-fired electricity generation. However, it is already becoming apparent that the decarbonisation of the transport and heat sectors will be accompanied by the increasing use of electricity as final energy in these sectors, resulting in a higher demand for electricity. At the same time, national targets and international commitments regarding GHG-emission reductions are steadily tightened and pulled forward, leading to a high pressure for an extremely rapid transformation of energy systems. Those aspects in combination require the electricity generation to reach carbon neutrality (or even net negative emissions) within a very short timeframe.

Studies on how the transformation of the power system can succeed are often calculated with optimization models (ref. [1], examples in [2–4]). With this modelling, a solution is found to how the demand for electricity can be met at a minimum system cost while complying with various technical and economic restrictions. Existing assets (In the following, we use the term "asset" to refer to all capacities that contribute to meeting the electricity demand, thus including conventional power plants, renewable power plants, storage and demand response technologies.) are usually considered assuming a remaining technical lifetime. To ensure that the demand for electricity can still be met when the capacity of existing assets decreases, the model has the option of deciding on the addition of new generation technologies as the integrated option for cost minimisation. The results outline the technology mix that can fulfil the corresponding power supply task at a minimum cost. The results of these model calculations serve as a basis for political decisions, e.g., with regard to support schemes, subsidies, guaranteeing the security of supply and grid planning, but also as a control mechanism for how, whether and at what cost political goals can be achieved. From this point of view, the application of cost minimisation approaches to this task is advantageous as it shows a normative transformation path.

However, in reality, there is a certain risk that the capacity additions identified by such a cost-minimising approach do not take place as calculated due to non-profitability in reality. This means that the addition of a certain technology may represent the solution with the lowest system costs from an economic perspective, but no investor would actually decide on this investment, as it is not profitable from an individual investor perspective.

According to economic theory for competitive energy markets (compare e.g., ref. [5], (p. 53)), all technologies can cover exactly their full costs ([5] (p. 123)), and cost-minimising modelling approaches basically follow these assumptions. However, this conclusion is only true if all conditions of perfect competition are satisfied. For example, scarcity prices (i.e., prices above the marginal costs of the most expensive technology) are required to occur at a sufficient level. For this to happen, there must be at least a few hours of scarcity in which the pivotal supplier is able to enforce prices above its marginal costs. In a market with overcapacities, scarcity prices are not possible according to economic theory, because at prices above the marginal costs, a producer would always be found who would offer at lower prices. However, scarcity prices at levels that would be expected under that theory have not been observed in existing European electricity markets (for explanations see Section 2) in the recent past. Furthermore, there is a risk that, even if scarcity exists, price spikes are limited (e.g., for political reasons), thereby preventing sufficient scarcity prices. These two aspects increase the risk for investors that sufficient scarcity prices to refinance the full cost of an investment will not occur in real markets. Accordingly, there is a risk that rational actors will not choose to invest in a particular technology even though it has been identified as the least-cost option in the cost minimisation model.

The existence of this risk has also been addressed in the latest description of the European Resource Adequacy Assessment (ERAA) methodology [6], which is the basis for the central pan-European assessment of the security of supply. The methodological approach to evaluating the economic viability of generation capacity is called Economic Viability Assessment (EVA), and the first results have already been published (see Section 3.3 for details).

From an investor's perspective, however, the risk of missing scarcity prices does not necessarily mean that no investment will take place, but rather that they will apply a different or higher risk premium when calculating their investment [7,8]. Risk premiums can be included in optimization models as part of the investment cost. Technologies that must cover a higher proportion of their fixed costs through scarcity prices in order to be profitable will have to apply a higher risk premium than technologies that depend only slightly on scarcity prices, according to this logic. This, in turn, shifts the relationship between the investment costs of different generation technologies, and the model will find a different solution considering this new information. To implement this logic into model analysis, we propose an iterative modelling approach in this paper that captures exactly this relationship by gradually adding a risk premium to the assumed investment cost for the risk of an unprofitable investment (due to a lack of scarcity prices). On the one hand, this iterative methodology better reflects the decision behaviour of investors. On the other hand, the methodology leads to a system with lower uncovered costs while keeping the increase in system costs as low as possible at the same time.

The result does not necessarily correspond to a technology mix in which all technologies are actually profitable, but the result is a technology mix in which the calculated investments actually take place with a higher probability. The disadvantage of system-cost-optimizing modelling discussed above can thus be mitigated.

We apply the methodology described (and explained in detail in Section 4.1) in this paper as a highly simplified brownfield model for the German power sector and show how and why this changes the technologies chosen by the model. However, we describe the methodology in a general manner so that it is applicable to other models, for different regional areas and other scenarios.

Summarizing the above means that successfully managing the extremely rapid change in the electricity sector requires extensive modelling exercises to support policy decisions. In this paper, we aim to add one aspect to these results that has been little considered so far, as follows: We study the impact of the risk of insufficient scarcity pricing in real markets on the composition of technology choice and the profitability of individual technologies. This might be of special importance with regard to the question of whether insufficient scarcity pricing might inhibit required capacity investments on the way to a purely renewable-based electricity sector. The research gap we aim to fill consists mainly of the following two aspects: First, there are very few studies on the electricity sector that consider a model endogenous feedback loop between the risk of non-profitability and technology choice. Second, existing studies often examine profitability in a general manner, which does not allow one to distinguish between effects that stem from a simplified representation of reality in the model and effects from actual structural deficits in the real market. In contrast, we only focus on the effect of insufficient scarcity pricing on profitability, which allows for a clear cause-effect analysis.

With those two aspects, we contribute to improving the representation of non-optimality in electricity market modelling [9] and demonstrate a method on how to investigate one aspect of uncertainty for investors, which is often considered underrepresented in energy system models [10,11].

The paper is organised as follows: In Section 2, the theory of pricing in electricity markets and the formation of prices in linear optimization models are summarized. The approach chosen in this paper to account for profitability is explained and compared to existing modelling approaches to profitability. In Section 3, the model and data used are described as well as the details of the iterative methodology applied. The results before and after the iterations as well as under a myopic and a perfect foresight model approach are summarised in Section 5. Conclusions and recommendations for further development of this approach are drawn in Section 6.

The basic setup of model assumptions in this paper is based on key data from the German electricity sector, which is why Germany is also frequently taken as an example within the next sections.

2. Empirical Findings on Electricity Price Formation, Profitability and Investment in Competitive Markets

According to economic theory, the price in a competitive market is determined by the intersection of the demand and supply curves. Within a competitive electricity market, this usually means that the price for electricity equals the marginal cost of the supplier with the highest marginal cost that is in operation at a certain point in time [5] (p. 62). The term "usually" indicates that there are circumstances in which this is not the case. One is that prices can rise above marginal cost in times of scarcity of supply. In order to understand why this is necessary for an efficient market, it is useful to distinguish between a short-term market equilibrium and a long-term one [5] (p. 56). In a short-term market equilibrium, a generator will decide to generate output as soon as the market price rises above its marginal cost. In a long-term equilibrium, a generator needs to be able to recover its full costs (variable costs plus fixed costs); otherwise, it will decide to exit the market [12] (p. 13). Generators can gain revenue to cover their fixed costs from (non-scarcity) inframarginal rents, which is the delta between their own marginal cost and the marginal cost of the price-setting generator. However, if this were the only revenue, it would mean that the generator with the highest marginal cost would cover its variable costs only and would have no chance to recover any of its fixed costs. In combination with scarcity on the supply side, the generator will be able to set the price above its marginal costs in times of high demand as there is a chance that it will be pivotal (i.e., the generator is the only one being able to increase production anymore). This delta between the resulting market price and the highest marginal cost is called scarcity rent (compare [5] (p. 71)) and will, according to theory, be set at a level where the generator with the highest marginal cost recovers exactly its fixed costs. Higher prices than that would attract other investors to enter the market and thus cause prices to decline. This, in turn, means that the scarcity premium will settle at an optimum level in the long term. In such a long-term market equilibrium, all generators are able to recover exactly their fixed costs [5] (p. 123). A generator's total earnings to cover its fixed costs (sometimes also called short-term profit or contribution margin) therefore constitutes from its inframarginal rent r_{inf} (which equals zero for the generator with the highest marginal cost) plus a scarcity rent r_{sc} as expressed in Equation (1).

$$CM = r_{inf} + r_{sc} \tag{1}$$

Furthermore, literature often distinguishes between the contribution margin (CM) reflecting the delta between revenue R and variable cost (Equation (2)). The second one is the (unadjusted) margin M which takes fixed operating costs and investment into account and therefore represents the delta between revenues and a generator's full cost as in Equation (3). As we focus on new investments in this paper, it is crucial for an investor that he can expect a positive (unadjusted) margin M, otherwise, it is quite clear that he will not be able to gain any profit. Therefore, the unadjusted margin is the most relevant indicator for this purpose, and we use the term "margin" synonymously to M, while the term "contribution margin" is used for the term CM. An overview of the interrelations of these terms is also given in Figure 1 (see ref. [12], p. 14 for a more detailed breakdown of costs).

$$CM = R - C_{var} \tag{2}$$

$$M = R - C_{var} - C_{fix} - C_{inv} \tag{3}$$

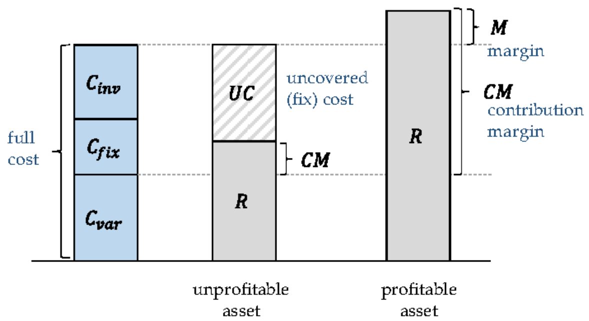

Figure 1. Definition of terms used for cost and margins in this paper.

As mentioned above, in an efficient competitive electricity market in its long-term equilibrium the margin M will equal zero for all generators. However, some aspects bear the risk that this situation will not materialize in a real electricity market. The case that prices in a real electricity market might not be high enough to recover investment costs is called the missing money problem [7]. This phenomenon can lead to a situation where the market fails to attract sufficient investments for serving the electricity demand.

Ref. [7] shows evidence that this problem actually occurs in the US liberalized electricity markets. The reasons why the missing money problem occurs are discussed in the following publications: Ref. [5] states that it is likely that there are old generators (not retired) in the system with higher marginal cost than the one operating, which means that the system actually is not scarce and scarcity rents might not occur or not be sufficient. Another reason frequently mentioned is that the majority of electricity consumers do not see real-time prices nor are able to adjust their electricity consumption to price signals, resulting in a high inelasticity of demand. A steep demand curve can support the emergence of price peaks, but in extreme cases, it can also lead to a situation where no market-clearing price can be found at all [13,14]. To avoid this situation, electricity markets often define a price cap that is applied when no clearing price can be found through the market. Whether and how high this price cap is set is a question of individual market design. A price cap that is set too low entails the risk of insufficient refinancing of capacities that need precisely these high prices in scarcity situations to cover their fixed costs. However, even in markets with non-capped prices, such as the German electricity market [15], there is a lack of empirical evidence that sufficiently high price peaks actually occur. Therefore, neither the question of whether sufficient price peaks occur in existing market designs nor the question of whether high prices—if they occur—are also “sustained” long enough from the political side, can be answered empirically.

The discussion about these real-world inefficiencies shows that there is a risk of retained investment in new power generation capacity, although—according to theory—the market is able to ensure the addition of enough capacity to achieve a sufficient level of security of supply. In the case of the German electricity market, this issue was analysed in detail in publications from 2011 to 2013 against the background of the question of whether or not Germany should establish a capacity market. The conclusion from this discussion was that the above-mentioned reasons are not sufficient to legitimize the introduction of a capacity market. On the one hand, it was argued that these inefficiencies either have very little impact or can be addressed by a careful market design. On the other hand, it was also highlighted that there was overcapacity in the German market at that time, leading to a fundamentally high level of security of supply (compare [8,16–18]). However, it is not the aim of that paper to add to this discussion, but the discussion provides evidence that there is some risk that the required investments might not occur. Instead, the procedure introduced in this paper offers an opportunity, to include this risk into the analysis of capacity development in a market-based power system.

An analysis of historical day-ahead electricity prices also indicates that there is still more generation capacity in Germany today than would be necessary to cover the peak load. Table 1 shows the distribution of hourly prices in the German/Luxembourg bidding zone for the period January 2015 to October 2021 [19]. Although the maximum electricity price increased in the past years and the frequency of electricity prices >EUR 100 increased especially in 2021, maximum prices did not come close to investment costs of a peak load technology (investment costs for an open cycle gas turbine add up to around 57,000 EUR/MW with our assumptions s, compare Table A1.) or an estimated value of lost load in the whole period considered (estimates of the value of lost load show a very wide range in literature, summarised e.g., by [20] between 1500 EUR/MWh and 22,940 EUR/MWh.).

Table 1. Frequency of day-ahead prices above 100 EUR/MWh within the German/Luxembourg bidding zone (incl. Austria until 30 September 2018).

Price Range	2015	2016	2017	2018	2019	2020	2021
[100;200)	0	1	61	13	7	24	1306
[200;300)	0	0	0	0	0	1	156
[300;400)	0	0	0	0	0	0	9
[400;500)	0	0	0	0	0	0	1

The fact that overcapacities exist not only in Germany but also in other European countries is also shown by [21]. Therefore, at least in the medium term, there seems a risk that there will be no scarcity prices in the German but also in other European electricity markets, which would be necessary to refinance the investment costs of new assets and to cover the fixed costs of existing assets. In recent years, for example, it has been observed that existing gas-fired power plants in some countries have actually become unprofitable [22]. Ref. [23] even concludes that "virtually all generators encounter a revenue gap in the current energy-only market".

Another reason for the missing money problem can be that compensation for ancillary services and/or reserve provisions are insufficient [24]. Some sources also mention the volatility of electricity prices as a potential risk for insufficient investment, which will become even more serious with the increasing share of variable renewable energies (VRE) (discussion in [25]). However, e.g., ref. [8] states that price volatility alone does not constitute a market failure, but the impossibility to hedge against those risks might do so. Ref. [24] calls this issue the "missing market problem" and points out that missing markets might lead to insufficient investments, meaning that an investor is not able to adequately use forward or future markets for hedging its risks. This is particularly relevant considering that the usual refinancing period of a generation capacity is long and changes in political targets and/or reforms are likely to occur within this period.

Therefore, there are plenty of empirical indications for a certain risk that scarcity prices either will not occur or will not occur sufficiently to refinance fixed costs. In the medium term, this probably results from existing overcapacity; in the long term, it may be compounded by the risk of price caps or other reasons hampering the occurrence of sufficient price peaks in the market. Investors assessing the risk of a new investment today must take this fact into account in their deliberations. While this does not necessarily mean that there will be no capacity additions at all, investors would likely take the risk of a shortfall into account in the form of a risk premium. This would de facto increase investment costs and lead to a correspondingly lower level of investment (compare also [8]). Technologies that are heavily dependent on scarcity prices for their refinancing would assume a proportionally higher risk premium than those that can already cover a large part of their fixed costs through inframarginal rents. Accordingly, the ratio of investment costs between the technologies will also shift, leading to a different composition of the optimal technology mix.

3. Modelling of Pricing and Profitability in Linear Optimization Models

In the following chapter, we address the link between the empirical findings above and the price formation in an optimization model in Section 3.1. We then present our approach to considering asset profitability in a schematic overview along with a discussion of its real-market interpretation. With this background, we can contrast our approach to existing literature, thereby discussing the WACC principle, discount rates, endogenous and exogenous profitability calculations, the methodology of the latest European resource adequacy studies, as well as the link to publications in the area of so-called modelling to generate alternatives. Chapter 3 concludes with a summary of the strengths of the applied modelling approach and the methodologic rationale why we apply the approach to a myopic as well as a perfect foresight model.

3.1. Prices and Cost in a Linear Optimization Model

As the pricing mechanisms in competitive electricity markets based on economic theory reflect the marginal cost of the most expensive generation unit required to meet the demand, electricity prices in linear optimization models can be read from the dual variable of the electricity demand equation (e.g., ref. [26]) (This applies at least to those models in their very basic configuration. Advanced electricity market models represent many characteristics of an electricity sector in detail, e.g., expansion or decommissioning targets are set, must-run conditions are set, minimum shares of renewables are exogenously specified or additional demands for heat, hydrogen, etc. are taken into account. All of these model features can ultimately influence the electricity price, so the simplified explanations of Section 2 alone are no longer sufficient to explain it, which is why we refer here to a highly simplified model only.). In our simple example, this implies that prices above marginal costs will occur in these models only if generation capacity is actually scarce. This could—for example—be the case in a capacity expansion model, where no existing assets are considered (often called "greenfield modelling") or the available capacity of existing assets is not sufficient to cover demand at all times. In this case, the model is usually able to choose the cost-optimal generation mix out of several technology options and consequently, scarcity rents above marginal costs will be visible in the price structure and the missing money problem will not occur (e.g., ref. [27]). In a pure unit commitment model, on the other hand, the cost-optimal dispatch under sufficient capacity is found only, i.e., prices will not include scarcity rents but follow the generator's marginal operation cost. With respect to the profitability of assets, this means that assets in a capacity expansion model earn exactly their full costs and that $r_{sc} > 0$ and $M = 0$ applies. In a pure unit commitment model, no scarcity rent occurs ($r_{sc} = 0$) and thus $CM = 0$ is valid for the technology with the highest marginal cost and $CM = R_{inf} > 0$ for all other technologies. Furthermore $M \leq 0$ applies to all technologies.

3.2. Considering Profitability Risk by an Iterative Modelling Approach

In this paper, we use a two-step procedure based on two linear optimization models, consisting of one model that optimises capacity expansion planning (and unit commitment at the same time) and one model that has no possibility for capacity additions but calculates only the dispatch of existing units. The models are called the capacity expansion model (CEM) and the unit commitment model (UCM) in the following. The models correspond with respect to all assumptions (costs, technology parameters, temporal and spatial resolution, etc.) and differ only in that the cost-optimal capacity mix calculated in the CEM is assumed as existing units in the UCM (see Figure 2). With this model setup, a cost-optimal capacity mix can be evaluated, but at the same time, a price series without scarcity rents are generated.

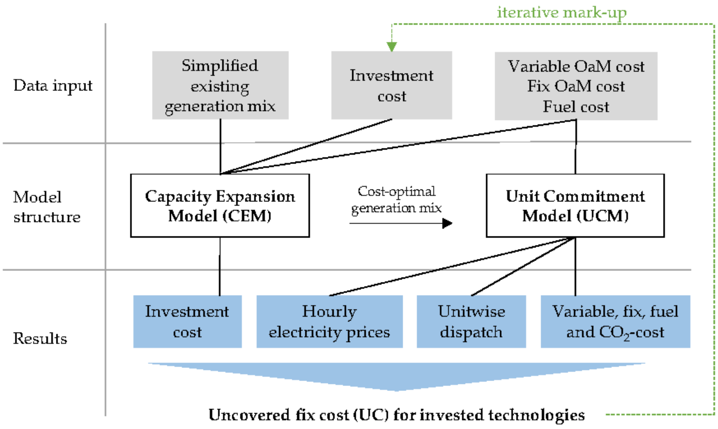

Figure 2. Model structure for profitability calculations.

The objective function in both models corresponds to the minimisation of system costs, i.e., those costs to meet the exogenously specified electricity demand. In both models, the system costs include the variable costs for operation and maintenance (OaM), the fuel costs, carbon costs and the fixed OaM costs of all generation technologies. In addition, in the CEM, investment costs are also part of the objective function. To account for the different lifetimes of the generation technologies, investment costs are allocated to the respective technical lifetime by an annuity approach. As described in the previous sections, there is a certain risk for an investor that the occurrence of scarcity prices is not sufficient to refinance an investment. In our model setup, the uncovered costs UC of a technology t in year y represent the contribution margins at risk for investments in those new generation assets in case the market price does not exhibit any scarcity price peaks. For a myopic case, the uncovered cost $UC_{y,t}$ is defined by Equation (4), where A corresponds to the annuity of investment costs.

$$UC_{y,t} = r_{inf,t,y} - C_{fix,\ t,y} - A\ (C_{inv,t}) \tag{4}$$

Since uncovered costs represent a risk for a potential investor, we assume a mark-up on the investment costs of those technologies. The relation of the mark-ups thereby corresponds to the relation of the uncovered fixed costs. On the basis of these increased investment costs for those technologies, we restart the CEM, resulting in a different composition of the capacity mix than that of the first iteration. Since resulting prices in the UCM, and thus the profitability of technologies, change as a result, we apply this methodology iteratively and assume new mark-ups for the next CEM run. We continue these iterations until one of the termination criteria described in Section 4.1 is reached. The result is a capacity mix with higher system costs—since any change from the original optimum solution means obviously higher costs—but at the same time lower total uncovered costs. In addition, this capacity mix takes into account the technology-specific risk of uncovered fixed costs and the resulting shift between technologies.

Compared to the decision process of an investor, the mark-up on investment costs assumed in this way has similar effects on the model results as an increase in the weighted average cost of capital (WACC) or a technology-specific hurdle rate. However, it is not to be understood exactly as such and, due to the methodology described above, can be significantly higher than the WACC or hurdle rate normally assumed in the literature. The mark-up is rather a tool to obtain the model to find a solution that is system cost-optimal but at the same time minimises the sum of uncovered fixed costs. A mark-up on investment costs is particularly useful in this context because it can be deducted from the results ex-post. In addition, marginal generation costs are not affected, and thus neither are prices that follow marginal costs.

A different approach would be to assume mark-ups on the variable cost to the extent of uncovered cost from the previous iteration. This could have a similar impact on model results, namely, that technologies with high uncovered costs are used less in the next iteration. However, this procedure would affect marginal costs and thus prices in the UCM, which makes it more difficult to deduct the effects of this mark-up from the model results ex-post. Higher investment costs in turn influence the level of the scarcity premiums only, which are not considered in the profitability calculations. This methodology, therefore, offers a possibility to identify a capacity mix with very little intervention in the model results, which is system cost-optimal but at the same time has lower uncovered costs due to missing scarcity prices compared to the initial solution.

From an optimization point of view, this approach leads to a simultaneous minimisation of system costs and uncovered costs. Since electricity prices are not known endogenously within an optimization, the two components cannot be minimised simultaneously. To still find such a solution, the markup on the investment costs acts as a "penalty term" for the uncovered costs of the previous iteration, which leads to the fact that uncovered costs become part of the system costs and will thus be part of the minimisation.

As a result, technologies with high uncovered costs are used less, which has the following two effects: On the one hand, this results in lower uncovered costs since technologies with high uncovered costs are exchanged for technologies with lower uncovered costs. On the other hand, this also leads to shifts in the price duration curve, which can have a positive effect on margins and thus further reduce uncovered costs, but can also have a negative effect on contribution margins. Thus, there is no guarantee that this method will result in systems with lower uncovered costs in all cases (Although it cannot be proven that the iterative procedure will converge at anytime, we observed good convergence after a limited number of iterations in almost all cases (see Section 5.2).). The heuristic termination criteria ensure that the cases in which the negative effect on margins predominates are not considered any further. The specific effects of the markups on generation, prices and margins are illustrated by a simple example in Appendix B.

3.3. Other Modelling Approaches

The problem of uncertain profitability of investments in competitive power markets and within a cost-minimising approach is well known in the literature. There are several existing methodological approaches to considering profitability in energy-economic modelling.

A first and very convenient approach is to include the risk of profitability in discount rates and integrate those adjusted specific investment costs into cost minimisation models. There exists an extensive literature on the identification and selection of appropriate discount rates. For example, ref. [28] finds that social discount rates and technology-specific hurdle rates can strongly influence the energy system's composition and behaviour. The authors of ref. [29] summarise social and individual discount rates used in studies and emphasise the importance of differentiating rates among different investor groups. The authors of ref. [30] propose actor- and region-specific discount rates to adequately reflect investor behaviour in optimization models, while [31] differentiate between sector- and actor-specific discount rates in their scenarios.

In summary, these calculations take into account different risks through corresponding premiums, but in the model calculation, it is implicitly assumed that these fixed costs can be fully covered. However, we see this as uncertain in real markets, as pointed out in Section 2. In contrast, our model setup generates an energy system in which (due to deviations from a perfectly competitive market) the fixed costs *cannot* be covered, and we examine the shifts in the energy system as a result in this particular example case by an iterative procedure.

Optimization models are also used to quantify asset or technology rents in defined scenarios, where the modelled electricity prices are used ex-post to calculate revenues. For example, rents on the asset level are examined under the influence of various policy measures in [32]. Ref. [33] calculates the shift in rents between generators and consumers also using a linear optimization model. In [34], the profitability of new and existing assets is calculated and evaluated with respect to the necessity of a capacity market. Although these approaches are able to quantify differences in profitability of different investments in competitive power markets, they do not model the impact of those differences on the development of the generation mix in the market. Ref. [35], for example, strives for that, as he implements a model endogenous consideration of profitability. However, the revenue calculation there is performed with an exogenously assumed subsidy and is therefore not completely modelled endogenously.

Ref. [36] applies a Monte Carlo simulation to determine the distribution of returns for different technologies. As he assumes invests and disinvests exogenously, no scarcity prices can be detected by this approach, and consequently, net present values (NPVs) for all technologies turn out to be negative. Ref. [25] conducts technology-specific risk measures from Monte Carlo simulations with a generic investment and dispatch model, thus considering investment decisions endogenously. However, the feedback effects on the investment decisions based on calculated profitability are not investigated in both cases.

The issue of profitability of generation capacities is currently also the subject of a discursive platform in the context of the major resource adequacy studies of the European network transmission system operators (entso-e). Following the Agency of the Cooperation of Energy Regulators (ACER) decision No 24/2020 [37], entso-e will implement a so-called economic viability assessment (EVA) as part of the European resource adequacy assessment, which evaluates market exits and entries based on an asset level comparison of revenue and costs. With a methodology still in the proof-of-concept stage, the EVA was first conducted within [38] and found significant capacity in Europe to be non-profitable (75 GW in 2025, revenues from capacity markets not considered). An iterative approach is applied in the latest adequacy study for Belgium [39] as follows: Revenues and costs arising from the dispatch simulation are used to calculate an internal rate of return on an asset level, which is compared to a technology-specific hurdle rate. Iteratively, the least profitable unit is then removed from the system and replaced by the most profitable out-of-market unit—until all units in the market are viable. This way, a non-viable gap of a maximum of 5.4 GW in Europe was found in 2025.

Obviously, the methodologies and results of these studies (still?) differ greatly. With this publication, we do not necessarily want to propose a new methodology for how to evaluate profitability in the frame of these studies. Rather, we want to place it in the theoretical framework and emphasise that in a long-term equilibrium, even under perfect competition, all producers can exactly cover their costs (see Section 2). Thus, a separate profitability calculation is necessary only for those aspects where the real market deviates from these assumptions. We consider these two issues of (1) the occurrence of sufficient scarcity prices and (2) the limited foresight of investors to be most relevant and therefore focus on the detailed analysis of their impact on profitability in the following.

From a methodological point of view, the paper can also be classified in the literature dealing with the so-called modelling to generate alternatives (MGA). The approach described here follows a similar idea to that of MGA, namely, not only to identify a single optimal solution but also to identify possible alternative solutions and thus take into account structural uncertainties that have not been modelled. In the MGA, the near-optimal solution space is systematically searched for solutions that show the smallest possible change in the objective function value but are maximally different with respect to the result variables [40]. The model structure is changed in an iterative process. In [41], among others, this approach is also applied in energy system modelling. Ref. [42] expands this method to identify all near-optimal solutions and ref. [43] proposes a method to determine "maximally different global energy system transition pathways". The approach used here follows a similar idea but differs methodically from the following approaches: On the one hand, only a change of parameters is made between iterations and the model structure is kept identical. On the other hand, not all or maximally different solutions are systematically searched for, but solutions under the risk of insufficient scarcity prices are selectively identified.

The distinction of the methodology proposed here from existing approaches can be summarised as follows: Unlike several of the existing approaches to considering profitability in energy system modelling, the methodology proposed here follows an iterative procedure. This means, above all, that results not only provide a statement on whether an asset is profitable or not under given assumptions but also consider the feedback loop between risk of non-profitability and investments (and consequently the technology mix). In contrast to existing iterative approaches, we limit our research to exactly the following two possible reasons for non-profitability in order to clearly identify cause-effect relationships: namely, insufficient scarcity pricing and limited foresight of investors. The assumption of an existing non-optimal generation mix in our model runs (brownfield) adds another valuable aspect of real market conditions.

3.4. Myopic vs. Perfect Foresight

Model calculations for the transformation of the power system often consider a long-time horizon of several years or decades. Optimization can be performed over the entire period under consideration (perfect foresight), the years can be optimised separately (myopic), or an "intermediate" way can be selected in which several years are optimised simultaneously. The reduction of the optimization period is a possibility to reduce the computing time significantly [44]. This may be necessary because power sector scenarios often require a high level of detail in terms of spatial, temporal and technological resolution. However, a shorter optimization period also takes into account that, in reality, an actor does not have complete information about the development of all influencing variables over such a long time horizon. In particular, this also applies to the information available to an investor at the time of his investment decision. The investor always has to take his decision under uncertainty about future developments, especially about costs and revenue opportunities. Considering that, in reality, the investor has obtained some reliable assumptions about future developments for some of the next years, but at the same time, a decision on an investment in a generation asset takes some years until it is realised, the myopic approach becomes probably closer to reality. This is because it models the investment decision in a way that the decision-maker would have ideal information for a short time period in the future, corresponding to the period between investment decision and commissioning of the asset, but no information thereafter.

A model run with perfect foresight, therefore, overestimates the information that is actually available to an investor as a basis for decision-making. However, such model runs show other advantages, e.g., they provide information from a more central point of view on how a cost-optimal capacity mix will develop or how a GHG mitigation path at minimum costs over several years could look like. This result is a decent one as it represents the normative transformation path with the least cost. At the same time, it is clear that it will not be possible to achieve this path, as information about the future is not completely evident at the time of decision. However, this reasoning misconceives that, at the time of the analysis, information about the future relies on assumptions only and is in reality not known exactly. This means that the decent normative path would be normative in terms of least cost only if the theoretical case occurred that the assumptions were realised exactly as assumed, which will never be the case. This means that the advantage of drawing up a normative path is not as reasonable as it looks.

Due to that reasoning and the fact that a realistic future path can never be evaluated exactly due to uncertainties, we propose to evaluate both "extreme" assumptions to provide some idea to the decision maker about the uncertainties of the future. Therefore, we apply our methodology to both "extreme cases" (1-year myopic and perfect foresight over the entire modelling period) and compare the results.

In the myopic model approach, investment costs are assumed as an annuity over the depreciation period of a technology (described e.g., in [45]). Accordingly, the mark-up in the myopic calculation only relates to the number of uncovered costs of the respective year. Information on how revenues develop over a lifetime, or whether a technology (from a system-cost perspective) is decommissioned before the end of its lifetime, is therefore not included. In other words, we assume that the cost and revenue situation in the first year remains constant in all other years of the technical lifetime. As already mentioned, this represents—despite any consideration above—an "extreme" assumption with regard to the foresight of actors. Therefore, we contrast this solution with a perfect foresight calculation. Here, the mark-up on investment costs corresponds to uncovered costs incurred over the modelling period, i.e., it includes information on changing revenues or a possible early decommissioning (In the current phase of transformation, this aspect is very relevant, as follows: With the phase-out of coal-fired power generation, a significant proportion of controllable generation capacity is leaving the system in many electricity sectors. On the way to emission-free power generation, gas-fired power plants represent a bridging technology, as they are controllable but show a lower emission intensity. They can thus be an important building block for ensuring the security of supply on the way to a zero-emission power generation system, but can no longer be used in a fully decarbonized power generation system. The more the climate targets are tightened or the GHG neutrality targets are moved forward, the shorter the period in which these assets have the opportunity to refinance their full costs.).

4. Proposed Modelling Approach

4.1. Modelling Structure for Identification of Investment Premium

As shown in Figure 2, we determine the capacity mix in a capacity expansion model (CEM) and run a unit commitment model (UCM) subsequently in order to derive prices without scarcity rents in the first instance. Then, we calculate uncovered fixed costs per investable technology from the UCM result and assume a technology-specific mark-up on investment costs for the next iteration for each technology with negative margins (i.e., with uncovered fixed costs) only.

This iterative procedure in the myopic model—in which the iterations are performed separately for each year—is described in Figure 3 as a flowchart. After the two model runs with CEM and UCM, the uncovered fixed costs UC of each invested technology follow Equation (4). Original investment costs of iteration 0 are used to calculate UC, since the iteratively assumed mark-up here only serves as a "tool" to find a solution with lower uncovered fixed costs. The sum of uncovered costs across all technologies then serves as an indicator for the following two termination criteria of the iteration: (1) iterations are terminated if either the moving average of UC over two iterations increases twice in a row or (2) if the change of UC in two consecutive iterations is less than 0.001% of the original system cost. If none of the termination criteria is reached, an updated mark-up on investment costs of the previous iteration is assumed and the CEM is started again. If several iterations are required, the mark-up on investment costs will accumulate. If one of the two termination criteria is met, iterations are terminated for the year under consideration. The capacity mix of the last iteration is then assumed to be the existing capacity mix for the following year, and the iterations are continued identically for the following year—as well as for all other years considered.

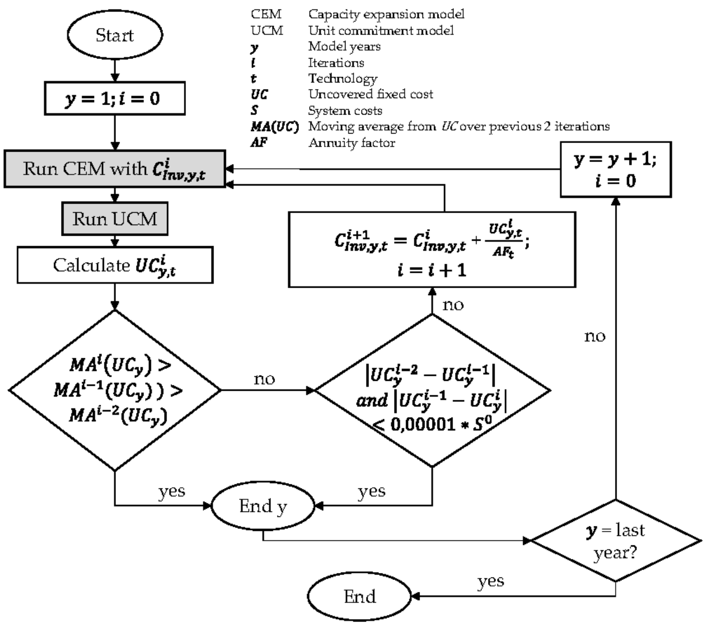

Figure 3. Iteration flowchart for myopic model runs.

In the case of a perfect foresight calculation, the procedure is identical, except for the sequential calculation of the years. Thus, the mark-up on investment costs does not correspond to the annual uncovered fixed costs but to those over the entire modelling period.

4.2. Model Description and Data Assumptions

The model used for the CEM and UCM runs is a very basic version of the European Electricity Market Model (E2M2). E2M2 is a bottom-up techno-economic model using linear or mixed-integer programming with the minimisation of power system costs as an objective function. For a more detailed description, basic model equations can be found in [46], recent extensions and applications, e.g., in [32,47–49]. The CEM optimises endogenous investment and dispatch simultaneously, while for the UCM run only dispatch is an endogenous decision. Electricity demand, emissions, fuel prices and the existing generation mix are linked to the key figures for the German electricity sector in 2020. However, E2M2 is applied in a very basic version for this work, which in concrete terms means that, e.g., heat production from combined heat and power, reserve provision, electricity exchange to neighbouring countries as well as startup and shutdown costs are not considered. In principle and depending on data availability, the approach and the model can consider these aspects as well, but since the focus of this paper is on the demonstration of the methodology and its implications, we keep the model as simple as possible.

However, we assume an existing generation mix with a simplified market exit curve (considering the German phase-out of nuclear and coal power plants) over the modelling time, which covers a 25-year period in 5-year steps. An upper bound for GHG emissions is set, declining linearly to zero until Y25. This model configuration is oriented towards the possible development of the German power sector with GHG neutrality in 2045, starting in 2020. However, considered years are denoted as Y0 to Y25 in the following to avoid the impression of a full-scale power sector analysis, which is not our intention in this paper. Support of renewables is considered for existing assets until the end of their funding period, while other technologies can be chosen endogenously by the CEM assuming their actual cost without further subsidies. Since prices are particularly important for the profitability of assets, we use an hourly time resolution in both models. Existing, as well as newly invested capacities, can be shut down before the end of their technical lifetime endogenously by the optimization if it serves cost minimisation.

In summary, the model set-up is a simplified brownfield calculation until 2045 with a high temporal resolution and based on the German electricity sector, in which no political subsidies are assumed for capacity additions. Market-exit for existing and invested assets follows an exogenous assumption but can be pulled forward for most technologies by endogenous divestment. Market entries are purely endogenous decisions.

The model configuration was chosen here, and thus exhibits the following deviations from the assumptions of perfect competition:

1. No scarcity prices occur;
2. The capacity mix is not in a long-term optimum (renewable existing assets cannot be disinvested);
3. And there is a limited foresight of actors in the myopic case.

The validation of the coupling between CEM and UCM has confirmed that the two models give identical results in terms of generation quantities and hourly dispatch. The prices are also identical except for the scarcity prices in peak hours, which, according to the theory in Section 2, only occur in the CEM. The price duration curves from CEM and UCM are exemplarily shown for Y20 in Figure 4.

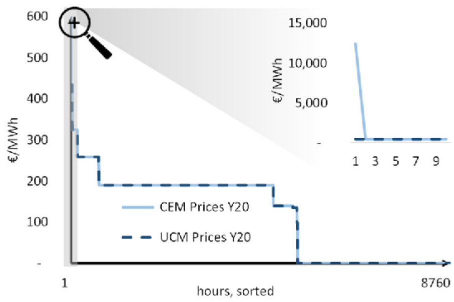

Figure 4. Price duration curves including (CEM) and without scarcity prices (UCM).

All technical and economic assumptions for existing and investable technologies in the two models are summarised in Appendix A (Table A1). The existing capacity mix consists of photovoltaic (PV), wind onshore and offshore, hard coal, lignite, natural gas combined cycle (CC), natural gas open cycle (OC), nuclear, biomass, run-of-river and pumped storage technologies. Other power plants are predominantly oil-fired and grouped under other (non-renewable). Investment technologies available to the model are natural gas OC and natural gas CC, PV, wind onshore and offshore, biomass, pumped storage and stationary batteries, each with no upper limits on investable capacity. Demand-side management (DSM) offering flexibility on the demand side is not taken into account for simplicity in this test case, as the inaccuracy is estimated to be too high if we assume an aggregation that is comparable to that of other technologies (however, DSM flexibility could be considered in the same way as other technologies in this approach). Emission factors for conventional fuels are taken from [50], fuel costs from [51], investment costs, fixed OaM costs and technical lifetimes from [2], variable OaM costs from [52], full load hours from [53] and biomass assumptions entirely from [54]. For an easier interpretation of the results, variable and fixed OaM costs are assumed to be identical for existing and new investments. However, the marginal costs of new investment are lower than those of an existing asset of the same technology due to higher efficiency. A technology-independent WACC of 10% is assumed for the annuity of the investment costs, based on [55].

Electricity demand and Y0 limitation of GHG emissions are consistent with historical levels in the German power sector in 2020 [56,57]. It is assumed that the power sector is to be completely decarbonized within 25 years; accordingly, an emission cap decreasing linearly to zero over the years is specified. All other costs and technical assumptions are assumed to be constant over the modelling period, i.e., there is no trend development.

The model assumptions as a whole contain some significant simplifications compared to reality. However, this serves to simplify the interpretation of the results and constitutes an acceptable step since the focus of this work is on the demonstration of the methodological approach and not on quantitative model results as a recommendation for decision-makers.

5. Results

In this chapter, the results of the myopic base model run (iteration 0) are presented and discussed first (Section 5.1). Changes in the myopic results due to iterations are then discussed in Section 5.2. The same follows for the results of the perfect foresight case in Section 5.3. Additionally, we have added a further simplified schematic example of the iterative methodology in Appendix B to demonstrate why and how the methodology used in this paper reduces the sum of uncovered fixed costs.

5.1. Model Results before Iterating (Myopic)

The results of the CEM for iteration 0 show that the capacity mix changes strongly from coal and lignite to gas capacities in the medium term due to model endogenous invest and decommissioning. In the long term, it shifts from gas to a system with a very high share of VRE, as well as storage and biomass capacities (see Figure 5, right) to achieve assumed GHG emission limits. In years Y0, Y5 and Y10, there is an addition of gas-fired CC power plants as well as wind onshore. At the same time, gas, lignite, hard coal and other existing power plants are partially decommissioned before reaching the exogenously specified market exit (decommissioning is shown as negative values in Figure 5 on the left). In these years, older existing gas-fired plants are partly exchanged for new investments in gas CC (savings in fixed costs of the existing plants plus the delta in variable costs exceed investment costs). In years Y15 and Y20, no additional gas capacity is built and the more stringent emission cap is met by the addition of onshore wind and PV. Year Y25 is a special case, as no emissions are allowed there at all. This is achieved—in this simplified model setup—by replacing gas with biomass (which occurs late, as biomass fuel costs are comparatively high without subsidies) and storage.

The price duration curves (PDCs) of the UCM resulting from this model configuration (i.e., without scarcity prices) are shown in Figure 6. The PDCs have become steeper over the years, pointing to the following two reasons: On the one hand, CO_2 prices increase, leading to higher marginal costs of conventional power plants. On the other hand, the share of VRE increases, resulting in more hours with a lower electricity price [58]. However, this development does not continue in Y25, where peak electricity prices are lower than in Y20. This is because the CO_2 price no longer has an impact on marginal costs in this fully decarbonized system. In this year, prices above zero occur due to the marginal costs of biomass, which do not include a carbon cost component and are thus lower than the marginal costs of e.g., gas in the previous year. However, it should be mentioned that the exact hourly pricing of such models, such as the one applied to UCM, has well-known shortcomings, as they typically simulate prices with lower volatility compared to actual market prices. This effect is assumed to increase for systems with high fractions of VRE and storage (see e.g., ref. [49]). Again, this problem is not considered relevant for demonstrating the methodological approach presented here.

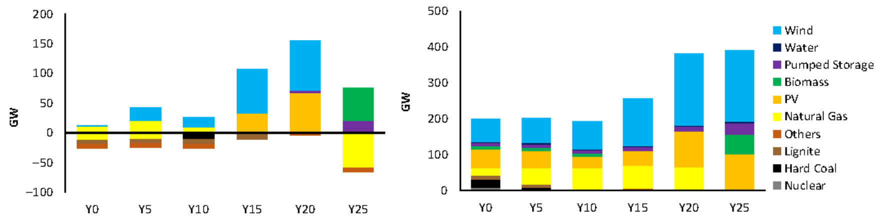

Figure 5. Endogenous capacity additions and removals (**left**) and total installed capacity (**right**) in iteration 0.

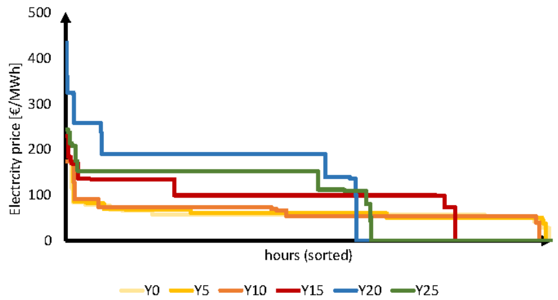

Figure 6. Development of price duration curves over modelling time in iteration 0.

As discussed in previous sections, only inframarginal rents contribute to the coverage of fixed costs under the assumption of no scarcity prices. The finding above that all technologies can just cover their fixed costs in an ideal market with unrestricted scarcity prices means, conversely, that in the same system *without* scarcity prices, hardly any technology can cover its fixed costs. The results of the model run in iteration 0 confirm the following finding: none of the endogenously added technologies earns its full costs. Figure 7 shows the uncovered fixed costs (corresponding here to fixed OaM costs plus the annuity of investment costs) of all invested technologies. The graph on the right shows an enlargement of small values since UC for some technologies is comparably small and cannot be seen in the left-hand graph. In the example calculation made here, in the early years of adding gas-fired power plants, they can cover a large part of their fixed costs since they benefit from the marginal cost delta to older existing assets. Biomass is added in Y25 only and then constitutes the only technology in the system with marginal costs > 0, and is consequently the one with the highest marginal cost. It can thus not generate any rent at all. In this case, revenues correspond to variable costs. Overall, it can be derived that the model results are in line with the following theory: Controllable technologies with comparatively low marginal costs (and correspondingly high utilization) generate a high rent by way of comparison, while the technology with the highest marginal cost cannot generate any rent at all (e.g., biomass in Y25).

Wind onshore and PV show a relatively small rent deficit within the years Y0–Y20. This is because VRE is hardly generated at all in the hours of greatest scarcity, which usually occurs during periods of low generation from wind and solar. In turn, this means that scarcity rents have a very small share in covering their fixed costs and, accordingly, the deficit *without* scarcity prices changes comparatively little. However, the situation is different again in Y25, where scarcity prices occur for significantly more hours than in previous years. Accordingly, VRE would then also miss a larger part of their rent.

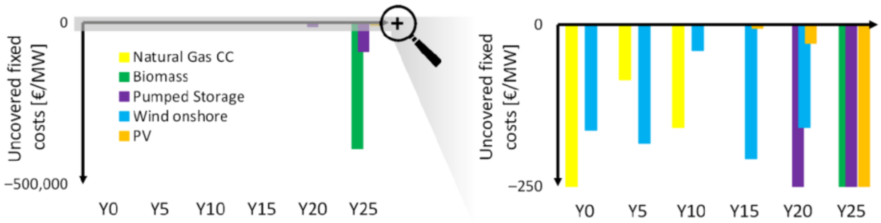

Figure 7. Uncovered fixed costs for invested technologies in iteration 0.

There is a tendency for uncovered costs to increase over time, which is partly caused by the fact that there is a greater scarcity in the system in later years. Although endogenous decommissioning is generally allowed in the model, this is not the case for capacities of biomass, PV, wind onshore and offshore that are already existing in Y0 (approximating existing support mechanisms for these technologies). As the model cannot disinvest in those technologies, scarcity is not very high in the early years and scarcity prices are correspondingly lower. Conversely, lower scarcity prices in the CEM mean lower uncovered costs in the UCM.

In summary, the following four conclusions arise from the evaluation of iteration 0 in terms of profitability:

1. Without scarcity prices, none of the invested technologies can cover their full costs (model result is in line with theory);
2. However, existing assets setting the price can provide much of the rent for new assets;
3. A lack of scarcity prices has little impact on the rents of VRE, as they typically show low production during hours of greatest scarcity;
4. A system with very low emissions (and a correspondingly high CO_2 price as in Y20) has a fundamentally different structure in terms of profitability than a system with no emissions at all, in which the CO_2 price is theoretically very high but no longer affects marginal costs and thus prices.

5.2. Results after Iteration (Myopic)

5.2.1. Iterations and Mark-Ups

In line with the procedure outlined in Figure 3, a mark-up on investment costs of new technologies is assumed in iteration 1 to the extent of uncovered costs from iteration 0. For Y0, Y5 and Y10, this affects gas CC and wind onshore (see Table 2). In Y0, the mark-up in iteration 1 for gas CC is 2284 EUR/MW, which corresponds to 2.32% of the yearly fixed costs (annuity of investment costs + fix OaM costs). The mark-up on wind onshore is 163 EUR/MW, representing 0.12% of yearly fixed costs. These mark-ups on the investment cost for iteration 1 shift the new investments in this iteration slightly towards more investment in wind onshore and less investment in gas CC. In total, eight iterations are required in Y0 until a termination criterion is met, namely, the delta of uncovered costs in two iterations in a row being <0.01% of the original system costs. In comparison with a total installed capacity of approx. 200 GW, changes in investments over these eight iterations are small, as follows: in iteration 8, the cost-optimal system consists of 588 MW less gas CC and 507 MW more of wind onshore capacity. Using the same procedure, the solution with the minimal uncovered cost is found in iteration 4 in Y5, in iteration 2 in Y10, in iteration 1 in Y15 and in iteration 7 in Y25. Iterations in Y20 do not lead to a decline in uncovered costs before the termination criteria are met. Since iterations are run subsequently in the myopic case, in total, 34 iterations are needed in order to meet at least one of the termination criteria for all of the considered years.

Table 2. Mark-ups on investment cost in iteration 1 for each year (myopic case) [EUR/MW].

Technology	Yearly Fixed Costs	Y0	Y5	Y10	Y15	Y20	Y25
Biomass	514,743	-	-	-	-	-	393,013
Natural Gas CC	98,255	2284	83	159	-	-	-
Pumped Storage	133,859	-	-	-	-	11,524	81,435
PV	100,931	-	-	-	-	44	26,442
Stationary Battery	92,311	-	-	-	-	-	-
Wind Onshore	135,617	163	184	40	168	320	41,743

Table 2 shows a summary of derived mark-ups on investment costs in iteration 1 of each year, the highest for biomass in Y25 at 76% of yearly fixed costs. Mark-ups for all 34 iterations can be found in Appendix C (Table A2).

5.2.2. Technologies

Introducing mark-ups changes the composition of technologies invested endogenously and, accordingly, the composition of the entire capacity mix. Figure 8 shows the technology mix of investments for iteration 0 and the last iteration of each year.

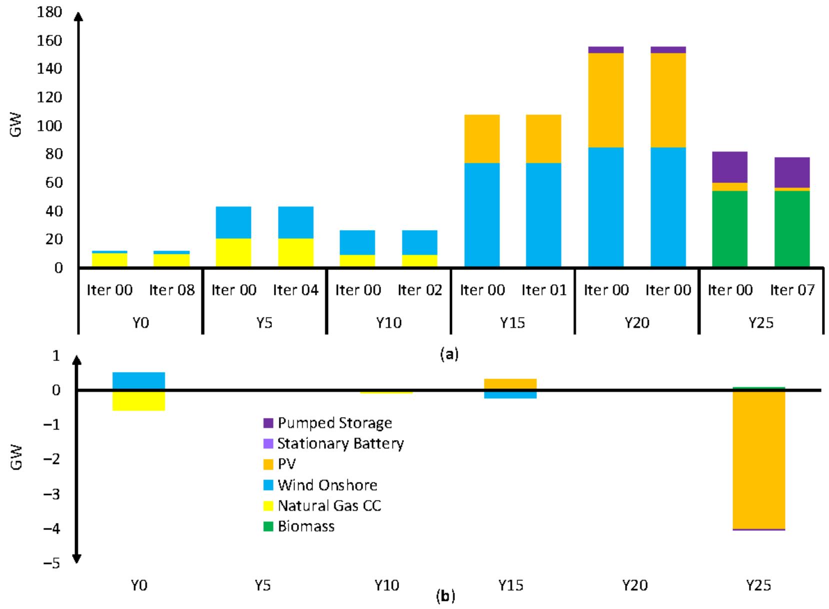

Figure 8. Change of endogenous investment over iterations (myopic): (**a**) technology mix for iteration 0 and the last iteration in each year; (**b**) delta between iteration 0 and last iteration per year and technology.

In the front years Y0, Y5 and Y10, the ratio shifts between investments in gas CC and wind onshore, in Y15 between wind onshore and PV and in Y20 between wind onshore, PV and (long-term) storage. However, some shifts are rather small compared to the total installed capacity in the system and therefore hardly visible in Figure 8. The largest changes occur in Y25, where new investments in PV and pumped storage are replaced by more biomass when profitability is considered.

In summary, relevant technology shifts (>100 MW) for our calculated example case are the following: In the short term, Gas CC is replaced by wind onshore; in the medium term, wind onshore is replaced by PV and in the long term, PV and (a very small amount of) storage are replaced by biomass capacities. Several factors may influence which technologies the shifts occur between, including the composition of the existing capacity mix, the degree of scarcity and presumably the level of emissions reductions or CO_2 prices.

5.2.3. Costs

Across the eight iterations for Y0, the level of uncovered cost for new investments declines from EUR 24.62 million (0.15% of system cost) to EUR 0.03 million (0.00% of system cost). Using the same procedure results in no or very low (<0.00% of system cost) uncovered costs in Y5 and in Y10. In Y15, uncovered costs were reduced from EUR 12.4 to EUR 10.8 million. While the four iterations in Y20 lead to the application of one of the termination criteria without any reduction of uncovered costs, ten iterations for Y25 lead to a decline of uncovered costs of EUR 535.5 million (see Figure 9).

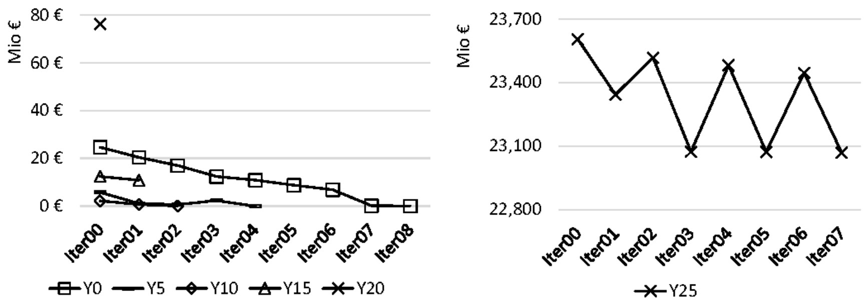

Figure 9. Change of uncovered fixed costs over iterations (myopic).

Since each iteration is identical to the previous one except for the mark-ups, the system costs of an iteration cannot decline between two iterations. Over the complete modelling period from Y0 until Y25, system costs increased by EUR 1.3 billion, which represents 0.54% of the original system cost. By far the largest share of the increase in system costs is attributable to Y25.

The following two important conclusions can be drawn from these results: First, capacity mix compositions exist in which new investments can cover (the annuity of) full costs only by inframarginal rents—i.e., without scarcity prices. Second, the capacity mix of this solution has (in this example) slightly higher system costs than the initial solution.

At a first glance, the result that new investments can cover the annuity of full costs even without scarcity prices contradicts the theory described in Section 2, according to which scarcity prices are necessary for full cost recovery. However, there are some differences between perfect competition as assumed in theory and the system considered here as follows: First, the model here assumes an existing capacity mix that is not necessarily optimal. In addition, model-endogenous decommissioning is not permitted for all technologies, so it is possible that the existing capacity mix is actually not scarce. In our case, the inframarginal rent between new investments and existing assets turns out to be so high that it is sufficient to cover full costs. On the other hand, only uncovered costs of new investments are considered here, while uncovered annual fixed costs of existing assets are disregarded. Thus, in the system described, new investments are profitable, but existing assets may continue to incur deficits at most equal to their annual fixed costs (A remark: the sum of total uncovered costs, considering those from new investments and existing assets, also decreased by EUR 590.1 million over the whole period Y0–Y25.).

In summary, the example calculated here provides evidence that new investments may be able to refinance the annuity of their full costs even in the absence of scarcity prices, at least in the short and medium term. In the long term, however, under very high GHG reduction targets and therefore the extensive need for new investment and a completely different price structure, scarcity prices may account for a large portion of revenues.

In the myopic case discussed here, the annual rents and costs are considered only. This does not imply that full costs are also covered over the entire lifetime of an asset. In order to be able to answer this problem better, the results of a calculation under perfect foresight follow in the next section.

5.3. Results under Perfect Foresight

For the perfect foresight model runs, the methodology is analogous to that used for the myopic case (see Section 4.1). The model, including all data assumptions and technical restrictions, corresponds to the myopic model, except that all years considered are solved simultaneously in one optimization problem. This represents the theoretical case where, for example, an investor has all the information about the development of the energy system until Y25 for his investment decision in Y0. As already described, this calculation represents an extreme case, just like the myopic calculation, and is carried out here in order to be able to contrast the effects of the methodology in both cases.

Two small changes to the methodology used above result from its application in the perfect foresight case. On the one hand, this concerns the calculation of the uncovered costs and thus the mark-ups for the subsequent iteration. For the perfect foresight case, the uncovered cost $UC_{y,t}$ is defined by Equation (5), where A corresponds again to the annuity of investment costs. In contrast to the myopic case, the uncovered costs caused by a technology t invested in year y are added up over the entire remaining modelling period and applied as a mark-up in the next iteration.

$$UC_{y,t} = \sum_{a=Y0}^{Y25} \left(r_{inf,t,a} - C_{fix,\,t,a} - A\,(C_{inv,t}) \right) \tag{5}$$

In addition, one of the termination criteria is slightly adjusted; namely, the iterations are terminated if the moving average of UC over the last six iterations (instead of the last two in the myopic case) increases twice. The reason for this is that in the perfect foresight case, there is first a shift of investments between the considered years. For example, if biomass receives a premium in year Y25 in the first iteration, the investment shifts to the previous year Y20 in the next iteration, where the technology has not yet received a premium, since no biomass was added in this year in the original solution. In the following iteration, biomass also receives a (presumably higher) premium in Y20 and the investment shifts to Y15. The premiums of some technologies must therefore first "settle" between the model years, which is not the case in the myopic case, in which only one year is calculated at a time. Therefore, the moving average over six iterations is used here as a termination criterion, since it is assumed that the mark-ups have then been iterated once through all model years.

5.3.1. Before Iteration

The delta of capacities between the myopic and the perfect foresight case is shown in Figure 10. The differences are rather small compared to the total installed capacity. However, it becomes obvious that the longer optimization period leads to less gas capacity being added since the model now has the information that gas capacities are no longer needed in Y25. Coal and lignite remain longer in the system, and early VRE (+storage) capacity additions replace those gas capacities.

The profitability of the individual technologies in the perfect foresight case is calculated based on costs and revenues over the entire modelling period. However, the same finding that could be retrieved from the myopic case can be drawn here as follows: all newly invested technologies are not profitable without scarcity prices over the modelling period. Moreover, following the myopic case, biomass capacity invested in Y25 shows the highest uncovered cost per MW, followed by storage capacity invested in Y25 and Y20.

5.3.2. Iterations and Mark-Ups

Mark-ups in iteration 1 are applied to similar technologies and in similar years as in the myopic case. Nevertheless, mark-ups are significantly higher in total because they now correspond to uncovered costs over the entire modelling period. For example, wind onshore shows high uncovered costs in Y25, which is then reflected in the mark-up for wind capacity invested in Y0. Wind onshore capacities thus receive a premium of 15,512 EUR/MW for Y0, representing 11.4% of yearly fixed costs (compared to 0.12% in the myopic case). A summary of derived mark-ups on investment costs in iteration 1 of each year is shown in Table 3.

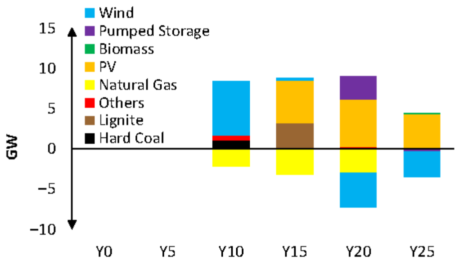

Figure 10. Delta of capacities between myopic and perfect foresight case in iteration 0.

Table 3. Mark-ups on investment cost in iteration 1 for each year (perfect foresight) [EUR/MW].

Technology	Yearly Fixed Costs	Y0	Y5	Y10	Y15	Y20	Y25
Biomass	514,743	-	-	-	-	-	389,652
Natural Gas CC	98,255	65,168	62,883	62,798	-	-	-
Pumped Storage	133,859	-	-	-	-	97,063	85,146
PV	100,931	-	-	-	9292	9263	-
Stationary Battery	92,311	-	-	-	-	-	-
Wind Onshore	135,617	15,512	15,349	15,165	15,064	14,370	-

The termination criteria in the perfect foresight case are met after 16 iterations, where the moving average of uncovered costs increases two times in a row. The iteration with the lowest UC until then is iteration 8. Technology shifts between new investments that result from accounting for uncovered costs within these eight iterations are shown in Figure 11.

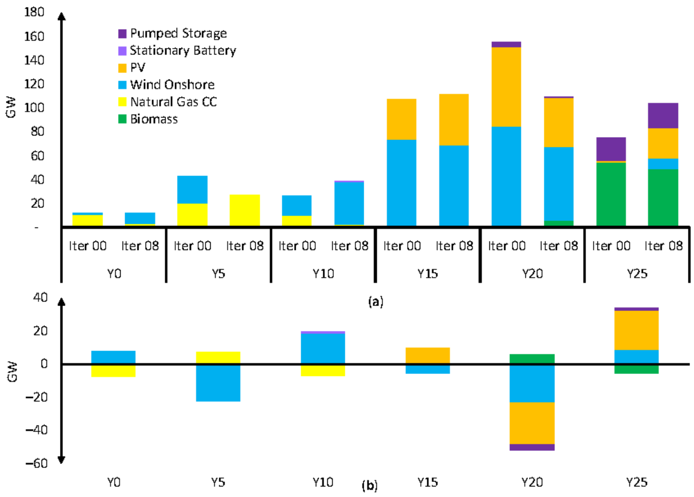

Figure 11. Change of endogenous investment over iterations (perfect foresight): (**a**) technology mix for iteration 0 and iteration 8; (**b**) delta between iteration 0 and iteration 8 per year and technology.

Figure 11a shows the absolute investments in iteration 0 and iteration 8. The delta between these two iterations per technology is shown again in Figure 11b for a better interpretation. The shifts between technologies are significantly higher than in the myopic calculation due to the higher mark-ups, but it is similar between which technologies the shift occurs. In Y0 (as in the myopic case), less gas CC is added and more wind onshore. The lower investment in gas capacity mainly happens due to existing gas plants that are used longer and more. The shift in Y5 and Y10 is mainly a temporal shift between years, namely, an earlier addition of gas capacities in Y5 instead of Y10 and a later addition of wind capacities (Y10 instead of Y5). In the medium term in Y20, as in the myopic case, a minor shift between wind onshore and PV takes place. The deltas in Y20 and Y25 again result mainly from a temporal shift, namely, the earlier addition of biomass capacity in Y20, which results in a correspondingly lower need for PV, wind onshore and storage in this year. The shift in absolute terms in Y25 took place in the myopic case from PV and storage to more biomass. In the perfect foresight calculation, this is the case from wind and storage to PV and biomass. Some shifts between investment technologies from the myopic calculations are thus also confirmed in the perfect foresight case, but there are also small differences. A summary of the technology shifts in the myopic and perfect foresight cases is shown in Figure 12.

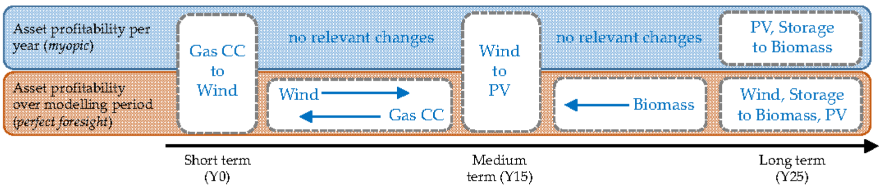

Figure 12. Investment shifts through iterative minimisation of uncovered costs in this case study.

The sum of uncovered costs over all years with perfect foresight amounts to EUR 29.37 billion, which corresponds to 13.09% of the system costs. Across the eight iterations, the level of uncovered cost for new investments declines by 16.4% to 24.55 billion €. Iterations result in a reduction of uncovered costs of EUR 4.82 billion in the perfect foresight case, which is significantly higher than the EUR 0.57 billion in the myopic case. System costs increased at the same time by EUR 13.12 billion (5.9%).

Myopic calculations have shown that some technologies can cover their annual fixed costs even without scarcity prices. The results of the perfect foresight case show that—after iterating—some technologies can even cover their full costs over a lifetime. Table 4 shows the deficits of all invested technologies over their respective lifetimes depending on the year of investment. Specifically, it shows that gas CC and wind onshore capacity were added very early, but also that wind onshore capacity added in Y10 can achieve a positive margin without scarcity prices. Particularly high deficits occur for storage, gas OC and biomass, but also for gas CC capacities added in the medium term. In general, our example shows that the later a technology is added, the worse its profitability becomes since the lowest contribution margin is generated in Y25 (and possibly subsequent years).

Table 4. Margin gap of invested technologies over their lifetime in the perfect foresight case (profitable investments marked green, very high gaps marked red).

	Y0	Y5	Y10	Y15	Y20	Y25
Biomass					84.7%	96.7%
Natural Gas CC	−10.6%	7.1%	42.2%			
Natural Gas OC	63.5%					
Pumped Storage					58.2%	61.9%
PV				1.2%	3.4%	11.2%
Stationary Battery			78.2%			
Wind Onshore	−8.9%		−2.0%	1.6%	4.2%	12.1%

In summary, in terms of achieving the objectives of the proposed methodology, the methodology leads to lower uncovered costs in five of the six years in the myopic case and in the perfect foresight model. This follows the expectation from Section 3.2 that a co-minimisation of the uncovered costs as a penalty on the investment costs leads to a system with lower uncovered costs in most cases. Why there may be exceptions to this was also explained. In the results, there is a tendency that in iterations where uncovered costs decrease, a shift between peak-load technologies towards technologies with higher marginal costs takes place. In iterations leading to higher uncovered costs, the shift in the lower part of the price duration curve (compare also Figure A1 in Appendix B) is often exclusive or at least dominant.

6. Discussion and Conclusions

6.1. Summary and Results

In the first two chapters, we summarised from the literature that in theory, generators under perfect competition and in a long-run equilibrium exactly cover their fixed costs. As long as an optimization model represents all these theoretical assumptions, the profit for all technologies is exactly zero, and there is no uncovered cost for any technology. However, the real market deviates from these theoretical premises in some aspects. Optimization models are often used to calculate scenarios that are as close to reality as possible, and so assumptions are also made in these models that deviate from a perfect market. One example of a deviation from these assumptions is that the real generation mix differs from the cost-optimal one due to, e.g., historical developments, supporting schemes, or a lagging reaction time by market participants. In real markets, this can lead to excess capacities, reflected by a price structure in which scarcity prices will not occur (or not occur at sufficient levels). This bears the risk of a shortfall in fixed costs for investors—also referred to as the "missing money problem" in literature—and thus the risk that investors retain investment in new generation capacity, resulting in a potential lack of capacity in the market in the future.

In this paper, we use a linear optimization model with a time horizon of 25 years and a GHG emission cap that linearly decreases to zero. With an investment calculation (CEM) and a subsequent dispatch calculation (UCM), we simulate the condition of insufficient scarcity prices. The results of the initial iteration show that all new investments cannot indeed cover their fixed costs completely. The deficit due to the absence of scarcity prices is particularly small for VRE but higher for peaking capacity, where scarcity prices reveal a high influence on contribution margins.

For analysing the influence of profitability on the development of investments and the generation mix in a market environment, we have developed and applied an iterative approach. For each iteration, we introduce mark-ups on specific investment costs of each technology in relation to the level of uncovered costs and recalculate the CEM. The results of the exemplified brownfield calculations show that a system with lower uncovered costs (i.e., better profitability) can be. It even leads to a system where some of the investments can cover their full cost over a lifetime without scarcity prices.

In the myopic case, each year's iterations resulted in one of the two termination criteria in ten or fewer iterations. In this case, systems with lower uncovered costs were achieved in five out of six years, and in three out of six years, the uncovered costs after the iterations were less than 0.00% of the system costs. In other words, in these cases, it was possible to find a system in which new investments could cover their annual fixed costs even without scarcity mark-ups (only by inframarginal rents). In each year, the resulting system does not deviate significantly from the original composition, with system costs increasing by 0.54% over the complete modelling period. In the perfect foresight case, the methodology also leads to a system with lower uncovered costs. The absolute reduction of uncovered costs after eight iterations is significantly larger than in the myopic case, as are the shifts between the technologies.

In our example case, considering profitability leads to main technology shifts in Y0 from investments in gas CC towards wind onshore and in Y15 from wind onshore towards PV (in both myopic and perfect foresight cases). In Y25, technologies change from PV and pumped storage towards biomass in the myopic case and in the perfect foresight case, from wind and storage towards biomass and PV (compare Figure 12). Technologies that are profitable over their lifetime even without scarcity prices are, in our example case, early-added gas CC and wind onshore capacity. These results are strongly influenced by the composition of the assumed existing technology mix, which in our example corresponds to a simplified German case.

Myopic and perfect foresight are fundamentally different modelling approaches, but it has been shown that and how the methodology can be applied to each of the two. The comparison of the technology shifts shows similar, although not identical, results for the two approaches. This can serve as a first indication, of which of the identified shifts could also be robust under different model configurations. However, the question of whether or not the perfect foresight approach provides a better indication of the realization probability of investments cannot be answered unambiguously.

6.2. Discussion and Limitations of Results

The results raise the following discussion points and conclusions:

1. If the risk of a lack of scarcity prices is considered by investors (by a correspondingly technology specific risk premium), a shift between technologies takes place and the generation mix changes;
2. The extent of deficits per technology provides an indication of the likelihood that an investment in this technology will actually be realised, which may be relevant especially to matters of security of supply. Very high deficits occur in our example for all technologies added in Y25 (by far the highest for biomass), but also for storages added in Y10 and Y20, gas CC added in Y10 and gas OC added in Y0;
3. In the short and medium term, against the background of a non-optimal existing capacity mix, there is the possibility that new investments will be able to cover their (annual) fixed costs even without scarcity prices, i.e., only through inframarginal rents, if the generation mix is adapted appropriately. Whether this is the case will vary with the composition and scarcity of the existing capacity mix, the degree of decarbonisation of the system (or CO_2 price level), allowed technologies (carbon capture and storage (CCS), nuclear, etc.) and the existence of other policies.

Those results can serve for informing policymakers on how an electricity system looks like that simultaneously minimises system costs and maximises profitability of new assets. Indeed, it might be a political target to act towards such a system, since lower scarcity prices are often seen as politically beneficial (e.g., refs. [8,18]). In addition, the proposed approach and specific results can support a potential investor's decision and make it more efficient.

As mentioned above, in the current phase of the transformation of power systems, the profitability of gas capacities is of particular interest. In many countries, a decision is being or has already been made to phase out coal-fired power generation, which means that a significant share of controllable capacity will be eliminated. From a security of supply perspective, it is therefore important that sufficient controllable gas capacity is available in the medium term. This is also the case for the German electricity sector, which has been used as a reference case in this paper. The results of this specific case show that at least the aspect of lack of scarcity prices is not necessarily a high risk for not adding new gas capacities. For example, gas CC investments in Y0 show a deficit of initially 7.0% of total fixed costs. However, this gap is fully closed with the shifts in the generation mix until the last iteration of the perfect foresight model runs. Concerning the transformation of the German electricity sector, this could e.g., imply that supporting mechanisms such as capacity payments are less important in the short term. However, they might become crucial in the medium term, when the payback period for new gas capacities is shorter. In the long term, the structure of prices and rents will change significantly, so a lack of scarcity prices will constitute a major risk for new investments. As described in the introduction, the German electricity market design generally allows for scarcity prices. However, in order to stimulate sufficient investment, investors must be confident that these scarcity prices will actually occur and will also be sustained politically.

However, simplifications made for the model run in terms of technological detail and the restriction to the electricity market as the sole source of revenue entail some limitations in the informative value of the quantitative results, which are discussed in the following.

As described above, additional revenues for asset operators from heat provision or reserve markets are not considered. This means that generation assets do not have to provide heat or balancing power in the model used here, so they can optimise their revenue in the electricity market without restrictions. However, in an ideal design of a heat or reserve market, revenues would also exactly cover the costs incurred by providing those services. A shortfall would only occur if these markets did not offer sufficient refinancing opportunities (compare [24]). In the real market, of course, this may differ and thus increase the risk of a revenue deficit. However, the described methodology is in principle also applicable to this case by including costs and revenues generated by those markets into the margin calculations. In addition, revenues from the option premium generated by the optionality of an asset deployment are not considered here. These would tend to increase the rents since assets can gain additional revenues without additional costs.

In principle, the prices modelled by the linear optimization model used here deviate from real prices. For example, prices generated by those models are generally considered to be insufficiently volatile (compare [26,59]). This is especially relevant during periods of scarcity, where it has to be assumed that the modelled price tends to be too low. Furthermore, uncertainties are not taken into account, which can strongly influence prices in general, but especially in systems with high shares of VRE and storage [49]. Consideration of these aspects in subsequent studies would increase the validity of the quantitative results, but all aspects mentioned above would rather contribute to closing the gap of uncovered cost and therefore will not change the general findings.

6.3. Discussion and Limitations of Methodology

The results show that the methodology proposed here is basically a way to identify a system with a higher profitability for generating assets in competitive markets by applying complex optimization models—while at the same time keeping the increase in system costs as low as possible. The methodology can thus also be applied in other optimization models, regardless of scenario assumptions, level of technological detail, regional and sectoral focus and the time horizon considered.

Some minor extensions of the methodology appear useful, but they do not imply a fundamental change in the approach as follows: One could also take into account the uncovered costs of existing assets by assuming (analogous to new investment) a mark-up on their annual fixed costs to the extent of the deficit. However, mark-ups on costs for existing assets would be comparatively low, since at most the annual fixed costs remain uncovered. However, the question examined here concerning the likelihood of new investments seems to be politically more relevant since existing power plants can be shut down or their operating times extended at a significantly lower cost and at shorter notice.

A further extension of the methodology concerns the issue that mark-ups on investment costs calculated by the iterations are quite high in some cases (see Table 3). Here, a threshold could be set above which it seems unrealistic that an investment in a certain technology would be realised and, consequently, this technology would be omitted in the subsequent iteration.

A fundamentally different approach could be a different way of coupling of the following two models applied: The prices calculated by the UCM in the first iteration could be brought to the CEM as an exogenous input in the second iteration. At the same time, the target function of the CEM in this iteration will be changed to maximise the margin or an additional restriction will be introduced that requires a positive margin for all new investments. However, it might happen that no solution to the problem exists or that the solution shows very high system costs. In contrast, the methodology proposed here serves to identify a solution close to the system cost optimum but with lower uncovered costs. Though spending further analysis on this issue might be worthwhile.

In order to map the profitability over the lifetime in a better way, an iteration over the depreciation period of technologies is also conceivable. In iteration 0, one could identify the period in which a particular technology is profitable and, in the subsequent iteration, specify that the technology must be able to recover all costs within this period. By shortening the payback period, annual investment costs would then be correspondingly higher in the next iteration.

One of the major disadvantages of this methodology is certainly the high computational effort. Brownfield models with a high temporal resolution and degree of technological detail suffer from a high computing time, which is in this case even multiplied by the iterations. However, since prices are particularly relevant for the calculation of profitability, both a sufficiently high temporal and technological resolution seem crucial. This is assumed to be the case a fortiori for systems with high fractions of VRE and storage or flexibility. Sensitivity to these two aspects could provide helpful hints on how computation time can be reduced, and we assume that approaches to reduce computational effort by other means, e.g., model reduction approaches, might be more constructive.

6.4. Outlook

With the application of the proposed methodology and the discussion of the results, the authors contributed to closing the previously identified research gap as follows: an iterative procedure has been used to establish a feedback loop between endogenously calculated electricity prices (and hence profitability of assets) and the choice of technologies. A simplified model was used to explain the shifts that occur between technologies when the risk of insufficient scarcity prices is considered. The chosen model setup allows observed changes to be attributed to this one aspect of deviation from perfect market conditions. However, there are still some aspects that require further investigation.

A central further investigation should be on the question of when and at which level scarcity prices occur in existing systems and under which conditions inframarginal rents are sufficient to cover new investment costs. Sensitivities with different existing power plant compositions, investment technologies and emission reduction assumptions could lead to better insights here. We could discuss this only based on one example case in this paper, but more general statements on this would be desirable, e.g., for decisions on future market designs and not least for the discussion on the necessity and design of capacity markets.

Such an assessment will also contribute to answering the question of why, in which system compositions and under which assumptions, the methodology proposed here leads to lower uncovered costs and under which not. An implicit presumption, based on the results of this paper, is that fixed cost recovery is much easier to achieve in systems with high inframarginal rents. This would be the case, for example, in a generation system with a wide spread of marginal costs. A high proportion of older existing plants thus contributes to higher inframarginal rents. In Y20 and Y25 of our example, this is no longer the case, but a large share of new capacities are added and variable costs are more homogenous, resulting in lower inframarginal rents. Accordingly, the uncovered costs turn out to be higher, and it is correspondingly more difficult to achieve better coverage of fixed costs without scarcity prices.

Moreover, valuable further developments of this work consist of introducing a higher level of technological detail, taking into account additional revenue sources, especially heat and reserve provision, as well as uncertainties. In addition, sensitivities related to available technologies in years with very high reductions (e.g., nuclear, biomass CCS) can complete the picture. The integration of demand-side flexibility would also increase the completeness of the analysis, especially because it is expected to have a significant impact on peak-hour prices.

Regardless of the specific quantitative results, however, it has been shown that the methodology proposed here works and provides a way to identify a system with a higher profitability for generating assets by using complex optimization models—while at the same time keeping the increase in system costs as low as possible. The methodology can also be applied to other, more complex models, and thus provide quantitative results closer to reality. As a component of the "large" brownfield scenario calculations mentioned at the beginning, it could thus provide valuable information for policymakers on whether new investments take place even in the presence of low or no scarcity prices and which technologies would be particularly affected by such a risk.

Finally, it should be part of further research to investigate further deviations from the assumptions of perfect competition (other than the lack of scarcity prices) in a similar way in order to obtain a complete picture of technology-specific investment risks and their impact on the generation mix.

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Appendix A

Table A1. Technical and economic assumption for generation technologies in CEM and UCM.

Technology	Emission Factor [t/MWh_{th}]	Fuel Cost [$EUR/MWh]_{th}$	Investment Cost [EUR/kW]	Variable O&M Cost [EUR/MWh_{el}]	Fix O&M Cost [EUR/kW]	Efficiency [%]	Full Load Hours [h]	Lifetime [a]
Biomass (exist)	-	55.07		7.7	53	33	-	
Biomass (new)	-	55.07	3300	7.7	53	38	-	30
Nuclear (exist)	-	6.28		9	102	33	-	
Hard Coal (exist)	0.341	9.42		3.3	38	37.5	-	
Lignite (exist)	0.364	8.22		3.3	46	37.5	-	
Natural Gas OC (exist)	0.202	22.33		1.6	13	35	-	
Natural Gas OC (new)	0.202	22.33	400	1.6	13	40	-	25
Natural Gas CC (exist)	0.202	22.33		1.6	24	44	-	30
Natural Gas CC (new)	0.202	22.33	700	1.6	24	60	-	30
PV (exist)	-	-		-	15	100	1105	
PV. open area (new)	-	-	780	-	15	100	1105	25
Wind Onshore (exist)	-	-		-	13	100	2500	
Wind Onshore (new)	-	-	1113	-	13	100	2500	25
Wind Offshore (exist)	-	-		-	93	100	3600	
Wind Offshore (new)	-	-	2590	-	93	100	3600	25
Runriver (exist)	-	-		2.5	45	100	-	
Others (exist)	0.267	31.49		2	12	35	-	
Pumped Storage (exist)	-	-		0	12	73.5	-	
Pumped Storage (new)	-	-	1218	-	12	76	-	100
Stationary Batteries (new)	-	-	550	-	20	90	-	15

Appendix B

In this appendix, we use a simplified example to demonstrate why and how the methodology used in this paper reduces the sum of uncovered fixed costs. The basic mechanism behind the markups as penalty terms in optimization has already been discussed in Section 3.2. In the following, the energy-economic relationships are additionally illustrated by means of a simplified example.

In this example, only three technologies, namely, gas OC, gas CC and wind onshore, are available to cover electricity demand and comply with a given emission cap. Gas OC is an existing technology, while gas CC and wind onshore can be added endogenously by the model. Initial model solutions (=iteration 0) of CEM and UCM are shown in Figure A1 in the left three plots by solid lines. The intersection of the full cost lines (Figure A1a) determines the cost-optimal split between the two technologies. As is common in a screening curve plot, the combination of full cost lines with the residual load curve (RLDC) can be used to derive the cost-optimal capacities (compare [5] (p 44)), which in this case is e.g., defined at level g for Gas CC (see Figure A1b). As the emission cap only allows for a certain amount of fossil generation, wind onshore is also part of the optimal capacity mix. The resulting price duration curve derived from the UCM is shown in Figure A1c), also with solid lines.

Without scarcity pricing, both invested technologies show uncovered fixed costs in iteration 0 (see Figure A1d)). Uncovered costs per MW for gas CC are higher than those for wind onshore.

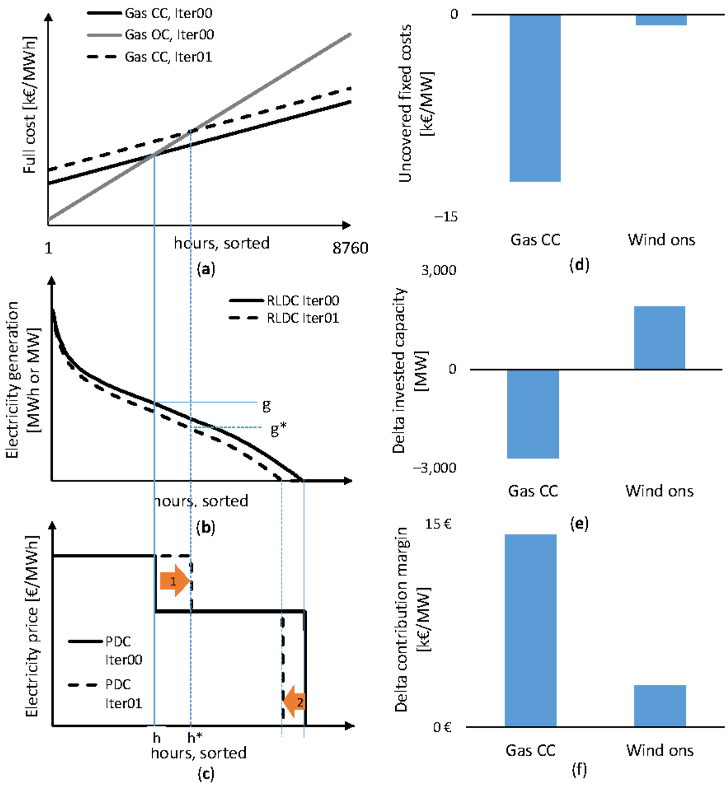

Figure A1. Exemplified effects of the invest premium. For iteration 0 and 1 respectively: (**a**) Full cost curves; (**b**) Residual load curves and optimal investment; (**c**) Resulting price duration curves; Delta for new technologies between iteration 0 and 1: (**d**) Uncovered costs per MW; (**e**) Cost-optimal capacities; (**f**) Contribution margins.

In line with the methodology from Section 3.2, mark-ups are added to the investment cost for iteration 1 to the amount of uncovered cost. The results of iteration 1 considering these mark-ups are shown by dashed lines in the left three plots. The full cost lines for gas CC shift with iteration 1 according to the mark-ups and the intersection of the lines moves to the right (see Figure A1a). This results in less gas CC being added for a cost-minimum system in iteration 1. The level of gas CC capacities declines from g to g* in Figure A1b). Wind onshore receives a comparatively small mark-up, so the technology has a cost advantage compared to gas CC in iteration 1, and more capacity is added. More wind capacity results in the change of the RLDC in Figure A1b) from the solid line towards the dashed line. The change of capacities between iteration 0 and iteration 1 is also summarised in Figure A1e), with less gas CC and more wind capacity additions.

Of course, these changes in the generation structure also affect the price duration curve. The lower installed capacity of gas CC leads to gas CC being price setting in fewer hours, which shifts the PDC in the upper part to the right (arrow 1 in Figure A1c). The shift of the PDC to the left in the lower part (arrow 2) is caused by a higher capacity of wind onshore, resulting in more hours with a price of zero.

Why does this system change now increase contribution margins per MW? This question can best be answered by looking at the PDC change in Figure A1c: The contribution margin of gas OC does not change and continues to be zero since gas OC is price-setting whenever it is in operation and therefore does not achieve any inframarginal rent. In contrast, gas CC can now generate an inframarginal rent in more hours, namely, in h* hours instead of previously in h hours, which increases the average contribution margin per MW for gas CC.

The shift of the PDC to the left in the bottom part (arrow 2) does not influence the margins of gas CC, since gas CC is price-setting in these hours and consequently does not earn any margin in these hours anyway. For wind onshore, two effects apply: During hours where the PDC shifts to the right, margins increase; during hours where the PDC shifts to the left, margins decrease. Thus, whether the average margin per MW increases or decreases depends on the level of price deltas and the amount of wind generation in those hours in which prices change. In this example, the positive effect on margins outweighs the negative one and margins for wind increase in iteration 1. Summarizing the effects on technology margins from iteration 0 to iteration 1 means that rents per MW for wind and gas CC increase (Figure A1f).

The exemplification in this appendix outlines why the methodology leads to a solution with lower uncovered costs. However, as mentioned earlier, it does not imply that this is the case in any constellation of assumptions. If this were not the case, the first termination criterion would apply, according to which iterations would terminate if the moving average of uncovered costs over two iterations increased twice.

Appendix C

Table A2. Mark-ups on investment cost in all iterations in the myopic case.

Technology	Yearly Fixed Costs	Y0_01	Y0_02	Y0_03	Y0_04	Y0_05	Y0_06	Y0_07	Y0_08	Y5_01	Y5_02	Y5_03	Y5_04	Y10_01	Y10_02	Y15_01
	[EUR/MW]	Y0	Y0	Y0	Y0	Y0	Y0	Y0	Y0	Y5	Y5	Y5	Y5	Y10	Y10	Y15
Biomass	514,743	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas CC	98,255	2284	1832	1532	1123	997	805	631	-	83	54	29	109	159	41	-
Pumped Storage	133,859	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PV	100,931	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Stationary Battery	92,311	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Onshore	135,617	163	811	687	528	420	348	285	81	184	-	-	-	40	17	168

Technology	Yearly Fixed Costs	Y15_02	Y15_03	Y20_01	Y20_02	Y20_03	Y20_04	Y25_01	Y25_02	Y25_03	Y25_04	Y25_05	Y25_06	Y25_07	Y25_08	Y25_09
	[EUR/MW]	Y15	Y15	Y20	Y20	Y20	Y20	Y25	Y25	Y25	Y25	Y25	Y25	Y25	Y25	Y25
Biomass	514,743	-	-	-	-	-	-	393,013	395,332	395,332	389,658	395,333	389,658	395,332	389,603	395,333
Natural Gas CC	98,255	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumped Storage	133,859	-	-	11,524	2131	2218	2172	81,435	85,725	89,940	88,471	89,494	88,471	89,123	88,471	89,355
PV	100,931	75	75	44	1663	1514	1573	26,442	12,296	9750	9062	9160	9028	9340	8862	9067
Stationary Battery	92,311	-	-	-	-	-	-	-	-	-	-	79,908	-	-	-	-
Wind Onshore	135,617	112	112	320	2174	2104	2126	41,743	-	29,064	-	27,270	-	27,239	-	26,664

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5 Discussion and Synthesis

The objectives of this thesis are to provide a building block for an overarching and comprehensive policy mix analysis by a techno-economic instrument analysis and to derive policy recommendations for the future instrument mix in the power sector. For this purpose, the selection of the instruments and their evaluation criteria considered were explained in Section 1.3.

In the following Section 5.1, the contributions of the three papers to these evaluation criteria are summarized: results of the first paper are discussed under “Cost-related Effects”, implications from the second paper are part of the section “Electricity Prices and Producer Margins” and the discussion of the third paper is done in “Profitability, Investments and Security of Supply”. Comprehensive conclusions and policy implications are drawn in Section 5.2 and the limitations of the work and the need for further research are discussed in Section 5.3.

5.1 Summary of Instrument Mix Evaluation

5.1.1 Cost-related Effects

In Section 1.3, it was discussed that an emission trading system can lead to a full internalization of externalities under perfect market conditions. One of these assumptions of a perfect emission market (that achieves a cost-efficient emission reduction path) is, that allowances should be tradable and usable for an unlimited period of time (Bocklet et al. 2019). From the perspective of minimum reduction cost, it therefore makes more sense to define an emissions budget over a longer period of time than to require annual emission limits to be met. Ellerman et al. 2015 highlight this need for "intertemporal permit trading" to ensure the long-term efficiency of an emissions trading system.

The European Commission is committed to this goal of intertemporal efficiency in climate policy (Fuss et al. 2018) and the design of the EU ETS reflects efforts towards intertemporal flexibility. However, the flexibility in the current design of the EU ETS is not unlimited: so-called borrowing (i.e., the use of allowances from future commitment periods) is indirectly allowed only between two years, in that allowances distributed in one year can be used for the compliance obligation of the previous year. Banking of emission allowances on the other hand (i.e., the use of allowances from past commitment periods), has been permitted without restriction since phase 2 of the EU ETS (UBA 2020). Since borrowing plays a minor role for intertemporal efficiency (carbon prices and abatement costs are expected to rise over time), the design of the EU ETS actually comes close to a budget approach.

However, it is not only the market design that affects the intertemporal efficiency of emissions trading, but also the foresight and uncertainties faced by market participants. Fuss et al. 2018 highlight three key aspects that can distort the intertemporal efficiency of the EU ETS: short foresight by private actors, lack of credibility and stability of the regulatory framework and excessive discounting by investors. They conclude that these three aspects have depressed the carbon price in the past and hindered temporal efficiency. Thus, e.g. taking the limited foresight of actors and a lack of credibility of political frameworks into account, means that the real market deviates from the idealized assumption of perfect intertemporal efficiency (even though the market design largely allows for it).

In the modeling in Chapter 2 of this thesis, four scenarios are calculated, two of which correspond to the extreme cases of intertemporal flexibility: The "CAP" scenario assumes annual compliance with mitigation obligations, as well as stakeholder foresight limited to only one year. The "BUDGET" scenario represents the other extreme, namely complete intertemporal flexibility over the 30-year period under consideration.

In addition to the two extreme scenarios in terms of temporal flexibility, a third scenario is calculated in Chapter 2 (CAP+CPO), in which the coal phase-out is implemented as an additional measure in parallel to an annual emissions cap. Compared to an annual cap alone, this measure leads to higher total costs, but also to lower emissions and lower average abatement costs over the period under consideration (see Figure 2-5). This is the case because the second measure leads to an early use of low-cost abatement options. The abatement level in the early years thus falls below the level of the cap specified in the CAP scenario, for which the actors in a system with an annual cap alone would have no incentive (compare Figure 2-7). If the market and all actors had full timing flexibility and foresight (scenario BUDGET), they would also implement these early mitigation options because they are cheaper than mitigation options that are available in later years.

This theoretical example shows that the coal phase-out as an “overlapping policy” besides the ETS can lead to a higher cost efficiency under the assumption of a very limited intertemporal efficiency (annual foresight). However, this statement cannot be easily transferred to the real ETS, since the real market probably does behave neither according to the CAP nor according to the BUDGET scenario. Indeed, it can be assumed that the real period of foresight (or a period for which market outcomes are judged to be sufficiently predictable) of market participants moves between these two extremes. It is not possible to quantify this exactly, as there are no comprehensive empirical studies available on how long e.g. the planning horizon considered in an investment decision actually is (Fuss et al. 2018) or for how long the framework conditions are assumed to be predictable. However, there are some indications of how long market actors actually plan. One indication could be the time horizon of traded future contracts or the hedging behavior of utilities, which can start five to six years in advance acc. to Ellerman et al. 2015. The duration of the phases within the EU ETS (over which there is a comparatively high degree of certainty about regulatory requirements) has been 2, 4 and 7 years in the past and is 9 years in the current phase.

Other indications about the intertemporal efficiency of emissions markets can be provided by past trading periods of the ETS or other emissions rights markets. For example, Ellermann and Montero 2002 examine the U.S. Acid Rain Program's SO_2 trading scheme between 1995 and 2001 and conclude that the banking behavior of actors indicates very good intertemporal efficiency. In a similar study for the EU ETS phases 1 and 2 Ellerman et al. 2015 conclude that at least part of the unused allowances at the end of phase 2 can be explained by efficient banking behavior of the actors. It is also shown that it is rational for actors to reduce their emissions below the cap level at the beginning of an ETS in order to bank allowances for later emissions.

In summary, there are two important conclusions from this discussion: First, there is a lack of precise empirical data on what time horizon actors in the ETS actually consider in their decisions or on the intertemporal performance of the real ETS. Second, neither the modelling with one year foresight (commonly used in energy transformation scenarios), nor the one with perfect foresight reflect real market conditions adequately. Once the empirical data is improved, it becomes necessary to also improve the modelling in order to reflect real market behavior in a better way.

However, the theoretical modeling experiment in Chapter 2 showed that if intertemporal efficiency is very poor, it might make sense to introduce a coal phase-out in addition to an ETS to improve it. In order to evaluate whether this conclusion is valid for the real ETS, the empirical basis on the actual intertemporal efficiency of the ETS would need to be improved. If this is found to be insufficient, a coal phase-out may help to ensure that favorable abatement options (e.g., fuel switch from coal to gas) are used early and thus improve cost-effectiveness.

However, this only applies if such an additional measure does not cause other inefficiencies in the system. For example, a coal phase-out with an unfavorable design or inappropriate parameterization can generate windfall profits for power plant operators. It also creates costs through compensation payments to power plant operators. If these inefficiencies exceed the gain in intertemporal efficiency, the introduction of the coal phase-out as additional measures would have a counterproductive effect.

In more general terms, implementing a coal phase-out in parallel with an ETS is justified from a cost-effectiveness perspective only if:

1. the market failure of non-perfect intertemporal efficiency is present and demonstrable,
2. the additional measure is suitable to establish or at least improve intertemporal efficiency and
3. the design of the measure does not cause other inefficiencies that negate the efficiency gain.

5.1.2 Electricity Prices and Producer Margins

The changes in prices due to the three instruments carbon pricing, addition of VRE and coal phase-out have been discussed in detail in Chapter 3 (see Figure 3-3) and are therefore only briefly summarized here.

An increasing carbon price leads to an increase in the average volume-weighted electricity price in a short-term equilibrium system, where prices follow marginal generation costs (without capacity changes). With an addition of VRE, more hours occur with an electricity price of 0€, leading to a lower volume-weighted electricity price on average[8] . In the case of a coal phase-out, the changes depend on which technology replaces the coal capacity. If it is replaced by generation from gas-fired power plants (which typically have higher marginal costs), the mean electricity price increases. In addition, a coal phase-out may create a capacity gap and thus scarcity prices above marginal costs, which also cause the median electricity price to increase.

If the three instruments are combined, these effects overlap. Assuming a replacement of generation from coal-fired power plants by gas, the electricity price-increasing effects of a carbon price and those of a coal phase-out can intensify and lead to very high electricity prices. An expansion of VRE, on the other hand, would dampen this effect.

In summary, all three instruments have a significant impact on the average wholesale electricity price. This can also be amplified in one direction if several instruments are combined. Whether and how strong these effects are, depends in particular on the replacement technology for coal and on the stringency of the individual instruments.

The contribution margins of the generators also depend directly on the electricity prices. The various generation technologies are affected very differently by changes in electricity prices (see Figure 3-6):

- In the simplified screening curves model in Ch. 3 biomass and gas CC can benefit from higher contribution margins in the medium term due to a carbon price increase and

[8] It should be noted here that only the wholesale electricity price is considered. Although a falling wholesale price also has an effect on the retail price, in Germany, for example, an expansion of VRE also increases the retail electricity price through the EEG surcharge and indirectly through the grid fees.

the coal phase-out, but in the long term, contribution margins fall far below the baseline values from 2020

- Lignite and hard coal loose heavily in terms of contribution margins due to all three instruments
- Gas and oil-fired OC turbines also loose contribution margin in the medium and long term, although not quite as much as coal

In Chapter 3 it is also shown that not only the contribution margins of the technologies are affected in different ways by the instruments, but that there are also clear winners and losers between the individual power plants within a technology. The cumulative contribution margins between existing coal-fired power plants over the remaining lifetime can differ by up to 10 times, with older power plants with lower efficiency being worse off.

5.1.3 Profitability, Investments and Security of Supply

The analysis of electricity prices and contribution margins of technologies and individual power plants in Chapter 3 is followed by an analysis of the profitability of generation capacities in Chapter 4, thus answering the question of whether the contribution margins generated are sufficient to cover a plant's full costs. This is the prerequisite for investments in new generation capacities to be taken and thus ensuring a sufficient level of security of supply in the long term.

If assumptions of a perfect market are fulfilled, prices above marginal costs would occur in case of a shortage of generation capacities (scarcity prices). These prices are necessary to induce the entry of new market participants and, in the long-run equilibrium, ensure that all technologies are able to cover their full costs (Stoft 2002, S. 123). However, the analysis in Chapter 4 (Table 4-2) shows, that real market prices have not come close to what would be expected from theory as a scarcity price. Also Joskow 2006 shows that that the problem of “missing money” actually exists in real markets. Therefore, the question whether necessary investments will actually be taken is very relevant as an aspect of security of supply.

Three features of a real market are deemed particularly significant and examined in more detail in Chapter 4: no or insufficiently occurring scarcity prices, a non-optimal existing power plant portfolio and limited foresight of actors. Using an iterative method, a market situation without scarcity prices is simulated in order to examine the profitability of different generation technologies under these conditions over time.

A calculation with very low foresight shows that even small shifts between existing power plants and new investments make it possible to cover the annual full costs for some new investments (see Fig 4-9). A model run with perfect foresight over the entire modelling period shows that early added wind onshore as well as gas CC capacities can even be profitable over their lifetime (see Table 4-4). Thus, in these cases, the risk of under-recovery due to lack of scarcity prices is not necessarily a reason that prevents sufficient investment. In contrast, biomass in particular, but also storage capacities, show very large contribution margin gaps without scarcity prices, especially in later years when decarbonization is already advanced. The reason for this is that acc. to theory scarcity premiums correspond to the annual fixed costs of the most expensive technology. Among the technologies considered here, biomass shows the highest marginal cost in a highly decarbonized system. In contrast, under less stringent emission constraints, the technology with the highest marginal cost that just gets used is a gas-fired open cycle gas turbine. The annual fixed cost of a biomass plant is about four times that of a gas turbine. Accordingly, scarcity premiums in a highly decarbonized system are also significantly higher and so are the contribution margin gaps in the absence of scarcity prices.

In this third analysis, the impacts of the policy instruments are no longer examined separately, but it is assumed that the three instruments carbon pricing, VRE expansion and coal phase-out are implemented with the target of complete decarbonization within 25 years. However, based on the findings from the previous considerations, a qualitative assessment can be made of how each instrument would affect these outcomes. The finding that gas CC can be profitable over its lifetime even without scarcity prices is consistent with the findings from Chapter 3, which find that gas CC can generate higher contribution margins in early years due to a high carbon price and a coal phase-out. Figure 3-4 explicitly demonstrates the course of contribution margins for different energy carriers under varying stringency of the three instruments. These results imply that inframarginal rents for gas CC increase in the case of higher carbon prices due to higher delta between marginal costs of gas CC and gas OC as well as coal-fired power plants. The same applies to inframarginal rents when coal capacities are replaced by capacities with higher marginal cost. Applying these results to the Chapter 4 analysis suggests that a higher carbon price and a more ambitious coal phase-out will increase this profitability of gas CC plants, due to higher inframarginal returns. In contrast, a very ambitious expansion of VRE would worsen the profitability of these plants due to lower utilization and thus fewer hours in which inframarginal rents occur (see Figure 3-4c). Combined with a low carbon price and a slow coal phase-out, this could likely challenge the outcome of a positive NPV. The margin gaps for biomass and storage would also be reduced by a fast coal phase-out (higher electricity prices due to replacement by gas generation) and a high carbon price (higher contribution margins for zero-emission technologies). However, in later years when the margin gap for these technologies is particularly high, also the stringency of the three instruments will have much less impact due to two reasons: First, the heterogeneity and the utilization rate of conventional (emitting) power plants will be less so that inframarginal rents will play a smaller role – and hence the change of marginal costs due to the CO_2-price. Second, in the case of completely CO_2 free power generation, the carbon price will no longer have any impact on the electricity price, because it is not an element of marginal costs anymore.[9] This leads to an average electricity price that increases first with increasing carbon price but decreases when emissions become zero. This price development can also be observed in the simplified model set-up in Chapter 4 (see Figure 4-6).

Overall, these calculations show that a lack of scarcity prices can cause high contribution margin gaps. Even under favorable conditions for profitability for new technologies (e.g. a high carbon price) these can only be closed for relatively early investments and only for some technologies. This form of market failure could thus pose a risk to security of supply, especially in a highly decarbonized electricity system. However, as discussed in Chapter 4, an extreme case of no scarcity prices is simulated here and in it is by no means certain that these scarcity prices will not materialize in reality. The current market design in Germany, for example, allows for price spikes of unlimited magnitude (Bundestag 2016). However, due to persistent overcapacities, there is a lack of empirical experience as to whether and at what level scarcity prices actually form in scarce situations.

Summarizing the analysis about investments and security of supply means that short-term investments in gas CC and wind onshore can be profitable even without scarcity prices. However, in a more decarbonized system it needs to be ensured that scarcity prices realize at a sufficient level, that investors also trust this, or that fixed costs are covered in some other way.

5.1.4 Discussion of Methods

This paragraph summarizes the application of methods within the three analyses and discusses their methodologic advantages. Content-related conclusions are subsequently discussed in chapter 5.2.

This thesis provides a methodological contribution on how complex techno-economic relationships - in this case between policy measures in the electricity sector - can be broken down to isolated effects and thus more easily presented and communicated. For this purpose, a comparable methodology was applied in all of the three papers: First, a highly simplified model was developed or a model experiment was carried out, which allows cause-effect relationships to be explained in isolation and presented graphically. An added value of this procedure is that these relationships can be easily understood due to the strong model simplifications. This makes the results valuable both for policy makers and (as suggested by Rogge and Reichardt 2016 in Section 4.1) for use in higher-level meta-studies to holistically

[9] Except for a system with biomass CCS (where the carbon price would determine the value of one removed ton of CO_2, which could in turn influence marginal costs of these plants), which has, however, not been part of the analysis here.

evaluate policy mixes. A better understanding of the coherences in the power sector also makes it possible to better assess the qualitative effects of changing framework conditions on the existing mix of instruments. Thus, the work also represents a support to deal with high uncertainties in an area with strongly and rapidly changing framework conditions. Furthermore, it supports successful interdisciplinary collaboration in policy mix analysis and thus contributes to the assessment and design of sustainable policy mixes for the further decarbonization of power sectors, even under high uncertainties.

In a second step, E2M2 was used as a high-resolution electricity market model to quantify the previously described effects. The methodological combination of elaborating generic effects and concretizing these effects using a case study, as well as a good graphical representation of coherences is identified in the literature as valuable but little explored. According to Turnheim et al. 2020 both aspects should be applied more widely to help improving the communication between sustainability transformation research and policy.

The two-step methodology introduced in Section 1.5 was applied in each paper as follows:

1. Generic model:
   In the first paper, this basic model is a highly simplified CO_2 abatement cost curve, which can be used to compare the abatement induced by an annual emissions cap and its costs with those of a budget or other political measures (see Figure 2-7). In the second paper, this basic model is a brownfield screening curve approach that can be used to derive the effects of three policy instruments on electricity prices and the utilization and contribution margins of various technologies (see Figure 3-3). In the third paper, this is an even more simplified screening curves model with only two technologies, which is used to show how missing scarcity prices influence the optimal technology composition (see Figure 4-13).
2. Case studies/high resolution model:
   In the first two papers, case studies are calculated in the second step with a high-resolution model that represents all techno-economic restrictions and is run in full temporal resolution. The scenarios are defined in such a way that only one parameter is changed. This makes it possible to trace the deltas of the results back to precisely this parameter. A more detailed model is also applied in the third paper. However, since the methodology in this paper is computationally very intensive, E2M2 could not be run in its full resolution but had to be aggregated with respect to the less relevant parameters (technology resolution of existing and new power plants). Parameters that are more relevant were retained at high resolution such as the time resolution.

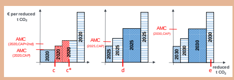
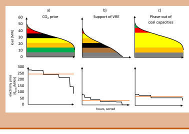
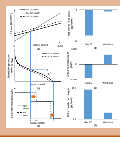
	Paper 1 Cost-related Effects	Paper 2 Electricity Prices and Producer Margins	Paper 3 Profitability, Investments and Security of Supply
Generic Model	**Marginal Abatement Cost Curve** incl. annual and budget CO_2-restrictions + additional instruments 	**Screening Curves Model** effects of 3 instruments on prices, utilization and contribution margins 	**Screening Curves Model** effects of missing scarcity prices on the optimal technology composition 
Case Study	**E2M2**	**E2M2**	**E2M2**
Regional scope	Germany	Germany	Germany
Scenarios	BAU, CAP, CP, CAP+CP, BUDGET	BAU, EE, CP, CO2, MIX	-
Time resolution	2 hours	1 hour	2 hours
Existing technologies	34 groups	33 groups, 125 single plants	12 groups
New technologies	20	20	8
CO_2 restriction	cap and budget	cap and budget	cap
Foresight	annual	annual	annual and perfect
Desinvest	no	no	yes

Figure 5-1. *2-step methodology applied in the three papers of this thesis*

A further need for research with respect to this two-step methodology exists in the structured and systematic definition of model experiments. Currently, hardly any literature can be found on how a model experiment in the area of energy systems should be set up in an optimal way. Two goals should be in the center of such a methodological development: on the one hand, a reduction in problem complexity to such an extent that model experiments can be carried out with the shortest possible runtime. But at the same time, the most important input parameters and techno-economic correlations should be represented in order to still be able to answer the research question under consideration.

In addition to this two-step approach, each paper makes individual methodological contributions in the appropriate area, which are summarized below.

In the first paper, a graphical representation of a simplified CO_2 abatement cost curve including a temporal component was developed. This representation makes it possible to show the effects of an annual CO_2 cap, a budget approach as well as additional measures on the reduction costs within one graph. This can also lead to a better understanding of commonly used CO_2 constraints in modelling (cap and/or budget).

In the second paper, the three instruments coal phase-out, addition of VRE and carbon pricing are examined in a holistic approach for the first time and their effects on two indicators (individually and in combination) are systematically investigated with the help of a screening curves model. The effects of a coal phase-out alone or its combination with other instruments have not yet been studied in a screening curves model. One advantage of this approach is that it offers the possibility to quickly assess the effects of changes in the framework conditions (stringency of the instruments, composition of the existing power plant fleet, fuel prices, etc.) in a qualitative way. Effects of the policy instruments in this analysis are assessed at the power plant level, whereas previous studies often remain at the technology level. In contrast to previous studies in this area, the screening curves approach used here also takes into account a (non-optimal) portfolio of existing power plants.

The third paper proposes a fundamentally new methodology to account for a potential real-market failure in a linear optimization model. This is done in an iterative approach, which addresses the research gap that no model in previous studies in this area has considered a feedback loop between endogenously calculated electricity prices, generation plant profitability and technology selection. Moreover, the analysis is limited to exactly two aspects that can cause non-profitability of generation assets, so that the changes in the system can be attributed to exactly these market failures. The methodology is described in a generalized manner, so that it can also be applied to other models, scenarios or framework conditions.

5.2 Conclusions

There are only a few publications that evaluate policy mixes and combinations of instruments as holistically as possible (i.e., in terms of several instruments and several criteria) and derive concrete and easily communicable recommendations for action (compare Section 1.4). This work contributes to closing this research gap. To this end, the interactions of three concrete instruments for decarbonizing the power sector were examined and results regarding seven indicators and three evaluation criteria were compiled in a final synthesis. Comprehensive conclusions from these analyses are discussed below along the two research questions of this thesis.

5.2.1 First research question

Question 1: How should the combination of the three core policy instruments carbon pricing, support of variable renewable energy (VRE) and coal phase-out be evaluated with respect to the criteria of cost-related, technological and distributional effects on the generation side?

With regard to the criteria of cost-related effects, it can be stated that a combination of a carbon price and a coal phase-out is unfavorable from the perspective of the indicator of total costs, but can be advantageous from the perspective of emission reduction costs. This is particularly the case if the coal phase-out is designed in such a way that the fuel switch potential between coal and gas is fully exploited as early as possible.

With regard to the average volume-weighted wholesale price for electricity, it was worked out that all three instruments have a significant, but in part also opposing effect. With the combination of a high carbon price and a coal phase-out, the price-increasing effects can intensify. A combination with a high expansion of VRE, on the other hand, can weaken this effect again. Thus, should it be a policy objective to limit electricity price increases, a combination of an instrument with a price-increasing effect and one with a price-reducing effect may well make sense. The stringency or speed of the individual instruments (how quickly the coal phase-out takes place, how high the expansion targets for VRE are set, etc.) is decisive for whether one of the effects strongly predominates.

There are also opposing effects on the distributional impacts on the generation side: A coal phase-out can lead to higher contribution margins when replaced by generation from gas-fired plants, and a carbon price leads to higher contribution margins for low-emitting technologies. The addition of VRE, on the other hand, reduces the contribution margins of all technologies. The German case study in Chapter 3 shows that in this case, reducing effects on contribution margins predominate and that the contribution margins of all technologies fall below their original level in the long end.

This result is also reflected in the considerations of the profitability of generation plants in Chapter 4. While early-investment gas CC plants can recover their full costs (even in the absence of scarcity prices), there are large contribution margin gaps for other technologies, especially in a highly decarbonized system. Consistent with the explanations above, the combination of an ambitious coal phase-out, a high carbon price, and a slow addition of VRE would be a policy environment that promotes the viability of generation plants, and vice versa.

5.2.2 Second research question

Question 2: What are the resulting recommendations for the design of the policy mix in the power sector?

Answers to the first research question show that the three instruments have different effects on the criteria examined here. Two instruments can reinforce (positively complement) each other with respect to a criterion, one instrument can compensate for negative side-effects of another instrument or instruments can also counteract each other with respect to certain effects.

So far, however, these have been case-by-case considerations that allow few conclusions to be drawn about whether a given or planned instrument mix is actually suitable and efficient in achieving its goals. This question is therefore discussed in the following on a more general level.

Two important objectives for the design of instrument mixes that concern the decarbonization of the power sector can be derived from this work:

1. <u>The number of instruments used should be kept as low as possible</u>: To achieve policy goals, instruments must be selected, designed, and implemented by policymakers. The

analysis in the introduction shows that a policy evaluation process that includes all instruments and criteria, as well as their interactions, can become very complex and, moreover, usually needs to be repeated at regular intervals (chapter 1.2). The more instruments are deployed in parallel, the more complex the process becomes and the more difficult it is for policymakers to incorporate all aspects into their decision and to assess all impacts of a mix of instruments.

2. <u>The design and assessment of the instrument mix should be based on what is theoretically achievable</u>: Effects and functioning of instruments are often described in theory under ideal market conditions. While these are not achievable in reality, those outcomes are a necessary guideline in determining whether and to what extent the instrument(s) deviate from the theoretically desired effect under real market conditions. However, in order to be able to investigate the deviations as well as the reasons for them in a targeted manner, policy makers need to be aware of what is theoretically achievable (see Chapter 2).[10]

At the European level the EU ETS is referred to as the leading instrument for decarbonizing the sectors it covers (i.e. including the power sector), as was evident most recently with the announcement of the "Fit for 55" package (Council of the EU 12/18/2022). As described in Chapter 1.3, an emission trading system leads to a cost-efficient avoidance of emissions by fully internalizing externalities. Against this background and in combination with the above-mentioned objectives in designing a policy mix, the question arises why additional instruments besides emissions trading are necessary or justified at all.

The results of this thesis agree with statements in literature that an additional instrument besides emissions trading is justified in particular, if it serves to compensate for a market failure occurring in the real market. However, how can scientific and political practice assess whether this is the case and accordingly whether an additional measure is justified from the perspective of cost-efficiency or not? The individual results of this thesis provide indications as to how science and policy might proceed in such a case in order to arrive at a decision that promotes an instrument mix that is efficient in achieving its targets. The following steps summarize these into a kind of guideline when answering this question:

1. A careful empirical analysis needs to be done, if market failure(s) exist.
    - It should be clearly shown empirically whether the real market does comply with ideal assumptions or not and which assumptions of an ideal market are actually violated.

[10] The literature analysis in Chapter 2 shows, that e.g. an intertemporal budget is applied only in a small fraction of published decarbonization scenarios. This indicates that the theoretically optimal (in this case intertemporal efficient) solution is communicated insufficiently to the policy community.

  - Thereafter, it should be empirically investigated which of these deviations actually affect the functioning of the instrument(s) and to what extent.
  - Comparisons with the theoretically achievable outcomes of the instruments are essential in this context.
2. It should be evaluated, whether there is a way to address the market failure(s) by adapting existing instruments.
3. If not, the additional measure should be designed carefully considering,
   - that measures should address the market failure(s) identified in the first step precisely and have minimal undesirable side-effects,
   - whether the efficiency gains from resolving the market failure(s) are greater than any other inefficiencies caused by the new instrument
   - that the new instrument has interactions with all other existing instruments in the mix. [11]

In order to explain this procedure more precisely, results of this work regarding the combination of a coal phase-out and the EU ETS are used as an example below.

Results from Chapter 2 show, that it can make sense to introduce a coal phase-out in addition to an ETS if the market actors have very poor foresight. However, to actually come to an informed decision on whether a coal phase-out should be introduced besides the EU ETS under real market conditions, empirical research is lacking. While it has been found that a coal phase-out could improve the market failure of non-perfect foresight, there is no empirical basis to evaluate to what extent this market failure actually exists. While perfect foresight is difficult to achieve (simply because of political conditions that are subject to uncertainty, e.g. under a government change), there is evidence that an emission trading system can show intertemporal efficiency (see section 5.1.1). Here, the empirical basis would need to be improved for an informed decision. If, on this basis, it would be found that insufficient intertemporal efficiency exists, the next step should be to examine whether this market failure can be remedied by adapting existing instruments. For example, a stricter cap in the ETS and thus a higher CO_2 price would make electricity generation from coal-fired power plants less profitable and lead to the closure of coal-fired power plants without additional political action. In addition, measures to make the future ETS and the CO_2 price level credible in the long term could improve this inefficiency.

[11] It needs to be considered that these steps describe a procedure under the objective of cost-efficiency as a main policy goal. As discussed in Section 1.3, delivering other goals besides efficiency might be a second rationale for an overlapping policy, which would require an additional assessment in a similar way.

If this option does not exist or suffice, careful consideration would be necessary to whether inefficiencies associated with the introduction of a coal phase-out would not negate the efficiency gains. Depending on the design, these could include compensation payments and possible windfall profits for power plant operators.

At least regarding the combination of an ETS with a coal phase-out in Germany, it can be concluded, that data and empirical research is lacking on these two steps.

The third step (if the introduction of a coal phase-out is justified on the basis of all preliminary considerations) is to design the instrument itself in such a way that it causes as few inefficiencies and unwanted side-effects or interactions with the existing policy mix as possible. One example of this are market-based approaches to compensation payments, which can take into account rapidly changing framework conditions as well as differences between technologies and individual power plants and thus prevent windfall profits on the generation side. If necessary, existing instruments may also have to be adapted in a next step to minimize unwanted interactions with the new instrument.

Although the introduction of a coal phase-out for the German power sector has already been decided and implemented, the above considerations show, how such a decision can be conceptualized. In a similar way, the approach is also applicable to the decision on future measures complementing the policy mix. Also, because the description of the approach is not specific to decarbonization of the power sector, it might be applicable to other policy goals as well as other sectors.

In addition to this general approach for evaluating the need for further instruments, this work has highlighted other important aspects that should be considered specifically for improving and further developing the policy mix in the power sector:

- The Market Stability Reserve explicitly concerns the market failure of insufficient intertemporal efficiency (European Commission 2014) and is a key design element for a better synergy between the EU ETS and overlapping instruments. However, empirical evidence is not unanimous, whether the tool is successful and suitable to achieve its goals or not. Therefore, it is important to intensify research on this question. Following the above considerations implies: Should the MSR found to be successful in the improvement or even elimination of intertemporal inefficiencies, it will become necessary to reconsider other overlapping instruments of which some might have be introduced with the objective of addressing the same market failure.

- The stringency of instruments should be very well coordinated. As shown in Chapter 3, high ambition of one instrument can weaken the impact of another or even make it redundant.
- A regular review and recurrent assessment of the existing policy mix is essential. Important occasions that can make a review necessary include a change in targets (e.g. tightening NDCs), a change in the stringency of one or more instruments (e.g. raising VRE expansion targets or lowering the EU ETS cap) or a relevant change of framework conditions (e.g. fuel prices).
- For the outcome and the design of a policy mix, the structure and composition of the existing power generation portfolio is crucial. Existing generation systems show different compositions and deviate from the theoretically optimal technology mix. Moreover, systems that are strongly or completely decarbonized have different characteristics than systems with a significant share of conventional plants (e.g. regarding prices, contribution margins and cost structures, see Chapter 4).
- Policymakers should (further) ensure that the market design allows for scarcity prices (which is the case in Germany, but not in all electricity markets). The next step should be to credibly communicate that sufficient scarcity prices actually occur and that they can be sustained politically long enough to recover fixed costs. If this is not sufficient (or if it can be proven that current scarcity prices are insufficient) to stimulate sufficient investment, this points to a market failure. In this case, additional instruments such as any type of capacity payment would have to be considered, taking security of supply as a guiding principle. In this case, the procedure above can be applied to decide over type and design of this kind of instrument.
- This becomes even more important the further the system moves towards a more decarbonized one or the higher the fixed cost share of the most expensive technology is.

Observing the above framework and the listed design principles will help to ensure that the policy mix for decarbonizing the power sector will continue to be suitable for achieving the climate targets in the power sector as efficiently as possible.

5.3 Limitations and Further Research

Limitations of the analyses made in this thesis as well as the need for further research have already been discussed in the context of the three individual papers. Therefore, only the most important aspects will be highlighted again in this section and, in addition, the limitations and the need for research for the overarching contribution of this work to policy mix analysis will be discussed.

In all three analyses above, the German existing power plant portfolio is used as a reference. The validity of the quantitative results could be increased by finding a way to cluster different existing power plant portfolios and apply the analyses to these clusters rather than just to one reference portfolio.

As common in electricity market studies, investments and thus security of supply are taken as given in the first two analyses. However, the results of the third analysis show, that this assumption might be at risk when scarcity prices are insufficient. This indicates the possibility for further sensitivity calculations of the respective scenarios of Chapter 2 and 3.

Methodological developments exist above all in the area of the third paper. Here, a method is proposed and tested to evaluate profitability of generation plants in a non-perfect market without scarcity prices. To obtain results closer to real market conditions, revenue sources outside the pure wholesale electricity market could be added here, e.g. from the sale of heat or balancing electricity. In addition, further deviations of the real market from idealized assumptions should be investigated here to obtain a complete picture of investment security or risk. For this purpose, an optimizing model approach could be combined with other models that better represent non-optimal behavior of actors. Such more sophisticated analyses should form a cornerstone for future discussions on possible capacity mechanisms.

With regard to the instrument mix analysis, the work can be supplemented by the analysis of further instruments and their interactions. In particular, energy efficiency measures should be mentioned as another core instrument, but also other measures with a major impact on the decarbonization of the power sector, as described in in Figure 1-2, could be incorporated.

According to the breakdown of the evaluation criteria and indicators in Section 1.3 it becomes clear that this thesis only covers the techno-economic part of an instrument mix analysis in the power sector. For a more complete instrument mix analysis, a synthesis with other models or other scientific disciplines is necessary here. Especially for the evaluation of the two criteria innovation and social effects, e.g. socio-scientific methods are much better suited. However, the results of the three papers in this thesis represent important inputs for the evaluation of the remaining criteria. Thus, findings on the criteria distributional and cost-related effects are relevant for the assessment of social effects and results on the use of technologies provide input for the criteria innovation and social effects (e.g. employment).

Finally, the aspect of iterative policy mix assessments remains. Explanations in the introduction have shown that it will continue to be relevant to regularly evaluate, review and, if necessary, adjust policy mixes. This requires a holistic analysis that is initiated and carried out at regular intervals. This analysis shall, first of all, involve a deep empirical analysis including a gap analysis on how instruments could perform theoretically and how they actually perform in real markets. This allows to identify relevant market failures as well as possibilities on how to tackle them. With this empirical basis, a synthesis of evaluations of numerous instruments according to several criteria and indicators (which might be carried out with different methods and from different scientific disciplines) can be performed. It must also include their interactions and the overarching characteristics of policy mixes. Despite this complexity, results should also be capable of being transmitted outside the field of sustainability transformation research and being communicated in a comprehensible way to relevant decision-makers. This remains a massive task with a very large need for research, but its accomplishment will be essential for a successful transformation (not only of the electricity sector) towards an emission-free energy system.

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Inhalt

Die Politiklandschaft zur Bekämpfung des Klimawandels wird zunehmend komplexer und damit auch ihre Analyse. Diese Arbeit liefert einen Beitrag zur Bewältigung dieser Aufgabe, indem drei Kerninstrumente zur Dekarbonisierung des Stromsektors, nämlich CO2-Bepreisung, Förderung von erneuerbaren Energien und Kohleausstieg, systematisch bewertet werden. Dabei werden in drei Einzelanalysen ökonomische, technologische und Verteilungseffekte auf der Erzeugungsseite betrachtet, sowie Wechselwirkungen zwischen den Instrumenten.

Die erste der Analysen beschäftigt sich mit ökonomischen Effekten eines Kohleausstiegs, der parallel zum EU ETS wirkt (sogenannte „overlapping policies"). Die zweite Analyse zeigt die kurzfristigen Effekte der drei Instrumente auf Marktpreise und Deckungsbeiträge einzelner Technologien auf. In der dritten Analyse wird die langfristige Rentabilität der Technologien in einem iterativen Ansatz untersucht, unter der Annahme von unzureichenden Knappheitspreisen im realen Markt. In allen drei Analysen kommt das lineare, systemkostenoptimierende Strommarktmodell E2M2 zum Einsatz, das für die jeweilige Fragestellung geeignet adaptiert wird.

Die aus diesen Analysen abgeleiteten zentralen Empfehlungen für die Gestaltung eines Politikmixes im Stromsektor sind: Erstens sollte die Anzahl an Politikinstrumenten so gering wie möglich gehalten werden. Und zweitens sollte sich die Gestaltung und die Bewertung eines Instrumentenmix an dessen theoretisch optimalem Ergebnis orientieren. Die Berücksichtigung dieser Empfehlungen kann dazu beitragen, dass der Politikmix zur Dekarbonisierung des Stromsektors in Zukunft besser geeignet ist, die Klimaziele so effizient wie möglich zu erreichen.

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