Powering Dispatchable Electricity Investments

Assessing policy instruments to incentivize investments in firm carbon-free dispatchable electricity generation capacity

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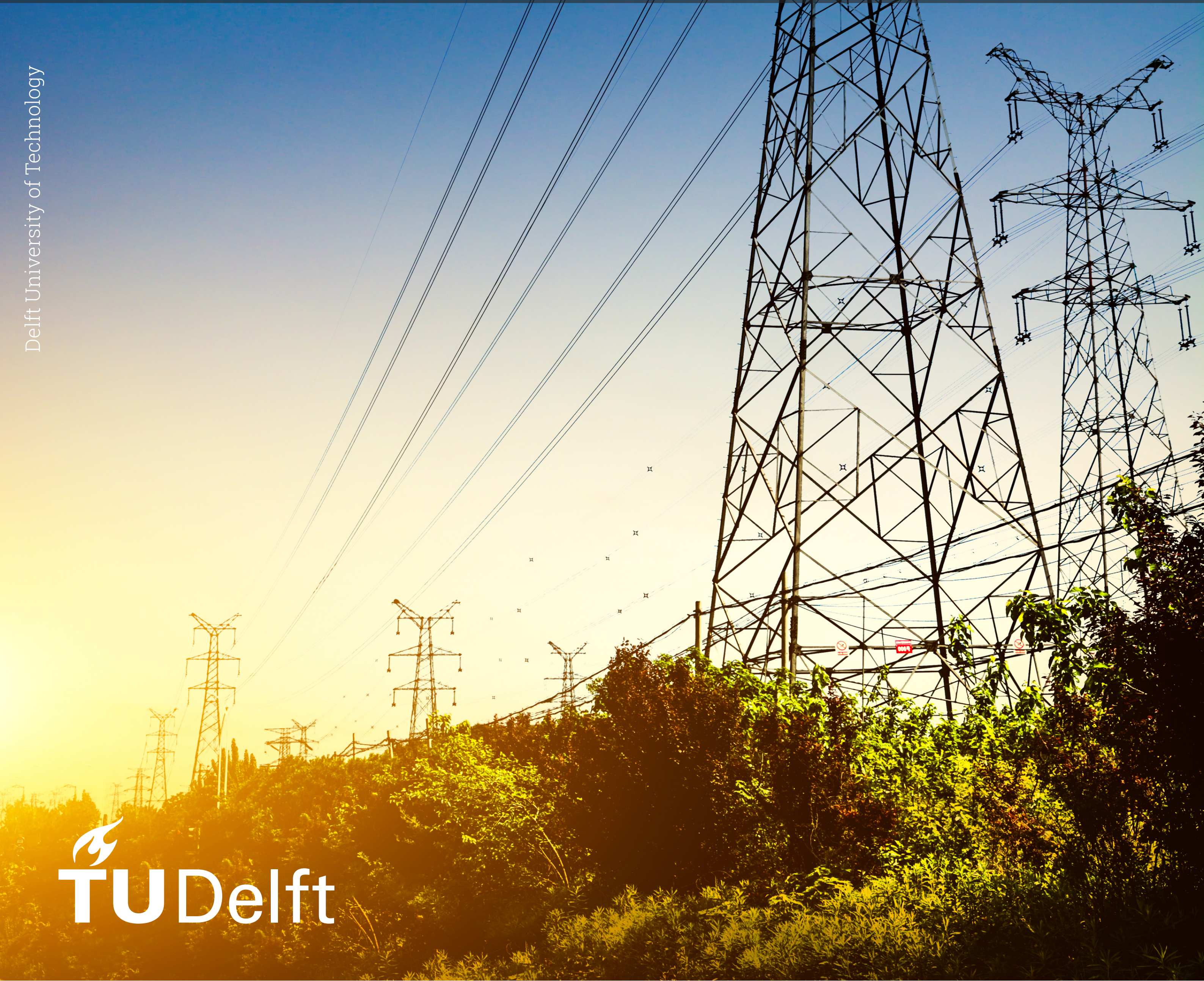

Powering Dispatchable Electricity Investments

Assessing policy instruments to incentivize investments in firm carbon-free dispatchable electricity generation capacity

by

Laura Drost

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Cover: Sun setting behind the silhouette of electricity pylons. Designed by Freepik (modified)

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Executive summary

Achieving 100% carbon-free electricity production in the Netherlands by 2035, while ensuring reliability and affordability; this aim was established by the Dutch government, which intensified the national climate ambitions (Minister voor Klimaat en Energie, 2023a). However, even without considering this intensified sustainability aim, the reliability of the electricity system is expected to decline beyond 2028 and surpass its norm by 2033, with an expected loss of load of 14.2 hours per year (TenneT, 2024). Central to this challenge is the crucial need for system flexibility to secure reliability (TNO, 2023). This need is heightened by the widespread integration of variable renewable energy sources (VRES) and an expected surge in demand due to electrification efforts (TenneT, 2023).

Several technologies, such as demand-side response, interconnection, and storage, can partially provide for system flexibility (Aurora Energy Research, 2021). However, during situations with high demand and low VRES supply, such as 'kalte dunkelflaute', there is a need for firm dispatchable generation capacity. However, projections on the expected operating hours and needed capacity during these hours vary widely. Different scenarios project a range between 4 GW and 20 GW by 2050 (Sijm, 2024). Currently, about 18 GW of firm capacity is installed in the form of gas power plants, compared to a total of 56 GW of installed generation capacity in the Netherlands (ENTSO-E, 2024). Given the sustainability aim, this capacity would need to be decarbonized. However, only 58% of the capacity is technically feasible for retrofitting to operate on hydrogen (den Ouden et al., 2023). Therefore, this thesis is built on the premise that investments in carbon-free firm capacity are crucial to achieving the 2035 sustainability aim, with a main focus on retrofitting current gas power plants to hydrogen power plants and potentially investing in new power plants.

Therefore, this thesis researched policy instruments that stakeholders and experts perceive as effective for incentivizing investments in firm carbon-free dispatchable electricity generation capacity while considering the 2035 100% carbon-free electricity production aim, overall system sustainability, reliability, and affordability. Additionally, this thesis aimed to provide explanations for differences in perceptions.

The research employed a qualitative exploratory and explanatory approach, using semi-structured interviews as the data collection method. A total of 14 interviews were conducted: 5 with stakeholders from (semi-)governmental organizations, 4 with stakeholders from electricity generation companies, 3 with experts from research institutes, 1 with a financial expert, and 1 with a stakeholder from an environmental organization. The interview data was analyzed using thematic analysis. First, to identify patterns of uncertainty factors that can challenge investments. Second, to identify potential policy instruments to mitigate uncertainties and enhance investment incentives. Third, to examine the perceived effects of these policy instruments regarding their effectiveness and impacts on sustainability, reliability, and affordability. Lastly, an explanatory approach was applied to identify potential explanations for differences in perceptions.

Several interconnected factors were identified that increase uncertainty in projecting the viability of investment business cases compared to conventional practices. These factors include, but are not limited to, uncertainty in operational costs, operating hours, electricity prices, and potential price cap implementation. Additionally, these uncertainties are influenced by factors including base load capacity, intermittent VRES supply, flexibility-providing technologies, and inflexible load.

Three policy instruments were identified for their potential to partially mitigate uncertainties and enhance the incentive to invest to allow for decarbonization: capital expenditures (CAPEX) subsidies, operational subsidies, and capacity remuneration mechanisms (CRM). CAPEX and operational subsidies are perceived primarily for their potential to support decarbonization, whereas CRMs are mainly perceived for their potential to enhance system reliability.

The research revealed that perceptions regarding the necessity and effects of these instruments vary. Generation companies generally favor CAPEX and operational subsidies more than other stakeholders

and experts. Some perceive both subsidies as essential to meet the 2035 aim, despite high and uncertain costs, to avoid carbon leakage and maintain domestic plant viability if the 2035 aim is adopted strictly. Others argue that subsidizing hydrogen for electricity generation could divert hydrogen from sectors that use it more efficiently, lowering overall emissions. Moreover, perceptions revealed concerns that setting the wrong subsidy level due to uncertainty will distort market dynamics. Additionally, some question the need for further subsidies, noting that carbon emissions are already decreasing with the decrease in operating hours, and further stimulated by the European Emission Trading System, which includes a European-level playing field.

Perceptions regarding the need for and effects of a CRM differ widely, both between and within stakeholder and expert groups. Some see the energy transition as causing a shift in the electricity system from a low-risk to a high-risk environment, which decreases the viability of business cases, lowers investment levels, and affects system reliability. As a result, they see CRM as necessary to maintain reliability and mitigate high prices, while also addressing the risk of price caps that could further discourage investments. Others, however, perceive that price spikes will drive sufficient investment in other flexibility-providing technologies, which would reduce the need for stimulating investments in firm generation capacity. They view CRM as a drastic and less efficient measure due to the need for government regulations, potentially leading to higher system costs. Additionally, some favor a wait-and-see approach to see how uncertain demand and supply develop before deciding on CRM.

Potential explanations of different perceptions were identified and include varying ideologies on balancing reliability, sustainability, and affordability, as well as differing perceived risks and perceived acceptable risks for system reliability. Additionally, differing perceptions can be influenced by how uncertainties are perceived to develop, what scope is considered, and by strategic considerations.

The key recommendations are as follows:

- Differing ideologies for balancing sustainability, reliability, and affordability require political decisions. Considerations that need to be taken into account include: to what extent stimulating sustainability is profitable compared to its cost and impact on reliability; to what extent we want to rely on uncertain development regarding the need to secure system reliability; and to what extent high prices are accepted for stimulating investment incentives compared to the social risks of high prices and potential blackouts.
- Politics need to be informed about the implications of trade-offs, the social costs of overcapacity and undercapacity, and the effects of an uneven playing field, such as potential effects of hydrogen diversion, carbon leakage, and distorted competition.
- Uncertainties need to be mitigated where possible: unforeseen price caps need to be prevented, and transparency needs to be ensured that caps will not be introduced. Moreover, policy aims and implementations need to be credible and, where possible, contracted.
- Conversations need to be initiated between the electricity sector and government organizations to explore different CRM designs, decarbonization instruments that ensure a level playing field, and options to integrate both sustainability and reliability objectives.

Acknowledgements

This master's thesis, titled *Powering Dispatchable Electricity Investments*, was written to fulfill the requirements for the program Engineering and Policy Analysis at the Faculty of Technology, Policy, and Management at Delft University of Technology. Throughout my five years of studying at this faculty, the energy transition has been a recurring theme, which greatly enhanced my interest in the energy sector, particularly the electricity market. I am grateful for the opportunity to conduct this research over the past six months as a graduation intern at Vereniging Energie-Nederland. This journey has been enriching and has fostered both academic and personal growth, and deepened my interest in the dynamics of the electricity system.

I would like to sincerely thank my graduation committee for their valuable guidance and feedback throughout the completion of this thesis. I would like to express my gratitude to Laurens de Vries, my first supervisor, for your academic guidance and support in structuring my thesis. Your expertise in the electricity market has been truly inspiring. Moreover, I want to express my gratitude to Sander Renes, my second supervisor, for your counsel and patience, as well as for providing crucial insights from your expertise into the economics underlying the electricity market.

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Finally, I wish to express my gratitude to everyone I had the pleasure of interviewing for this research. Your insights have been crucial to the completion of this thesis. Without your generosity in sharing your time and information, conducting this thesis would not have been possible.

Laura Drost
Delft, August 2024

Contents

Nomenclature

Abbreviation	Definition
BECCS	Bio-Energy with Carbon Capture Storage
CAPEX	Capital Expenditures
CCS	Carbon Capture and Storage
CRM	Capacity Remuneration Mechanism
DSR	Demand-Side Response
EPA	Engineering and Policy Analysis
EU ETS	European Union Emissions Trading System
FIT	Feed-in Tariffs
FIP	Fed-in Premia
FOM	Fixed Operation and Maintenance
GSR	Gas Switching Reforming Plant
IRR	Internal Rate of Return
LOLE	Loss of Load Expectation
MSR	Market Stability Reserve
NPV	Net Present Value
RES	Renewable Energy Sources
SMR	Steam Methane Reformer
SR	Strategic Reserve
SDG	Sustainable Development Goal
TSO	Transmission System Operator
VOLL	Value of Lost Load
VRES	Variable Renewable Energy Sources
WACC	Weighted Average Cost of Capital

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1 Introduction

1.1. Problem background: a reliable carbon-free electricity system

Achieving 100% carbon-free electricity production in the Netherlands by 2035; this aim was established by the Dutch government in the spring of 2023 as a pivotal addition to the national climate policy (Minister voor Klimaat en Energie, 2023a). With this aim, the Netherlands intensifies its ambition to be part of a carbon-neutral Europe by 2050, as agreed upon in the European Green Deal, which is crucial to limit global warming to $1.5\,°\mathrm{C}$ (European Commission, 2019). This poses a significant challenge for the electricity sector, as electricity production in the Netherlands still emitted 30.3 megaton CO_2 in 2022 (Centraal Bureau voor de Statistiek, 2022).

In alignment to attain carbon-free electricity production, the Dutch government is also committed to maintaining an electricity system that remains both affordable and reliable (Minister voor Klimaat en Energie, 2023a). Reliability in the electricity system refers to the degree of performance ensuring electricity delivery to customers within accepted standards and in the amount desired (NERC, 2012). Currently, according to the latest Security of Supply Monitor report by the Dutch Transmission System Operator (TSO) TenneT, the reliability of the Dutch electricity system is expected to remain high until 2028 (TenneT, 2024). However, projections beyond 2028 indicate a decline in reliability, raising concerns about potential shortages by 2030, and a Loss of Load Expectation (LOLE) of 14.2 hours per year in 2033, which significantly surpasses the LOLE norm of 4 hours per year (Minister voor Klimaat en Energie, 2024d; TenneT, 2024).

This decline in reliability forecasted beyond 2028 can be primarily attributed to two key trends stemming from the decarbonization objectives. Firstly, a significant surge in electricity demand is expected due to widespread electrification. Secondly, there's the widespread adoption of renewable energy sources (RES) (TenneT, 2023). By 2030, RES are projected to supply nearly 80% of Dutch electricity (Planbureau voor de Leefomgeving, 2022), a substantial increase from only 20% reported in 2020 (Centraal Bureau voor de Statistiek, 2020). The anticipated growing demand for electricity, alongside the significantly increasing dependence on weather-dependent RES characterized by their intermittent nature, poses critical challenges to balancing supply and demand in the system. This challenge is particularly evident during ”kalte dunkelflaute” situations, referring to periods of simultaneous low wind and solar generation, often occurring during the winter months (TenneT, 2023).

During these times when energy demand is high and renewable energy generation is low, the system's ability to maintain a reliable electricity supply is being challenged. Consequently, timely action is required to address these challenges and uphold system reliability while advancing toward 100% carbon-free electricity production in the Netherlands by 2035.

1.2. Problem analysis: the need for system flexibility

Central to the challenge of achieving 100% carbon-free electricity production that is reliable, is the crucial need for a sufficiently flexible electricity system; the system must be able to effectively balance the fluctuating supply of renewable sources with varying demand patterns, therefore, needing more flexibility (TNO, 2023). The International Energy Agency defines flexibility as "the extent to which a power system can modify electricity production or consumption in response to variability, expected or otherwise" (IEA, 2011). In this section, a short analysis is conducted of the most relevant technologies that can provide this flexibility in the carbon-free Dutch system, as identified by TNO (2023) and Aurora Energy Research (2021). These technologies include demand flexibility, storage solutions, interconnections, and dispatchable generation capacity technologies (Aurora Energy Research, 2021; TNO, 2023).

Demand flexibility
Demand flexibility is facilitated by demand side management that entails a wide range of means to affect patterns and magnitude of the electricity consumption, known as demand response. The aim of demand response can be to reduce energy consumption (peak shaving, conservation), reschedule energy consumption (load shifting), or increase consumption (valley filling, load growth) (Lund et al., 2015). All of which contributes to the optimization of resource utilization. Therefore, by introducing demand flexibility, the need for additional capacity in the system will be reduced (Aurora Energy Research, 2021). Demand flexibility can be enhanced through various means. Palensky and Dietrich (2011) distinguish two main approaches for managing demand response: market-based and physical methods. Market-based approaches involve real-time pricing, price signals, and incentives, while physical methods entail grid management and emergency signals. While in theory these measures are widely known to increase flexibility, their widespread implementation has several challenges. These include the lack of necessary infrastructure like advanced metering and control methods, an increase in system complexity, its high costs, and difficulties in aligning the interests of various stakeholders (Strbac, 2008).

Storage solutions
Energy storage can serve an important function in power systems by shifting the delivery of power to allow for temporary mismatches between supply and demand (Lund et al., 2015). The use of energy storage can increase the efficiency of the power system, both economically and technically. During periods of low energy demand and prices, base load production can continue while excess energy is stored. This stored energy can then be sold at higher prices during peak demand periods, reducing the need for peaking power with high marginal costs (Ummels et al., 2008). Similarly, excess variable renewable energy supply could also be stored to mitigate the risk of curtailment. A wide range of various storage technologies exist, each with different characteristics such as lifetime, costs, efficiency, and discharge duration. Consequently, there is no one-size-fits-all solution, and the optimal storage type should be selected based on context and case specifics (Lund et al., 2015).

The study by Aurora Energy Research (2021) that is conducted in the Dutch context, focuses on batteries (such as Li-ion and Redox-Flow), compressed air, and vehicle-to-grid systems. Numerous other researchers identify a wide variety of different technologies, each with its advantages and disadvantages in varying contexts, including technologies such as supercapacitors, magnetic energy storage, pumped hydro, and hydrogen storage (see, for example: Cruz et al., 2018; Gür, 2018; Hossain et al., 2020; Olabi et al., 2021). Overall, Cruz et al. (2018) summarizes that energy storage systems have several key advantages: they reduce the need for peak capacity, enhance grid reliability and stability, facilitate effective utilization of intermittent RES, and their performance and cost-efficiency are continually improving. Moreover, because of the multitude of benefits and significant advances in technologies, they are gaining attention from policymakers and planners. However, Cruz et al. (2018) also highlights some key disadvantages of energy storage; it comes with extra energy losses, adds costs and complexity, and requires extra infrastructure and space. Overall, the field of energy system storage is widely researched and knows many recent advances that can increase its contribution to the system.

Interconnections
Interconnections involve linking transmission networks across regions or countries, enabling the exchange of power between them. This enlarges the geographical scope of the power system and integrates markets, where power flow depends on price differences between these interconnected markets. According to de Vries and Verzijlbergh (2018), a large body of literature shows that an increase in interconnection capacity smooths out the variability of RES production, thereby reducing the need for alternative flexibility sources. Moreover, not only will generation variability be smoothed by geographi-

cal expansion, but also demand, as noted by (Cruz et al., 2018). This smoothing of variability decreases flexibility requirements, thus allowing for further decarbonization through scaled-up variable renewable energy sources (VRES) integration. Besides the benefits of more and higher capacity interconnections, there are also challenges such as geopolitical difficulties, technical limitations, and economic issues (Cruz et al., 2018). Currently, the Netherlands has interconnection capacity with Germany and Belgium, and overseas with Denmark, Great Britain, and Norway (Aurora Energy Research, 2021).

Dispatchable generation capacity
Another relevant flexibility offering technology is dispatchable generation capacity. Dispatchable generation capacity offers supply-side flexibility by being able to freely dispatch electricity to the market against their marginal costs (Aurora Energy Research, 2021). Because of operational flexibility, the supply of electricity can be aligned with demand and answer to unexpected fluctuations. However, there are a number of different technologies that have various constraints to the extent of their flexible operation, such as capacity, ramp rates, minimum power load, efficiency, costs, and emissions. Consequently, also for these technologies there is no one-size-fits-all solution.

Conventionally, gas and coal plants have been the primary sources for providing flexible electricity supply in the Netherlands. A review of the operational flexibility of several cases of gas and coal power plants by Gonzalez-Salazar et al. (2018) shows that overall gas-fired plants are more efficient and generally less polluting than coal-fired power plants. In their study, they highlight the importance of significant improvement in ramp rates, minimum load, and emissions for the future to be able to complement the increasing share of renewables. Nonetheless, these conventional power plants, while essential for current energy needs, remain carbon-intensive, emitting significant amounts of carbon dioxide during operation.

Since the Dutch government announced the prohibition of coal-fired power plants by 2029 (Minister voor Klimaat en Energie, 2023b) and set the objective of achieving carbon-free electricity production by 2035 (Minister voor Klimaat en Energie, 2023a), there is a pressing need for carbon-free dispatchable generation to emerge and take over the role of conventional flexible technologies. Aurora Energy Research (2021) identifies promising technologies that are considered carbon-free or carbon-neutral and dispatchable, such as biomass, biogas, bio-energy with carbon capture storage (BECCS), gas with carbon capture and storage (CCS), hydrogen, and even nuclear technologies, which are currently not considered flexible due to their limited ramping capacity and costs.

Research Direction
In this brief analysis of flexibility-providing technologies, it becomes apparent that each technology carries its own set of advantages and specific challenges. Consequently, no single technology can offer a comprehensive solution for the entire electricity system. Instead, a synergistic integration of various flexibility options is necessary to address the inherent strengths and weaknesses of each technology. In recent years, numerous advancements have been made through studies focusing on the first three discussed flexibility-providing technologies that enhance the flexibility and, consequently, the reliability of the electricity system: storage solutions (see, for example, Cruz et al., 2018; Gür, 2018; Hossain et al., 2020; Olabi et al., 2021), demand response strategies (see, for example, Lund et al., 2015; Palensky and Dietrich, 2011; Strbac, 2008), and the potential of interconnections (see, for example, references in the study by de Vries and Verzijlbergh (2018)).

However, despite advancements in these three flexibility offering technologies, there are limited advancements in decarbonization of dispatchable generation capacity in the Netherlands. However, it is widely recognized that in a carbon-free system, dispatchable electricity generation capacity remains crucial in addition to the other three flexibility offering technologies; due to the increase in VRES generation and advancements in the other flexibility proving technologies, the operating hours for dispatchable generation capacity are projected to decline, although the required capacity during these hours remains significant. According to Wildt et al. (2022), this need for dispatchable generation operating hours is expected to decrease from 5,500 hours in 2030 to around 3,000 hours in 2040. However, the capacity required during these peak demand periods is projected to be approximately 20-22 GW by 2030, potentially increasing to 24-26 GW by 2040.

The previously introduced technologies identified by Aurora Energy Research (2021) can provide for this dispatchable generation capacity, such as biomass, biogas, BECCS, gas with CCS, hydrogen, and nuclear. However, these technologies have different limitations regarding their flexibility and availability. Especially during extreme peak demand and periods such as the ”kalte dunkelflaute” conditions, accounting for less than 1,000 hours annually or even less than 300 hours (Wildt et al., 2022), the system needs dispatchable generation capacity that is known as ’firm’; that is, always available and can ramp up quickly and reliably due to the possibility of storing their fuel reserves. Various studies have assessed the needed capacity during these events, but the range of estimated capacity varies significantly from 13 GW to 18 GW (including base load capacity) by 2030 and 4 GW to 20 GW by 2050 (solely peaking capacity), depending on the scenario (Sijm, 2024).

According to Sijm (2024), retrofitted or new hydrogen gas power plants or gas power plants with CCS are the most viable sustainable options for answering the demand during these extreme peaking hours in the Netherlands. Unlike other countries that might use hydropower or marine energy, these options are technically and economically limited in the Netherlands (Sijm, 2024). Additionally, the necessity of retrofitting gas power plants to hydrogen-based systems has already been recognized in recent Dutch public policy announcements (Minister voor Klimaat en Energie, 2024c).

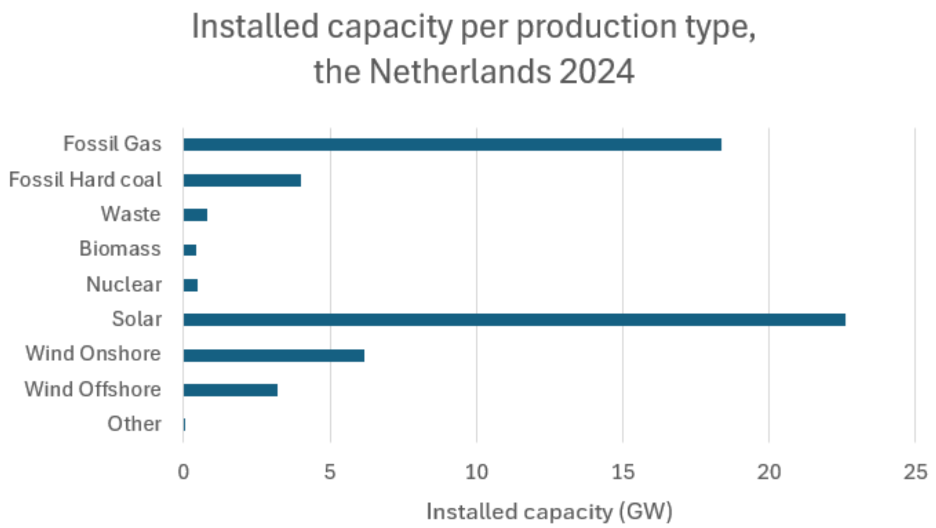

Figure 1.1: Installed capacity per production type in The Netherlands, 2024 (Data source: ENTSO-E (2024)

In contrast, the Netherlands currently meets its peak demand primarily using various types of gas turbines, which have a combined installed capacity of about 18 GW. This accounts for 32% of the total installed capacity of 56 GW in the Netherlands (ENTSO-E, 2024). Figure 1.1 visualizes this current capacity in comparison to other installed production types. Given the current high share of installed gas capacity and the projected need for capacity in the future, it is evident that to achieve the 2035 carbon-free electricity aim with a reliable supply, this firm dispatchable generation capacity must transition to decarbonized alternatives.

Consequently, there is a pressing need for more insight into the potential of carbon-free firm dispatchable production to address the challenges of maintaining a reliable electricity supply in a decarbonized system. Hereby, the focus will be on hydrogen gas power plants and gas with CCS, as they are the most promising technologies for firm carbon-free dispatchable electricity generation in the Netherlands.

1.3. Synthesis of literature review

The state-of-the-art literature on flexible electricity generation capacity, which is fully presented in the next chapter, reveals several key debates. These key debates revolve around the necessity for system flexibility, the need for clear governance, several technological solutions, and a potential business case of conventional gas turbines. The studies by Child et al. (2019) and Cruz et al. (2018) emphasize the importance of flexibility in transitioning to a 100% renewable energy system, and highlight technologies like hydropower and sustainable gas-based generation with CCS. A research on governance by Mitchell

(2016) stresses the need for effective European policies to support this transition that can be adapted for regional levels. Moreover, technological advancements for supply-side flexibility are also a key debate that include novel hybrid systems for conventional power plants to procure hydrogen when VRES output is low, and electricity in times of scarcity (Cloete & Hirth, 2020; Szima et al., 2019, 2021), power-to-fuel technologies (Pochet et al., 2017), and cost-effective storage solutions (Hunter et al., 2021). Moreover, demand-side flexibility through hydrogen production is also well-explored in literature, with studies by Ruggles et al. (2021) and Ruhnau (2022) that demonstrate the potential of hydrogen production to stabilize market values and reduce renewable energy curtailment, where they do presume the use of the produced hydrogen to be mainly in the transport and industry sectors.

Despite these key debates on the need for flexibility and governance support, the technical possibilities for supply-side and demand-side flexibility, and the debate on strengthening the business case of conventional gas turbines by providing them a hybrid function to produce hydrogen at times when they do not produce electricity and still use gas, there is still a gap in knowledge on how to transition to carbon-free firm dispatchable generation capacity in practice. This gap is particularly evident in the context of the Netherlands, where, as highlighted before, the necessity for firm dispatchable generation capacity is acknowledged, but no visible changes are apparent in practice since 18 GW of current installed capacity in the Netherlands is still gas-based (ENTSO-E, 2024).

Therefore, this highlights a lacuna in knowledge: despite the recognized need for carbon-free dispatchable generation capacity, the existence of technical possibilities, and the literature-identified need for governance, there is no existing research on what hinders the business case in practice. Additionally, there is a lack of literature on how to stimulate the business case for transitioning conventional dispatchable generation capacity to firm carbon-free dispatchable generation capacity, which could incentivize investments to realize the transition.

1.4. Research objective and question

This thesis is built upon the premise that investments in firm carbon-free dispatchable electricity generation capacity are crucial to achieving a 100% carbon-free electricity system in The Netherlands by 2035 that is reliable and affordable, as evident from the previous problem analysis and synthesis of current literature.

This thesis aims to bridge the identified knowledge gap within the context of the Dutch electricity system. Therefore, the main objective of this thesis is to identify and analyze the policy instruments that stakeholders and experts perceive effective for incentivizing investments in firm carbon-free dispatchable electricity generation capacity, while considering the overall system sustainability, reliability, and affordability. This analysis is framed within the context of the Dutch goal of achieving 100% carbon-free electricity production by 2035, while ensuring reliability and affordability. Additionally, this thesis aims to understand and explain any differences in perceptions among stakeholders and experts regarding the effectiveness of these policy instruments.

The central question guiding this thesis is as follows:

What policy instruments do stakeholders and experts perceive to be effective for incentivizing investments in firm carbon-free dispatchable electricity generation capacity, while considering the Dutch 2035 100% carbon-free electricity production aim, system reliability, and affordability, and how can differences in perceptions be explained?

To address this question, the thesis first provides the necessary theoretical background on the electricity market, its inherent challenges, investment decisions, and theoretical insights in the uncertainties and potential policy instruments that can impact investments in generation capacity in general. This theoretical background forms a theoretical framework, providing a lens through which this research is conducted and results are interpreted.

Subsequently, to fully address the main research question, this thesis researches the following sub-questions:

- Sub-question 1: What are key uncertainties that in practice obstruct investments?

- Sub-question 2: What policy instruments are perceived to mitigate the identified uncertainties and enhance the incentive to invest?
- Sub-question 3: How do stakeholders and experts perceive the effects of the policy instruments on the 2035 sustainability aim, system reliability, and affordability?
- Sub-question 4: How can differences in perceptions be explained?

1.5. Scope

The scope of this thesis is divided into three parts: geographical, temporal, and technical. Initially, the geographical scope is set on the Netherlands. However, since the Dutch electricity system is interconnected with several other countries and integrated within the European market, the effects of changes in policy instruments and investment decisions cannot be considered in isolation. Therefore, even though the geographical scope is focused on the Netherlands, significant interactions and interdependencies outside its borders that impact the reliability, sustainability, and affordability of the Dutch electricity system are also taken into consideration.

The temporal scope is set in alignment with the Dutch aim of achieving 100% carbon-free electricity production in the Netherlands by 2035 (Minister voor Klimaat en Energie, 2023a). However, given the possibly long duration time of policies, the long investment lead time, and the long lifespan of generation capacity this scope is set in a flexible manner.

The technical scope will focus on technologies considered viable for meeting extreme peak demands and periods such as 'kalte dunkelflautes': firm dispatchable electricity generation capacity, that is carbon-free. While other countries may rely on hydropower or marine energy, in the Netherlands, the most viable options include retrofitting gas turbines to hydrogen (blending) gas power plants (Sijm, 2024), or potentially retrofitting them with CCS.

Nevertheless, even without considering the public goal of achieving a carbon-free electricity supply by 2035, projections by TenneT (2024) indicate that the Dutch system may exceed its reliability norm; by 2033, a LOLE of 14.2 hours per year is projected, surpassing the norm of 4 hours per year well before the 2035 aim date. If the 2035 carbon-free aim were strictly adopted, this in theory would mean all current peaking capacity would need to be retrofitted, and possibly new power plants would need to be built to mitigate the increasing LOLE and maintain system reliability. However, the study by den Ouden et al. (2023) analyzed dispatchable capacity in the Netherlands for 2035 and assessed which gas power plants are most promising for conversion to hydrogen plants from a technical perspective. Their analysis reveals that 58% of the current gas power plants, accounting as well for 58% of the volume of dispatchable capacity, are technically suitable for retrofitting to pure hydrogen. Even though in this thesis the application of post-combustion CCS technology is assumed to be technically possible for all currently existing gas power plants, these projections still underscore the need for investments in both retrofitting current capacity, and establishing investments in newly-built firm dispatchable generation capacity to ensure system reliability and meet future climate goals.

The following Figure 1.2 visualizes an indication of a timeline for the initial scoping of this thesis when taking into account the 2035 sustainability aim and the technical limitations to retrofit all current firm dispatchable generation capacity.

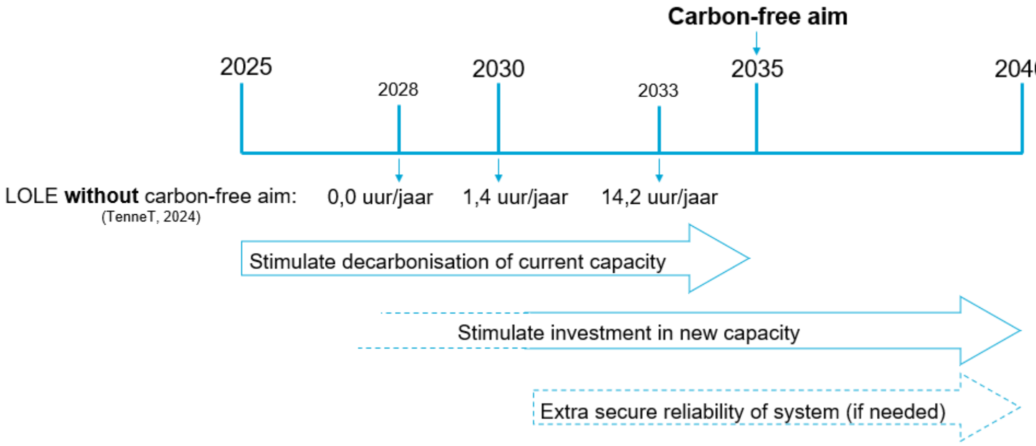

Figure 1.2: Indication of initial scoping timeline, considering the Netherlands

1.6. Relevance

The relevance of this thesis has several dimensions; first, the scientific relevance of this thesis is highlighted, followed by the social relevance and the relevance of this thesis considering the Engineering and Policy Analysis (EPA) study program.

Scientific relevance

As evident from the identified knowledge gap, this thesis mainly contributes to the field of research concerning dispatchable carbon-free electricity capacity. This field of research is of increasing importance, considering the growing importance of flexibility in our electricity system due to the integration of high shares of VRES. While investment theory in the electricity sector has been extensively researched, its practical application in the midst of a transition is limited. This thesis bridges this gap by examining both theoretical knowledge in literature and practical insights on investments in flexible capacity through stakeholder, and expert interviews in the transitioning electricity system. By exploring how sustainability transitions intersect with investment decisions, especially investments in peaking capacity, this research offers valuable insights for both policymakers and the private sector while adding to the scientific field of investments in a carbon-free electricity system.

Social relevance

The social relevance of this thesis is evident; without sufficient flexibility, the electricity system risks facing shortages, high price spikes, or involuntary blackouts, all of which can significantly impact society. By researching investments in dispatchable carbon-free electricity capacity, this thesis aims to provide useful policy advice to mitigate these potential effects and ensure reliability. Moreover, because of this societal importance, this topic has also gained attention within Dutch governmental institutions and parliament. In several letters to parliament, the Minister of Energy and Climate has underscored the importance of subsidizing schemes for hydrogen-based flexible electricity generators to ensure the security of supply (Minister voor Klimaat en Energie, 2024a). However, the exact structure of these subsidy schemes remains unclear. Therefore, given the existing knowledge gap, further research is necessary to clarify this issue. Hence, this thesis offers valuable insights to guide policy advice on this matter.

EPA relevance

In addition to the social and scientific relevance, this thesis is also highly relevant to the EPA curriculum. Primarily, the central problem in this thesis; achieving a reliable carbon-free electricity system, is closely linked to United Nations Sustainable Development Goal (SDG) number 7: ”Ensure access to affordable, reliable, sustainable, and modern energy for all” (United Nations, n.d.). This highlights the EPA relevance since the curriculum revolves around addressing the international grand challenges. Moreover, given the complexity and interdisciplinary characteristics of the electricity system, the problem at hand involves many actors, which is also a central focus in the EPA studies. Furthermore, given the focus on the interplay between politics, policies, and investment behavior of the private sector, including the effects on energy security for society, the thesis is well situated within a socio-economic and political environment that intersects the public and private domains.

1.7. Thesis structure

The following Figure 1.3 visualizes the structure of this thesis report.

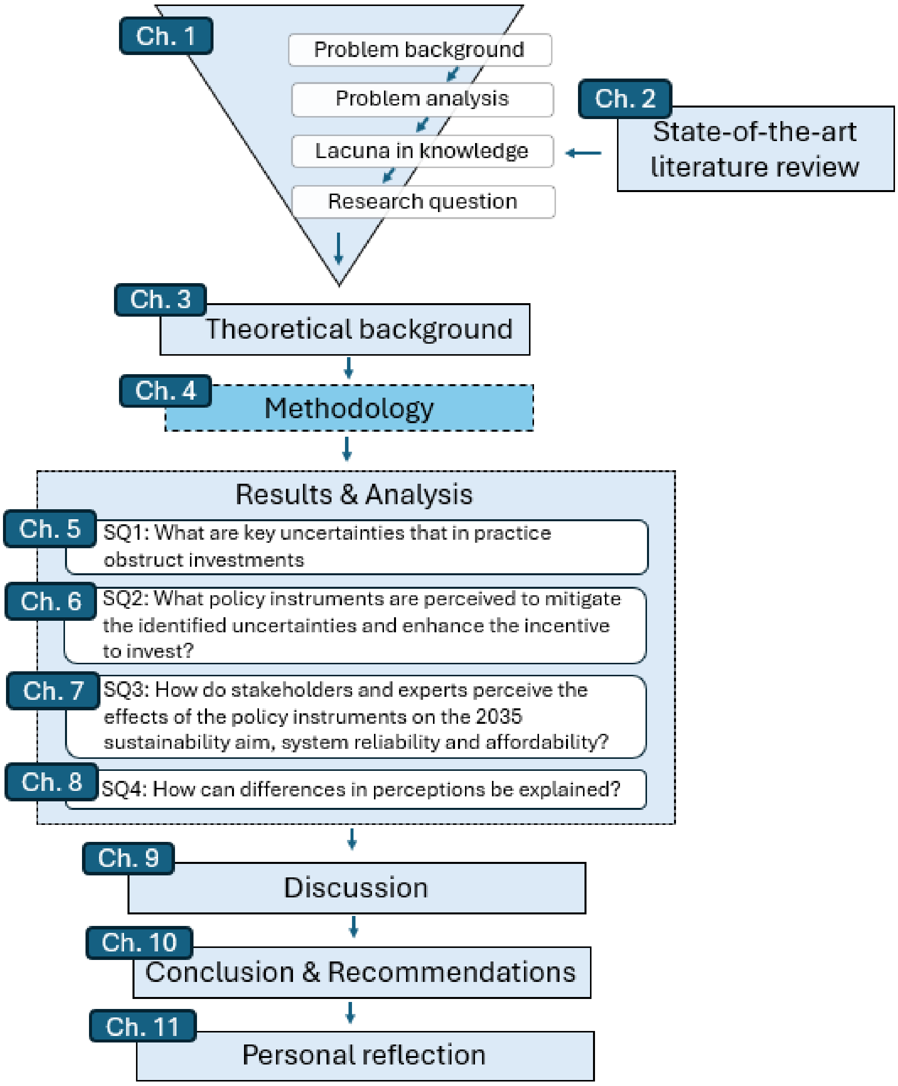

Figure 1.3: Thesis structure

2 State-of-the-art literature: Flexible generation capacity

This chapter provides a concise state-of-the-art literature review to address key debates on flexible electricity generation capacity. This chapter aims to identify existing insights and highlight gaps in current knowledge. By establishing what is addressed in current literature and highlighting what knowledge is missing, this chapter justifies the research questions formulated in the introduction in the previous chapter. First, Section 2.1 addresses the literature selected, and Section 2.2 highlights the lacunae in knowledge. The synthesis of this chapter was incorporated in the previous introduction to position the research questions.

The search strategy applied is discussed in Appendix A. In Scopus, the query included the term 'carbon-free', and related concepts, combined with various terms for 'dispatchable production'. Sequential searches were conducted with and without the term 'hydrogen'. After excluding articles published before the Paris Agreement in 2016, which marked the start of international decarbonization (United Nations, 2016), and those with fewer than 10 citations, the resulting articles were filtered for relevance, leading to the selection of 12 articles.

2.1. Reviewed literature

The state-of-the-art literature reveals several key debates at present. The key debates identified are focused on the overall need for system flexibility, the governance needed for providing this flexibility, various supply-side flexibility technologies, demand flexibility through hydrogen production, and the business case for conventional gas turbines to transition to hybrid gas turbines.

Necessity for flexibility

The study conducted by Child et al. (2019) investigates the feasibility of transitioning Europe's power sector to 100% renewable energy by 2050. The study employs the LUT Energy System Transition model to simulate two pathways toward a carbon-free power sector. The results indicate that a 100% renewable energy system is not only economically competitive, but can also be technologically feasible for Europe. However, the study underscores the crucial role of flexible generation, improved interconnections, and expanded energy storage capacity to provide for flexibility. Concerning flexible generation, Child et al. (2019) highlight the potential for increased capacity through hydropower, dispatchable bioenergy, and sustainable gas-based generation.

In line with the conclusions drawn by Child et al. (2019), Cruz et al. (2018) also stresses the crucial importance of system flexibility as the integration of intermittent RES continues to increase drastically. The article provides an extensive review of various potential flexibility options, exploring their challenges and advantages. Regarding supply-side flexibility Cruz et al. (2018) discuss two options: conventional power plants and strategic RES power curtailment. Regarding conventional power plants, they discuss peak power plants and load-following plants such as gas and hydropower, emphasizing their traditional balancing role due to their fast responses, startup, and ramping capabilities. The study highlights the high efficiency of combined heat and power plants that can exceed 80%, alongside the potential downside of their high fuel prices (Cruz et al., 2018). Remarkably, with respect to conventional power plants, this study does not address the dependence on fossil fuels and their emissions.

Governance for flexibility
Moreover, the research by Child et al. (2019) emphasizes the need for clear governance at a European level that allows for development that is appropriate for regional contexts to effectively transition to a 100% renewable European energy system. In line with this study, the article by Mitchell (2016) presents a persuasive essay centered on the governance required to facilitate the transition to renewables. Mitchell advocates for a "no-regrets" energy policy that places significant emphasis on enhancing system flexibility, especially in light of the increasing integration of VRES due to declining prices. Despite widespread announcements of supportive public policy, Mitchell stresses the necessity for more effective governance support and pressure to further accelerate the transition (Mitchell, 2016).

Supply-side flexibility
In contrast to the broader focus on the system level of the previously discussed articles, the following articles explore the debate regarding technological solutions to enhance supply-side flexibility.

To address the challenge of intermittency in RES, a study by Alvarez-Mendoza et al. (2017) proposes a novel hybrid system designed to mitigate the volatility of wind power. This hybrid approach combines storage technology, advanced forecasting techniques, and predictive control within a single system that includes a wind generator, an electrolyzer, hydrogen storage, and a fuel cell. The results of the study show that the hybrid system can be managed as semi-dispatchable energy at the distribution level for housing sectors and small stores.

In contrast, the study by Pochet et al. (2017) aims to enhance both the flexibility and efficiency of power-to-fuel technologies by integrating them into one technology for power and heat production: Homogeneous-Charge Compression-Ignition engines. The study investigated the feasibility of using a single engine technology to combust multiple types of fuels derived from stored electricity, such as gaseous (hydrogen or methane), easily liquefiable (ammonia), or liquid (methanol) fuels. The study found that this single engine design could ignite all four fuels under specific intake conditions, thus adding to flexibility since different fuels can be used as input depending on fuel availability.

Similarly, the study by Hunter et al. (2021) also investigates storage solutions in combination with dispatchability options. However, this study investigates multiple technology options at once to determine the least-cost option. By employing a techno-economic research methodology, they determine that for a 120-hour storage duration rating, hydrogen systems with geologic storage and natural gas with CCS are the least-cost low-carbon technologies for both current and future capital costs, even under uncertainty.

Demand-side flexibility: hydrogen production
In contrast to supply-side flexibility, studies by Ruggles et al. (2021), Li and Mulder (2021), and Ruhnau (2022) investigate the role of flexible electricity demand facilitated by hydrogen production from excess RES. Ruggles et al. (2021) demonstrate that integrating higher flexible loads into electricity systems can reduce the need for curtailment of renewable energy in different scenarios using a least-cost electricity system model. On a different scale, Li and Mulder (2021) provide an economic assessment of power-to-gas technology and highlights its potential to mitigate price volatility in electricity markets. However, they underscore the importance of higher carbon prices in making PtG investments profitable.

Moreover, Ruhnau (2022) explores the impact of flexible hydrogen electrolyzers on market values of wind and solar energy. Their research indicates that flexible electrolyzers can stabilize market values in the range of projected levelized costs, preventing them from declining to marginal cost levels and becoming victims of their own success. By enabling the efficient utilization of renewable energy and minimizing curtailment, hydrogen production emerges as a critical component of demand-side flexibility, offering economic and market stability benefits in renewable energy-dominated electricity systems.

Business case for conventional gas turbines
Another debate in the literature revolves around the business case for conventional gas plants themselves. With the increasing integration of VRES, dispatchable gas plants offering flexibility are com-

pelled to operate at lower capacity levels with frequent electricity production ramps due to the renewable-based system. This scenario poses economic challenges for conventional power plants. The research conducted by Szima et al. (2019) and Szima et al. (2021) addresses this challenge by proposing the combined cycle gas switching reforming plant (GSR) with carbon capture. They provide an economic assessment of these power plants, designed to generate electricity during periods of low VRES output and to generate hydrogen during times of high VRES output. This flexibility enables continuous operation, even when a high VRES output renders electricity production uneconomical (Szima et al., 2019, 2021). Additionally, Cloete and Hirth (2020) conduct research on the interaction of GSR with the system. They demonstrate that GSR offers substantial benefits compared to conventional technologies, including increased optimal wind and solar share, reduced total system costs, reduced emissions, and the production of hydrogen for use in other sectors like transport and industry.

2.2. Identification of lacunae in knowledge

The existing literature presents various key debates, all of which focus on the necessity of flexibility within the electricity system. Notably, several studies focus solely on demand-side flexibility, emphasizing the production of hydrogen from excess renewable energy to minimize curtailment, reduce price volatility, and enhance the market value of solar and wind energy (Li & Mulder, 2021; Ruggles et al., 2021; Ruhnau, 2022). However, these studies predominantly consider the end-use of hydrogen for other sectors like industry and transport. In contrast, research by Alvarez-Mendoza et al. (2017) and Pochet et al. (2017) specifically explores the utilization of hydrogen as a fuel to produce electricity on small scale (semi-dispatchable) and large scale, thus addressing supply-side flexibility. The study by Hunter et al. (2021) indicates that hydrogen-based electricity production can offer an economical solution for providing supply-side flexibility. However, the debate in the literature concerning the business case for conventional gas plants solely revolves around equipping them with hybrid functionality, producing electricity during periods of VRES and hydrogen during high VRES output, both while still utilizing fossil fuels (Cloete & Hirth, 2020; Szima et al., 2019, 2021). Moreover, the studies by Child et al. (2019) and Mitchell (2016) emphasize the need for clear governance to realize the transition.

To summarize, the reviewed studies highlight the need for both demand-side and supply-side flexibility in electricity generation. They examine the technological feasibility of techniques such as hydrogen and CCS and assess the economic viability of hydrogen power plants. Moreover, they analyze the business case for conventional gas plants by implementing a hybrid function that combines electricity and hydrogen output, using gas as input with CCS. Despite the recognized need for flexible generation capacity and the availability of technologies like hydrogen and CCS, and despite the urgency emphasized by the government to achieve a carbon-free electricity system, there is a noticeable lack of significant progress toward transitioning to carbon-free dispatchable electricity generation.

The key debates on the need for flexibility thus provide several technical solutions and advocate for government support. However, none of the studies address how the business case for carbon-free firm dispatchable generation capacity operates in practice. Although the literature on the Dutch context addressed in the previous chapter indicates that investments are necessary, this need has not yet been realized or thoroughly discussed in the literature. Therefore, the gap in knowledge lies in understanding the challenges that hinder and can stimulate progress in transitioning to firm carbon-free dispatchable electricity generation capacity.

3

Theoretical background: Investments in the electricity market under uncertainty

This chapter builds further from the introduction and provides the theoretical background for this thesis. The aim is to establish the theoretical foundation by discussing the key theories and concepts that underpin this research.

First, Section 3.1 addresses theories related to investments in electricity generation capacity in general. Thereafter, Section 3.2 highlights common theories of investment in electricity generation capacity under uncertainty. Subsequently, Section 3.3 addresses how capacity resources can derive value, and Section 3.4 discusses the uncertainties considered in the literature. Lastly, Section 3.5 synthesizes the theoretical background and provides the theoretical framework for this thesis.

3.1. Investments in electricity generation capacity

3.1.1. Investments in theory

In the electricity market, the optimal level of investment in generation capacity is found when social welfare is maximized. In the centralized planning model by Ventosa et al. (2013), where one central decision maker holds control, it is shown that social welfare is maximized when the total costs of power supply and the cost of energy not served are minimized. To determine the optimal mix of generation technologies that maximize social welfare, Ventosa et al. (2013) uses the cost functions of different technologies. These functions account for the varying fixed and variable costs of each technology, making no single technology economically efficient for all hours of the year in a static context. This is based on assumed known fixed and variable costs for each technology and a known load duration curve, meaning it does not consider dynamic changes over time. By projecting these cost functions onto the load duration curve, Ventosa et al. (2013) identifies the optimal mix of technologies required to achieve a static long-run equilibrium that maximizes social welfare.

Figure 3.1 visualizes the graphical solution of this centralized optimal investment problem for two technologies: gas turbines (GT) and coal. In the figure, the y-intercept of each line represents the fixed costs, while the slope represents the variable costs. Coal has higher fixed costs and lower variable costs compared to gas, making coal more economically efficient to produce at high capacity factors. This efficiency holds up to the point where the cost functions of the two technologies intersect. At this intersection, the cost of generating electricity with gas turbines becomes equal to that of coal. Beyond this point, gas turbines, with their lower fixed costs but higher variable costs, become more economically efficient at lower capacity factors.

When this intersection point is projected onto the load duration curve, it establishes the proportion of time that capacity levels are needed over a year. This allows for the determination of the optimal installed capacities for coal and gas turbines, ensuring that the generation mix is cost-effective and meets demand throughout the year. This visualized solution is often referred to as 'screening curves', and was initially developed by Phillips et al. (1969).

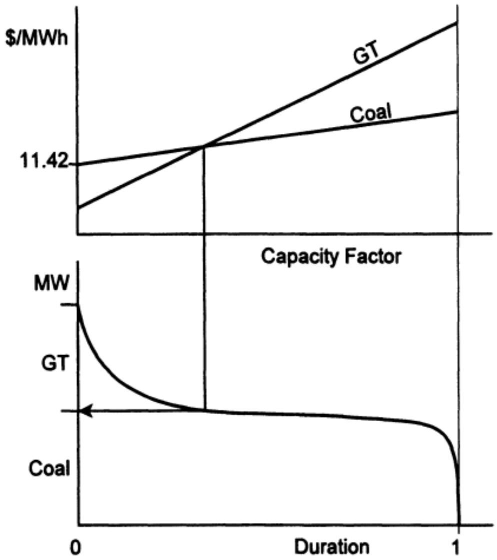

Figure 3.1: Screening curves to find the optimal mix of technologies in long-term equilibrium under a static optimization (Source: Stoft, 2002)

Following up on this central planning approach, Caramanis (1982) introduces the theory of spot pricing. According to this theory, optimal spot pricing aligns individual profit-maximizing behavior with socially optimal investment decisions in an unregulated market. Caramanis (1982) argues that participants in spot pricing markets are expected to exhibit socially optimal investment behavior in a dynamic system. This optimality is primarily achieved through real-time price signals based on marginal costs that continuously adjust supply and demand, bringing the market into equilibrium by achieving operational efficiency. Real-time pricing ensures that the electricity market operates efficiently by providing immediate signals that influence both consumption and production decisions, which, in this theory, dynamically aligns market behavior with social optimality.

However, in practice, literature presents various arguments that suggest the market tends to identify only a narrow investment optimum. This could lead to underinvestment and make it challenging to achieve an equilibrium in a socially optimal state.

3.1.2. Investments in practice: conventional

In practice, investment decisions in electricity generation capacity are influenced by the characteristics of electricity itself, the characteristics of investment in electricity generation capacity, and several market failure and imperfections that complicate the achievement of an optimal equilibrium in the market.

Electricity is distinct from typical commodities due to its unique characteristics. Unlike most commodities, electricity cannot be efficiently stored in large quantities. This necessitates nearly simultaneous production and consumption of electricity, as well as a real-time balance of supply and demand. Consequently, the system is highly dynamic and complex, prone to failures if not managed carefully. Additionally, electricity must be transmitted over grids, where its path is determined by the laws of physics. These characteristics require transmission and distribution grids that interconnect the entire system and maintain a permanent balance between supply and demand (Ventosa et al., 2013).

Besides these characteristics of electricity, investments in generation capacity itself also know specific characteristics that can influence investments. Firstly, the electricity industry, especially with regard to conventional gas and coal turbines, is capital intensive, and the product, electrons, are completely homogeneous, which can lead to booms and busts in investment (Roques et al., 2005). Moreover, the lead time and construction period for new generation capacity is also extensive, and the generation facility can have effective operation lives of about thirty to fifty years, causing one investment to influence the future system operation for many years (Conejo et al., 2016). According to Ford (1999), similar to other commodities characterized by high capital costs, prolonged construction times, and low elasticity of supply and demand, these factors can result in boom and bust cycles of investment because of insufficient responsive price signals that can lead to alternating periods of overinvestment and underinvestment.

Moreover, on top of these characteristics that make that electricity is not just like any other commodity, several market failures and imperfections are known to complicate this in practice (Based on de Vries, 2004; Hobbs et al., 2001):

Price restrictions
As mentioned before, the theory of spot pricing assumes real-time price signals that continuously adjust supply and demand. However, in practice, customers may not have real-time metering capabilities, which can lead to relatively low price elasticity. Neuhoff and de Vries (2004) argue that as a result, supply and demand do not always intersect and consumers may be exposed to paying prices higher than their value of lost load (VOLL); consumers thus have to be protected by the institution with a price cap in the short-term market. According to Stoft (2002) a price cap equal to the average VOLL will result in an optimal level of investment and blackout duration that results in minimal total system costs. However, the average VOLL is difficult to determine and consumers are known to be inhomogeneous about the VOLL (Neuhoff & de Vries, 2004).

Imperfect information
To make socially optimal investment decisions, producers need information about the probability that plants will operate and the expected return on investment. To obtain this information, they require knowledge of the stochastic distribution of the demand function and the future development of total available capacity (Hobbs et al., 2001). However, producers often lack this information, which increases investment risk and decreases the willingness to invest (de Vries, 2004).

Risk aversion by investors
Investments in electricity generation, particularly in peaking plants that mostly generate income when electricity prices are high, thus come with high risk. As argued by Vazquez et al. (2002), risk-averse firms may decline investment opportunities despite a positive expected business case with reasonable profit margins, due to the unpredictable income fluctuations associated with these investments. Following this, Neuhoff and de Vries (2004) show that if investors are risk-averse, investments would only be optimal when investors can sign long-term contracts. However, they observe that there is not a sufficient level of long-term contracts in existing markets. Possibly because retail companies are not credible counterparties if their final customers can easily switch to retailers offering lower prices.

Regulatory uncertainty and restrictions
Not only does a deficiency in knowledge increase investment risk, but regulatory uncertainty and restrictions also contribute to this risk. de Vries (2004) states that regulatory uncertainty can be seen as a negative externality associated with changes in public policy. These changes can take many forms, all impacting the market and, consequently, the business case for new capacity. Examples include changes in market design, interventions during shortages, network expansion, and changes in input markets such as the gas market. In addition to regulatory uncertainty, the regulator can impose restrictions on new investments, such as permitting processes that can both limit investment and have long lead times. This can increase the response time of generating companies to higher demand. Particularly in situations with incomplete information about future supply and demand developments, these restrictions can contribute to increased investment risk (de Vries, 2004).

Risk asymmetry
Furthermore, the asymmetrical distribution of social risk can influence the investment levels in electricity generation capacity. Cazalet (1978) already showed that the social costs of over- and under-capacity are not distributed symmetrically; the social costs of excess generation capacity are lower than the costs related to the risk of shortages. Therefore, de Vries and Heijnen (2008) argue that if investment in generation capacity exceeds the social optimum, it would act as inexpensive insurance against the high costs of power shortages since the social cost of excess capacity is significantly lower than that of

shortages. However, they also argue that strategically, it is beneficial for generators to invest less than the social optimum, as this leads to higher prices and greater profits, especially if other competitors make a similar assessment and also invest below the social optimum. Therefore, de Vries and Heijnen (2008) argue that given the uncertainty about whether the optimum level of generation capacity will be achieved, this optimum level should be higher than the static optimum level.

Market power
Moreover, market power can also pose a challenge to achieving the social optimum in the electricity market. Market power is typically exercised by charging prices higher than the marginal cost or by withholding output that could be profitably sold at the current market price. According to Stoft (2002), when these strategies are successfully implemented, they lead to higher market prices, increased profits for the firm with market power, and reduced output availability in the market. Therefore, market power can distort the market to benefit the dominant firm, which negatively affects competition and market dynamics.

These previously discussed characteristics, market failures, and imperfections highlight the challenges in achieving optimal investment levels even within conventional electricity markets. However, amid the current energy transition, the system is undergoing significant changes to mitigate the negative externalities of carbon emissions. This adds further complexity to the existing challenges and uncertainty within the system, making it even more difficult to achieve optimal levels of investment.

3.1.3. Investments in practice: energy transition
Amid the energy transition, the electricity system is undergoing significant changes. However, investments in generation capacity, characterized by long lead times and operational lifespans of thirty to fifty years, necessitate a long-term perspective (Conejo et al., 2016). Given the changes in the electricity market, the uncertainties inherent to such long-term investments are further heightened.

According to Conejo et al. (2016) the long-term decision-making for investment is primarily complicated because of the following uncertainties:

- Future load evolution.
- Future investment cost evolution of investment alternatives.
- Future operation cost evolution of production technologies.
- Future investment decisions of other producers in the market.

Moreover, investors now face not only the traditional market challenges, but also additional uncertainties due to stricter climate policies and government interventions (Fuss et al., 2008). The transformations of the European electricity markets driven by policies aimed at reducing carbon emissions have led to decreased electricity prices and increased market volatility (Sinn, 2017). For instance, as intermittent RES such as wind and solar become more prevalent, the residual demand for conventional generation technologies that provide flexibility has become increasingly volatile and uncertain. During periods of high renewable energy production, the demand for conventional peaking technologies diminishes, leading to reduced capacity utilization.

Consequently, while government interventions are essential for meeting climate policy objectives, they introduce additional and heightened uncertainty. These uncertainties complicate investment decisions, particularly in peaking technologies, which have high marginal costs and are more vulnerable due to their low position in the merit order.

3.2. Investment decision making under uncertainty
3.2.1. Uncertainty in investment models
To make informed decisions regarding generation capacity investments under uncertainty, large-scale models that can encompass a wide range of operating conditions are necessary. The model should be capable of handling large-scale optimization problems, take a long-term perspective, and thus account comprehensively and carefully for uncertainty (Conejo et al., 2016). Conejo et al. (2016) visualizes this as follows in Figure 3.2:

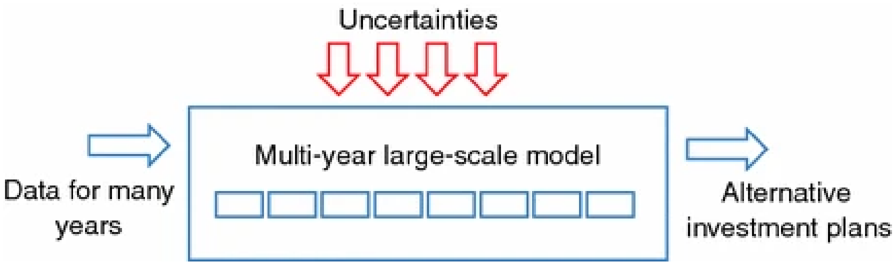

Figure 3.2: Long-term decision-making under uncertainty (Source: Conejo et al., 2016

When an investment is not a single decision but rather a multistage process where interventions occur sequentially at different points in time, a multistage decision framework can be applied. In this framework, decisions are made as uncertainty unfolds. According to Conejo et al. (2016), such a dynamic framework may be computationally intractable. Therefore, a simplified rolling-window approximate static framework could be used. In this framework, decisions are made at a given point in time, considering all future uncertainties but disregarding the fact that future investment decisions will be made afterwards. Figure 3.3 visualizes this framework.

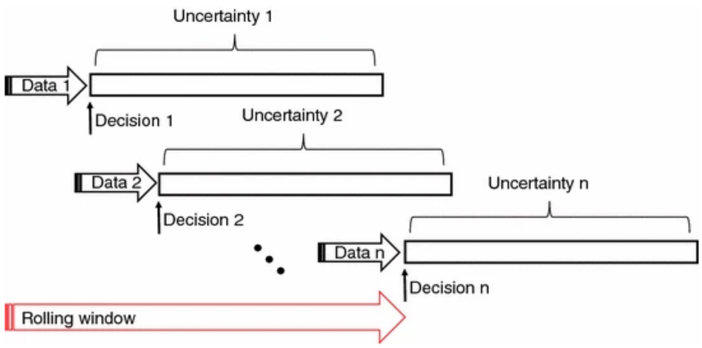

Figure 3.3: Long-term decision-making under uncertainty: rolling window single-stage framework (Source: Conejo et al., 2016

This framework aligns closely with the real option theory by Dixit and Pindyck (1994) that provides a framework for making investment decisions under uncertainty.

3.2.2. Advanced Approach: real options theory

Real options theory provides a framework for evaluating investment opportunities and treats investment decisions as options that can be exercised when conditions are favorable. This theory recognizes that investment decisions are often irreversible and made under high uncertainty. A real option gives the right, but not the obligation, to defer, abandon, or adjust a project in response to changing circumstances (Dixit & Pindyck, 1994).

A central principal of real options theory is the value of maintaining flexibility and delaying investment decisions until uncertainties diminish. At each decision point, stakeholders can choose to invest, delay, or abandon based on the latest available information. Thus, the approach emphasizes the intrinsic value of waiting and preserving flexibility in decision-making processes. In a volatile and unpredictable business environment, the ability to adjust strategies can be crucial for ensuring long-term corporate success (Dixit & Pindyck, 1994).

In the energy sector, real options theory is particularly relevant due to its focus on addressing uncertainties, managing irreversible investments, and considering the long lifecycle of energy assets (Glensk & Madlener, 2019). Therefore, as Gugler et al. (2020) argues, investments decrease with uncertainty, which is particularly relevant if investment decisions entail sunk costs, because the investment is irreversible and therefore future returns are uncertain.

Applying this theory to generation capacity investments implies that waiting to make investment decisions under uncertainty holds value, which can potentially lead to fewer investments compared to a scenario with less uncertainty.

3.2.3. Traditional approach: NPV and IRR

Where real options theory emphasizes flexibility and adaptability in decision-making under uncertainty, two widely used traditional capital budgeting methods focus solely on the expected profitability of the investment; the net present value (NPV) and the internal rate of return (IRR). The traditional methods NPV and IRR are the classic textbook examples of investment decision-making. Both methods are widely used, and both methods utilize the time value of money and evaluate an investment by discounting cash flow (Osborne, 2010). However, they both approach the evaluation differently.

A positive net present value implies that the rate of return on the investment is higher than the cost of capital, that is, higher than one could earn by investing in financial markets (Brealey et al., 2011). The following equation presents the calculation of the NPV.

$$\text{NPV} = \left(\sum_{t=1}^{k} \frac{\text{CashflowIn}_t - \text{CashflowOut}_t}{(1+\text{r})^t} \right) - I \tag{3.1}$$

where:

- t: Time (in years)
- k: The final time period
- CashflowIn_t: Incoming cash flow at time t
- CashflowOut_t: Outgoing cash flow at time t
- r: Discount rate
- I: Initial investment

On the other hand, the IRR is the discount rate that makes the NPV of all cash flows from a project equal to zero. It represents the rate of return at which the present value of future cash flows equals the initial investment. The internal rate of return rule is to accept an investment project if the cost of capital is less than the internal rate of return.

$$\text{NPV} = 0 = \left(\sum_{t=1}^{k} \frac{\text{CashflowIn}_t - \text{CashflowOut}_t}{(1+\text{IRR})^t} \right) - I \tag{3.2}$$

When the investment only includes cashflows at one time, the NPV and IRR rules will render the same ranking in results. However, with more complex investment decisions the two criteria can provide different rankings. A difference between rankings implies inconsistent recommendations about 'best project'. This inconsistency gives rise to an old debate in the literature about which criterion is superior. Regarding this thesis, this debate is not deemed relevant, but for the interested reader, the debate traces back to Dorfman (1981) who traces it back to Boehm-Bawerk (1889).

In the context of the electricity market the method of Boudt (2021) can be applied, who tested the theory on investments in generation capacity, under uncertainty. In this method the initial investment costs are calculated using the following equation:

$$I = \text{CAPEX} + \sum_{t=1}^{k} \frac{\text{FOM}}{(1+r)^{t-1}} \tag{3.3}$$

where:

- t: Time (in years)
- k: The final time period

- CAPEX: Initial capital expenditure
- FOM: Fixed annual Operation and Maintenance costs
- r: Discount rate

In Equation 3.3, Boudt (2021) incorporates the fixed annual operation and maintenance (FOM) costs into the initial investment. Both of these variables are considered to be certain fixed amounts. Only the FOM costs, which are annual, are discounted over time, while the capital expenditures are assumed to be incurred only at the start of the project.

Traditionally, in the equations for NPV and IRR, fixed costs are included in the cash outflows, while the initial investment consists solely of the investment costs. Boudt (2021), however, replaces these cash flows with inframarginal rent, which excludes the fixed costs that are already accounted for in the FOM costs as part of the initial investment (I). Instead, Boudt (2021) regards the inframarginal rent as representing only the total revenues remaining after subtracting the total variable costs, such as fuel and variable operation and maintenance costs. Incorporating this into Equation 3.2, the resulting question is as follows:

$$\text{NPV} = 0 = \left(\sum_{t=1}^{k} \frac{\text{Total Revenues}_t - \text{Total Variable Costs}_t}{(1+\text{IRR})^t} \right) - (\text{CAPEX} + \sum_{t=1}^{k} \frac{\text{FOM}}{(1+r)^{t-1}}) \tag{3.4}$$

Boudt (2021) argues that when solving for the IRR, the business case is considered viable when the IRR is higher than a hurdle rate. This hurdle rate is the sum of the weighted average cost of capital from an investor plus a hurdle rate premium that is specific to the technology the investor is assessing, and dependent on its risks and uncertainties.

Solve equation 3.4. for IRR, invest when:

$$\text{IRR} > \text{WACC}^* + \text{H}_{\text{techpremium}} \tag{3.5}$$

where:

- WACC^*: Weighted Average Cost of Capital of the investor.
- $\text{H}_{\text{techpremium}}$: Hurdle premium for the technologies considered.

Since the CAPEX and FOM costs are considered certain and fixed, uncertainties are only involved in the variables Total Revenues and Total Variable Costs that form the inframarginal rent. Boudt (2021) argues that the higher the uncertainties, the higher the hurdle premium, and thus the hurdle rate, to account for the project risk. Therefore, when uncertainties arise and the hurdle rate increases, the expected IRR must be higher before the business case is deemed viable. However, given that uncertainties do not have a known probabilistic function, the total revenues and total variable Costs are difficult to quantify.

To conclude, both in the real options theory and in the traditional IRR method extended with the hurdle rate approach, an investment is less likely to be made when uncertainties are present. The real option theory argues that there is value in waiting until the uncertainty diminishes, whereas the IRR hurdle rate approach demonstrates that the higher the uncertainties, the higher the projected IRR should be before an investment is made.

However, the total value of capacity that influences investment decisions and viability is derived from various value drivers. The following section presents a framework for these drivers.

3.3. Value drivers for capacity resources

The total revenue from capacity is not solely derived from sales in one market in one time frame, but also includes revenues from markets in different time frames, and other value drivers. The whitepaper by Zappa et al. (2024) analyzes the economic viability of capacity resources and presents a framework for assessing the full value that resources can generate. This framework evaluates various value drivers, including revenues from electricity markets at different timeframes, non-electricity-based revenues such as those from ancillary and balancing services, and other sources like capacity payments. Figure 3.4 visualizes the value drivers included in this framework.

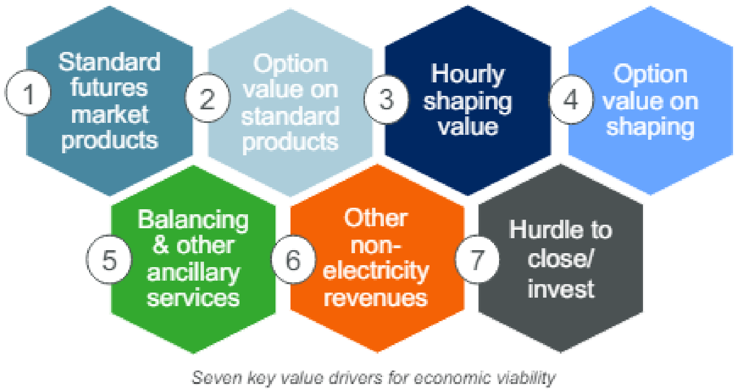

Figure 3.4: Key value drivers for economic viability of capacity resources (Source: Zappa et al., 2024)

Based on Zappa et al. (2024) the value drivers are summarized as follows (order is changed for better flow):

1 Intrinsic market value from standard products: this value is generated by selling electricity through futures contracts on the forward markets. These contracts allow power plants to secure revenue by delivering electricity at a predetermined price at a future date.

3 Intrinsic market value from hourly shaping: this value is achieved by optimizing electricity sales on the day-ahead and intraday markets. Power plants adjust their output to match hourly fluctuations in demand and prices to maximize revenue.

2 Extrinsic market value from standard products: this refers to the value derived from the ability to respond to changing market conditions by buying back electricity at lower prices when market spreads decline and reselling it when prices rise. This can create option value by exploiting market volatility through so-called 'asset-backed trading'.

4 Extrinsic market value from hourly shaping: similar to the extrinsic value from standard products, this value is derived from making strategic decisions in the day-ahead and intraday markets, such as adjusting bids to take advantage of short-term price movements.

5 Ancillary services & balancing: revenue from providing grid services like frequency regulation and balancing supply and demand.

6 Other revenues: this includes potential revenue from sources like capacity payments, which are payments for maintaining generation capacity that can be called upon when needed, rather than for actual electricity production.

Moreover, value driver number 7, the hurdle rate to close, refers to the hurdle rate approach discussed by Boudt (2021) in Section 3.2.3. Additionally, the whitepaper by Zappa et al. (2024) also identifies a hurdle rate for closing or mothballing power plants, which represents the opportunity cost of keeping a plant operational in the market.

Besides these value drivers that account for the full value of capacity resources, it is important to consider the influence of uncertainties on investment decisions, especially in the context of the ongoing energy transition. Therefore, the next section provides further insights into the uncertainties discussed in the literature that can impact investments in generation capacity.

3.4. Uncertainties considered in literature

A supplementary literature review is conducted to gain foundational knowledge about uncertainties regarding investments in electricity capacity and potential policy instruments that can mitigate these uncertainties. This review helps form an initial theoretical framework of uncertainty types and policy instruments to structure the thesis results. Applying the approach discussed in Appendix B, 12 articles are selected and reviewed. The following Table 3.1 provides an overview.

Table 3.1: Overview of studies on investment in renewable energy technologies and their methodologies

Article reference	**Technology to stimulate investment in**	**Considered uncertainties**	**Assessed policy instrument**	**Methodology**
Boffa et al. (2016)	VRES	• Carbon price uncertainty in economic factors and policy changes	• Feed-in tariffs & premia • EU ETS • Market Stability Reserve	Game-theoretic model
Ritzenhofen and Spinler (2016)	VRES	• Electricity price uncertainty • Regulatory uncertainty in changes in feed-in-tariff schemes and possible regime switching	• Feed-in-tariffs	Real option model with regime switching
de Weerdt et al. (2023)	Zero-emissions power plants	• Market uncertainty under policy regimes with (non-)binding emission targets	• Incentive payments • Penalties for emissions • Increasing emissions price	Real option model
Chronopoulos et al. (2016)	RE technologies with lumpy and stepwise investment	• Market uncertainty in electricity price fluctuations • Policy uncertainty in adjustments in subsidies	• Feed-in premium	Stochastic model
Sendstad and Chronopoulos (2020)	Sequentially improved RE technologies	• Technological uncertainty in arrivals of innovations • Policy uncertainty in provision or retraction of subsidies • Electricity price uncertainty	• Feed-in premium	Real option model with stepwise and lumpy investments

Continued on next page

Table 3.1 – *Continued from previous page*

Article reference	Technology to stimulate investment in	Considered uncertainties	Assessed policy instrument	Methodology
Zhang et al. (2014)	CCS retrofitting and CCS pre-investment	• Uncertainties in carbon price • Government incentives • Annual running time • Power plant lifetime • Technological improvements	• Capital cost subsidies • CO_2 utilization introduction • Carbon pricing	Real option model
Blyth et al. (2007)	Coal and gas power plants with CCS	• Climate policy uncertainty in carbon pricing	• Carbon pricing	Real option model
de Vries and Heijnen (2008)	Electricity generation capacity in general	• Growth rate of demand uncertainty	• Capacity payment • Operating reserves pricing • Capacity market (obligations and options) • Existence of market power	Stochastic dynamic model
Sun et al. (2023)	Energy storage systems	• Electricity price uncertainty • Policy uncertainty in subsidies	• Stable subsidies and potential adjustments in subsidies	Real option model

Boffa et al. (2016) assessed investments in VRES under the uncertainties of carbon price and economic factors. They utilized policy instruments such as Feed-in Tariffs (FIT), Feed-in Premia (FIP), European Union Emissions Trading System (EU ETS), and Market Stability Reserve (MSR). Their findings indicate that the reform of the EU ETS with the introduction of MSR necessitates a shift from FIT to FIP to maximize investment incentives in RES.

In another study, Ritzenhofen and Spinler (2016) evaluated VRES investments under electricity price uncertainty and regulatory uncertainty due to changes in feed-in-tariff schemes and possible regime switching. They used FIT as the policy instrument. The study concluded that RES investment projects under fixed FIT schemes become now-or-never decisions, with specific FIT thresholds needed to induce investment. Moreover, uncertainty about future regulatory regimes delays or reduces investment activity, especially when FIT levels are close to market prices and the likelihood of a regime switch is high.

Similarly, de Weerdt et al. (2023) explored investments in zero-emissions power plants under market uncertainty in different policy regimes with binding and non-binding CO_2 emission targets. Their research utilized incentive payments, penalties for emissions, and increasing CO-emission-allowance prices as policy instruments. They found that binding and credible policies with clear penalties for not meeting emissions targets are crucial in promoting timely investments. While incentive payments are somewhat effective, penalties for missing zero-emissions targets are more effective, and a steadily increasing CO_2-emission-allowance price most effectively accelerates investment.

Investigating renewable energy projects with lumpy and stepwise investment, Chronopoulos et al. (2016) examined the impact of market uncertainty in electricity price fluctuations and policy uncertainty in the provision or retraction of subsidies. They employed subsidies in the form of a fixed premium on top of the electricity price as the policy instrument. Their results showed that permanent subsidy retraction increases investment but lowers capacity, while provision decreases investment but raises capacity, with larger subsidies amplifying these effects. Despite higher subsidies, stepwise investment remains more valuable than lumpy investment due to more policy interventions reducing subsidy value and project size.

Sendstad and Chronopoulos (2020) analyzed investments in renewable energy technologies with sequentially improved versions. They analyzed the impact of technological uncertainty in the arrival of innovations, policy uncertainty in the provision or retraction of subsidies, and electricity price uncertainty. Using subsidies in the form of a fixed premium on top of the electricity price, their study found that higher chances of subsidy withdrawal decrease investment incentives. Contrasting stepwise and lumpy strategies, they revealed that stepwise adoption of technology mitigates subsidy uncertainty by promoting earlier technology uptake, especially under technological uncertainty, countering delays prompted by subsidy retraction.

In their analysis, Zhang et al. (2014) examined CCS retrofitting technologies and CCS pre-investment under uncertainties in carbon price, government incentives, annual running time, power plant lifetime, and technological improvements. They used capital cost subsidies, CO_2 utilization introduction, and carbon pricing as policy instruments. The results indicated that a large gap exists between the carbon price needed for CCS retrofitting of both typical types of power plants and current prices in the voluntary emission reduction market, even if the proportion of government subsidy reaches a significant level.

On the other hand, Blyth et al. (2007) focused on coal- and gas-fired power plants with CCS technologies under climate policy uncertainty in carbon pricing. Using carbon pricing as the policy instrument, their research showed that policy uncertainty increases the payoffs required to justify immediate investment in projects; the necessary investment thresholds increase with the proximity and magnitude of policy risk.

Exploring electricity generation capacity in general, de Vries and Heijnen (2008) investigated the growth rate of demand uncertainty using capacity payment, operating reserves pricing, capacity market (obligations and options), and existence of market power as policy instruments. They concluded that all capacity mechanisms reduce investment cycles. However, an oligopoly raising prices by 10% can stabilize prices and reduce shortages. This strategy may deter competition and affect consumers negatively. Reliability contracts are preferred for stabilizing investments and prices, reducing market power, and offering incentives to generating companies.

Finally, Sun et al. (2023) examined energy storage systems under electricity price uncertainty and policy uncertainty in subsidies. They employed stable subsidies and potential adjustments in subsidies as policy instruments. Their findings suggest that sequential investment strategies and stable subsidy policies are key to promoting early and efficient investment in energy storage projects, especially under the uncertainty of subsidy policies.

Additionally, two of the selected articles do not investigate the impact of policy instruments under uncertainty, but solely focus on studying the effect of the uncertainties on the system. In their concluding remarks, however, both studies do recommend policy instruments to mitigate the effects of these uncertainties on the system. The following Table 3.2 provides a short overview.

Table 3.2: Overview of studies on the impact of uncertainties on investment decisions in energy sources

Article reference	Technology to stimulate investment in	Considered uncertainties	Methodology	Policy recommendations
Pinho et al. (2018)	Conventional energy sources	Market uncertainty in demand, supply and intermittency	Game-theoretic model	Implementation of capacity mechanisms to stimulate investments in backup capacity to ensure a secure electricity supply
Gugler et al. (2020)	Electricity generation capacity in general	Uncertainty at industry level and firm-level	Econometric analysis at asset level	Two solutions: keep RES support which increases the need for capacity remuneration mechanisms, or foster a comparative EOM without external interventions with possibly high price spikes

The study by Pinho et al. (2018) evaluates the impact on investments in conventional energy sources, under market uncertainty in demand, supply, and intermittency resulting from VRES intergration. Utilizing a game-theoretic model, they find that integrating RES into the wholesale market reduces short-term electricity prices but raises long-term supply security concerns due to intermittency. They argue that firms might strategically lower prices to outcompete conventional sources, which affects incentives for investing in backup capacity. To counteract these challenges, the study proposes capacity mechanisms to encourage sufficient investment in backup capacity, to address market failure and ensure the security of supply.

Moreover, Gugler et al. (2020) researches investments electricity generation capacity under uncertainty at both the industry level and the firm level, using econometric analysis at the asset level of 13 European countries. They find that asset-specific uncertainty hinders investment in conventional technologies, especially in peak-load assets. Interestingly, the study also reveals that industry-level uncertainty can sometimes trigger investment. However, to address the negative impacts of uncertainty, the study proposes two potential solutions: continue support schemes for renewable electricity, where the implementation of capacity remuneration mechanisms becomes more pressing but may potentially distort the market dynamics, or foster competition in the energy-only market without external interventions, which will include high price spikes.

3.5. Theoretical framework

In theory, a static optimal level of investment in electricity generation capacity is achieved when social welfare is maximized (Ventosa et al., 2013). The centralized planning model, constructed by Ventosa et al. (2013), demonstrates that this social welfare is maximized when a central planner identifies the optimal mix of generation technologies to minimize the total costs of power supply and energy not served. This static optimization approach assumes a known load duration curve and cost functions for various technologies, leading to a theoretically operational efficient allocation of resources.

Similarly, the spot pricing theory by Caramanis (1982) shows that in a market with real-time pricing based on marginal costs, individual profit-maximizing behaviors align with socially optimal outcomes. In this theory, real-time price signals ensure that market participants' investment decisions reflect the social optimum, achieving operational efficiency dynamically.

However, in practice, electricity and investments in generation capacity exhibit specific characteristics that narrow the investment optimum. Electricity cannot be efficiently stored and requires real-time balancing of supply and demand, which necessitates a robust transmission grid (Ventosa et al., 2013). Moreover, investments in generation capacity are capital-intensive, and, combined with the homogeneous nature of the produced electrons, this can lead to investment booms and busts (Roques et al., 2005). Additionally, the long lead times and operational lifespans of 30 to 50 years entail that investments have long-term impacts on the system (Conejo et al., 2016). Furthermore, various market failures and imperfections, as noted by de Vries (2004) and Hobbs et al. (2001), further complicate achieving the narrow investment optimum: price restrictions, imperfect information, risk aversion, regulatory uncertainty and restrictions, risk asymmetry, and market power.

Currently, amid the ongoing energy transition, the electricity system is undergoing significant changes driven by regulatory influences aimed at mitigating the externalities of emissions. This transition introduces additional uncertainties and exacerbates the challenges already present in investment decision-making.

Under uncertainty, the real options theory, as proposed by Dixit and Pindyck (1994), argues that there is value in waiting till uncertainties are diminished. This theory emphasizes the importance of maintaining flexibility in decision-making processes, especially in a volatile and unpredictable environment like the energy sector, which knows irreversible investments and long life cycles of the assets (Glensk & Madlener, 2019).

In contrast, traditional investment evaluation methods such as the NPV and IRR, focus on expected profitability. To account for uncertainties and risks, the extended IRR method by Boudt (2021) incorporates a hurdle rate with a risk premium to account for uncertainties specific to the technology of the investment under consideration. This approach argues that as uncertainties increase, the hurdle rate increases to justify an investment. Thus, higher uncertainties necessitate higher projected returns on investment to make the investment viable. In this thesis, the following reasoning is adopted, adapted from Boudt (2021):

- If uncertainties impacting inframarginal rent (i.e., total revenues minus total variable costs) are mitigated, ceteris paribus, the hurdle rate decreases.
- If total revenues increase, ceteris paribus, the IRR increases.
- If variable costs increase, ceteris paribus, the IRR decreases.
- If the ratio IRR to the hurdle rate increases (for IRR > 0), the investment becomes relatively more viable.

In addition to these theoretical considerations, the framework proposed by Zappa et al. (2024) addresses value drivers that account for the total revenue that can be derived from capacity. These value drivers include: intrinsic market value from standard future products and hourly shaping; extrinsic market value from option value on standard products and shaping; and values derived from balancing and other ancillary services, as well as extra revenues and hurdles related to closing or investing.

Moreover, in reviewing literature on investments under uncertainty in renewable energy technologies, it becomes evident that a broad range of uncertainties are assessed across various studies. These uncertainties provide preliminary insights into the uncertainties that could potentially obstruct investment in practice. However, due to the varying levels of detail in how these uncertainties are assessed in literature, they are categorized in types to offer a preliminary structure for addressing the results of the first sub-question of this thesis. Table 3.3 below organizes these uncertainties into three primary types: electricity market uncertainty, regulatory uncertainty, and technological uncertainty.

Table 3.3: Categorization of uncertainty types assessed in current literature

Uncertainty Type	Uncertainty	References
Electricity Market Uncertainty	Electricity price uncertainty	Ritzenhofen and Spinler (2016), Chronopoulos et al. (2016), Sun et al. (2023)
	Carbon price uncertainty	Boffa et al. (2016), Zhang et al. (2014), Blyth et al. (2007)
	Annual running time and power plant lifetime uncertainty	Zhang et al. (2014)
	Growth rate of demand uncertainty	de Vries and Heijnen (2008)
	Electricity demand, supply and intermittency uncertainty	Pinho et al. (2018)
Regulatory Uncertainty	Changes in FIT schemes and regime switching uncertainty	Ritzenhofen and Spinler (2016)
	Subsidising policy uncertainty	Chronopoulos et al. (2016), Sendstad and Chronopoulos (2020), Sun et al. (2023)
	Policy regimes with (non-)binding emission targets uncertainty	de Weerdt et al. (2023)
Technological Uncertainty	Innovation uncertainty	Sendstad and Chronopoulos (2020), Zhang et al. (2014)
Non specified uncertainty	Firm and industry level uncertainties	Gugler et al. (2020)

4 Methodology

This chapter discusses the methodology applied in this thesis. First, Section 4.1 outlines the overall design of the research. Thereafter, Section 4.2 argues the selection of interviewees, and Section 4.3 outlines the interview guide applied. Subsequently, Section 4.4 discusses the data collection and Section 4.5 the data analysis. Lastly, the ethical considerations are discussed in Section 4.6.

4.1. Research design

The main objective of this thesis is to identify and assess policy instruments that stakeholders and experts deem effective for incentivizing investments in firm carbon-free dispatchable electricity generation capacity, while also considering the 2035 sustainability aim, and the reliability and affordability of the system. Additionally, this thesis aims to understand and explain differences in these perceptions. To address this objective, a qualitative exploratory and explanatory approach has been applied. This approach is particularly suited for addressing this complex and context-specific subject, as it enables the exploration of nuanced and subjective perspectives of stakeholders and experts, that quantitative approaches might lack. Finally, the explanatory element allowed for further analysis to explain differences in perceptions and contextual influences (Ritchie et al., 2003).

The data collection methodology employed semi-structured interviews with a non-random sampling strategy of stakeholders and experts. According to Alshenqeeti (2014), interviews as a data collection method offer rich, and context-sensitive data, making them useful in qualitative research where understanding nuance, and complexity is crucial. The interactive nature of semi-structured interviews allows for understanding personal experiences and opinions that can provide insights that might have been inaccessible through other qualitative methods like surveys or observations (Alshenqeeti, 2014).

Given the aim of exploring stakeholder and expert perceptions, the application of Q-methodology was also considered due to its ability to identify clusters of subjective thoughts through factor analysis (Exel & Graaf, 2005; Stephenson, 1993). However, Q-methodology, while effective in identifying common patterns of thought, does not capture the rich, narrative detail necessary to fully understand why specific perceptions are held (Brown, 1993). This level of detail is crucial for addressing the nuanced and context-specific nature of perceptions in this thesis. Therefore, while Q-methodology could identify general clusters of opinion, it would not provide the depth of insight required for this research. Instead, semi-structured interviews were adopted.

However, Alshenqeeti (2014) also highlights the disadvantages of conducting interviews. Interviews can be time-consuming, and the quality can depend on the interviewer's knowledge and the participant's willingness to share openly. Moreover, interviews may introduce bias as respondents' answers can be influenced by the framing of the interviewer's questions or by participants tailoring their responses to align with perceived expectations. To mitigate these challenges, the semi-structured interview manual by Kallio et al. (2016) has been applied.

Details of the application of the interview guide, as well as the research flow diagram, visualized in

Figure 4.1, are further addressed in the following sections.

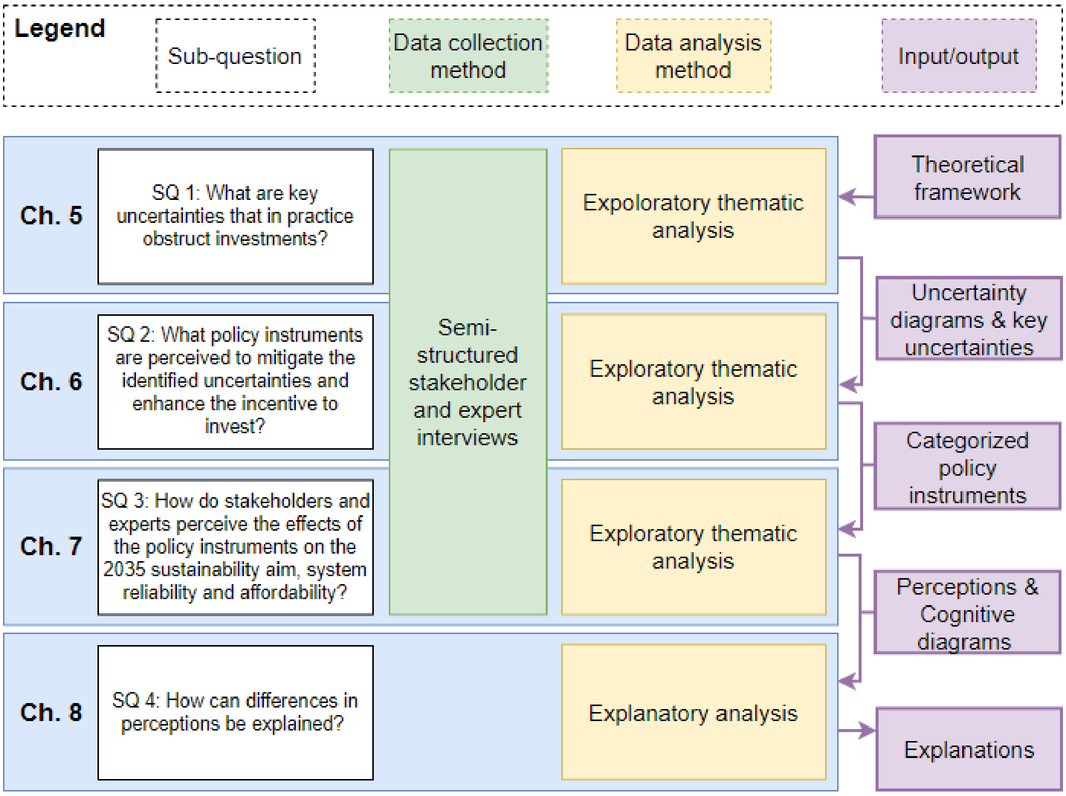

Figure 4.1: Research flow diagram

4.2. Interviewee selection

The sampling strategy for selecting interviewees adopted a non-random approach. This strategy was chosen to ensure that the study captures data from stakeholders and experts involved in or impacted by policy instruments for incentivizing investments in firm carbon-free dispatchable electricity generation capacity. This approach allows for the exploration of perceptions that could be influenced by the specific roles, backgrounds, and knowledge stakeholders and experts have regarding the electricity system.

To preserve anonymity, the interviewees have been grouped and addressed by type. Table 4.1 presents these types and number of stakeholders and experts interviewed.

Table 4.1: Number of interviews by stakeholder or expert type

Type of stakeholder or expert	Number of Interviews	Method
Electricity generation companies	4	
(Semi-)governmental organizations	5	
Research institutes	3	Semi-structured interviews
Environmental organization	1	applying guide by Kallio et al. (2016)
Financial expert	1	
Total	**14**	

Given that the objective of this thesis concerns the effectiveness of policy instruments on the electricity system, five interviewees were selected from various (semi-)governmental organizations. These interviewees play roles in the field of policy-making and the regulation of the electricity market and hold crucial insights from their involvement.

Additionally, four interviews were conducted with stakeholders from electricity generation companies who are either involved in investment decisions or regulatory matters. Their insights are crucial for understanding the practical challenges and effects of policy instruments on investments and the system.

Three interviews were also held with experts from research institutes who possess broad knowledge of electricity market dynamics, technological implications, and policy impacts. Their insights help to balance the understanding of the problem field.

Furthermore, one interview was conducted with a stakeholder from an environmental organization to incorporate additional insights on sustainability in the electricity sector. Lastly, one interview was conducted with a financial expert involved in the electricity markets to balance potentially biased views regarding investment decisions.

4.3. Interview guide

The interviews were set up by applying the semi-structured interview manual by Kallio et al. (2016). This guide contains five steps. First, the appropriateness of the semi-structured interview as a rigorous data collection method was assessed; according to Barriball and While (1994), semi-structured interviews are suitable for studying perceptions and opinions or complex issues, which aligns closely with this thesis objective. Second, prior knowledge of the research field was gathered by conducting a problem analysis, a literature review, and constructing the theoretical framework, presented in Chapters 1, 2 and 3, respectively. Third, a preliminary interview guide was developed and, fourth, reviewed with the thesis committee. The finalized guide is presented in Appendix C. The central questions that align with the first three sub-questions are as follows:

- How are investment decisions in (carbon-free) dispatchable generation capacity made in practice?
- What are uncertainties and challenges for investment decisions in carbon-free dispatchable generation capacity?
- What policy instruments can mitigate the previously discussed challenges and incentivize investments?
- What are the effects of the policy instruments on the electricity system, and what criteria should the policy instruments adhere to?

4.4. Data collection

The interviews were conducted in person when possible to facilitate a more direct and nuanced interaction. However, eight were conducted online utilizing Microsoft Teams. All interviews were conducted in Dutch. Additionally, all interviews were recorded and transcribed via Microsoft Teams. The duration of the interviews was approximately 60 minutes to allow for an in-depth exploration of the interviewee's insights. The central questions, paired with the consent form presented in Appendix C, were sent to the interviewees a few days prior to the scheduled interview to provide the interviewees time to prepare if needed.

4.5. Data analysis

To address the first three sub-questions, an exploratory thematic analysis approach was employed. This method is particularly suitable for identifying, analyzing, and reporting patterns or themes within qualitative data. As noted by Braun and Clarke (2006), "a theme captures something important about the data in relation to the research question and represents some level of patterned response or meaning within the data set." Since understanding perceptions is central to this analysis, a realist thematic approach was utilized. According to Braun and Clarke (2006), this realistic approach enables the reporting of patterns related to experiences, meanings, and participants' perceived realities. Therefore, it aligns well with the research objective.

The coding process was carried out using ATLAS.ti, following the steps suggested by Braun and Clarke (2006). First, the transcripts were read through multiple times to become familiar with the data. Subsequently, initial codes and resulting themes were identified. After this initial phase, the identified themes were further reviewed and refined to produce the final output. The initial codes for sub-questions one and two were developed through abductive reasoning based on the theoretical framework. In contrast, the coding for the third research question was established inductively from the data, utilizing the findings from the previous sub-questions. The final codes are presented in Tables 4.2, 4.3, and 4.4, for sub-questions 1, 2, and 3, respectively.

Codes sub-question 1	Description
Investment Decision	General aspects of investment decisions.
Electricity Market Uncertainty	Uncertainties related to electricity market dynamics.
Regulatory Uncertainty	Uncertainties related to changes or unpredictability in regulations.
Technological Uncertainty	Uncertainties regarding the advancements of new technologies.
External Uncertainty	Uncertainties from external factors, such as weather.
Economic Uncertainty	Uncertainties related to economic conditions, such as GDP growth.

Table 4.2: Codes and descriptions for data analysis sub-question 1

Codes sub-question 2	Description
Subsidizing Policy Instrument	Instruments providing financial support.
Regulating Policy Instrument	Instruments designed to regulate factors such as emissions.
Pricing Instrument	Instruments impacting prices of goods.
Facilitating Instrument	Instruments facilitating usage or investment.
Capacity Remuneration Mechanism	Mechanisms designed to compensate available capacity.

Table 4.3: Codes and descriptions for data analysis sub-question 2

Codes sub-question 3	Description
Objective	Objectives for policy instruments effects or system outcome.
Effect of CAPEX Subsidy	
Effect of Operational Subsidy	Effect on electricity system;
Effect of Strategic Reserve of Capacity	sustainability, reliability, and affordability.
Effect of Other CRMs	
Additional Effect	Any other related effects.

Table 4.4: Codes and descriptions for data analysis sub-question 3

After addressing the first three sub-questions with exploratory thematic analysis, the fourth and final sub-question was addressed using an explanatory analysis. Explanatory analysis allows for examining the reasons why patterns in data are found (Ritchie et al., 2003). Given the aim of this thesis to explain differences in perceptions of effects, adopting an explanatory approach is particularly appropriate. However, Ritchie et al. (2003) does highlight the challenge of qualitative explanatory analysis as it can be bottomless. To address this challenge, a selection of contrasting perceptions was analyzed to identify underlying explanations of differences.

Finally, after completing the data analysis, the resulting themes for each sub-question were presented as the output of the representative chapter. For the first sub-question, the output consists of patterns in uncertainties per investment possibility, which are visualized through diagrams. The resulting key uncertainties are extracted from these patterns. For the second sub-question, the output features the explored policy instruments categorized by their perceived effectiveness in addressing decarbonization, reliability, or both simultaneously. The instruments that are perceived to stimulate both decarbonization and reliability are included in the following chapters. For sub-question three, the patterns resulting from exploratory analysis are presented on axes of the overall perception of effectiveness per policy instrument per interviewee. In addition, the common lines of reasoning regarding perceived favorable and unfavorable effects of the policy instruments are combined and presented using cognitive diagrams. The resulting differences in perceptions are utilized as input to answer the final question that present possible explanations for differences in perceptions. The final column in Figure 4.1 visualizes these inputs and outputs for each sub-question.

4.6. Ethical considerations

Throughout and after this research process, ethical considerations are in accordance with the Human Research Ethics and Consent application of the TU Delft. Informed consent is obtained from all respondents before starting the interview. Their confidentiality and privacy will be protected, and personal information will only be known by the author and TU Delft graduation committee. The data presented in this thesis is aggregated on such a level that confidentiality of their specific business information is ensured. The recordings and transcripts are stored on the TU Delft personal OneDrive of the author for a maximum of one month after publication of this thesis in the TU Delft Education Repository.

5 Uncertainties of investments

This chapter presents and analyzes the results derived from the interviews, with the aim of identifying the key uncertainties that obstruct investments in carbon-free firm dispatchable electricity generation capacity. Central to this chapter is the first sub-question: *What are key uncertainties that in practice obstruct investments?*

To address this question, Section 5.1 presents the interview results concerning the uncertainties. Subsequently, Section 5.2 provides a synthesis.

5.1. Results: uncertainties

This section presents the results of stakeholder and expert interviews regarding the uncertainties encountered in decision-making for investments in firm carbon-free dispatchable electricity generation capacity. The central questions posed during the interviews to obtain the data were as follows: ”How are investment decisions in (carbon-free) dispatchable generation capacity made in practice?” and ”What are current uncertainties and challenges for investment decisions in carbon-free dispatchable generation capacity?”

As discussed in the previous chapter, the data from the interviews were analyzed using an exploratory approach to identify and understand the uncertainties impacting investment decisions. Thematic analysis was applied to code and group the data into two primary themes: uncertainty types and groups of uncertainty factors. Uncertainty types categorize the identified factors, while groups of uncertainty factors reflect key influences on the revenues or variable costs associated with investment possibilities. Both themes were examined through abductive reasoning, utilizing the theories from Chapter 1 and the theoretical framework in Chapter 3 as starting points.

The previously discussed theory revealed that the most relevant technologies for achieving firm carbon-free electricity generation capacity in the Netherlands include retrofitting existing gas power plants to hydrogen power plants, building new hydrogen power plants, or retrofitting gas power plants with post-combustion CCS. However, the interviewees highlighted that post-combustion CCS technology cannot capture all carbon emissions, necessitating compensation for residual emissions to achieve carbon neutrality. Additionally, some interviewees suggested that instead of retrofitting, solely compensating for emissions could be a viable alternative.

Consequently, the results focus on uncertainties associated with the following investment possibilities:

- Retrofitting existing gas plants to hydrogen or building new hydrogen gas power plants.
- Retrofitting with CCS and compensating for residual emissions.
- Not retrofitting but solely compensating for emissions.

Moreover, the theoretical background established three uncertainty types: electricity market uncertainty, regulatory uncertainty, and technological uncertainty. Based on the interview data, three additional uncertainty types were found, that were not covered in the reviewed literature: hydrogen market uncertainty, economic uncertainty, and external uncertainty.

The thematic analysis of interview data identified patterns in how uncertainties influence revenues and variable costs, which, in turn, affect the inframarginal rent of power plants, as discussed in the theoretical framework. This analysis led to the grouping of uncertainty factors that impact investment possibilities. Diagrams have been created to structure and visualize these patterns and their influences. The final themes, which provide insight into the key uncertainties, are discussed in the analysis and synthesis sections.

Reading guide for uncertainty diagrams
The diagrams visualize the identified uncertainty factors and their influences on other uncertainty factors, eventually influencing the revenues and variable costs of the possible investment. Arrows in the diagrams indicate a influence of one uncertainty factor on another. Higher positions in the diagram thus represent higher levels of aggregation. However, this does not necessarily mean that an uncertainty with a higher aggregation level has a greater impact on revenues or variable costs. Additionally, the dotted lines around groups of uncertainty factors show their structuring, as indicated by the text or mathematical symbols within these areas.

The uncertainty factors are grouped into the six identified types and color-coded accordingly. These color codes are illustrated in Figure 5.1 and utilized as a legend in the diagrams.

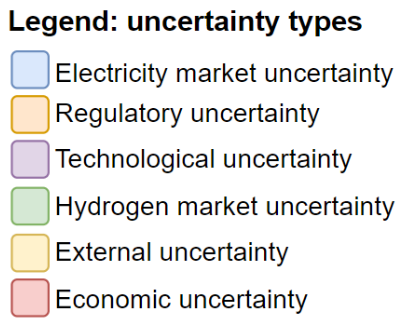

Figure 5.1: Uncertainty types color coding legend

The following structure is adopted: Subsection 5.1.1 presents the uncertainties impacting the revenues after an investment, which are consistent for all three investment possibilities. Subsequently, Subsection 5.1.2 presents the uncertainties affecting the variable costs for both retrofitted and new-build hydrogen power plants. Last, Subsection 5.1.3 presents the uncertainties impacting the variable costs of gas power plants, both with and without retrofitting the power plant with post-combustion CCS and compensation for (residual) emissions.

5.1.1. Uncertainties in revenues

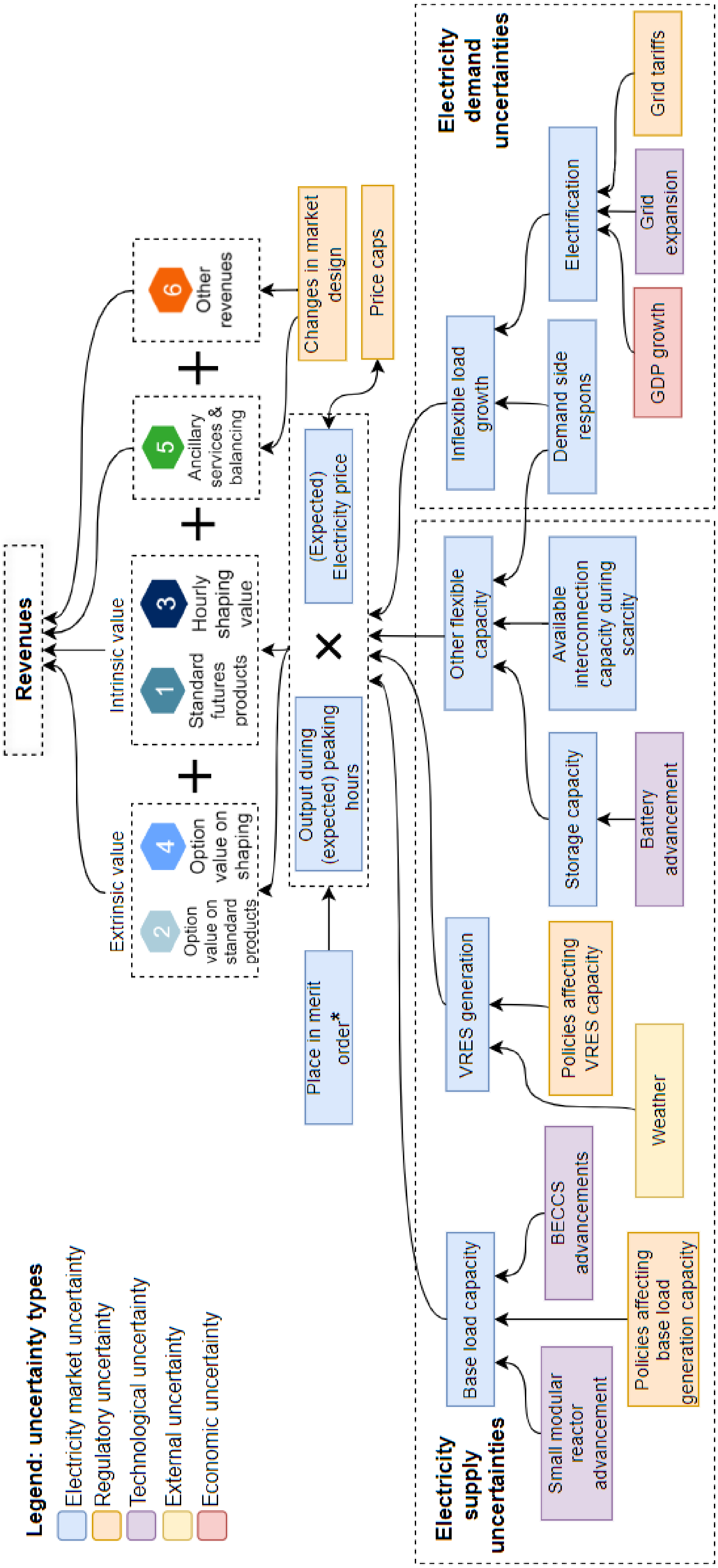

Figure 5.2: Uncertainties impacting total revenues

* Place in merit order is influenced by uncertainties in operational costs as depicted in the following sections.

For all relevant investment possibilities, the uncertainties influencing the revenues are visualized in Figure 5.2. The revenues are influenced by key value drivers identified in the economic viability analysis by Zappa et al. (2024), as addressed in Section 3.3 of the theoretical background. The value driver for the hurdle rate is excluded from consideration since the identified uncertainties partially form the height of the hurdle rate when regarding the theory from Boudt (2021). These key value drivers include; intrinsic value drivers, extrinsic value drivers, value drivers from ancillary services and balancing, and other non-electricity revenues. As visualized in Figure 5.2, these drivers are all impacted by various uncertainty factors. Therefore, all of the value drivers are deemed uncertain as well. Each factor is addressed per structured area within the dotted lines, moving from the bottom to the top of the conceptual model and following the direction of the arrows. Finally, the value drivers impacting the revenues are addressed.

Electricity demand uncertainty
Based on the interviews conducted, the demand for electricity that is met by dispatchable generation capacity is considered uncertain. One factor influencing this uncertainty is the unpredictability of inflexible load growth that contributes to peak demand. This uncertainty in inflexible load growth stems from factors related to electrification and demand-side response (DSR). The uncertainty regarding electrification is influenced by GDP growth, possibilities for grid expansion, and grid tariffs.

First, the uncertainty about grid tariffs makes it difficult to predict their impact on electrification. High grid tariffs may deter the adoption of electric technologies. Interviewees noted that unpredictable tariff policies contribute to overall uncertainty in estimations of electrification efforts. Second, uncertainties regarding grid expansion were frequently mentioned. If the grid does not expand sufficiently or if congestion issues are not resolved, these factors could pose significant barriers to electrification. Third, while GDP growth is considered somewhat more stable than other factors, it still introduces uncertainty that impacts electrification predictions.

Despite the theoretical expectation of a significant rise in electrification, interviewees observe that this trend is less visible in practice. However, it is agreed that if electrification increases this will lead to increased electricity demand. Nevertheless, this potential increase in demand might be partially addressed by DSR measures, such as industries adjusting their load in response to price signals. However, the future development of DSR are also regarded as uncertain. Consequently, the increased electricity demand that cannot be met by DSR is referred to as inflexible load growth and is considered a factor of uncertainty.

Electricity supply uncertainty
On the other hand, electricity supply is also subject to uncertainty. The uncertainty factors influencing the electricity supply can be separated into uncertainties about the base load capacity, VRES generation, and 'other flexible capacity' which is further explained below.

According to the interviews, uncertainties regarding base load capacity arise from several factors, including advancements in small modular reactors, developments in BECCS, and policies affecting base load generation capacity. First, interviewees indicated that small modular reactors, as an emerging technology, have the potential to reduce the need for firm dispatchable generation capacity in the future by supplying part of the base load. However, the uncertainties surrounding the development and deployment of small modular reactors complicate predictions about their impact on base load capacity. Second, advancements in BECCS are also considered potentially influential for base load capacity. Their future market role remains speculative, as BECCS technologies could potentially primarily operate based on the price of negative emissions rather than the electricity market price and their position in the Merit Order. Finally, policies that impact base load generation capacity are identified as a source of uncertainty. For instance, the "Hoofdlijnenakkoord" (*General Agreements*) in the Netherlands outlines plans for new nuclear plants to enhance firm base load capacity. Nevertheless, the unpredictability of such policies, influenced by political changes and evolving energy priorities, complicates future projections of base load capacity.

Uncertainties regarding VRES generation are primarily influenced by policies affecting VRES capacities and by weather conditions. First, existing policies, such as the 'salderingsregeling' (net metering policy), as well as potential future policies, contribute to the uncertainty in predicting trends in VRES capacity. The variability in future policy introduces challenges in forecasting the development and deployment of VRES technologies. Second, the inherently intermittent nature of solar and wind energy leads to volatility in VRES generation. This intermittency results in uncertainties over both short-term and long-term generation patterns, complicating the forecasting of VRES output.

The uncertainties regarding other sources of flexible capacity, beyond what dispatchable generation capacity can provide, stem from demand-side response, storage capacity, and interconnection capacity during periods of scarcity. First, interviewees highlighted that the development of storage capacity is influenced by the uncertain future viability of battery technologies. If advancements in storage capacity, duration, and economic viability lead to increased market penetration of batteries, they could potentially provide the flexibility currently expected from hydrogen or gas power plants. Second, uncertainties persist about future interconnection capacity and its availability during simultaneous scarcity events. For example, if both the Netherlands and Germany experience electricity shortages, importing electricity might not be feasible despite existing interconnections. Moreover, further integration of the European market could reduce the need for peaking capacity from hydrogen and gas plants, as a larger geographical area could provide balancing more economically. These factors collectively contribute to the uncertainty surrounding flexible capacity sources.

Market value uncertainty
The uncertainties surrounding inflexible load growth, base load capacity, VRES generation, and other flexible capacity influence the expected output during operating hours of hydrogen or gas power plants. If the inflexible load increases due to electrification efforts that cannot be shifted during peak demand, this could increase the expected operating hours of peaking plants. Conversely, an increase in base load capacity reduces the expected operating hours of peaking power plants by consistently meeting a portion of electricity demand. Additionally, an increase in VRES generation can lead to a more volatile electricity supply, increasing the demand for flexibility technologies. However, this demand for flexibility does not solely rely on dispatchable generation capacity; other flexible capacity options such as storage technologies, interconnection availability, and DSR could potentially answer this demand.

Moreover, the placement of a peak power plant in the merit order impacts expected peaking operating hours. For example, if a new peaking plant with higher efficiency, thus lower marginal cost, enters the market and is therefore placed earlier in the merit order, this plant would respond to demand first before the plant with the higher marginal cost operates. This also relates to the increase in marginal cost if a producer decides to invest in carbon-free technology. This is addressed in the next section.

Additionally, the uncertainty factors affecting both supply and demand not only impact expected peaking operations, but also influence electricity prices in the market. During periods of peak demand or supply shortages, electricity prices increase, and price spikes can occur. Uncertain market dynamics, particularly due to variable VRES generation, contribute to generally lower and more volatile electricity prices that depend on real-time weather situations. This makes it challenging for dispatchable generation capacity to secure positive spread in future markets. Moreover, as operating hours are expected to decline, price spikes must be more extreme to cover the fixed costs and investment costs of the peaking capacity within a similar timespan. However, the frequency and magnitude of such spikes remain highly uncertain due to various discussed factors. It is unpredictable whether extreme price spikes will occur next year, in 10 years, or in 15 years, for example due to prolonged cold periods with low supply from VRES. Besides, in the event of a price spike, there is regulatory uncertainty surrounding the potential implementation of price caps. However, some interviewees only see this uncertainty in the context of generally high prices over extensive periods, rather than during extreme price spikes. Nevertheless, any form of price cap would significantly impact the business model of peaking plants, as high prices and price spikes are crucial for covering investment and fixed costs.

In conclusion, interviewees generally expect a decline in peaking operating hours combined with more volatile operational needs. However, the extent of this decline and volatility is highly uncertain and unpredictable, particularly when combined with the increased volatility of electricity prices and potential price spikes. This uncertainty is further heightened by the long lifespan of peaking power plants, which could be extended if these plants operate less frequently. An extended lifespan would also require the need for longer-term projections in decision-making, which inherently involves more uncertainty.

Considering the uncertainties surrounding expected operating hours and electricity prices, it's evident that the revenue is inherently uncertain. However, since the electricity market operates across multiple time segments, where revenue depends not only on electricity sold at a specific moment, but also across various market periods, an additional layer of complexity further contributes to the uncertainty in revenues. This will be addressed in the following paragraphs regarding the value drivers.

Intrinsic and extrinsic market value uncertainty
The uncertainty in expected operating hours and electricity prices impacts the intrinsic market value drivers of a power plant. The intrinsic market value refers to the revenue a power plant can generate by selling its output on the different electricity markets over time. This value includes two main components; first, the standard futures products (number 1 in Figure 5.2) can generate revenue from selling electricity through futures contracts on future and forward markets. These contracts involve delivering electricity at a future date for a predetermined price. Second, the hourly shaping (number 3 in Figure 5.2) can generate additional revenue obtained by optimizing electricity sales on the day-ahead and intraday markets. This involves adjusting sales based on hourly fluctuations in electricity demand and market prices, maximizing revenue beyond what is secured through futures contracts.

Similarly, extrinsic value, also known as optionality value, adds another dimension of revenue derived from future price fluctuations. Flexible power plants can strategically sell electricity when prices are high and buy back when prices are low. Thereby, they can exploit market volatility resulting from future price movements and market conditions. This optionality value can be derived both from the futures market, known as option value on standard products (number 2 in Figure 5.2), and closer to real-time on the day-ahead and intraday markets, referred to as option value on shaping (number 4 in Figure 5.2).

In contrast to the conventional market, where generators secured part of their returns through futures and forward markets, the current transition and increased dependence on VRES necessitate greater reliance on markets closer to real-time. Interviewees emphasize that the current negative spreads in future and forward markets, and the dependence on real-time markets increase uncertainty, as it becomes more difficult to lock in returns in advance. The impact of this dynamic on the extrinsic value has not been addressed in this stage of the research. However, future studies are encouraged to explore this area further, as especially the extrinsic value remains relatively under-researched according to interviewees from other stakeholder types than the generating companies themselves.

Ancillary services & balancing, and other revenues uncertainty
Another stream of revenue can be derived from revenues related to ancillary services, balancing, and other revenue drivers. Interviewees consistently highlighted the regulatory uncertainty surrounding potential changes in policies and market design. A key point of concern was the uncertainty regarding other revenues, which refers to payments for having generation capacity available, rather than solely receiving payments from actual electricity production. Currently, in the Netherlands, producers do not receive payments for capacity availability since the country operates on an energy-only market model where revenue is generated from actual electricity sales. However, many European countries have implemented capacity remuneration mechanisms, and interviewees noted that this topic is under consideration in the Netherlands as well. Despite this, opinions on the need for such mechanisms vary widely, and many forms of these mechanisms exist, making it uncertain for producers to take such revenues into account when assessing investment possibilities.

5.1.2. Uncertainties in variable costs: hydrogen power plant

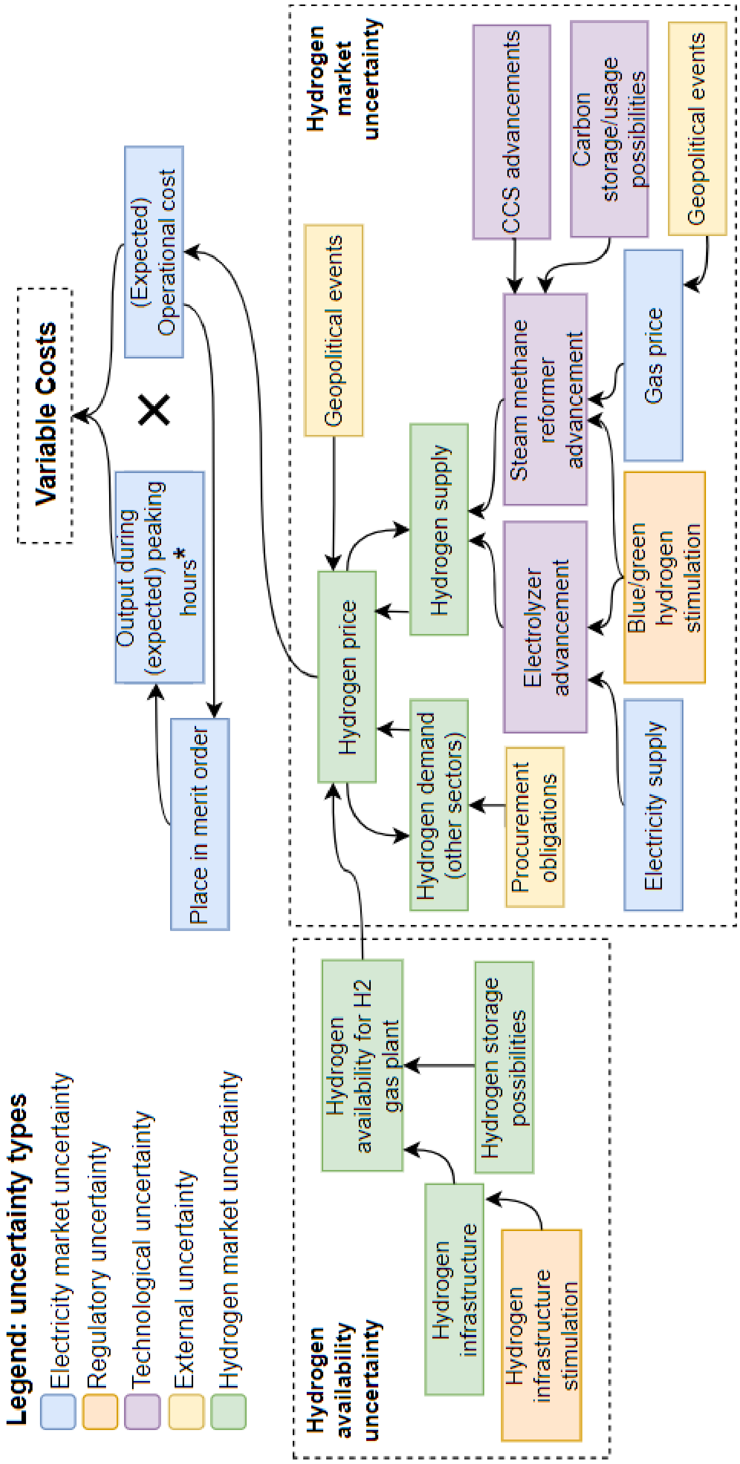

Figure 5.3: Uncertainties for hydrogen power plant impacting variable costs
* Output during expected operating hours is influenced by the uncertainty factors as similarly depicted for the revenue uncertainties.

The uncertainties impacting the variable costs of both retrofitted and new-build hydrogen power plants are visualized in Figure 5.3. The uncertainty factor regarding the output during expected peaking hours is similar to the previous conceptual model of the uncertainty factors impacting variable costs. Here, the asterisk (*) indicates that all the uncertainties presented in the previous section play the same role. Additionally, the place in the merit order is the same uncertainty factor as before. However, it is visible here that the uncertainty about the place in the merit order is influenced by the expected operational cost, which is also regarded as uncertain and influenced by other uncertainty factors. These uncertainty factors will again be addressed per structured area within the dotted lines.

Hydrogen market uncertainty
The uncertainty regarding the expected operational costs for retrofitted and new-build hydrogen plants are mainly impacted by the uncertainty about the hydrogen price, which is in turn influenced by supply and demand. The interviewees addressed that uncertainty in demand primarily stems from the uncertain future demand for hydrogen from other sectors. The interviewees referred to the ”hydrogen ladder,” where hydrogen use for power generation ranks lower in priority for effective and sustainable applications. A future increase in demand from higher-priority sectors could drive up hydrogen prices. Uncertainty about future changes in obligations for hydrogen blending in other sectors, like the industry, affects demand and consequently hydrogen prices. However, this could also lead to a more liquid green hydrogen market in the long run, as high demand attracts more supply through market dynamics.

The supply of green hydrogen involves different technologies compared to blue hydrogen. Green hydrogen is produced using electrolyzers, which are powered by RES such as solar and wind when supply is high and prices are low. However, since RES supply is volatile and uncertain, electrolyzers need to be flexible. Interviewees pointed out uncertainties not only in the technical advancements of flexible hydrogen supply, but also in the associated business case. If electrolyzers would only produce hydrogen when RES generation is high, rather than continuously as a base load, this would alter their business model. The question then becomes whether and when enough of these flexible electrolyzers will enter the market, and what impact this has on the hydrogen price, as unstable supply would also lead to unstable prices. Conversely, if electrolyzers are supplied by more stable RES sources, such as nuclear plants, hydrogen prices could be more stable. However, it remains uncertain if and when the green hydrogen market will become liquid enough to support such capacity, whether within the Dutch market or internationally.

Blue hydrogen supply is another factor of uncertainty. According to interviewees, the gray hydrogen market in the Netherlands is already relatively liquid. Gray hydrogen is mainly produced using steam methane reformers (SMR), which convert methane (from natural gas or synthetic sources) and steam, into hydrogen and carbon dioxide. To produce blue hydrogen, the relatively clean output of carbon dioxide from the gray hydrogen process process would need to be captured and stored using CCS technologies. Several factors make this transition uncertain. First, future advancements in CCS technology, including improvements in efficiency and cost, remain uncertain. Even if the technology improves, retrofitting existing SMRs will require extra investment and will increase operational costs due to the extra energy needed for CCS, which reduces overall efficiency. Additionally, there is uncertainty about the future development of carbon storage or utilization options. Furthermore, since SMRs depend on methane, the price of natural gas, subject to geopolitical events, adds another layer of uncertainty.

Last, regulatory stimulation, influenced by political perspectives on gray, blue, and green hydrogen, could impact these dynamics significantly. Government incentives or policies could affect the supply and price of the different hydrogen types. Given that operational cost uncertainties are primarily driven by fluctuations in input prices, these regulatory changes inherently affect the expected variable costs for retrofitted or newly built hydrogen power plants.

Hydrogen availability uncertainty
In addition to uncertainties surrounding the hydrogen market and its future price dynamics, another critical uncertainty is the availability of hydrogen for power plants. One uncertainty factor is the infrastructure required to transport hydrogen to these plants. The ’Besluit algemene regels ruimtelijke ordening’, which outlines general rules for spatial planning, dictating the locations for electricity generation. Currently, not all power plants are situated near the envisioned hydrogen backbone in the Netherlands, and the timeline for establishing this backbone is also uncertain. Without adequate hydrogen transport infrastructure, these plants would be unable to operate effectively. Furthermore, given that the power plants are intended for peak demand and periods of low renewable energy availability, there is a substantial need for hydrogen storage capabilities. The technical possibilities and development of hydrogen storage options are also considered uncertain.

5.1.3. Uncertainties in variable costs: gas power plant (+CCS)

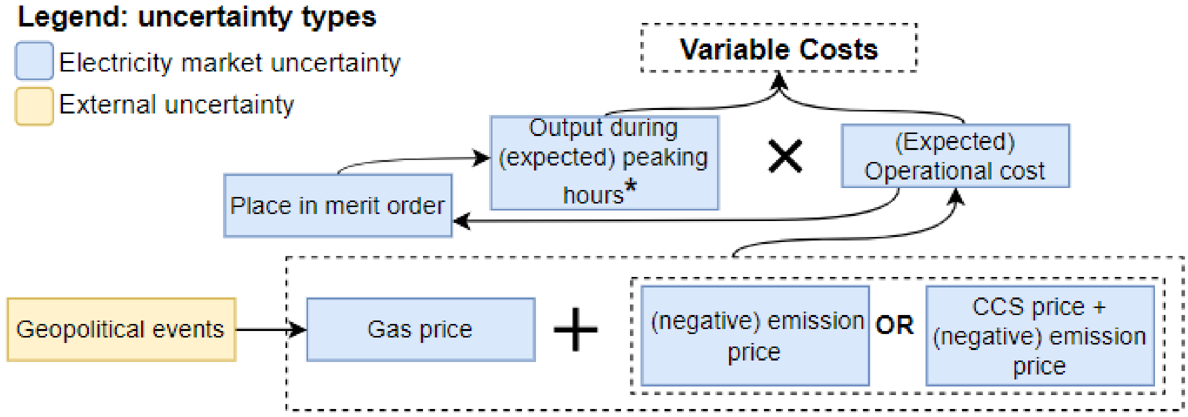

Figure 5.4: Uncertainties for gas power plant impacting variable costs

* Output during expected operating hours is influenced by the uncertainty factors as similarly depicted for the revenue uncertainties.

Partly, the uncertainties impacting the variable costs of gas power plants are visualized in Figure 5.4. The additional uncertainties influencing the uncertainties in this figure are addressed below. Here, the distinction is made for different investment possibilities: an existing gas power plant can decide to retrofit with post-combustion CCS or not. If the producer decides not to invest, it has to pay the carbon emission price or compensate with negative emissions, both of which incur costs. If the producer does invest in post-combustion CCS, there are still residual emissions depending on the CCS technology's efficiency. These residual emissions must also be compensated if 100% sustainability is to be achieved, which incurs the cost of carbon emissions or the negative emission price. Therefore, in addition to the uncertainties discussed in the previous paragraphs, including output during expected peak hours, operational costs affecting the merit order, and gas price uncertainty related to geopolitical events, three additional uncertainties play a role: CCS price uncertainty, emission price uncertainty, and negative emission price uncertainty. Each of these price uncertainties is addressed in the following paragraphs.

CCS price uncertainty

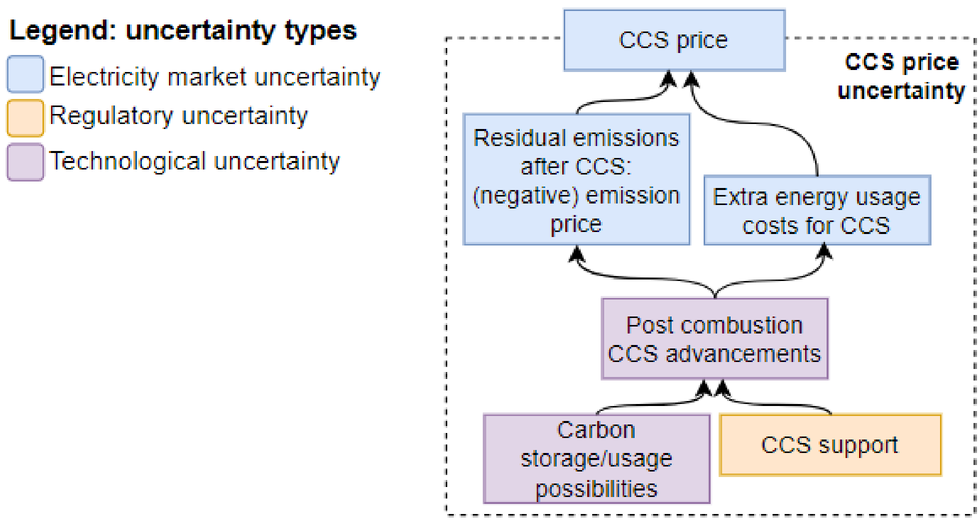

Figure 5.5: Uncertainties for gas power plant with CCS impacting variable costs

Figure 5.5 visualizes the uncertainty factors that influence the uncertainty about the CCS price. Note that here the CCS price only considers the variable costs, thus not the investment, fixed operation and maintenance costs, as these factors are considered certain and are accounted for in the initial investment cost (I) the IRR calculation when assessing the business case as discussed in Section 3.2.3.

When investing in post-combustion CCS for gas power plants, the technology requires additional energy to operate, impacting overall efficiency. While CCS technology already exists, future advancements remain uncertain and could affect efficiency. In contrast to CCS used for SMR to produce blue hydrogen, post-combustion CCS deals with unclean carbon output mixed with other gases that make carbon capture significantly less efficient. This results in residual emissions even after employing CCS at gas turbines. Interviewees highlighted the uncertainty in future developments in post-combustion CCS technology, influenced by uncertain regulatory support. Additionally, an important uncertainty factor in utilizing CCS is the availability of carbon storage or usage possibilities and its costs.

Emission price uncertainty

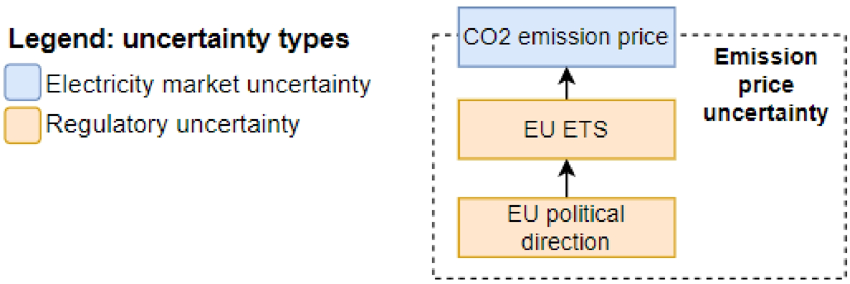

Figure 5.6: Uncertainties for (residual) emissions from gas power plant impacting variable costs

The total CO_2 emissions of a gas power plant without CCS, or the residual emissions of a retrofitted gas power plant with CCS, can potentially be offset by paying the CO_2 emission price. However, it should be noted that this investment possibility is neither carbon-free nor carbon-neutral since carbon is still emitted. Figure 5.6 visualizes the uncertainty factors impacting this emission price. Currently, the price of carbon emissions is determined by the EU Emissions Trading System (EU ETS). This system gradually reduces the number of CO_2 emission certificates available on the European market. Therefore, the emission price is influenced by both the demand for these certificates and the reduction in their availability on the market. Since the process is affected by EU political decisions, there is also uncertainty regarding the exact timeline for the reduction of CO_2 emission certificates.

Negative emission price uncertainty

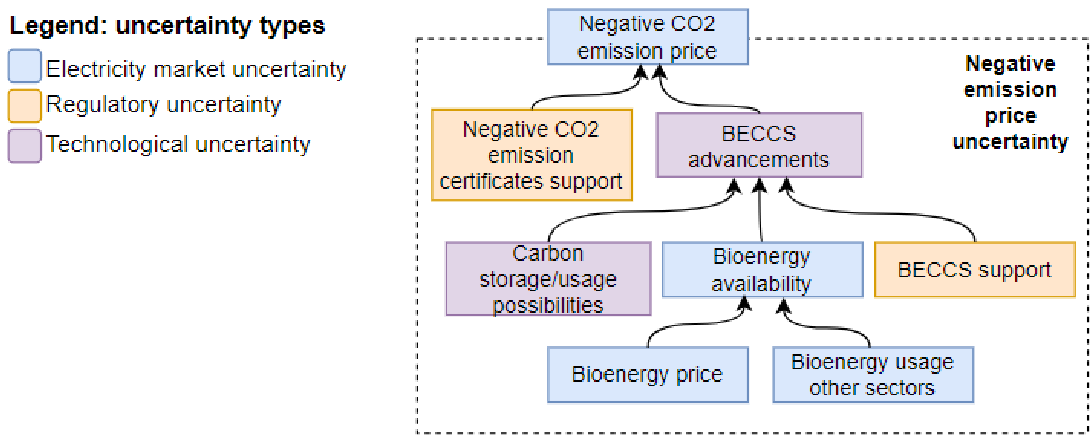

Figure 5.7: Uncertainties for negative (residual) emissions from gas power plant impacting variable costs

Instead of offsetting (residual) emissions by paying the CO_2 emission price, a carbon-neutral option would be to introduce negative CO_2 emissions. The uncertainty factors impacting the negative CO_2

emission price are visualized in Figure 5.7. To facilitate payment for negative emissions, a system with negative CO_2 emission certificates that producers can buy and sell would be necessary. The timing and implementation of such a system remain uncertain.

A commonly referred to technology capable of producing negative emissions is the earlier mentioned BECCS. BECCS utilizes bio-energy as a fuel, which contains carbon from biological sources and captures the carbon after combustion. This allows the plant to generate electricity, and achieve negative emissions simultaneously. However, BECCS is currently expensive, and due to its high capital costs, it would likely operate during base load hours when bio-energy prices are low enough or during periods of high prices for negative emissions.

The advancement of CCS technology and the availability of carbon storage or usage options are also uncertain. Additionally, there are uncertainties regarding the availability and price of bio-energy, and whether other sectors might use it more efficiently. Furthermore, regulatory uncertainty exists about whether BECCS should be stimulated since the perspectives on whether utilizing bio-energy on a big scale is desirable differ widely.

5.2. Synthesis of key uncertainties

The resulting diagrams demonstrate the uncertainties in the investment decision stem from a complex combination of uncertain dynamics in both the electricity and hydrogen markets, regulatory uncertainties, technological advancements, and economic and external uncertainties. These uncertainties are highly interconnected, affecting both the revenues and variable costs associated with the different investment possibilities.

The resulting diagrams present the following key patterns of uncertainty factors:

Uncertainties in revenues: The uncertainty in the expected market value of a power plant that influences expected revenues is influenced by the expected output during operating hours and the expected electricity price. Both of these are affected by uncertainties in electricity demand, such as the impact of electrification and demand-side response on inflexible load growth, and supply uncertainties, which are influenced by uncertainties in base load capacity, VRES generation, and other flexible capacity. Additionally, uncertainties regarding market value are influenced by the power plant's position in the merit order and the regulatory uncertainty of potential implementation of price caps during price spikes. Furthermore, revenues from ancillary services and other extra revenues are subject to uncertainty due to potential changes in market design and regulatory frameworks.

Uncertainties in variable costs of hydrogen power plants: The variable costs of hydrogen power plants are primarily influenced by uncertainties in operational costs, which affect their position in the merit order and thus the expected output during operating hours. Hydrogen prices, which impact these operational costs, are highly uncertain and influenced by various factors in the hydrogen market, including the future supply of blue or green hydrogen from SMRs or electrolyzers, and demand from other sectors that could use hydrogen more efficiently. These factors are also affected by regulatory and technological uncertainty, and are interdependent with electricity market dynamics. In addition to uncertainties about the liquidity of the blue and green hydrogen markets, the availability of hydrogen for power plants highlights another key pattern of uncertainty, given the unpredictability surrounding advancements in hydrogen infrastructure and storage possibilities.

Uncertainties in variable costs of gas power plants (+CCS): Similarly, the variable costs of gas power plants are primarily influenced by uncertainties in operational costs, which impact their position in the merit order and expected output during operating hours. These operational costs are largely determined by gas prices and the costs associated with emitting or compensating for carbon emissions. The costs of carbon emissions are further affected by whether post-combustion CCS is employed, which involves additional energy use and reduced efficiency. Gas price uncertainty is influenced by geopolitical factors, while the extra costs associated with CCS are uncertain due to unpredictability in residual emissions costs, decreased efficiency, and advancements in CCS technology and carbon storage or utilization. Additionally, uncertainties in the costs of emitting or compensating for residual emissions are influenced by the EU ETS price and potential developments in payments for negative emissions and advancements in BECCS that potentially can provide for negative emissions.

These patterns are summarized in the following key uncertainties, which are derived from the grouped uncertainty factors. It should be noted that these key uncertainties are interdependent, as indicated by the presented diagrams.

- **Operational uncertainty:** Uncertainties in operational costs, influencing the position in the merit order and operational hours.
- **Market value uncertainty:** Uncertainties in the electricity price during operating hours.
- **Electricity demand uncertainty:** Uncertainties in inflexible load growth.
- **Electricity supply uncertainty:** Uncertainties in base load capacity, intermittent VRES supply, and other flexibility-providing technologies.
- **Operational costs uncertainty for hydrogen:** Uncertainties in hydrogen prices and its availability, including infrastructure and storage.
- **Operational costs uncertainty for gas**: Uncertainties in gas prices, CCS operational efficiency ad costs, and residual (negative) emissions costs.

6 Policy instruments to mitigate uncertainties and incentivize investment

This chapter presents and analyzes the results from the interviews, with the aim of identifying policy instruments perceived to mitigate the uncertainties discussed in the previous chapter and to enhance the incentive to invest in carbon-free firm dispatchable electricity generation capacity. Central to this chapter is the second sub-question: *What policy instruments are perceived to mitigate the identified uncertainties and enhance the incentive to invest?*

To address this question, Section 6.1 first presents the results from the interviews. Subsequently, Section 6.2 synthesizes the results.

6.1. Results: policy instruments

This section presents the results of the interviews regarding the policy instruments the interviewees highlighted during the interviews and their perceived effect on the previously identified uncertainties and the incentive to invest. The central question posed during the interviews to obtain the data was as follows: ”What policy instruments can mitigate the previously discussed challenges and incentivize investments?”

As discussed in the methodology chapter, the interview data were analyzed using an exploratory approach to identify policy instruments and assess their potential to mitigate uncertainties and enhance investment incentives. Similar to the previous results, a thematic analysis approach was employed to identify patterns in the perceived effects of the policy instruments on the uncertainties and the investment incentives.

The results are structured by applying the reasoning adapted from the theory by Boudt (2021), as discussed in Chapter 3:

- If uncertainties impacting inframarginal rent (i.e., total revenues minus total variable costs) are mitigated, ceteris paribus, the hurdle rate decreases.
- If total revenues increase, ceteris paribus, the IRR increases.
- If variable costs increase, ceteris paribus, the IRR decreases.
- If the ratio IRR to the hurdle rate increases (for IRR > 0), the investment becomes relatively more viable.

After presenting these results, the identification of themes is discussed in the interpretation and synthesis section.

Initially, the identified policy instruments are categorized by type of intervention, which are applied as codes during the data analysis. Subsection 6.1.1 presents the results regarding the identified subsidizing policy instruments and their perceived impact on uncertainties and investment incentives. Subsequently, Subsections 6.1.2, 6.1.3, 6.1.4, and 6.1.5 similarly present the results regarding the identified regulating instruments, pricing instruments, facilitating instruments, and capacity remuneration mechanisms, respectively.

6.1.1. Subsidizing instruments

CAPEX subsidy

A CAPEX subsidy would cover, potentially in part, the initial investment costs for retrofitting a gas power plant. In theory, this could apply to retrofitting gas power plants for partial hydrogen blending, full hydrogen operation, or installing post-combustion CCS. However, all interviewees only addressed the CAPEX subsidy in light of retrofitting existing gas power plants to hydrogen power plants, both blending and full operation, depending on the technological possibilities.

Since a CAPEX subsidy solely covers (a portion of) the initial investment in retrofitting current capacity, it does not directly affect the revenues or operational costs associated with running the power plant. Therefore, in the IRR calculation, this subsidy primarily impacts the CAPEX variable by reducing the upfront investment costs. However, the uncertainties influencing the business case, as discussed in Section 3.2.3, are reflected only in the inframarginal rent. Consequently, this policy instrument does not directly mitigate any of the uncertainties impacting revenues or operational costs. It mainly prepares a power plant to run on hydrogen without addressing uncertainties related to operational aspects, as long as the retrofitting allows for continued operation on gas. If the retrofitted technology permits operation utilizing hydrogen without eliminating the option to use gas, hydrogen would only be used if it became cheaper than natural gas. Conversely, if retrofitting limits the power plant to solely utilizing hydrogen, the uncertainties related to hydrogen operation would be introduced (see Figure 5.3). Additionally, retrofitting can potentially impact the efficiency of a power plant and its lifespan, depending on the technological possibilities for retrofitting.

When comparing the investment decision to retrofit or new-build in a scenario with a CAPEX subsidy to a scenario without this policy, the CAPEX subsidy does not mitigate any additional uncertainties for the decision to decarbonize. Therefore, the hurdle rate of the investment decision to retrofit does not differ between the two scenarios. However, the IRR does increase since a portion of the initial investment is subsidized. Consequently, the ratio of the IRR to the hurdle rate is relatively higher when a CAPEX subsidy is implemented.

Hydrogen operational subsidy

A second frequently addressed subsidizing policy instrument is a hydrogen operational subsidy, also known as an exploitation subsidy. This form of subsidy would cover (partially) the cost gap between natural gas and blue or green hydrogen until a set date in the future.

By subsidizing hydrogen operational costs, this instrument mitigates the hydrogen market uncertainties regarding its price, as outlined in Figure 5.3, by compensating for the price differential between natural gas and hydrogen. However, operational costs will still be affected by gas price uncertainty. Additionally, uncertainties related to expected output during operating hours, electricity prices, and the availability of hydrogen due to infrastructural and storage needs still persist.

If the operational subsidy fully covers the price differential between hydrogen and natural gas, assuming no effect on the efficiency of the power plant, the expected inframarginal rent when blending hydrogen would be similar to operating solely on natural gas. For the investment decision to retrofit a gas plant, that cannot already blend hydrogen without retrofitting, this entails that the IRR with the subsidy would be higher compared to a scenario without the subsidy, assuming hydrogen prices are higher than gas prices; since the policy instrument reduces operational costs when utilizing hydrogen, the variable costs of a hydrogen power plant are lower with the subsidy compared to the hydrogen costs in a scenario without the subsidy. Furthermore, by mitigating hydrogen price uncertainty, the hurdle rate is lowered.

Consequently, the investment decision to retrofit becomes more attractive with the subsidy compared to the investment decision without an operational subsidy. This effect would also apply to investments in new hydrogen-based capacity, where the subsidy similarly increases the IRR and reduces the hurdle rate compared to the no-policy scenario, making the investment more appealing. However, all other uncertainties, besides the hydrogen price uncertainty, persist.

6.1.2. Regulating instruments

Hydrogen Blending Mandate

A regulating instrument addressed by the interviewees is a hydrogen blending mandate, which requires that a certain percentage of blue or green hydrogen be mixed with natural gas for combustion.

This regulating instrument imposes additional operational costs on power plants as long as hydrogen prices remain higher compared to natural gas. Consequently, it does not mitigate uncertainties related to the operational costs of power plants. Instead, as it mandates hydrogen blending, the power plants are involuntarily exposed to price and availability uncertainties of hydrogen. Furthermore, the increased operational costs could alter the competitive position of the power plants within the international merit order. This potential change exposes the power plant to heightened uncertainty regarding operational hours, as possibly cheaper electricity can be imported depending on the available interconnection capacity. Besides, the power plants that cannot blend hydrogen without retrofitting are forced out of the market if they do not decide to retrofit.

For power plants that must retrofit before being technically capable of blending hydrogen, the investment decision in a scenario with the blending mandate compared to a scenario without the policy leaves the uncertainties of the investment decision for retrofitting unmitigated and the inframarginal rent and initial investment costs unchanged. However, if the decision is not to retrofit, the power plant would have to be mothballed or closed, which, as mentioned by the interviewees, also incurs costs. Therefore, a trade-off must be made between retrofitting under uncertain circumstances or mothballing/closing the plant, both of which come with associated costs.

6.1.3. Pricing instruments

EU ETS

Currently, the EU ETS system applies to the electricity sector. This emission trading system is seen as a combination of a regulatory and pricing instrument that requires purchasing emission certificates. The price of the certificates is determined by supply and demand mechanisms, where the number of available certificates on the market declines over time, thus providing incentives to lower, and eventually phase out carbon emissions. Most interviewees foresee that the number of certificates available on the market will potentially reach zero around 2040; however, the exact timeline is uncertain as addressed in the previous chapter. Over time, the EU ETS is expected to close the price gap between electricity production technologies with and without carbon emissions.

This instrument increasingly internalizes the external costs of carbon emissions across Europe and ensures a level playing field within the region. However, given the projected timeline for certificates to potentially reach zero around 2040 and the current significant price gap between gas with the EU ETS emission price and hydrogen, it is not considered unlikely that this instrument will ensure a carbon-free electricity system in the Netherlands by 2035. Nevertheless, the interviewees who addressed the EU ETS perceive the effects favorably, as it promotes a level playing field in Europe and stimulates decarbonization with minimal disruption to market dynamics.

Given that the EU ETS already applies and its effects on decarbonization are perceived as favorable, but it falls outside the initial temporal scope of this thesis, it will not be assessed further. However, it will be reflected upon in the discussion.

6.1.4. Facilitating instruments

Hydrogen market and availability stimulation

Considering that the decarbonization of firm dispatchable generation capacity in the Netherlands mainly relies on hydrogen, the stimulation of hydrogen market liquidity, as well as infrastructural and storage needs, are frequently addressed by the interviewees. Overall, if there is no infrastructure or storage capacity to support hydrogen supply for a power plant, this inherently depresses the decarbonization incentive of transitioning to hydrogen. Moreover, if the price of hydrogen remains higher compared to gas, including the EU ETS carbon emission price, hydrogen is not economically advantageous.

Therefore, policy instruments that stimulate the hydrogen market and its infrastructure and storage possibilities could, over time, partially mitigate the current high uncertainties. If hydrogen stimulation leads to increased market liquidity and decreased prices, it would also lower the expected operational costs of a hydrogen power plant compared to a scenario without hydrogen stimulation. However, the interviewees often mentioned the 'hydrogen ladder,' which prioritizes different uses of hydrogen based on their effectiveness and sustainability. According to the hydrogen ladder framework, using hydrogen for electricity generation is considered a lower priority compared to other applications where hydrogen might be more efficient.

However, when considering the investment decision to retrofit or new-build a hydrogen gas power plant in a scenario where hydrogen market stimulation is assured, compared to a non-policy scenario, the hurdle rate would be relatively lower due to reduced hydrogen market uncertainty. Moreover, depending on the level of stimulation, the expected hydrogen price could decrease, leading to lower expected operating costs and, consequently, a higher expected IRR, compared to a scenario without hydrogen stimulation.

6.1.5. Capacity remuneration mechanisms

Capacity remuneration mechanisms
Another highlighted instrument is the implementation of a capacity remuneration mechanism (CRM). When introducing a CRM, electricity generators can derive value from having available capacity, in contrast to solely deriving value from electricity. Implementing a CRM represents a change in market design, shifting from an energy-only market to one that allows for deriving value from available capacity. As noted by the interviewees, a CRM can take many different forms, but the only explicitly addressed mechanisms are a central capacity market and a strategic reserve of capacity. Here, we focus on CRMs in general, excluding the strategic reserve capacity, which is addressed subsequently.

When implementing a CRM, an additional driver of value is created alongside the existing value drivers from the electricity markets. Consequently, the uncertainties regarding revenues and variable costs from electricity alone remain unchanged. However, the extra value driver provides for additional certainty. Figure 5.2 illustrates this with the value driver 'other revenues', adopted from TenneT (2024). While other uncertainty factors remain unaffected, the CRM introduces certainty in the form of a value driver beyond the uncertain revenues from electricity sales. Therefore, the overall uncertainty regarding total revenues is relatively lower when implementing a CRM. Additionally, depending on the specifics of the CRM's design, this value driver could improve the IRR.

However, the interviewees highlight the challenge of incorporating sustainability objectives into a CRM design. Assuming it integrates carbon-free technologies, the decision to retrofit or build new facilities becomes more appealing in a scenario with a CRM, compared to one without, as the lower hurdle rate and potentially higher IRR relatively enhance the investment opportunity.

CRM: Strategic reserve of capacity
The strategic reserve (SR) of capacity is a variant of CRMs. However, whereas other CRMs aim to incentivize investment in new capacity, according to the interviewees, this CRM primarily serves as an additional layer of security for system reliability rather than being implemented explicitly to stimulate new investments. A strategic reserve is a certain amount of capacity contracted by an authority, which is generally the TSO. This contracted capacity is separate from the regular electricity market, which remains similar to the energy-only market. In case the market does not achieve equilibrium where supply meets demand, the contracted capacity outside the market can be dispatched. The interviewees primarily perceive that the capacity contracted in this reserve would likely be older power plants that are no longer economically viable in the regular market.

Thus, the policy instrument does not directly impact the investment decision for potential new capacity, assuming that the reserve is only attractive to those not economically viable in the market. However, as highlighted by one of the interviewees, for capacity that remains in the market, withdrawing capacity and allocating it to the reserve could, in the short term, potentially increase prices due to reduced supply, thereby creating stronger incentives to invest. Nevertheless, for capacity remaining in the market, this instrument does not address any of the uncertainties identified in the previous chapter. Therefore, in the long run, it would not affect the hurdle rate or the IRR of new investment projects as long as the price for which the reserve capacity is dispatched does not interfere with market price signals.

6.2. Synthesis of relevant policy instruments

Table 6.1 provides a summary of the policy instruments and their impacts on investment decisions for retrofitting or building new carbon-free dispatchable electricity generation capacity. The table compares scenarios with and without the policy instruments, highlighting the relative differences in:

- Uncertainties affecting the hurdle rate.
- inframarginal rent and initial investment costs affecting the IRR.
- The ratio of the IRR to hurdle rate (for IRR > 0)

However, it should be noted that a higher IRR to hurdle rate ratio does not necessarily mean that the IRR exceeds the hurdle rate. It is still possible for the IRR to be lower than the hurdle rate, even if the ratio improves in the policy scenario compared to the scenario without the policy.

Table 6.1: Relative difference in the investment decision to retrofit or build new carbon-free capacity in a scenario with policy, compared to a scenario without policy.

Policy	Relative difference in uncertainty	Hurdle rate	Relative difference in expected infra-marginal rent	IRR	Ratio IRR to Hurdle rate (for IRR > 0)
		Policies to stimulate decarbonization and possibly reliability			
CAPEX subsidy	Equal	Equal	Covers (partially) initial investment costs	Higher	Higher
Hydrogen operational subsidy	Mitigates hydrogen price uncertainty	Lower	Reduces operational cost by (partially) covering price differential hydrogen and natural gas	Higher	Higher
Capacity remuneration mechanisms (excluding SR)	Provides certainty of additional value driver	Lower	Depending on CRM design: Additional value driver	Higher	Higher
		Policies to stimulate overall decarbonization and potentially reliability			
Hydrogen market and availability stimulation	Partially mitigates hydrogen price and availability uncertainty	Lower	Potentially lowers hydrogen operational costs in the long term	Potentially higher	Higher
		Policies to stimulate decarbonization			
Hydrogen blending mandate*	Equal	Equal	Equal	Equal	Equal**
		Policies to stimulate system reliability			
CRM: strategic reserve of capacity	Equal for capacity still in the market in the long term	Equal in the long term	Equal for capacity still in the market in the long term	Equal in the long term	Equal in the long term

* Considers investment decisions for power plants that require retrofitting before being technically feasible to blend hydrogen

** Trade-off decision has to be made between retrofitting or mothballing/closing*

By applying the theory utilized by Boudt (2021), the results indicate that the policies in the subsidizing category, CAPEX subsidies, and hydrogen operational subsidies, along with CRMs excluding the SR, could relatively enhance the incentive to invest in carbon-free dispatchable generation capacity, since the IRR to hurdle rate ratio is relatively higher. These policies achieve this by lowering hurdle rates and/or increasing the IRR of carbon-free technologies compared to scenarios without these policies. Therefore, these policies are perceived to enhance the incentive to retrofit, utilize hydrogen, or potentially invest in new capacity.

Additionally, stimulating the hydrogen market, including its infrastructure and storage needs, could enhance investment incentives. However, given that electricity generation holds a low priority on the 'hydrogen ladder,' the effects of such market stimulation would be impactful in the long term rather than immediate.

In contrast, the regulatory policy instrument, a hydrogen blending mandate, does not mitigate the uncertainties in the investment decision, nor does it impact the expected IRR. However, if the utilization of hydrogen is mandatory, this would entail that for current capacity that is not technically feasible for hydrogen blending, a trade-off decision must be made: retrofitting the power plants if needed based on their technology, or opting to mothball or close the plant.

Furthermore, the strategic reserve of capacity would primarily provide additional system reliability by contracting mainly older power plants that are no longer economically feasible in the market. In the short term, taking this capacity out of the market into a strategic reserve could provide extra incentives for the capacity remaining in the market, but in the long term, it does not mitigate any of the previously addressed uncertainties, nor does it provide for a higher expected IRR. Therefore, this instrument is mainly perceived to solely provide an extra layer of system reliability.

Consequently, the patterns derived from these results are summarized into three main themes that represent the stimulation of the policy instrument: stimulating decarbonization, stimulating system reliability, and the combined effects of both. The Venn diagram in Figure 6.1 visualizes these categories.

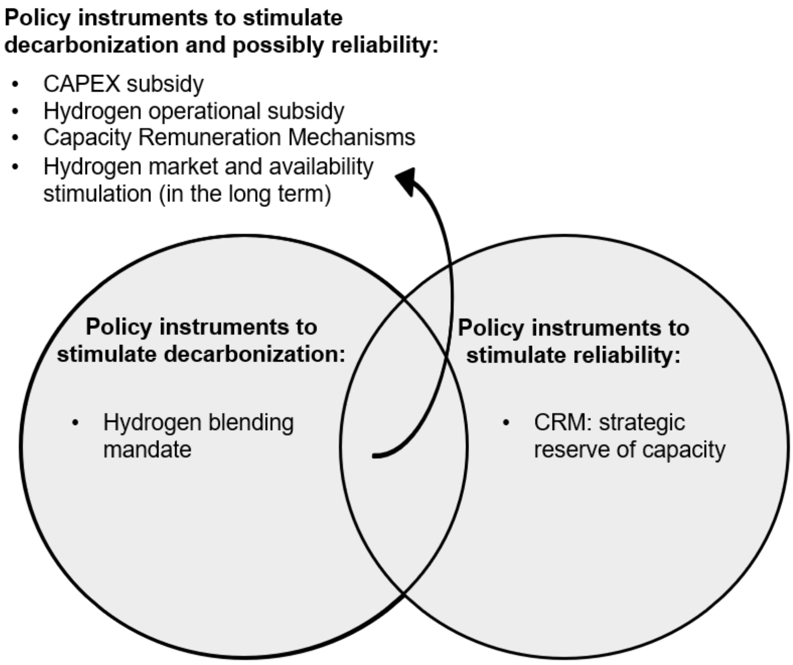

Figure 6.1: Venn diagram of categorization of identified policy instruments and their stimuli

The three policy instruments that are perceived to stimulate both decarbonization and potentially system reliability, are further selected as potentially relevant for achieving the 2035 carbon-free aim while maintaining reliability. Although the EU ETS and overall hydrogen market stimulation are also seen as effective in decarbonization, and hydrogen market stimulation potentially in stimulating reliability, they are not assessed further in this context since they already play a crucial role in practice and do not specifically focus on dispatchable generation capacity. Nevertheless, they are again highlighted in the final discussion.

While the results of this chapter solely address the impact on investment decisions, this thesis aims to further assess the perceptions regarding the policy instruments in terms of overall sustainability, system reliability, and affordability. Therefore, the next chapter provides a further assessment of the perceived effectiveness of the three relevant policy instruments: CAPEX subsidy, hydrogen operational subsidy, and CRMs excluding the SR.

7 Perceived effects of policy instruments on the electricity system

The previous chapter explored the perceived effects of policy instruments on the uncertainties, the IRR, and the investment incentive to retrofitting or new-building firm dispatchable electricity generation capacity. This chapter aims to broaden the scope by examining how the relevant policy instruments are perceived to impact sustainability, system reliability, and affordability. Central to this chapter is the third sub-question: *How do stakeholders and experts perceive the effects of the policy instruments on the 2035 sustainability aim, system reliability, and affordability?*

This chapter focuses on three of the four policy instruments perceived to stimulate both decarbonization and enhance system reliability: CAPEX subsidies, operational subsidies, and capacity remuneration mechanisms (excluding a strategic reserve). As discussed in the synthesis of the previous chapter, these policies are seen as enhancing the incentive to invest in carbon-free technologies, thus addressing the dual challenges of sustainability and reliability.

To address the central question of this chapter, Section 7.1 presents the results derived from the interviews per policy instrument per interviewee. Second, Section 7.2 presents a structuring of these results grouped by the lines of reasoning regarding the perceived favorable and unfavorable effects of the policy instrument on the electricity system. Subsequently, Section 7.3 synthesizes these results.

7.1. Results: Perceived effects of policy instruments

This section presents the results of the interviewees regarding the perceived effects of the previously selected policy instruments on the system, rather than solely on the investment incentive. The central question posed during the interviews to obtain the data was as follows: What are the effects of the policy instruments on the electricity system, and what criteria should the policy instruments adhere to?

As discussed in the methodology chapter, the interview data were analyzed using an exploratory approach to assess the perceived effects. Also here, the thematic analysis approach identified patterns regarding the perceived effects. First, Subsection 7.1.1 presents the perceived overall effects of CAPEX subsidies. Subsequently, Subsection 7.1.2 covers the perceived effects of operational subsidies, and Subsection 7.1.3 presents the perceptions regarding capacity remuneration mechanisms.

After presenting the results, the following section further organizes these findings. Subsequently, the identification of themes regarding the perceived effects is discussed in the analysis and synthesis sections.

7.1.1. CAPEX subsidy

In addition to enhancing the incentive to invest by lowering upfront costs, CAPEX subsidies are perceived by interviewees to have varying effects on the overall system in terms of sustainability, reliability, and affordability. Some interviewees primarily perceive positive effects with some nuances, while others view the effects mainly as negative or overall as nuanced. Figure 7.1 visualizes these perceptions for each interviewee, distinguished by letter and color-coded according to their stakeholder or expert group. The position on the axes is derived from the interview, where the focus was on the interviewee's argumentation. Therefore, the location should be interpreted as an overall estimate relative to the other interviewees. The results leading up to this visualization are presented per interviewee following the figure.

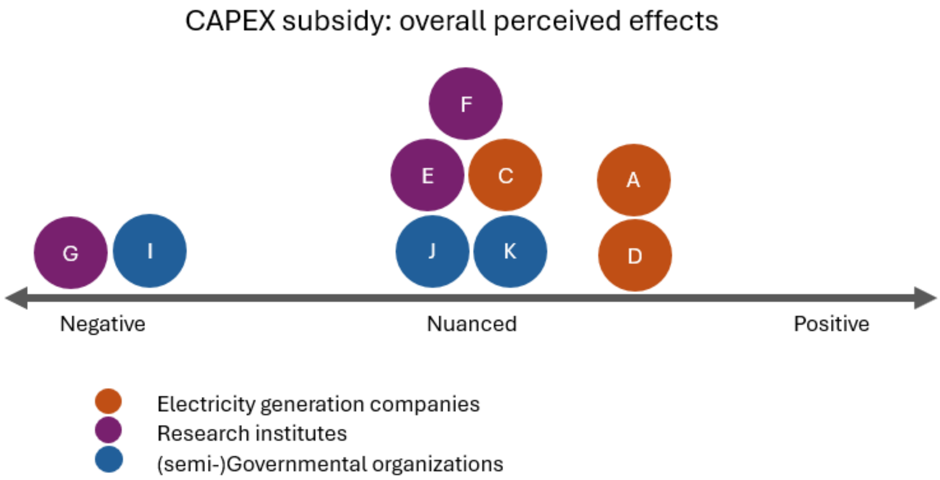

Figure 7.1: Perceived effects of CAPEX subsidy, per interviewee in stakeholder/expert group

Positive with nuances
Interviewees A and D from electricity generation companies primarily perceive positive effects of CAPEX subsidies, but also address some nuances.

First, interviewee A from an electricity generation company underscores that a CAPEX subsidy is the first logical step to take. Some turbines can already blend hydrogen with minor modifications, but others require significant changes. This subsidy ensures future readiness. By taking this step first, producers can address technical challenges associated with hydrogen usage, such as the need for higher combustion temperatures and potentially increased nitrogen emissions. However, Interviewee A also points out that full hydrogen usage is not yet feasible and that immediate emission reductions are unlikely. Hydrogen remains too expensive compared to natural gas, so reducing emissions right away may not be practical. The interviewee perceives significant emission reductions could take another 10 to 15 years.

Secondly, Interviewee D, also from the electricity generation stakeholder group, similarly underscores that a CAPEX subsidy can be a good initial step. However, this interviewee highlights that the decision to retrofit for partial hydrogen blending is distinct from retrofitting for full hydrogen usage without the option to use natural gas. They address that the more hydrogen has to be used, the higher the marginal cost will be, and the lower the plant's position in the merit order. Moreover, the interviewee sees that currently hydrogen is not available and that a mandatory hydrogen blend is not feasible. The interviewee emphasizes that if a CAPEX subsidy were implemented alongside mandatory hydrogen blending, there would be no economic rationale to accept the CAPEX subsidy. Therefore, the interviewee perceives that a capex subsidy should go along with another regulating measure or an operational subsidy that makes it interesting to operate on hydrogen.

Negative
On the other hand, interviewee G from a research institute, and interviewee I from a (semi-)governmental organization primarily perceive negative effects of CAPEX subsidies.

Interviewee G from a research institute argues that providing a CAPEX subsidy is unjustified when considering the broader system. They highlight that the operational hours of gas turbines are already decreasing, resulting in minimal emissions from natural gas. According to this interviewee, currently, there is no environmental rationale for transitioning power plants to hydrogen. They argue that the limited hydrogen available would be better utilized in decarbonizing other sectors, such as the fertilizer industry. Furthermore, Interviewee G notes that retrofitting turbines for hydrogen is a minor investment compared to regular maintenance updates and is not technically demanding. The interviewee therefore highly questions the need for such a subsidy.

Moreover, interviewee I, from a (semi-)governmental organization, argues that a CAPEX subsidy is not a realistic possibility due to the juridical measures of the European state aid regulations, which prevent distortive advantages over competitors. Moreover, Interviewee I also argues that even if a CAPEX subsidy could be provided, it would not immediately reduce emissions in the sector.

Nuanced
In contrast, interviewee C from an electricity generation company, interviewees E and F from a research institute, and interviewees J and K from (semi-)governmental organizations perceive the effects of CAPEX subsidies as fairly nuanced, with both positive and negative perceived effects.

Firstly, Interviewee C from an electricity generation company questions the logic of solely providing a CAPEX subsidy to retrofit existing power plants to use hydrogen, without an additional operational subsidy. They believe that a significant portion of the plants may not even utilize hydrogen after receiving the CAPEX subsidy. Additionally, combining a CAPEX subsidy with a mandatory hydrogen purchase regulation would result in additional upfront costs since not only the gas turbines need retrofitting, but also the technology before and after the gas turbines necessitates adjustments to accommodate hydrogen use.

Similarly, Interviewee F from a research institute argues that while a CAPEX subsidy ensures a power plant is prepared for hydrogen use, it does not guarantee that hydrogen actually will be utilized. However, they argue that to ensure hydrogen usage, a regulatory measure such as a blending mandate or an end-of-life date for existing technologies should be implemented as a 'stick' measure, in addition to the CAPEX subsidy, which can be seen as the 'carrot' measure. However, Interviewee F also notes that there is no certainty that a CAPEX subsidy will be accepted if such stick measures are introduced. They point out that opportunity costs can play a role in this decision.

Moreover, Interviewee E, also from a research institute, similarly underscores that a CAPEX subsidy on itself would not be sufficient. On the one hand, it would not guarantee emission reduction when natural gas usage is still an option; on the other hand, if hydrogen usage is necessary, the plant would end up last in the merit order. A possibility Interviewee E considers to be effective in reducing emissions is if a buyer is prepared to pay for a guarantee of origin, but they perceive this possibility to be unrealistic.

Interviewee J from a (semi-)governmental organization argues that while it is beneficial to have power plants prepared for hydrogen use, the hydrogen itself is not yet available. Therefore, they question the impact of the subsidy on carbon reduction in terms of costs per carbon emission reduction. In addition, they underscore that besides the power plants themselves, the infrastructure readiness is also crucial. Moreover, they point out that other industries also have CO_2 emission reduction aims, and address that the final emissions should be viewed as part of a scarcity allocation problem.

Lastly, Interviewee K from a (semi-)governmental organization addresses the potential benefit of retrofitting current power plants for hydrogen usage to ensure they are prepared when hydrogen becomes available. Moreover, they argue that providing a CAPEX subsidy upfront mitigates the effects of the long lead time associated with the CAPEX decision. The interviewee perceives that this approach can also reduce the risk of existing capacity being decommissioned and no longer participating in the market. They argue that maintaining current capacity is always cheaper than building new capacity. However, as the price difference between natural gas and hydrogen narrows, the interviewee considers that companies might make the CAPEX decision independently. Furthermore, if retrofitting results in mandatory hydrogen usage, the interviewee argues that Dutch power plants could move down the international merit order, potentially leading to leakage effects where carbon emissions are reduced in the Netherlands but increased in neighboring countries where power plants can still operate on natural gas.

7.1.2. Operational subsidy

As discussed in the previous chapter, an operational subsidy that covers, either partially or fully, the price difference between natural gas and hydrogen is perceived to mitigate the hydrogen price uncertainty for electricity producers and increase the IRR on investments in retrofitting existing plants or constructing new hydrogen gas power plants. This policy instrument is thus seen as a possible policy to enhance the incentive to invest. However, also for this policy instrument, the interviewees have varying perceptions regarding its effects on the overall system. Some interviewees primarily pointed out positive effects with some nuances, while others perceive mainly negative impacts, and some have mainly nuanced views. Figure 7.2 visualizes the overall perceived effects derived from the results presented following the figure.

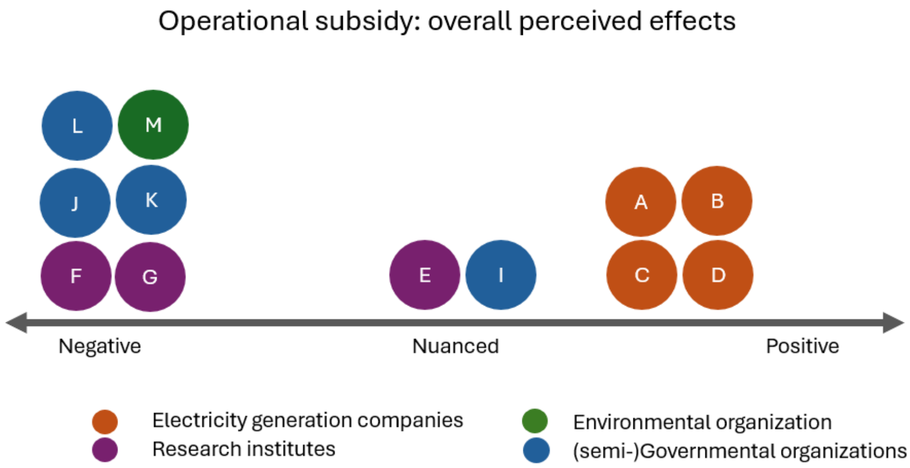

Figure 7.2: Perceived effects of operational subsidy, per interviewee in stakeholder/expert group

Positive with nuances

Interviewees B, C, and D from electricity generation companies mainly perceive positive effects of operational subsidies with some nuances.

First, interviewee C from an electricity generation company perceives that an operational subsidy can be positive if it is adjusted in such a way that it mitigates the risks of not being able to cover the CAPEX costs associated with operating hours. Therefore, the operational subsidy, assuming the €1 billion already announced by the government, could be tendered to a select number of power plants in the form of a long-term contract integrated with infrastructure needs. A long-term operational subsidy provides the opportunity to sign contracts with hydrogen suppliers and, on the other hand, with electricity suppliers. The interviewee highlights that such a subsidy enhances the reliability of the system based on sustainable production. Moreover, the interviewee adds that urgent action is needed and we have to be willing to pay learning costs because, even if the goal is to achieve a sustainable electricity supply by 2035 or we wait until the EU ETS reaches 0, possibly around 2039, this is both already tomorrow if we take into account the long duration time of the investments.

Second, interviewee D, also from an electricity generation company, views the operational subsidy in an international context. They argue that if the Netherlands aims to achieve its sustainability goal by 2035 and prohibits gas utilization, while neighboring countries do not adopt similar ambitions, the Netherlands will massively import cheaper electricity from those countries that continue using gas. As a result, power plants in the Netherlands may not operate. Therefore, the interviewee believes that an operational subsidy covering the price gap between hydrogen and gas is necessary to achieve the Netherlands' position as a leader in the transition if this is the objective of the Netherlands.

Third, interviewee A views an operational subsidy that covers the price delta between natural gas and hydrogen as a positive second step following a CAPEX subsidy that ensures the technical readiness of power plants to operate on hydrogen. They believe this approach supports the transition to carbon-free production until the market can fully adopt carbon-free technologies and these technologies can compete with each other. Although the interviewee considers this approach favorable, they have concerns about the feasibility of the operational subsidy due to the high and uncertain costs of hydrogen.

Lastly, Interviewee B from an electricity generation company draws a comparison with the blending option for bio-energy in coal-fired power plants, which was part of the SDE++ subsidy (Minister voor Klimaat en Energie, 2024b). They perceive that such a subsidy is a strategic opportunity for power plants, as it allows them to prepare technically for the long term when other fuels may be prohibited. As a company, it is important to anticipate future changes and follow trends, making it possible to already prepare and be future-ready.

Negative

On the other hand, interviewees G and F from research institutes, interviewees J, K, and L from (semi-)governmental organizations, and interviewee M from an environmental organization primarily perceived negative effects of operational subsidies.

Interviewee G from a research institute perceives that, without an additional subsidy, the operational costs of natural gas and hydrogen power plants will naturally reach a equilibrium with the help of the EU ETS. Specifically, for blue hydrogen, which is cheaper than green hydrogen, this equilibrium will be reached sooner. The interviewee questions the need for additional policy instruments to achieve this equilibrium. The interviewee perceives that implementing such extra policies implies that the final carbon emissions of the electricity sector are prioritized over emissions from other sectors that still produce significant amounts of CO_2 and could potentially carbonize more efficiently. They also note that the reduction of CO_2 in peaking and backup power plants is already being addressed through increased supply RES, which reduces the operational hours of gas power plants. Additionally, they argue that natural gas is already a relatively low-carbon fuel compared to other options like coal.

Moreover, interviewee F, also from a research institute, argues from another point of view. The interviewee perceives an operational subsidy to be an illogical option since this subsidy does not mitigate the uncertainty regarding the operational hours. They perceive that with an operational subsidy, there is still a lack of certainty regarding how many hours the power plant will operate, and thus it is uncertain how much subsidy is allocated. Moreover, they argue that if there is increased demand for electricity despite other sources of flexibility, prices will spike to such an extent that the procurement costs of hydrogen will be covered. However, the interviewee highlights that this argument does not hold if a price cap is implemented.

Interviewee J from a (semi-)governmental organization highlights the high costs of an operational subsidy in combination with the relatively limited carbon emission reductions it will induce. They perceive that the subsidy funds will be exhausted quickly, leading to a halt in the operation of power plants utilizing hydrogen. The money thus should be allocated more efficiently to achieve high carbon reduction with lower costs.

Interviewee K from a (semi-)governmental organization perceives the uncertainty surrounding hydrogen infrastructure and future hydrogen prices as a concern for the estimation of the subsidy height needed. They argue that as long as these factors remain uncertain, it is nearly impossible to accurately calculate a business case for hydrogen projects. More clarity would allow for a more precise calculation of the funding needed to cover the unprofitable top in the transition. A wrong estimation of the needed funding would influence the market in undesirable ways. Besides, the interviewee also perceives it undesirable to use hydrogen for power plants while other sectors could more effectively reduce carbon emissions.

Similarly, interviewee L from a (semi-)governmental organization also follows this line of reasoning. They perceive that if the carbon price is not high enough to stimulate hydrogen, but the government wants hydrogen to be integrated into the electricity system, some form of production subsidy would be necessary. However, they argue that a production subsidy could make the electricity price dependent on the height of the subsidy provided. Since it is difficult to estimate the optimal subsidy price due to uncertainties and volatile electricity prices, the market could be significantly distorted if the subsidy amount is not optimal. Therefore, the interviewee perceives that providing a hydrogen operational subsidy comes with high risks.

Last, interviewee M from an environmental organization perceives an operational subsidy as one of the most expensive solutions for society. They would prefer a solution in the form of a supplier obligation to purchase electricity from RES or a regulatory measure for decarbonization in combination with a CRM. Besides the perceived high costs of an operational subsidy, the interviewee also highlights that such a subsidy might distort a level playing field if one company receives a subsidy while another does not if the funding is not substantial enough.

Nuanced
In contrast, interviewee E from a research institute, and interviewee I from a (semi-)governmental organization perceived both the operational subsidy with nuances.

Interviewee I from a (semi-)governmental organization does perceive the positive effects of an operational subsidy to stimulate hydrogen usage for the power plants. However, they argue that such a subsidy would only be beneficial at later stages when there is more clarity about the hydrogen market, the infrastructure, and hydrogen storage. Thus, the interviewee views the operational subsidy as a potentially valuable tool, but only in the future, when there is more information about hydrogen, rather than focusing on the 2035 aim amidst current uncertainties.

Similarly, interviewee E from a research institute also holds nuances. They argue that if the government aims to achieve its 2035 aim, an operational subsidy is indeed necessary in addition to a CAPEX subsidy. However, they express uncertainty about whether the subsidy funding will be sufficient and whether hydrogen will be readily available for power plants. Therefore, they believe it is crucial to further stimulate the hydrogen market to enhance its liquidity and overall development.

7.1.3. Capacity remuneration mechanism

In addition to CAPEX and/or operational subsidies, the previous chapter discussed how implementing a CRM is also perceived to enhance investment incentives by providing an additional income stream for available capacity, which increases the certainty of covering the investment costs of a power plant. However, regarding this policy instrument, the interviewees also perceive its effects on the overall system in various ways. The following Figure 7.3 visualizes the relative perceptions of the interviewees regarding these effects. The positions on the axes are based on the results presented for each interviewee following the figure. These results exclude the perceptions regarding the CRM of a strategic reserve of capacity. As discussed in the previous chapter, this mechanism is seen primarily as a way to enhance reliability by keeping capacity available outside the market if not viable in the market, rather than enhancing the incentive to invest in new capacity in the long term.

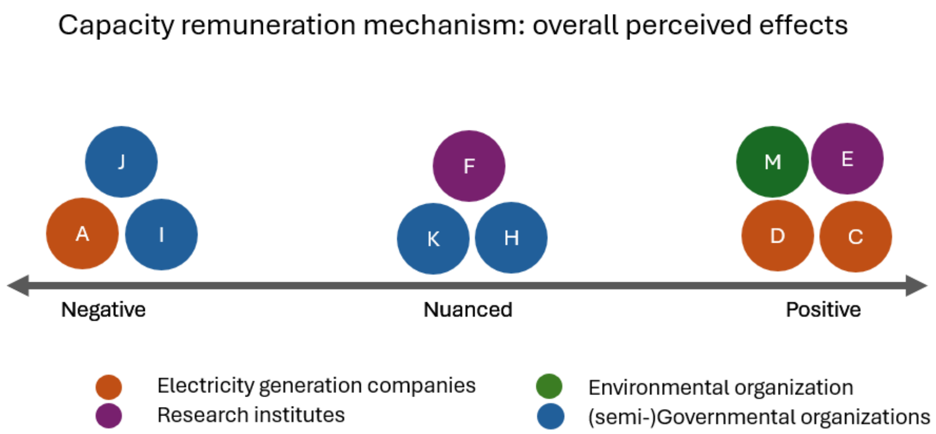

Figure 7.3: Perceived effects of Capacity remuneration mechanism, per interviewee in stakeholder/expert group (excluding strategic reserve of capacity)

Positive
Interviewees C and D from electricity generation companies, interviewee E from a research institute, and interviewee M from an environmental organization primarily perceived positive effects of capacity remuneration mechanisms.

First, interviewee C from an electricity generation company perceives that ultimately the Netherlands, like its neighboring countries, needs to implement a CRM. They argue that since the government has intervened in the market by subsidizing wind and solar power, they have become dominant in determining medium-term electricity prices. Due to these market interventions, the economic conditions that support an EOM no longer apply. They argue that in the past, when the government did not intervene and only coal and gas power plants were in operation, investing in electricity generation capacity involved low risks and low margins, with a natural hedge; if gas was cheaper, companies could profit from gas power plants, and if coal was cheaper, they could profit from coal power plants. However, now investing in capacity involves higher risks and potentially high margins [during high demand and low VRES supply, resulting in price spikes]. The interviewee perceives that this is not the ideal situation for the electricity sector. They perceive that an electricity system with high risks and high margins is difficult to justify from a public perspective, even though it is economically explainable since there can be many years of losses for peaking power plants in such a system. Therefore, in the event of price spikes, when gas power plants can benefit, the government could intervene and cap these high margins. With a CRM, part of the risks are shared socially, and the system partially returns to a low-risk, low-margin situation since capacity investments are partially compensated. This would ensure that capacity is available to meet peak demand when necessary. They emphasize the need for a capacity mechanism that provides long-term certainty through long-term contracts, which should be tendered in a central market to ensure competition *for* the market, instead of the current competition *in* the market. However, the interviewee highlights that implementing a CRM is not without challenges. They point out that estimating the optimal contracted amount of capacity beforehand is inherently imprecise, rather than allowing the market to determine this autonomously. Additionally, they see a challenge in aligning the CRM with sustainability goals.

Moreover, interviewee D, also from an electricity generation company, perceives a growing need for implementing a CRM in the Netherlands. They argue that due to a previous state of overcapacity in the Netherlands, there was no immediate need for a CRM and no immediate legal basis from the EU for its implementation. However, other European and neighboring countries have already adopted various forms of CRMs. The interviewee argues that because capacity operates within a largely similar wholesale market, electricity prices across countries are generally similar for most hours. In this context, if some countries offer incentives for capacity, investors might prefer to invest in those regions. Therefore, they argue that a level playing field across Europe is preferred.

Interviewee E from a research institute perceives that if we want to maintain a similar level of system reliability in the Netherlands over the coming decades, implementing some form of CRM is likely needed to create incentives for investing in new capacity. They argue there are two options: either the EOM is kept as it is, which results in limited investments and high price spikes that may not be sufficient to incentivize new investments, leading to quite some hours with loss of load during extreme weather events; or we implement a CRM that facilitates investment decisions. The interviewee draws the comparison with neighboring countries that have implemented a CRM, except for some countries that have ample hydropower available and do not require additional dispatchable generation capacity. However, the interviewee questions which type of capacity mechanism would be the most efficient.

Lastly, interviewee M from an environmental organization also views a CRM positively, but only if it is created specifically for carbon-free technologies. They perceive the positive effects that a CRM would provide for the necessary investment certainty and help prevent price increases. However, the interviewee highlights that it is important to maintain sufficient price incentives to enhance demand-side response or demand reduction.

Negative
On the other hand, interviewee A from an electricity generation company, and interviewees I and J from (semi-)governmental organizations mainly perceived negative effects of capacity remuneration mechanisms.

First, interviewee A from an electricity generation company perceives installing a CRM as unnecessary as long as the government does not intervene in the market during high price spikes. They argue that a CRM would distort market dynamics and would lead to generally higher electricity prices. The interviewee anticipates that a CRM, once implemented, would not be easily reversed and views it as a drastic measure. They believe that only during the energy transition period additional government support is needed to stimulate the change to a carbon-free system, with the EU ETS being its main driver. After the transition, they expect that all carbon-free technologies will be able to compete with each other effectively within an EOM.

Also, interviewee I from a (semi-)governmental organization perceives the implementation of a CRM as currently unnecessary and advocates for a wait-and-see approach to observe how electrification develops and how other flexibility-providing technologies develop. For instance, the interviewee perceives there will be learning effects, for example, how demand-side response will develop as a result of high electricity prices. Moreover, the interviewee perceives that if neighboring countries implement a CRM and thus achieve a higher level of investment, the Netherlands will also benefit from this [due to interconnection capacity that can facilitate electricity imports]. However, they also see the need for the Netherlands to have some firm capacity available domestically, but argue that the investment costs for gas power plants are relatively low per unit of power produced. However, they acknowledge that the declining number of operational hours poses a challenge to covering these relatively low investment costs. Therefore, they argue for the need to closely monitor developments in the system and decisions made by neighboring countries, and do not completely rule out the possibility of eventually partially following the lead of other countries in the European Union.

Similarly, interviewee J from a (semi-)governmental organization questions the necessity of a CRM and emphasizes the European Union regulations that define how and when a CRM may be implemented. They argue that a CRM, being a market intervention, inherently has negative effects and that such interventions should be minimized. They also stress the importance of monitoring other flexibility technologies, such as reliability in neighboring countries and demand-side response, to evaluate the Dutch system's reliability. The interviewee perceives that interconnection capacity will continue to expand where economically viable, not only to meet peak demand through imports but also to manage future excess wind capacity through exports. They perceive an energy-only market can be quite effective, but they do question its political feasibility [considering objectives for energy independence of the Netherlands].

Nuanced

In contrast, interviewees H and K from (semi-)governmental organizations, interviewee F from a research institute, and interviewee B from an electricity generation company perceived the effects of capacity remuneration mechanisms as nuanced.

First, interviewee H from a (semi-)governmental organization questions how well the energy-only market will still perform over the next 20 to 30 years. They argue that in a stable situation, the market naturally reaches equilibrium and that the default approach should be to let the market operate freely where possible. However, given the currently increasing market volatility and uncertainties, such as increasing electrification and potential demand-side response, they note that at times they perceive the need for more control over the market than at times in the past. On the other hand, they also point out that implementing a CRM is a drastic measure and question its desirability, as they perceive that it could lead to increased costs for the system. Moreover, they highlight the existence of different perceptions regarding the need for self-sufficiency in the Netherlands and how much we can, and want to be reliant on importing electricity during scarcity, which impacts the need for domestically installed capacity.

Second, interviewee K from a (semi-)governmental organization perceives there is an important difference between retrofitting current capacity and investing in new capacity. They see that the current high-risk system is unattractive for basing new large-scale investments on. Consequently, they perceive it as unlikely that substantial investment in, for example, new CCGTs will be developed in the near future. For existing capacity, the large-scale investment has already been made, so the relevant question is whether to keep the plant operational or not. They then perceive the question as whether the market can be sustained with existing capacity and possibly supplemented by other targeted smaller measures, such as additional battery capacity, or if, over time, nuclear energy could become a viable option. Therefore, they believe there should be a focus on sustaining current capacity. They perceive that the strategy might involve making small adjustments in the market to transition and fully utilize current capacity, rather than forcing large-scale shifts [towards decarbonization], which would require substantial new capacity and likely necessitate significant additional stimulation or market interventions.

Last, interviewee F from a research institute also holds a nuanced view regarding the implementation of a CRM. They believe that payments for having capacity available would ensure more certainty regarding the reliability of the system, but argue that this discussion could be considered separately from the discussion on making the system sustainable. They perceive that the energy transition has increased the challenges related to the low operational hours of power plants, but they perceive this problem [of achieving sufficient investments] would also have existed without the energy transition. Given the previous state of overcapacity in the Netherlands, this issue was not as relevant as it was in other countries. In this context, they perceive it is an ideological political debate between maintaining an overall liberalized but regulated market, given the high public interest in the electricity market, and having the government exercise full control, which is less efficient. With the implementation of a CRM, part of the liberalization of the electricity market will be reversed and brought back under governmental control.

7.2. Results: perception of problem situation

The previous results section shows that the interviewees have varying perceptions of the overall effects of the policy instruments and the need for their implementation. While their reasoning shows they have a similar understanding of how the electricity system fundamentally addresses peak demand, their evaluations of how the policy instruments influence the system's outcomes, and whether these effects are advantageous or disadvantageous, or even necessary, differ. Because the lines of reasoning consider complex dynamics of the electricity market, this section further analyzes patterns in reasoning regarding the perceived necessity and effects of the policy instruments. This section aims to visualize the lines of reasoning by grouping the perceptions presented in the previous section into those presenting favorable effects of the instrument, and those presenting unfavorable effects.

To structure this, first, Subsection 7.2.1 presents an aggregated causal relation diagram of the electricity system concerning peak demand to address the fundamental system. Second, Subsection 7.2.2 places the causal relation diagram in the problem diagram and explains the objectives incorporated. Subsequently, for each policy instrument, the problem diagram is translated to a cognitive diagram that visualizes the effects of the policy instrument that are perceived favorable or unfavorable by the groups of interviewees as addressed in the previous section. Subsection 7.2.3 presents the cognitive diagram with a CAPEX subsidy as an alternative, including the perceived effects. Thereafter, Subsection 7.2.4 presents the cognitive diagram for an operational subsidy in a similar manner, and Subsection 7.2.5 presents it for a CRM.

7.2.1. Causal relation diagram

To present the electricity system regarding peak demand, an aggregated causal relation diagram of the fundamental understanding of this system is visualized in Figure7.4. The diagram represents a collection of the causal relationships identified by the interviewees. The aggregation level is set to simplify the analysis while ensuring that key influencing factors are still included. This means that not all factors that could also have an impact are included.

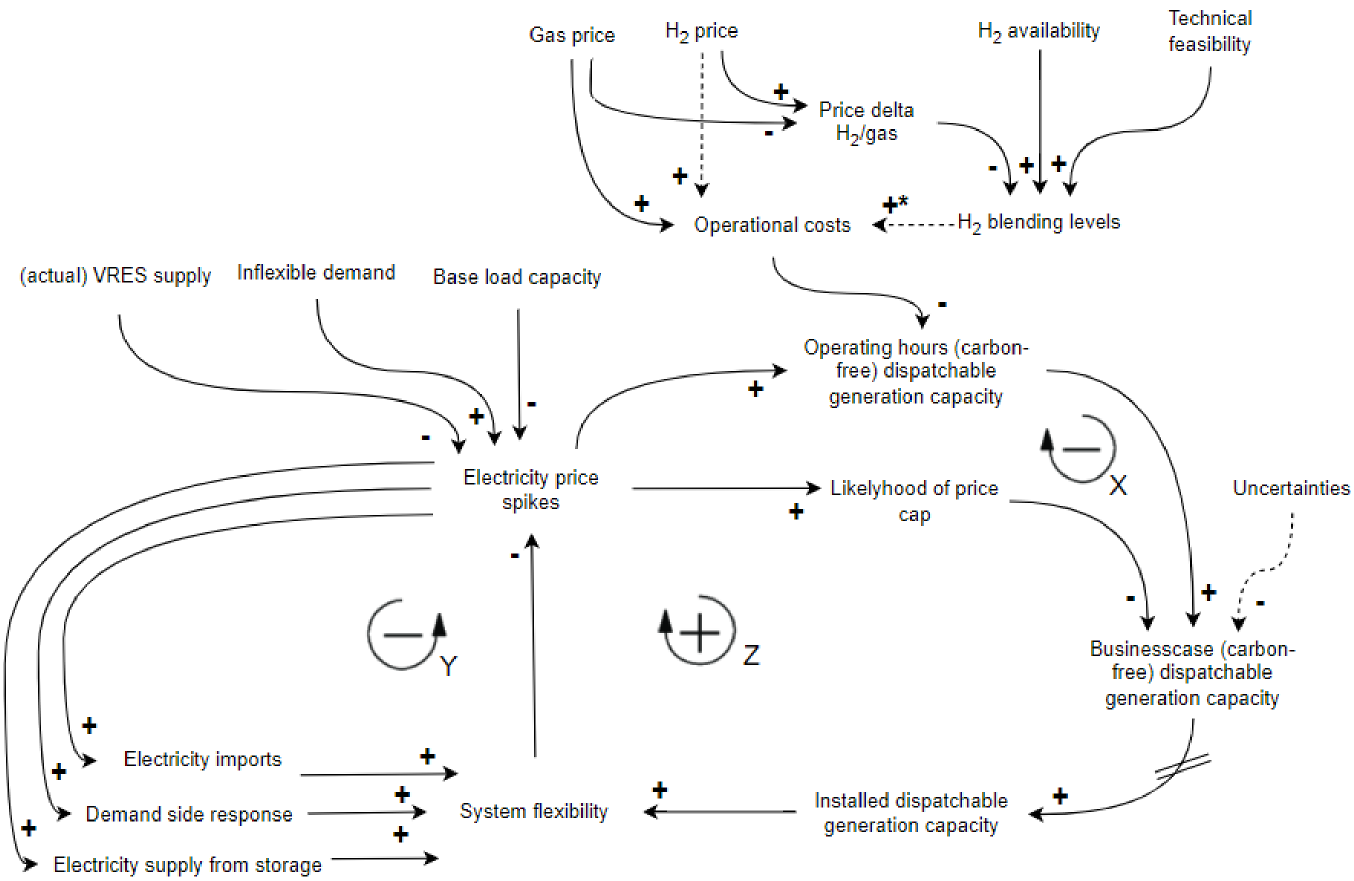

Figure 7.4: Causal relation diagram of electricity system concerning peak demand

\+ *Arrow with plus sign presents a positive causal relation; if factor A increases, factor B increases.*
\- *Arrow with minus sign presents a negative causal relation; if factor A increases, factor B decreases.*
.. *Dotted arrows are explained in text below.*
* *Depends on the price delta H2/gas. Positive relation as long as H2 price > gas price.*
** *Uncertainty variable represents uncertainties from Chapter 5.*

In the causal relation diagram, the factors that only have outgoing arrows are context factors, which at this level of aggregation are considered unaffected by other factors. However, an exception to this is the 'uncertainty' factor, indicated by a dotted arrow. This factor represents all the uncertainty factors discussed in Chapter 5 concerning gas and hydrogen power plants, which partially overlap with the factors in this diagram. The same reasoning applies here; if uncertainties increase, the business case worsens. Besides these context factors, all other factors are influenced within the system, resulting in two balancing feedback loops X (-) and Y (-) and one reinforcing feedback loop Z (+). The causal relations are explained starting with the three context factors that influence the height of electricity price spikes.

When the actual supply from VRES is low, for instance during cloudy days, and inflexible demand is high, for instance due to the electrification of industries that cannot easily reduce demand, and base load capacity is low, it would add to the height of the electricity price. Depending on the actual levels. these factors would add to the height of a possible price spike.

However, the price signal transitions into a balancing feedback loop: if high electricity price spikes occur, dispatchable generation capacity operates in case the electricity price meets or exceeds its marginal costs. More expected operating hours increase the viability of the business case for dispatchable generation capacity. An improvement in the viability of the business case enhances investment decisions and can increase the installed capacity of dispatchable generation capacity. However, given the long lead time of this investment, there is a delay between these factors, represented by the double stripes on the arrow. If the installed capacity of dispatchable generation capacity increases, system flexibility increases. This increase in flexibility decreases electricity price spikes, which in turn reduce the operating hours of dispatchable generation capacity, concluding the balancing feedback loop X.

Incorporated within this balancing feedback loop X is the reinforcing feedback loop Z: When an electricity price spike increases in height, the perceived likelihood of a price cap also increases, as mentioned previously by some interviewees. This worsens the business case for dispatchable generation capacity and, over time, could lead to a decrease in installed capacity. A decrease in installed capacity reduces system flexibility, which increases the height of possible price spikes, which again increases the likelihood of a price cap. This concludes the reinforcing feedback loop Z.

Linked to these two feedback loops is the balancing feedback loop Y: When the electricity price increases, other flexibility-providing technologies also respond, depending on their availability and place in merit order; when the electricity price in the Netherlands is higher than in neighboring countries, electricity will be imported as long as the interconnection capacity can facilitate. Also, due to price signals of price volatility, demand-side response increases, as well as electricity supply from storage. Similar to the business case for dispatchable capacity, the capacity for these flexibility-offering technologies increases when there is a viable business case. An increase in these technologies also leads to an increase in system flexibility, which again decreases prices and concludes the balancing feedback loop Y.

Here, it is notable that both balancing feedback loops X and Y respond to electricity price signals by enhancing system flexibility, which in turn reduces the high prices. However, the long lead time for investments in dispatchable generation capacity, coupled with uncertainties and the perceived likelihood of a price cap, impacts the business case. Additionally, the operating costs of dispatchable generation capacity influence the number of operating hours, which also affects the business case. An increase in operating costs decreases the number of operating hours, thereby weakening the business case.

Currently, at this level of aggregation, operating costs primarily depend on the gas price. Higher gas prices lead to higher operational costs. If hydrogen is blended or fully used for operation, the hydrogen price will also affect the operational costs. Here, the reasoning applies that hydrogen is currently more expensive than gas. Thus, an increase in gas prices or a decrease in hydrogen prices reduces the price difference between hydrogen and gas. A smaller price difference would typically lead to higher blending levels of hydrogen. However, this is only feasible if the power plant can technically blend hydrogen and if hydrogen is available for the power plants, such as when sufficient infrastructure and storage are in place. If a power plant blends hydrogen while hydrogen remains more expensive than gas, operational costs increase. This relationship is regarded as hypothetical by interviewees, as hydrogen is economically viable only when it is cheaper than gas, which is currently not the case. Therefore, these relationships are indicated with a dotted line. The following subsections will further address these relationships and their perceived effects.

7.2.2. Problem diagram

When connecting the causal relation diagram to objectives and incorporating alternatives, the problem diagram is created. During the interviews, several objectives at different aggregation levels were identified. A long list of these objectives is presented in Appendix D. Although the objectives span various aggregation levels, they can be categorized into the three main objectives of the electricity system: reliability, affordability, and sustainability, as well as the viability of a business case for carbon-free firm dispatchable generation capacity. This final objective is highlighted by both generation companies and other stakeholders and experts, as it not only entails sustainable profitability for the generation companies but also enhances the system's reliability and sustainability. Given that all three identified alternatives are perceived to enhance the business case by increasing the IRR and mitigating uncertainties as addressed in the previous chapter, this objective is not explicitly visualized in the problem diagram, but incorporated as a factor within the causal relation diagram itself. The objectives of reliability, affordability, and sustainability are incorporated at an aggregation level that matches the causal relation diagram. However, this entails that some objectives and the perceived effects of the policy instruments on these objectives, which are already addressed in the previous sections, are not fully addressed in the diagrams.

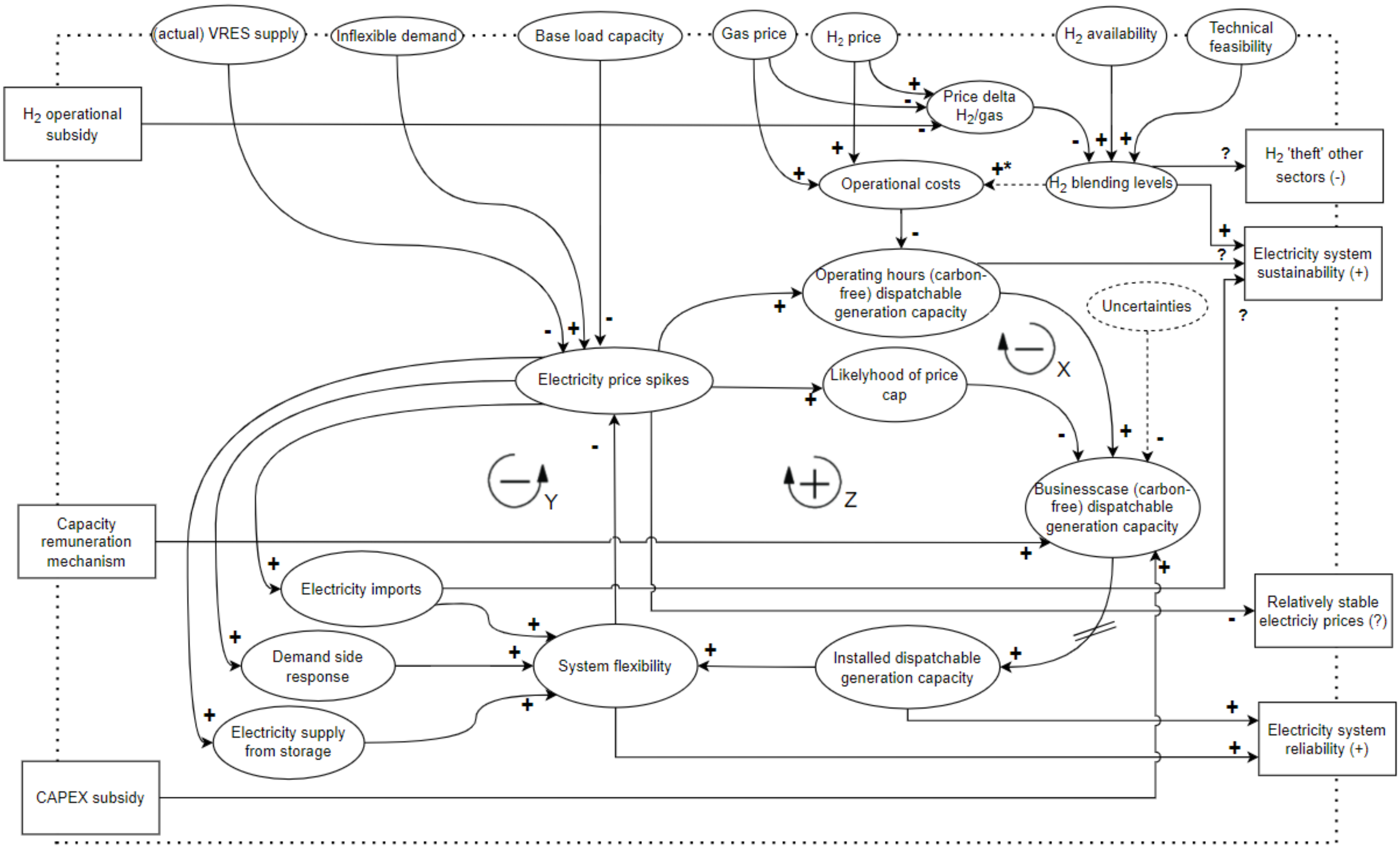

Figure 7.5: Problem diagram of electricity system concerning peak demand

The resulting problem diagram is visualized in Figure 7.5. The dotted line represents the system boundary, with the context variables positioned at the top. On the left side, the three identified policy instruments and their effects on the system are depicted as addressed in the previous chapter: a CAPEX subsidy lowers initial investment costs, thereby enhancing the business case for dispatchable generation capacity; thus, a higher CAPEX subsidy improves the viability of the business case. Similarly, the operational subsidy (partially) covers the price difference between hydrogen and gas; a higher operational subsidy reduces the price difference. Lastly, the implementation of the capacity remuneration mechanism also increases the viability of the business case for generation capacity by providing an extra stream of revenue.

On the right side of the problem diagram, four objectives are included, matching the aggregation level of the causal diagram. Regarding sustainability, there are two main objectives: first, to ensure that hydrogen is not diverted from sectors where it can more efficiently reduce carbon emissions, and second, to enhance the overall sustainability of the electricity system by achieving low carbon emissions. The objective of maintaining a reliable system is included directly at its high level of aggregation. Finally, the objective of maintaining relatively stable electricity prices is incorporated; however, not all interviewees viewed this objective consistently, as indicated by the question mark (?). This is further explained in the next subsections. Additionally, the effects of electricity imports on the system's sustainability, the hydrogen blending levels on H2 'theft' from other sectors, and the effect of the number of operation hours are dependent on the interviewees' line of reasoning, which is also indicated by a question mark (?). When applicable, this is addressed per line of reasoning. Moreover, since all three policy instruments involve some form of subsidization and thus affect affordability in the form of system costs, this objective is not included in the diagram but is addressed separately.

The following subsections visualize the collections of lines or reasoning for both the perceived favorable and unfavorable effects, per policy instrument, utilizing the perceived impacts on the causal relations in the system. Here, the arguments from interviewees who viewed the effects as nuanced are also incorporated; both their lines of reasoning in favor and against are represented in the diagrams.

7.2.3. Cognitive diagram: CAPEX subsidy

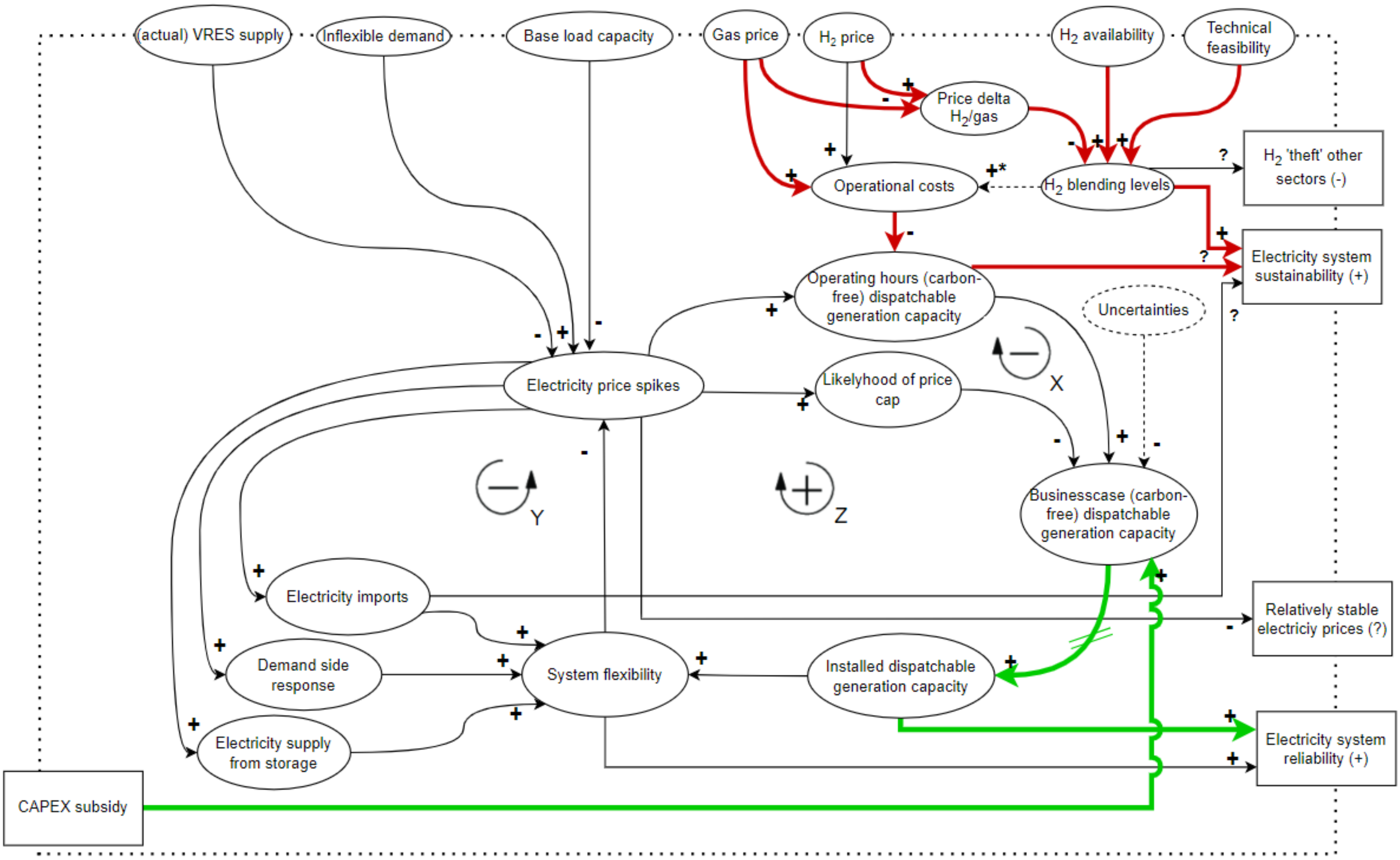

Figure 7.6: Visualization of the key lines of reasoning for and against a CAPEX subsidy
Green lines represent the perceived favorable effects, while red lines represent the reasoning why the CAPEX subsidy has no additional favorable effect.

As noted in the previous results section, interviewees perceive the CAPEX subsidy in different ways. Figure 7.6 visualizes the main lines of reasoning for and against the subsidy, considering the objectives. The green lines present the perceived effects that form the arguments in favor of the subsidy, while the red lines present the perceived effects that form the arguments against.

Line of reasoning in favor of CAPEX subsidy
The line of reasoning in favor of a CAPEX subsidy, based on the collection of arguments of perceived favorable effects of the CAPEX subsidy presented by the interviewees, is relatively straightforward. By covering the initial investment costs for retrofitting existing capacity, the business case for retrofitting becomes more economically viable. Retrofitting prepares the power plant for potential hydrogen blending, should it become economically viable compared to gas utilization. By incentivizing the investment to retrofit, the long lead time of the investment is addressed, allowing the retrofitted capacity to already prepare for operation on hydrogen once it becomes economically viable. Moreover, this incentive to retrofit could also encourage the maintenance of current capacity in the market, which further contributes to system reliability.

However, no interviewees perceived a favorable effect on system sustainability in the short term when only considering the CAPEX subsidy. Some interviewees believe that combining the CAPEX subsidy with an operational subsidy could produce favorable effects, which is addressed in the next subsection. Additionally, Interviewee F from a research institute indicated that to ensure emission reductions, a regulatory or pricing instrument should be used in conjunction with the CAPEX subsidy. Although these pricing and regulatory measures are not assessed further here, as they do not directly stimulate system reliability (as discussed in Chapter 6), the cognitive diagram visualizing the line of reasoning regarding the perceived unfavorable effects is presented in Appendix E.

Line of reasoning against CAPEX subsidy
The line of reasoning against a CAPEX subsidy, as a collection of the arguments of unfavorable effects by the interviewees, consists primarily of arguments why a CAPEX subsidy in the short term would not cause emission reduction. Notably, this is similarly perceived by the interviewees who perceive the subsidy as an initial favorable step. Since the line of reasoning regards why the subsidy is not impactful on sustainability, nor needed to reduce emissions, it does not initialize from the CAPEX subsidy in the diagram.

All interviewees agree that, at present, implementing a CAPEX subsidy would not reduce emissions because the gas price remains higher than that of hydrogen. Due to the substantial price differential, hydrogen will not be utilized, and system sustainability will not improve. Additionally, as long as hydrogen is not available or if retrofitting is technically infeasible, hydrogen blending will be hindered, and the system's sustainability will not increase. However, if the CAPEX subsidy were to lead to mandatory hydrogen usage, the effects would resemble those illustrated in the cognitive diagram for the unfavorable effects of pricing and regulatory measures, as presented in Appendix E. Furthermore, some interviewees argue that the sustainability of the electricity system is already improving due to the decline in operating hours of current power plants. This effect is further enhanced by the rising gas prices driven by the EU ETS and the increasing capacity of other flexibility-providing technologies.

7.2.4. Cognitive diagram: operational subsidy

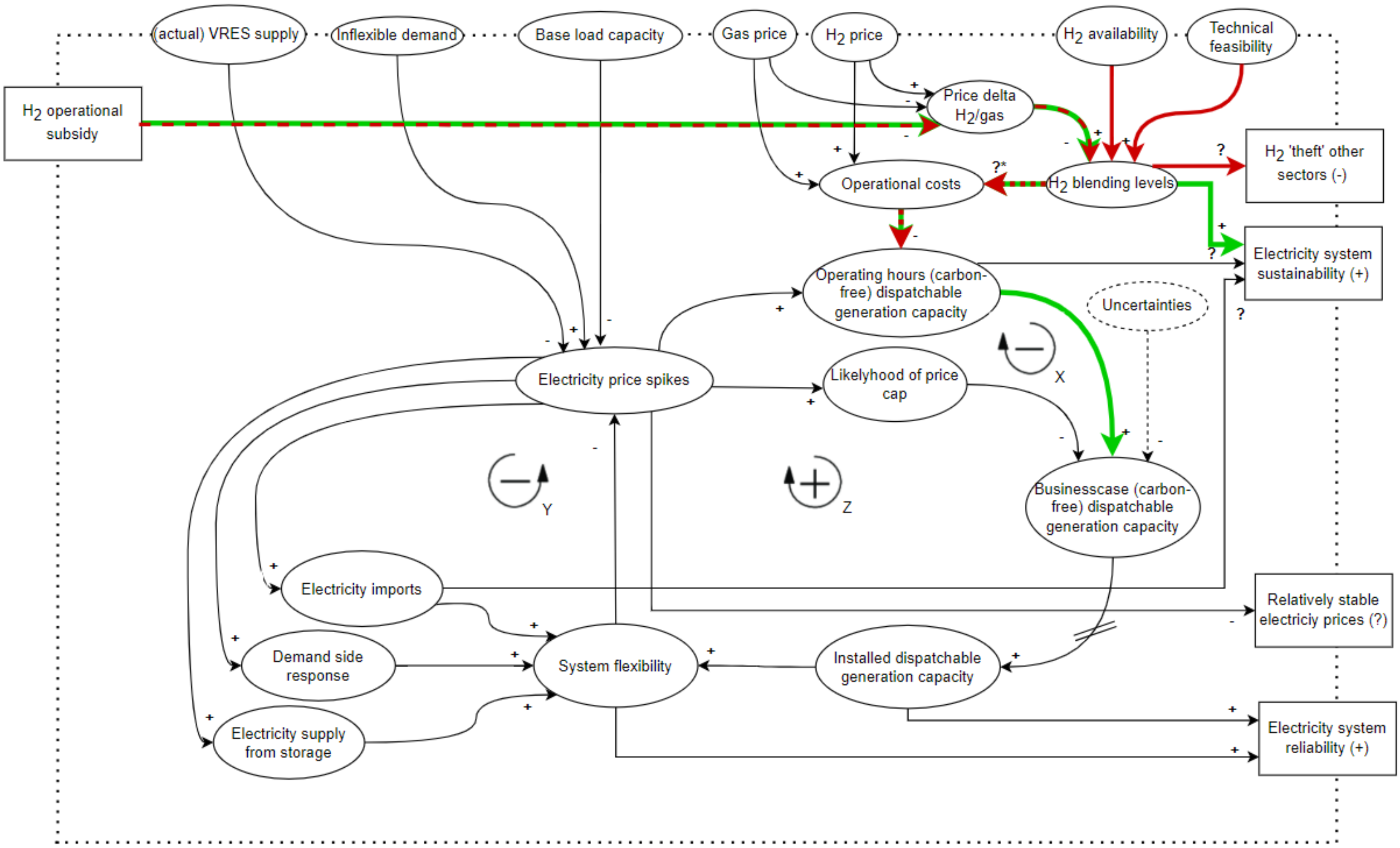

Figure 7.7: Visualization of the key lines of reasoning for and against an operational subsidy
Green lines represent the perceived favorable effects, while red lines represents reasoning why a CRM has no additional favorable effect.

Similarly, the operational subsidy is perceived in various ways by the interviewees. Figure 7.7 visualizes the main lines of reasoning for and against the operational subsidy, considering the objectives. The green lines present the perceived effects that support the operational subsidy, while the red lines highlight the perceived effects that argue against it.

Line of reasoning in favor of operational subsidy
The line of reasoning as a collection of arguments that perceive favorable effects of an operational subsidy starts at lowering the price difference between hydrogen and gas, the subsidy increases the potential for higher hydrogen blending levels. This increase in hydrogen blending lowers carbon emissions and thus enhances the sustainability of the electricity system. Additionally, if operational costs remain relatively similar to those of gas, the number of operational hours remains unaffected, making the business case for retrofitting existing capacity more viable with the subsidy, compared to without the subsidy. If retrofitting should be needed to make hydrogen blending feasible, accepting the subsidy and opting to retrofit allows for strategically preparing the power plant in case hydrogen may become economically viable without the subsidy or in case regulatory or pricing instruments are applied against natural gas utilization.

On the other hand, the operational subsidy does not address the uncertainty surrounding the number of operating hours for power plants. Consequently, it does not significantly improve the business case for constructing new power plants compared to not having the subsidy, as it only covers price uncertainty. Nonetheless, if the subsidy is contracted for the long term, it would allow the generation company to sign long-term contracts as well, which, on the other hand, would help strengthen the business case.

Although not visualized, it is generally agreed that if the subsidy is not provided but the 2035 sustainability aim does remain, the effects would be similar to those presented in Appendix E. This line of reasoning would begin with high operational costs leading to a weakened business case, followed by the feedback loops resulting in increased electricity imports from countries using gas. This would lead to lower overall system sustainability, and by following the feedback loops, to reduced reliability. Therefore, if achieving the 2035 aim is to be strictly adopted, the subsidy is perceived to be necessary to keep current capacity operational, despite its high cost.

Line of reasoning against operational subsidy
As previously addressed, a commonly argued unfavorable effect of the operational subsidy is its high and uncertain costs, particularly while the price difference between hydrogen and gas remains significant. Besides this affordability argument, there are different lines of reasoning regarding other unfavorable effects interviewees highlight.

First, by covering the price difference, the subsidy reduces the delta between hydrogen and gas prices, thereby increasing hydrogen blending levels. While the arguments favoring the subsidy perceive this increased blending reduces carbon emissions in the electricity sector, the arguments that highlight the unfavorable effects point out that extra stimulating hydrogen usage in the electricity sector might come at the expense of other sectors where hydrogen could be utilized more efficiently, potentially leading to greater overall emissions reductions.

Another concern is the uncertainty surrounding the optimal level of the subsidy. Given the inherent uncertainties in the system, the subsidy could affect operational costs in unpredictable ways. For example, if the subsidy is set too high, it could lower operational costs and subsequently increase operating hours, which exposes the risk of disrupting market dynamics.

Moreover, similar to what was addressed for the CAPEX subsidy, it is argued that market dynamics naturally reduce the price delta over time, thereby incentivizing hydrogen utilization without the need for an operational subsidy. This market-driven reduction in the price delta would also contribute to decreased carbon emissions in the system, including a European-level playing field. Additionally, like the CAPEX subsidy, the operational subsidy is perceived as ineffective for system decarbonization as long as challenges related to hydrogen availability and the technical feasibility of blending hydrogen and retrofitting continue to exist.

7.2.5. Cognitive diagram: capacity remuneration mechanism

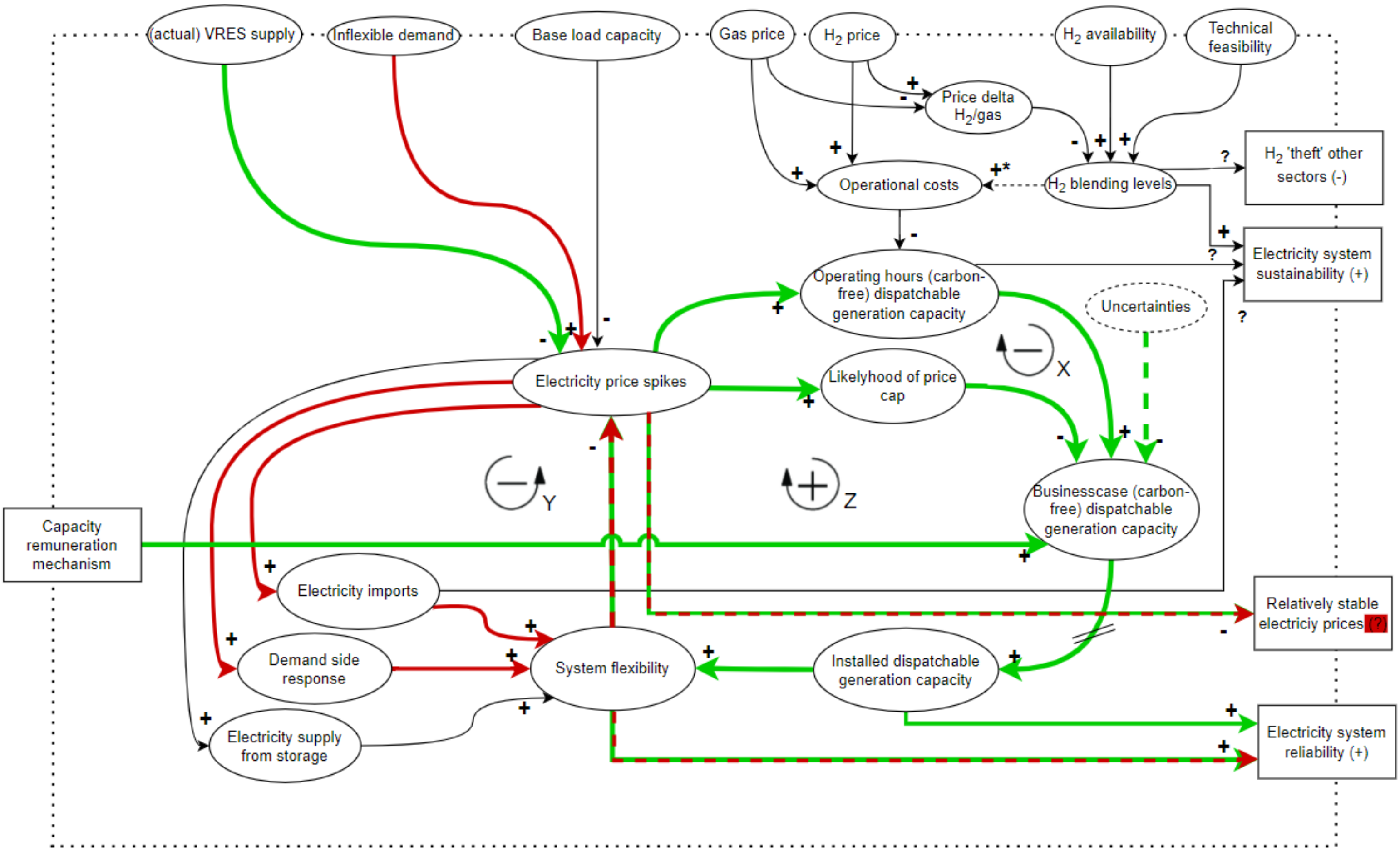

Figure 7.8: Visualization of the key lines of reasoning for and against a CRM
Green lines represent the perceived favorable effects, while red lines represent the reasoning why the CRM has no additional favorable effect.

Regarding the CRM, interviewees have varied perceptions and lines of reasoning. Figure 7.8 visualizes the collection of lines of reasoning for and against the CRM. The green lines present the perceived favorable effects that form the arguments in favor of the CRM, while the red lines present the perceived unfavorable effects that constitute the arguments against it.

Line of reasoning in favor of CRM
The arguments favoring the CRM revolve around the perception that the market alone will not incentivize sufficient investments in new dispatchable generation capacity to maintain a reliable electricity system, without experiencing extreme price spikes, hours with loss of load, or being reliant on uncertain electricity imports.

Notably, none of the arguments supporting the CRM view it currently as a means to enhance the system's sustainability. However, some interviewees have highlighted the challenge of integrating sustainability strategies into the construction of a CRM.

One line of arguments presented by the interviewees starts with the high penetration of VRES capacity in the market due to government intervention. This resulted in volatile and overall lower electricity prices and increased dependence on real-time market conditions. This dynamic diminishes the opportunity to lock in profits in advance and is by some interviewees perceived to have taken away the preconditions of an energy-only market given the government interventions for increasing RES.

Additionally, while the capacity of other flexibility-providing technologies also responds to price signals, the argumentation favoring a CRM entails that the increasing flexibility of these other technologies is not sufficient to ensure system reliability and to mitigate high spikes in electricity prices. The decreasing electricity prices because of high VRES supply, and the growing capacity of other flexible technologies that also answer to the price signals, reduce the expected number of operating hours of dispatchable generation capacity and diminishes the viability of the business case, which is influenced by the current uncertainties. However, the firm capacity is perceived to still be needed in cases of extreme periods of high demand and/or low supply.

Nonetheless, if high price spikes occur and dispatchable capacity is needed alongside other flexible technologies and is able to make profit above its marginal costs to cover the fixed and investment costs, it is perceived that the likelihood of a price cap will also increase, which adds to the uncertainties and further decreases the viability of the business case.

Additionally, a line of reasoning favoring a CRM highlights that the Netherlands should have sufficient domestic capacity to answer its own peak demand rather than relaying on electricity imports.

In summary, proponent arguments of the CRM include the need to provide certain payments for having capacity available to improve the viability of the business case, as the viability of the business case currently lacks rationality, but is needed to maintain the reliability of the electricity system, thereby keeping electricity prices relatively stable.

Line of reasoning against CRM
The reasoning against the implementation of a CRM considers the same effects that the instrument would have on the system but argues that, on the one hand, greater certainty to achieve a reliable system is not necessary and that more stable prices are not particularly seen as an objective. Additionally, although not visualized in Figure 7.8, a commonly mentioned argument is that implementing a CRM is inherently a market intervention that will not be easily reversed. This could lead to less overall efficiency compared to what market competition would achieve, resulting in higher overall system costs.

The common line of reasoning that deems the implementation of a CRM unnecessary highlights a wait-and-see approach. An argument supporting this is the perceived increase in other flexibility-providing technologies. It is suggested that electrification may not progress as expected, and any potential increase in electrification might primarily be flexible. Furthermore, the installation of more firm base-load facilities, such as nuclear power plants, might reduce the need for additional firm dispatchable generation capacity.

Additionally, it is argued that increasing electricity prices could have a learning effect, leading to greater demand-side response and potentially increased electricity imports from other countries with ample installed firm capacity such as those with CRM implementations. This line of reasoning perceives that electricity price spikes will provide the necessary price incentives for other flexibility-providing technologies, or potentially even in new firm dispatchable capacity, to achieve the required system flexibility and thus ensure a reliable system.

Although some interviewees do perceive it unlikely that large investments will be made in new power plants with high installed capacity without a CRM, they argue that such investments are not urgently unnecessary. The current capacity, which has already made significant initial investments, can still be further utilized and maintained and can continue to provide system reliability, besides the increase in other flexibility-providing technology, as long as no drastic sustainability objectives are implemented that impact the economic viability of current capacity.

7.3. Synthesis of perceived effects

The results highlight that interviewees have varied perceptions of the policy instruments' effects on the system, including differing views on whether these effects are favorable, unfavorable, or necessary. Moreover, perceptions also differ regarding the need to achieve the 2035 sustainability goals, the necessity of additional instruments beyond the EU ETS, and the requirement for additional measures to ensure system reliability. Besides, for each instrument, several interviewees have nuanced views, perceiving both favorable and unfavorable effects of the policy instrument without expressing a clear preference for or against its implementation.

Notably, the perceptions show a different focus on the aspects of sustainability, reliability, and affordability, depending on the policy instrument that is considered. The policy instrument of implementing a CRM is primarily discussed in terms of its impact on system reliability, and its effects on affordability, with little focus on its potential role in achieving sustainability. In contrast, the operational subsidy is primarily considered in light of its effects on sustainability and its affordability. Moreover, the CAPEX subsidy is addressed concerning all three factors, but the emphasis is mainly on its short- and long-term effects on sustainability and its cost-effectiveness.

This distinction highlights that there are actually two separate but highly interconnected challenges concerning the three policy instruments: achieving sustainability and maintaining system reliability. The CAPEX subsidy and operational subsidy are primarily addressed mainly based on their effects on sustainability, while the CRM is addressed mainly based on its impact on reliability. However, all three instruments are also considered in terms of their effects on affordability, including overall system affordability, potential price spikes, and the costs of implementing the policy.

Sustainability
Regarding the CAPEX and operational subsidies, mainly the interviewees from generation companies highlight that if the 2035 aim is to be met, the CAPEX subsidy is a favorable first step, followed by the operational subsidy as a second step. However, these interviewees, along with interviewees from the other stakeholder types, do recognize that in particular, the operational subsidy comes with very high and uncertain costs, and that infrastructure and storage need to be aligned with these subsidies for them to be effective.

If the operational subsidy is not provided, but power plants are still forced to reduce emissions more than other plants in Europe to meet the 2035 aim, this is perceived as creating an uneven playing field in Europe and will move the Dutch plants back in the European merit order. This could lead to high imports of cheaper electricity, potentially from fossil sources, and resulting in carbon leakage and depressed viability of Dutch power plants. Conversely, if the operational subsidy is provided, some interviewees perceive this might lead to hydrogen ”theft” from other sectors that could potentially use hydrogen more efficiently. Additionally, given the uncertainties and market volatility, estimating the optimal level of subsidy is difficult. One interviewee from a (semi-)governmental organization perceives that this could result in power plants becoming dependent on the height of subsidy, thus influencing operating hours and risking a disruption of market dynamics.

On the other hand, all interviewees agree that the CAPEX subsidy alone would not lead to emission reduction, but would mainly prepare power plants for the future. Some interviewees connect this to the reliability objective and perceive that this subsidy could help maintain the existing capacity in the market. However, other interviewees see that not all power plants are technically feasible to retrofit for hydrogen operation.

Some interviewees point out that both the 2035 aim and the EU ETS timeline, which is uncertain, but mainly expected to reach zero around 2040, are approaching quickly, especially when regarding the long lead time of investments. Therefore, they perceive it necessary to implement such subsidies to facilitate learning effects and address technical challenges. Others, however, question whether these additional sustainability goals and policies, which come with high costs, are necessary on top of the current EU ETS, which already provides incentives to lower emissions and incorporates a European-level playing field, but comes later in time.

Reliability
Notably, when considering the CRM as a policy instrument, which is primarily evaluated for its impact on reliability, there is no clear distinction in overall perceptions for the different stakeholder types. A slight exception is interviewees from (semi-)governmental organizations, who generally perceive the effects as nuanced or predominantly unfavorable.

The perceptions vary on whether the EOM will still provide sufficient incentives for investments in firm dispatchable generation capacity, or whether a CRM is necessary to ensure higher certainty and investment incentives. On the other hand, some interviewees perceive that stimulating the maintenance of current capacity in the market, combined with increased flexibility from other technologies; demand-side response, interconnection capacity and storage, and potentially expanding base-load capacity, might also be sufficient to ensure reliability without the need for a CRM.

Interviewees who support the CRM express concerns that without it, the electricity market is moving from a low-risk, low-margin system to a high-risk, potentially high-margin system, characterized by high price spikes and potentially LOLE, where the EOM characteristics no longer fully apply due to the governmental interventions for decarbonization. They see that in such a system long-term contracts are not possible, which are needed to base investments on. Moreover, they question whether such a high-risk system is favorable for the electricity market with its public function. Additionally, they perceive potential price caps during price spikes, which would distort the market and undermine the viability of the business case for firm capacity.

However, those interviewees who perceive negative effects of the CRM also perceive that high price spikes will likely occur, but that these spikes would create a learning effect and provide incentives for more of the three other flexibility-providing technologies, such as demand-side response. They also express concerns that once a CRM is implemented, it could be challenging to reverse, less efficient than a market-based approach, and result in higher overall system costs.

Furthermore, some interviewees believe that if neighboring countries implement a CRM, the Netherlands could benefit due to the interconnection capacity. However, other interviewees argue that if other countries implement a CRM while the Netherlands does not, it results in an uneven playing field.

Differences
These high-over lines of reasoning are further summarized to provide an overview of the main perceptions and differences between perceptions regarding CAPEX and OPEX subsidies, which are mainly considered for their effects on sustainability, and CRM, which is primarily assessed for its effects on reliability. Table 7.1, provides this overview for CAPEX and operational subsidies, and Table 7.2 provides this overview for CRM.

CAPEX and operational subsidies - Favoring	CAPEX and operational subsidies - Disfavoring
• Without operational support, forcing Dutch plants to reduce emissions more than those in other European countries weakens their business case and can lead to carbon leakage through increased imports of fossil-based electricity. • CAPEX subsidies are a favorable first step in preparing power plants for future hydrogen usage, followed by operational subsidies to actually stimulate hydrogen and emission reduction. • Despite the high costs, these subsidies are important for meeting the 2035 emissions aim, or even the upcoming EU ETS targets, both of which are approaching relatively quickly given the long lead times of investment. • The CAPEX subsidy can help maintain existing capacity in the market and support system reliability by keeping retrofitted plants operational, if retrofitting does not exclude natural gas utilization. • The subsidies could facilitate learning effects and help overcome technical challenges. • Aligning infrastructure and storage development with these subsidies is key to making retrofitted plants operationally effective once hydrogen is competitive.	• CAPEX subsidies alone are not expected to reduce emissions in the short term, as they mainly serve to prepare plants for potential future hydrogen usage. • The costs of providing operation subsidies are high and uncertain. • Estimating the optimal level of operational subsidy is challenging due to market volatility and uncertainties. This could lead to market distortions by creating dependency on the subsidy levels to determine operating hours. • Operational subsidies could divert available hydrogen from sectors that can use it more efficiently and create more carbon reductions. • Not all power plants are technically feasible for hydrogen retrofitting, and providing subsidies to only a few plants could undermine a level playing field across the sector. • The existing EU ETS already incentivizes emission reductions, making additional decarbonization measures unnecessary and potentially leading to inefficient resource allocation and unnecessary costs.

Table 7.1: Summary of perceptions favoring and disfavoring CAPEX and operational subsidies

CRM* - Favoring	**CRM* - Disfavoring**
• Government interventions in carbonization undermine the dynamics of an EOM, thus the EOM preconditions do not hold anymore. • High VRES capacity has increased market volatility and reduced revenue certainty for firm dispatchable generators. • Without a CRM, limited investments could lead to price spikes, load shedding during extreme conditions, and potentially leading to price caps that distort market dynamics. • A CRM can offer predictable revenue streams, making investment more attractive in uncertain conditions, especially if the CRM incorporates long-term contracts. • Increasing capacity of other flexibility-providing technologies are insufficient to ensure reliability during peak demand or low supply periods, making a CRM necessary for securing firm capacity. • Energy self-sufficiency and reduced dependence on imports justify securing domestic capacity through a CRM. • Neighboring countries' CRMs could attract investments away from the Netherlands. A level playing field is important. • A CRM spreads investment risks across society, transitioning from a high-risk, potentially high-margin system, partially back to a low-risk system.	• A CRM is unnecessary if the government avoids intervening during high price spikes, as the market can still function effectively without it. • Implementing a CRM could distort market dynamics, leading to reduced competition, lower efficiency, and overall higher system costs. • A CRM is a drastic measure that would be difficult to reverse. • Electrification may not progress as expected or be flexible enough, reducing the need for additional firm capacity. • Price spikes can drive necessary investments in other flexibility-providing technologies, without requiring a CRM. • Increased flexibility from other flexibility-providing technologies may be sufficient to maintain system reliability without a CRM. • The Netherlands could benefit from the CRMs in neighboring countries through imports, reducing the need for its own CRM. • Existing capacity, with already significant investments made, can still ensure reliability without the need for new large investments driven by a CRM.

Table 7.2: Summary of perceptions favoring and disfavoring CRMs
*CRMs excluding strategic reserve of capacity

8 Explanation of differences in perceptions

This chapter further analyzes the results from the exploratory analysis of the previous chapters by utilizing an explanatory approach. The aim of this chapter is to identify possible explanations for the differences in perceptions identified in the previous chapter. The central question of this chapter is the final sub-question: *How can differences in perceptions be explained?*

First, Section 8.1 provides an introduction to structure the chapter. Following this, the subsequent sections 8.2 to 8.6 present the results. Finally, Section 8.7 provides a synthesis.

8.1. Introduction to possible explanations of differences

As addressed in the synthesis of the previous section (Section 7.3), it was found that stakeholders and experts not only hold differing perceptions regarding the effects of the instruments on sustainability, reliability, and affordability, and the favorability or unfavorability of these effects, but also can differ in their perceptions about the need for additional instruments to stimulate decarbonization beyond the EU ETS, the need for additional instruments to secure system reliability, and the need and effects of achieving the 2035 sustainability goals.

The previous results showed that perceptions vary within and among different stakeholder groups and experts, and that for each policy instrument, not every stakeholder perceived only favorable or unfavorable effects; nuanced views are also held. Here, an exception was identified: generation companies perceive CAPEX and operational subsidies more favorably compared to other stakeholders and experts. Additionally, it was notable that all stakeholders from (semi-)governmental organizations held nuanced, or unfavorable perceptions of all three instruments.

Moreover, when grouping the lines of reasoning of the perceived favorable and unfavorable effects of the policy instruments in Section 7.2, the feedback loops and relations in the electricity market revealed the complexity of the perceived effects. Additionally, the results showed that the CAPEX subsidy and operational subsidy are primarily perceived regarding their need and effects on retrofitting and sustainability, whereas CRMs are mainly perceived regarding the need and effects on securing reliability.

Given this complexity and varied views on several factors besides sustainability, reliability, and affordability, and the warning of Ritchie et al. (2003) of qualitative explanatory research being 'bottomless', this chapter analyzes a selection of the contrasting perceptions presented in Tables 7.1, and 7.2, rather than differing perceptions of individual interviewees. Where applicable, the stakeholder type or expert group is taken into consideration.

Moreover, given that perceptions are inherently subjective and vary widely due to the complexity and variability among stakeholders and experts, conducting member checking to validate the interpretations of this explanatory research was preferred. However, this was deemed unfeasible due to time constraints. Therefore, the results of this explanatory analysis should be interpreted as 'possible explanations' rather than definitive conclusions. The selection from contrasting perceptions of the previously presented tables, is presented in Table 8.1.

No.	Perception favoring implementation of policy instrument	vs.	Perception disfavoring implementation of policy instrument
1	*Increasing capacity of other flexibility-providing technologies are insufficient to ensure reliability during peak demand or low supply periods, making a CRM necessary for securing firm capacity.*	vs.	*Increased flexibility from other flexibility-providing technologies may be sufficient to maintain system reliability without a CRM.*
2	*Without a CRM, limited investments could lead to price spikes, load shedding during extreme conditions, and potentially leading to price caps that distort market dynamics.*	vs.	*Price spikes can drive necessary investments in other flexibility-providing technologies, without requiring a CRM.*
3	*Energy self-sufficiency and reduced dependence on imports justify securing domestic capacity through a CRM.*	vs.	*The Netherlands could benefit from the CRMs in neighboring countries through imports, reducing the need for its own CRM.*
4	*CAPEX subsidies are a favorable first step in preparing power plants for future hydrogen usage, followed by operational subsidies to actually stimulate hydrogen and emission reduction.*	vs.	*Operational subsidies could divert available hydrogen from sectors that can use it more efficiently and create more carbon reductions.*
5	*Despite the high costs, CAPEX and operational subsidies are important for meeting the 2035 emissions aim, or even the upcoming EU ETS targets, both of which are approaching relatively quickly given the long lead times of investment.*	vs.	*The existing EU ETS already incentivizes emission reductions, making additional decarbonization measures unnecessary and potentially leading to inefficient resource allocation and unnecessary costs.*

Table 8.1: Selection of contrasting differences in perceptions

The results of the analysis of possible explanations are presented in the following sections. First, Section 8.2 discusses an explanation related to ideologies. Subsequently, Section 8.3 addresses the influence of the perceived development of uncertainties. This is followed by explanations concerning perceived risk and acceptable risk, perceived scope, and possible strategic considerations in Sections 8.4, 8.5, and 8.6, respectively.

8.2. Ideologies

A selection of the contrasting perceptions shows that the perceived effect is similar, but the favorability of this effect differs. An explanation for this can be that different ideologies are considered. These ideologies can differ in how they, explicitly or implicitly, balance sustainability, affordability, and reliability, or how they favor connected concepts, such as the ideology of the extent to which the country should be energy self-sufficient, or how price spikes and overall system costs are seen in relation to each other.

Partially, the contrasting perceptions numbered 2, 3, and 5 perceive the same effect, either due to the implementation of the policy instrument or because they perceive this effect as a result of the dynamics of the electricity market. However, their views on the favorability of these effects differ. Therefore, this could be explained by differences in balancing ideologies;

Perception number 3 reflects a difference in ideology regarding energy self-sufficiency. The favorable perception holds that creating energy self-sufficiency with reduced dependence on imports justifies the implementation of a CRM. On the other hand, the contrasting perception does not share this ideology and sees dependence on neighboring countries that have implemented a CRM with secured levels of installed capacity as potentially beneficial, as this could facilitate imports and reduce the need for extra regulation by implementing a CRM domestically to secure reliability.

Moreover, the contrasting perceptions numbered 5 can also be explained by differences in ideologies from another focus. The favorable perception of the CAPEX and operational subsidies implies that if the sustainability aim is strictly adopted, the high costs of the policy instruments are justified in contrast to the consequences of achieving the sustainability goal. On the other hand, the unfavorable perception implies an ideology that the effects of additional sustainability aims are valued less than the high costs of the policy. Thus, a different balance between the ideology of favoring sustainability over affordability, or vice versa, can explain these contrasting perceptions.

Additionally, for the contrasting perceptions numbered 2, differing ideologies can also partially account for the divergent views. The disfavoring perception of implementing a CRM reveals an ideology that price spikes should not be mitigated by securing investment with a CRM, as they see price spikes incentivize investments. On the other hand, the favorable perception implies that price spikes are seen as undesirable. In this case, a different balance in how affordability is perceived can be part of the explanation for why the perceptions differ. However, this perception can also be explained differently, as addressed in the following section regarding perceived risk.

8.3. Perceived risks and perceived acceptable risks

Following up on the possible explanation of differences in ideology that can account for differing favorability of similar perceived effects, is an explanation based on perceived risk and perceived acceptable risk.

Contrasting perceptions number 3, as addressed in the previous section, relate to the perceived need for energy self-sufficiency. Differences in how reliance on other countries is perceived can be explained not only by differing ideologies, but also by the perceived risks associated with insufficient importing capacity. For instance, even if neighboring countries have sufficient firm capacity, it could be diverted to other interconnected countries, which potentially limits availability.

Similarly for contrasting perceptions number 2, perceived risk can explain differing views on the effects of a CRM. The favorable perception of a CRM sees risks not only of high price spikes, but also of load shedding during scarcity or the implementation of price caps. In contrast, the opposing perception does not explicitly address these risks.

8.4. Perceived development of uncertainties

Closely related to perceived risks that explain differing perceptions are varying views on how uncertain factors within the system develop. Since the dynamics of the system are influenced by the development of uncertain factors, as identified in Chapter 5, this can explain differences in perceptions regarding the need for or effectiveness of a policy instrument.

For instance, the favoring perception of number 1 perceives that an increase in capacity of other flexibility-providing technologies is insufficient to ensure reliability during peak demand and thus sees the need for a CRM. This implicitly indicates that they also perceive insufficient investment levels in firm capacity. In contrast, the opposing perception believes that increased flexibility from other technologies may be sufficient for ensuring reliability. This difference can be explained by how they perceive the uncertainty of the need for system flexibility to develop; one perspective anticipates that flexibility needs will be met without additional instruments, whereas the contrasting perspective sees that the uncertain flexibility needs may develop sufficiently. On the other hand, this can also be explained by how much risk one associates with reliance on other flexibility-providing technologies and whether this risk is deemed acceptable.

8.5. Perceived scope

Moreover, the scope of the problem considered can also explain differences in perceptions, both regarding the perceived effects and the need or favorability of the policy instruments.

For instance, the disfavoring perception of number 4 considers the potential diversion of hydrogen from other sectors if an operational subsidy is provided for the electricity sector. In contrast, the favoring perception focuses solely on the effects within the electricity sector and does not consider the impact on other systems.

Similarly, perceptions number 5 both consider the time scope of the EU ETS. However, the favoring perception of CAPEX and operational subsidies also emphasizes the 2035 sustainability goal. Given that the 2035 goal represents a shorter time frame, this could affect the perceived need for additional stimulation. In contrast, the disfavoring perception views the timeline of the EU ETS and its effects as sufficient for sustainability objectives. This can thus also be explained by a difference in balancing ideologies.

8.6. Strategic considerations

Finally, a possible explanation for differences in revealed perceptions could be strategic considerations by the stakeholders.

The previously discussed favoring perception number 5 supports the need for both CAPEX and operational subsidies, taking into account both the 2035 sustainability goal and the EU ETS timeline. This perception was, among others, held by a stakeholder from a generation company. Since CAPEX and operational subsidies enhance the viability of power plant business cases, as discussed in Chapter 6, advocating for these subsidies despite their high costs can be explained by the strategic interests of the power plant operator. This explanation also accounts for the primarily positive or nuanced views of stakeholders from generation companies regarding CAPEX and operational subsidies, as illustrated in Sections 7.1.1 and 7.1.2.

Moreover, strategic considerations regarding revealed perceptions of policy instruments can also partially explain the nuanced views held by stakeholders from (semi-)governmental organizations. Due to their obligation to adhere to regulations such as the 'Ambtenarenwet en de Gedragscode Integriteit Rijk' (*Civil Servants Act and the Code of Conduct for Integrity in the Government*) (Tweede Kamer der Staten-Generaal, 2024), they are, depending on the situation, required to refrain from publicly disclosing personal perceptions. Here, if they would reveal a strongly favorable or unfavorable perception of a policy instrument, this could lead to market anticipation.

Notably, the contrasting perceptions do not explicitly address trade-offs between achieving the 2035 sustainability goals and maintaining system reliability. However, the previous chapter indicated that stakeholders generally see the instruments of CAPEX and operational subsidies, and their impact on sustainability, as distinct from the CRM policy instrument for securing reliability. Therefore, even though the previous results showed concerns about the impact of adopting the 2035 goal on reliability, no explicit differences in trade-offs are highlighted in this selection, which only considers the main contrasting perceptions of these distinct policy instruments.

8.7. Synthesis of possible explanations

The previous chapters revealed that perceptions of the effects of policy instruments on sustainability, reliability, and affordability, as well as the need for and favorability of these effects, vary significantly. Additionally, there are differences in views regarding the necessity of additional measures for decarbonization, system reliability, and achieving the 2035 sustainability goals. The analysis also showed that these perceptions vary both within and among stakeholder groups. An exception is that generation companies tend to view CAPEX and operational subsidies more favorably, though they also hold nuanced views. Meanwhile, (semi-)governmental stakeholders generally hold nuanced or unfavorable views of all three instruments.

Additionally, this chapter identifies several possible explanations for these differing perceptions among stakeholders. One explanation considers differences in ideologies, particularly in how stakeholders balance and interpret the meaning of sustainability, reliability, and affordability.

Moreover, differences in how risks are perceived and whether these risks are considered acceptable are also identified as possible explanations for differing perceptions. Closely related to this is the perceived development of uncertainty factors that can also explain differences in perceived effects or needs for the implementation of policy instruments. Additionally, the perceived scope, for example, whether effects on other sectors or other countries are taken into consideration, or whether the 2035 goal is, or is not considered alongside the EU ETS, can also explain for differences. Lastly, strategic considerations by stakeholders can explain why generation companies tend to view CAPEX and operational subsidies more favorably because they stimulate the business case. Additionally, the inability to share personal views in specific situations may explain why (semi-)governmental stakeholders generally hold nuanced or unfavorable perceptions of all three instruments.

The following possible explanations of differences in perceptions are identified:

- Differences in ideologies regarding the balance between sustainability, reliability, and affordability.
- Differences in perceived risks and perceived acceptable risks.
- Differences in perceived development of system uncertainties.
- Differences in perceived scope, e.g., the electricity sector or including other sectors, the Netherlands or Europe, and the 2035 sustainability aim or the EU ETS timeline.
- Strategic considerations of stakeholders.

9 Discussion

The main objective of this thesis is to identify and analyze the policy instruments that stakeholders and experts perceive as effective for incentivizing investments in firm carbon-free dispatchable electricity generation capacity, while considering the overall system's sustainability, reliability, and affordability. Additionally, this thesis aims to provide explanations for differences in perceptions. The research is based on the premise that investments in firm carbon-free dispatchable electricity generation capacity are crucial for achieving a 100% carbon-free electricity system in the Netherlands by 2035, while ensuring reliability and affordability. This aim, set by the Dutch government in 2023, has intensified the ambition for the Dutch electricity sector (Minister voor Klimaat en Energie, 2023a).

First, the research reveals a wide range of uncertain factors that heighten or add to uncertainties already addressed in literature. These uncertainties make it challenging to project the viability of investments in carbon-free firm dispatchable generation capacity, especially given their long lead times and lifespans. While Conejo et al. (2016) focused on uncertainties related to aggregated uncertain factors such as load evolution, future operational costs, and the investment decisions of other producers, this study reveals more detailed uncertainty factors and uncertainties due to the energy transition. The findings are consistent with previous research on the heightened uncertainties driven by the energy transition. These include heightened price volatility, as noted by Chronopoulos et al. (2016), policy uncertainties identified by Chronopoulos et al. (2016) and de Weerdt et al. (2023), and carbon price uncertainties discussed by Blyth et al. (2007) and Zhang et al. (2014). This research further contributes by providing an overview of uncertainties impacting market value, electricity demand and supply uncertainty, operational cost uncertainties, and their relations.

Further results show that subsidies for capital expenditures (CAPEX), operational expenditures, and capacity remuneration mechanisms (CRM), are perceived to partially reduce uncertainty and potentially stimulate investment. Stakeholders from generation companies, (semi-)governmental organizations, and expert groups addressed these instruments with a focus on retrofitting conventional power plants to hydrogen and investing in new capacity. CAPEX and operational subsidies are mainly perceived for their sustainability impact by incentivizing investments to retrofit, while CRMs are primarily perceived for their role in securing reliability. This aligns with literature where different CRM designs are discussed as tools for securing new investments under uncertainty and ensuring sufficient capacity, as explored by de Vries and Heijnen (2008). However, the results of this research only reveal general perceptions regarding CRM, without specific insights into different designs, possibly due to limited practical knowledge of these options.

Moreover, the focus on CAPEX and operational subsidies' impact on sustainability is consistent with literature, such as de Weerdt et al. (2023), who examines incentive payments for transitioning to hydrogen or hydrogen blending, and Zhang et al. (2014), who investigates CAPEX subsidies for retrofitting. However, while this research emphasizes retrofitting to hydrogen, Zhang et al. (2014) focuses on investments to retrofit with carbon capture and storage (CCS). Notably, Zhang et al. (2014) concludes that the carbon price required for retrofitting with CCS is far above current price levels, even when full

CAPEX subsidies would be provided, this would not incentivize investments, amongst others, due to efficiency losses. This can explain the main focus on hydrogen in this exploratory research.

Perceptions of CRM's necessity and effects differ, both within stakeholder groups and between experts, with the slight exemption of stakeholders within (semi-) governmental organizations who mainly perceive CRMs as nuanced or disfavorable. The results show that proponents of a CRM perceive that current high uncertainties and the anticipated lack of viability in power plant business cases lead to insufficient investment incentives. They also see a CRM as an instrument to partially move away from the current high-risk system caused by the effects of decarbonization. This includes the uncertainty of high price spikes, which might be capped, and expected loss of load. The perception that uncertainties reduce investment aligns with Real Option Theory, which emphasizes the value of waiting until uncertainties decrease (Dixit & Pindyck, 1994). Similarly, Gugler et al. (2020) found that asset-specific uncertainty particularly hinders investment in peak-load assets. Moreover, price caps lower than the value of lost load, are key to the debate of obstructing sufficient investment levels, as researched by Stoft (2002). Besides, the perceived need to move away from a high-risk system aligns with the market imperfection of an asymmetrical distribution of social risk, which entails that the costs of slight overcapacity are lower than the costs of undercapacity, which can lead to shortages (Cazalet, 1978). Therefore, as concluded by de Vries and Heijnen (2008) slight overcapacity can be seen as cheap insurance against the high costs of shortages.

On the other hand, some stakeholders argue against CRM, favoring a wait-and-see approach. They perceive price spikes will drive sufficient investment or encourage investment in other flexibility-providing technologies to ensure reliability. Thereby perceiving a CRM as a drastic measure that reduces competition and includes higher overall system costs. This line of reasoning corresponds with the Spot Pricing Theory, which suggests that price signals in a dynamic spot market will lead to socially optimal investment behavior (Caramanis, 1982). However, this theory does not include the effects of uncertainties and long investment lead times. Moreover, the perception that a CRM is a drastic instrument aligns with the notion that it represents a change in market design, moving away from an energy-only market, and aligns with the conclusion by Gugler et al. (2020), which notes that distortions can occur when implementing a CRM. However, Gugler et al. (2020) does address an increasing need for a CRM if support schemes for renewable energy persist.

Moreover, perceptions of CAPEX and operational subsidies vary among stakeholders. Stakeholders from (semi-)governmental organizations and experts generally hold unfavorable or nuanced views on operational subsidies, while generation companies view them more favorably, despite concerns about high costs. Some stakeholders perceive risks as market distortions, diverting hydrogen from other sectors, and carbon leakage to other countries if the 2035 aim is strictly enforced and the policies are implemented. Therefore, some question the favorability of the 2035 aim in addition to the European Emission Trading System (EU ETS). Conversely, others believe both CAPEX and operational subsidies are important for preparing power plants for the future, maintaining current capacity, and reducing emissions in the electricity sector, not just for 2035, but also to support learning effects when the EU ETS reaches zero. de Weerdt et al. (2023) concluded that the credibility of implementing announced policies encourages investments. Given that the 2035 aim is solely announced and its implementation is debated, this uncertainty may contribute to the diversity of stakeholder views.

Furthermore, several potential explanations for differing perceptions are identified, including varying ideologies about balancing reliability, sustainability, and affordability. This relates closely to the discussion in the literature and practice on balancing 'The Energy Trilemma,' which incorporates similar objectives (McCauley, 2017). Moreover, perceptions can be explained by differing views on perceived risks and acceptable risks related to system reliability, and how uncertainties are expected to develop. Additionally, the considered scope and strategic considerations may also account for differing revealed perceptions.

Limitations

The results of this study are subject to several limitations that should be considered when interpreting the findings. First, given the limited number of interviews across various stakeholder and expert groups, the findings may not fully capture all perspectives within the field. Additionally, the semi-structured exploratory approach of the interviews limited the gathering of perceptions from every interviewee on the identified policy instruments, as not all interviewees identified similar instruments. This was mitigated by directly asking about policy instruments when the interviewee did not address them. However, this approach could lead to abstract or incomplete perceptions, particularly if the interviewees were unfamiliar with the instrument in question. Consequently, not all interviewees are considered in the results for each policy instrument, which further narrows the sample size and limits the generalizability of the results.

Furthermore, the broad scope of the research on three aspects of the electric sector, affordability, reliability, and sustainability, forms a limitation for the depth of the research. Particularly, this thesis was built upon the premise that investments are needed to achieve the 2035 sustainability aim, but several interviewees perceived disadvantages in achieving this aim, in addition to European decarbonization goals. This limits the research, as possibly not all interviewees considered the same initial perspective or time frame when answering questions.

Additionally, given the qualitative approach of this research, the results can be interpreted with researcher bias. However, a structured data analysis was adopted to mitigate this limitation. Lastly, the perceptions gathered may be influenced by the strategic considerations of the interviewees about not disclosing sensitive business information.

Recommendations for future research

To provide greater depth regarding the possible explanations for differences in perceptions, further research is recommended on the impact of ideologies on trade-offs in balancing reliability, sustainability, and affordability, and how uncertainties are perceived to develop. A potential method to apply to research concrete perspectives is the mixed-method Q-methodology, as addressed by Exel and Graaf (2005) and Stephenson (1993).

Furthermore, this thesis did not include the impact of the extrinsic market value of capacity on the viability of business cases. However, Zappa et al. (2024) estimates that the extrinsic market value can account for up to 50% of the total value of a modern gas power plant. Therefore, this could impact differing perceptions regarding the need for additional simulations. Even though the methodology would be challenging since the information can be sensitive business data, research in this field is recommended.

Lastly, given the complexity of the uncertainty factors that impact the system and the differences in risk distribution of over- and under-capacity in the electricity market, a recommendation for further research is to assess robust scenarios under deep uncertainty, while taking into account ideologies and trade-offs between sustainability, reliability, and affordability. A possible methodology would be the utilization of the exploratory modeling workbench by Kwakkel (2017).

10 Conclusion & recommendations

In this thesis, the following research question was investigated: *What policy instruments do stakeholders and experts perceive to be effective for incentivizing investments in firm carbon-free dispatchable electricity generation capacity, while considering the Dutch 2035 100% carbon-free electricity production aim, system reliability, and affordability, and how can differences in perceptions be explained?*

This research is based on the premise that investments in firm carbon-free dispatchable electricity generation capacity are crucial for achieving the 2035 sustainability aim. This aim, set by the government, has intensified climate ambition for the Dutch electricity sector (Minister voor Klimaat en Energie, 2023a).

The research found that the energy transition introduces heightened uncertainty in assessing investment viability compared to conventional practices. This includes heightened uncertainties in operational costs, operating hours, electricity prices, potential price caps, and connected factors including base load capacity, intermittent VRES supply, flexibility-providing technologies, and inflexible load growth.

The perceptions of stakeholders from electricity generation companies, (semi-)governmental organizations, and experts regarding the need and effects of policy instruments that are perceived to stimulate the incentive to invest, differ. Even within stakeholder and expert groups, perceptions vary.

The policy instruments identified for their potential to stimulate the incentive to invest are perceived by the stakeholders and experts regarding their effects on two distinct but interconnected problem areas: stimulating decarbonization, and achieving a reliable system. Subsidies for capital expenditures (CAPEX) that cover the initial investment costs for retrofitting current capacity for hydrogen utilization, and operational subsidies that, partially, cover the price difference between hydrogen and natural gas are primarily addressed regarding their perceived effects on sustainability in contrast to affordability. Whereas capacity remuneration mechanisms (CRM), which provide payments for having available generation capacity in the market, are primarily addressed regarding their perceived need and effect on reliability.

Regarding CAPEX and operational subsidies, stakeholders from generation companies perceive the subsidies more favorable than other stakeholders and experts. Some perceive that if the 2035 aim is to be met, both subsidies are necessary, despite high and uncertain costs, to prevent carbon leakage to connected countries and depress domestic power plants' viability. Others perceive that if hydrogen is subsidized for electricity generation, it could lead to diverting hydrogen from other sectors that utilize it more efficiently, potentially resulting in lower overall emissions. Moreover, there is a perceived risk of incorrectly determining the optimal subsidy level due to uncertainties, which could distort market dynamics. Additionally, some see that the carbon emissions of conventional power plants are already decreasing, further stimulated by the European Emission Trading System that incorporates a European-level playing field; they question the need for additional carbon reduction aims and costly subsidies.

Moreover, perceptions regarding the need for and effects of a CRM differ, even within stakeholder groups and between experts. Some perceive that due to the energy transition, the electricity system is shifting from a low-risk to a high-risk system, and perceive that the impact of the transition decreases the expected viability of business cases and lowers investment levels, which affects system reliability. As a result, they see a need for a CRM to maintain system reliability and mitigate potential high prices, while also addressing the perceived risks of price caps that further depress investment incentives. Others, however, do not perceive the need for a CRM and perceive that price spikes will create a learning effect to incentivize sufficient investment in other flexibility-providing technologies, reducing the need for additional stimulation of investments in firm generation capacity. Some view a CRM as a drastic instrument that is less efficient due to the need for government regulations, which could lead to higher overall system costs. Moreover, some perceive that the implementation of a CRM in neighboring countries only benefits the reliability of interconnected countries, whereas others see this as creating an uneven playing field that can decrease domestic investments, while energy self-sufficiency is seen as desirable. Additionally, some hold nuances and favor a wait-and-see approach to how demand and supply will develop.

Several potential explanations for the varying perceptions are identified. These perceptions can be influenced by ideologies in balancing reliability, sustainability, and affordability, as well as the perceived level of risk and the acceptable level of risk in ensuring system reliability. Additionally, they can be influenced by how uncertainties are perceived to develop and what scope of the system is considered. Moreover, differing revealed perceptions can also be influenced by strategic considerations.

These findings contribute to the literature on investments under uncertainty during the energy transition, focusing on the discussion around the need to secure adequate investment levels in firm carbon-free generation capacity. The study adds practical insights into the diverse perceptions of stakeholders and experts regarding the need and effectiveness of policy instruments on the balance of system reliability, sustainability, and affordability.

Recommendations
First, differences in ideology require political consideration when balancing sustainability, reliability, and affordability. Key considerations include:

- To what extent is stimulating sustainability profitable compared to its costs and potential impact on reliability?
- To what extent should we rely on estimates of uncertain developments regarding the need to secure system flexibility for ensuring system reliability? Here, long lead times of investments need to be taken into account.
- To what extent are high price spikes acceptable for stimulating competition and investments, or should the social risks of price spikes and potential blackouts, due to inefficient levels of flexible capacity, be regulated?
- To what extent should the Dutch electricity system be self-sufficient in meeting peak demand?

Second, politics needs to be informed on the implications of trade-offs when balancing sustainability, reliability, and affordability:

- Insight needs to be provided regarding the effects of an uneven playing field within and between sectors and countries, such as the potential effects of hydrogen diversion, carbon leakage, and distorted competition.
- Insight needs to be provided on the social costs of overcapacity and undercapacity.

Third, given the impacts of uncertainties within the system, these need to be mitigated where possible, particularly concerning regulatory uncertainty:

- Implementation of unforeseen price caps needs to be prevented, and transparency needs to be ensured that price caps will not be introduced.
- Announced and implemented policies need to be credible and, where possible, contracted.

Finally, it is recommended to open up the conversation between the electricity sector and governmental organizations regarding different CRM designs, potential policy instruments for sustainability that ensure a level playing field, and possibilities to integrate sustainability and reliability objectives.

11 Personal reflection

Let me begin by saying that writing this thesis has taught me many things beyond what I have learned over the years from studying for exams or working on group projects. I gained a much deeper understanding of the electricity market, both in theory and in practice. I learned a lot about my personal process of tackling a big project, and I discovered how complex the interactions are between policy, politics, and the sector, and how the many challenges, trade-offs, and uncertainties are involved in finding a balance in the energy trilemma.

When I began this project, it felt like a start without an end, and now that I am technically finished, it feels like I have just barely begun. I started my project by studying the first two parts of the book by Stoft (2002) and ever since I have been truly intrigued about the system. I know there is so much more to this problem area and that I only scratched the surface, also considering that likely the relevance of the problem field will become even higher as sustainability goals approach and part of the current installed capacity gets nearer to its end-of-life date. The problem field of achieving sufficient investments has been around since the electricity markets got liberated, and countless books and literature have been written about it, which made scoping and starting the research quite challenging.

This brings me to one of the key lessons I learned about the process; I made the classic mistake of not scoping the problem enough from the start. The exploratory approach in the interviews made this even harder. I set a strict timeline for myself, as you are actually supposed to, but looking back, I should have done the detailed planning only after figuring out exactly how to collect, analyze, and present the data. Especially presenting the data was particularly difficult, due to the many interdependencies involved and the explorative approach, which led me to not exactly being able to know what I was working towards. Throughout the process, the scoping actually got extended instead of narrowing down, which made it challenging to find the best way to present the results, while keeping the steps made understandable.

This brings me to another key lesson: I have a tendency to start writing only when I know exactly what I want to say and fully understand the problem. So far, this approach has worked well for me academically and helped me produce high-quality work. However, writing a thesis is a long process with important feedback points. Especially with an exploratory approach, it is crucial to start writing things down right away and develop your work iteratively, even if the quality is not what you are used to, and you do not fully understand everything yet. Given the complexity and broad scope of the topic, I felt like I was near the bottom of the Dunning-Kruger curve for a long time (Kruger & Dunning, 2000). This was compounded by an early green light deadline, which I took on because I usually excel when facing challenges. However, this time I occasionally felt a bit overwhelmed. This led me to more theory reading than I should have done, which led me to —just as my supervisors had warned me beforehand not to do- drown in literature.

So, if you are reading this and you are about to start your thesis, or for myself when I start a new challenging project, my advice is: be very clear about your objectives, scope the problem thoroughly, maybe even more than you think is needed, and know what you need to present your findings in line with your goals. Start writing things down as soon as you can. It is okay if you do not understand everything yet; but do not wait until you do, because with such complex problems, you might never reach that point, let alone within your project timeline. Moreover, ask as many questions as possible to peers, colleagues, and supervisors, since (almost) no question is stupid to ask, and it will only help you. Also, when conducting interviews, especially semi-structured, processing the data may be more difficult than you expect if you are not familiar with the methodology. Before conducting an interview, you cannot predict exactly what answers you will get. Thereby, in this thesis, I realized relatively late that I was actually researching two distinct but interconnected problems: achieving sufficient investment levels and achieving carbon neutrality. However, I very much enjoyed the opportunity to interview experts and stakeholders in the field, which allowed me to understand things more nuanced than one could understand from theory.

Additionally, I highly recommend doing your thesis as a graduation internship because, first, you will learn a lot from the practical field. Even though you are conducting your own research, you will gain insights and knowledge from your supervisors and colleagues. And, besides, doing a thesis can be a bit of a lonely process, so having supportive colleagues and a pleasant working environment really helps brighten the journey!

In conclusion, I have learned a lot about the electricity system and conducting research, and, maybe a bit cliché, I have learned a lot about myself and how I handle conducting a large project. There is so much more to this topic than this thesis covers, so I hope it sparks discussions at the intersection of politics, policy, and the sector, about how and where we should locate risks and how different ideologies could come together to realize the energy transition.

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A

State-of-the-art literature search strategy

A strategy for the search of the literature is essential to examine current insights and key debates in the field of carbon-free dispatchable production technologies. The chosen database for this review is Scopus because of its broader range of research metrics.

The search query used to identify relevant literature is designed to be comprehensive, covering various terms associated with carbon-free dispatchable production technologies. The query is visualized in Figure A.1.

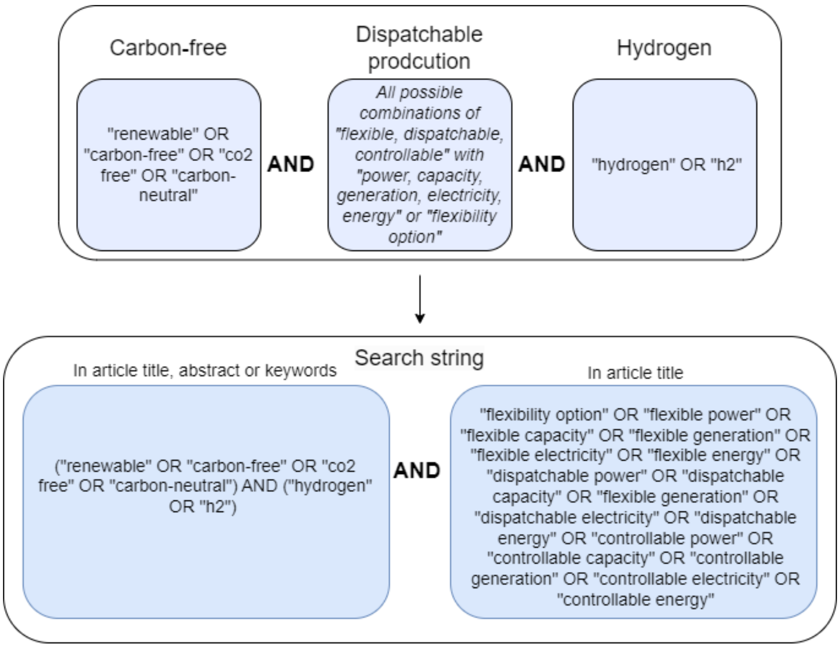

Figure A.1: State-of-the art: search query formation

The main part of the string includes different commonly used terms for carbon-free dispatchable production, enclosed in double quotes to ensure an article is selected only if the full phrase is present in the title. The second part of the string focuses on narrowing down the search to articles specifically related to carbon-free generation, as the terms related to dispatchability are also used in the conventional electricity system. For the first search, to narrow down the most relevant articles, the terms ”hydrogen” or ”H2” are also selected. In contrast to the terms related to ’dispatchable’ in the article title, additional terms are also searched for within the abstracts or keywords to broaden the scope of the search and capture relevant literature that may discuss decarbonization implicitly.

To refine the search results, articles published before the publication of the Paris Agreement in 2016 are excluded since this marked the start of international decarbonization (United Nations, 2016). After applying this criterion, the search yields 30 out of 33 articles. Among these, 15 articles with limited citations are deemed insufficient for the research, leaving 15 articles for consideration. From the remaining 15 articles, 6 are identified as not directly relevant to the research topic and are consequently excluded. This careful selection process leaves us with a set of 9 articles that meet the criteria for relevance and significance. However, not all flexibility options include hydrogen. Therefore, to keep the review balanced, the top 3 most cited articles without the search terms for hydrogen are also included. The final 12 articles form the foundation for the literature review. An overview of these in- and exclusion criteria and the resulting number of articles is visualized in Figure A.2.

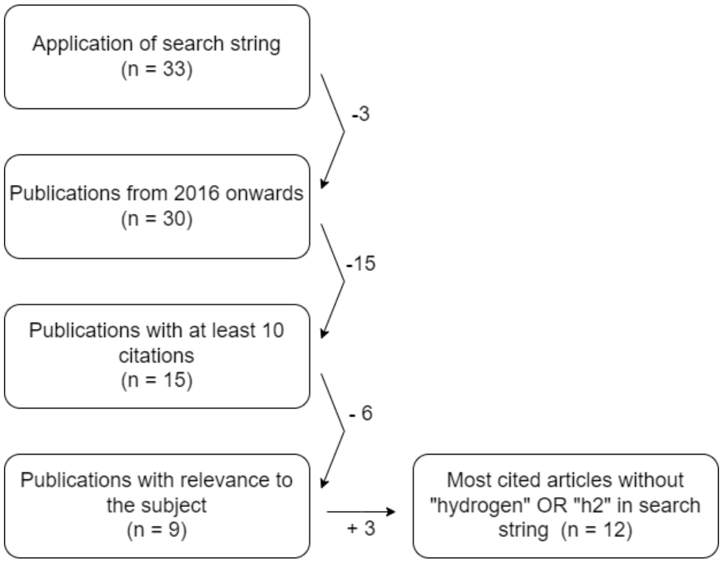

Figure A.2: State-of-the art: in- and exclusion criteria and the resulting number of articles

B

Theoretical background search strategy

To conduct a preliminary investigation into uncertainties in the electricity sector and potential policy instruments to stimulate investment, a systematic selection of literature is applied. Figure B.1 presents the search query formation of the search utilizing the Scopus database.

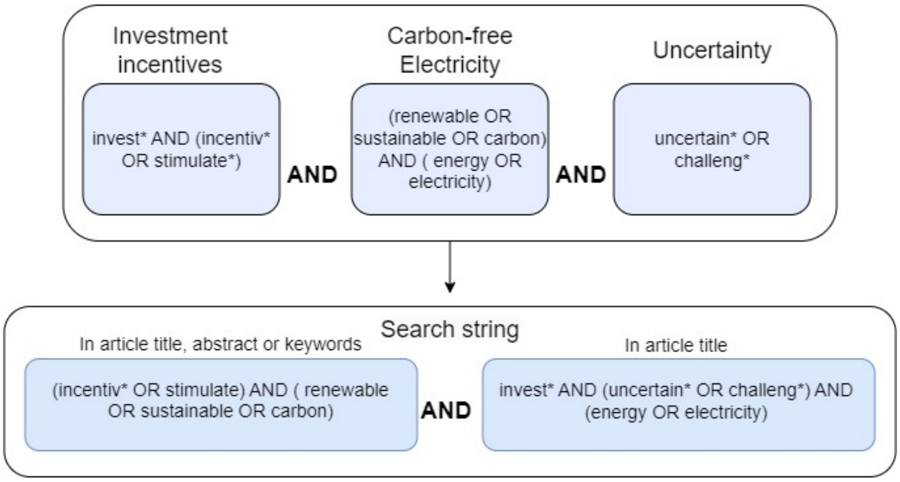

Figure B.1: Theoretical background: search query formation

The search resulted in 21 articles that were screened and further selected using the in- and exclusion criteria presented in Figure B.2.

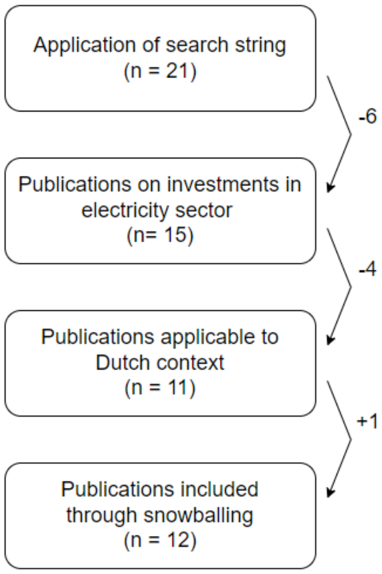

Figure B.2: Theoretical background: in- and exclusion criteria and the resulting number of articles

C

Interview protocol

C.1. Informed consent form

C.1.1. Opening statement

U wordt uitgenodigd om deel te nemen aan het Master Thesis onderzoek genaamd ”Powering Dispatchable Electricity Investments: Assessing policy instruments to incentivize investments in carbon-free dispatchable electricity generation capacity for a reliable and affordable net-zero emission Dutch electricity system by 2035”. Dit onderzoek wordt uitgevoerd door Laura Drost, MSc. student Engineering and Policy Analysis aan de Technische Universiteit Delft, in samenwerking met Vereniging Energie-Nederland.

Het doel van dit onderzoek is om te identificeren welke onzekerheden en barrières investeringen in CO2-vrij regelbaar vermogen belemmeren en welke beleidsinstrumenten effectief zouden zijn om deze uitdagingen aan te pakken. De deelname aan dit onderzoek middels een semigestructureerd interview zal ongeveer 60 minuten in beslag nemen. De verkregen data zal enkel worden gebruikt voor dit onderzoek die gepubliceerd wordt op de TU Delft Education Repository.

Enkel uw naam, email en eventueel telefoonnummer zullen bekend zijn bij de auteur en haar directe TU Delft begeleiders om het inplannen van het interview mogelijk te maken. Daarnaast zullen uw antwoorden vertrouwelijk blijven binnen het TU Delft studieteam. Met uw expliciete toestemming zal het interview audio-opgenomen worden om vervolgens getranscribeerd te worden. De verkregen data zal op een zodanig geaggregeerd niveau in het onderzoek gepresenteerd worden dat bedrijfsspecifieke gegevens niet af te leiden zijn.

Uw deelname aan dit onderzoek is volledig vrijwillig, en u kunt zich op elk moment terugtrekken zonder reden op te geven. U bent vrij om vragen niet te beantwoorden. De verzamelde data zal op het persoonlijke TU Delft Onedrive account van de auteur opgeslagen worden tot maximaal een maand na publicatie van het onderzoek op de TU Delft Education Repository die openbaar is.

Voor verdere vragen of opmerkingen kunt u contact opnemen met de auteur.

Dank u wel voor uw deelname!

C.1.2. Consent questions

1. Ik heb de bovenstaande informatie over het onderzoek gelezen en begrepen, of deze is aan mij voorgelezen. Ik heb de mogelijkheid gehad om vragen te stellen over het onderzoek en mijn vragen zijn naar tevredenheid beantwoord.
2. Ik doe vrijwillig mee aan dit onderzoek, en ik begrijp dat ik kan weigeren vragen te beantwoorden en mij op elk moment kan terugtrekken uit de studie, zonder een reden op te hoeven geven. Ik begrijp dat mijn deelname aan het onderzoek de volgende punten betekent:
    - Uw persoonlijke gegevens zullen vertrouwelijk blijven binnen het TU Delft onderzoeksteam. Uw naam, email en eventueel telefoonnummer zullen bekend zijn bij de auteur en haar

directe TU Delft begeleiders om het inplannen van het interview mogelijk te maken.

- Met uw expliciete toestemming zal het interview audio-opgenomen worden om vervolgens getranscribeerd te worden.
- De audio-opname en getranscribeerde data zal op het persoonlijke TU Delft Onedrive account van de auteur opgeslagen worden tot maximaal een maand na publicatie van het onderzoek op de TU Delft Education Repository.
- De verkregen data zal op een zodanig geaggregeerd niveau in het onderzoek gepresenteerd worden dat bedrijfsspecifieke gegevens niet af te leiden zijn.

3. Ik begrijp dat de studie in september 2024 afgerond zal worden, mits er geen onvoorziene vertragingen zijn.
4. Ik begrijp dat deelname aan dit onderzoek volledig vrijwillig is en ik mij op elk moment terug kan trekken zonder reden op te geven en dat ik vrij ben om vragen niet te beantwoorden.
5. Ik begrijp dat mijn deelname betekent dat er persoonlijke identificeerbare informatie en onderzoeksdata worden verzameld, met het risico dat ik hieruit geïdentificeerd kan worden.
   - Om dit risico te minimaliseren zullen uw persoonsgegevens als naam, emailadres en telefoonnummer, enkel bekend zijn bij de auteur en haar directe TU Delft begeleiders.
   - De verkregen data zal op een zodanig geaggregeerd niveau in het onderzoek gepresenteerd worden dat bedrijfsspecifieke gegevens niet af te leiden zijn.
6. Ik begrijp dat binnen de Algemene verordering gegevensbescherming (AVG) een deel van deze persoonlijk identificeerbare onderzoeksdata als gevoelig wordt beschouwd, met name politieke standpunten.
7. Ik begrijp dat de persoonlijke informatie die over mij verzameld wordt en mij kan identificeren, zoals naam, emailadres en telefoonnummer, niet gedeeld worden buiten het TU Delft studieteam.
8. Ik begrijp dat de persoonlijke data die over mij verzameld wordt, binnen een maand na publicatie, in september 2024 mits er geen onvoorziene vertragingen zijn, vernietigd wordt.
9. Ik begrijp dat na het onderzoek de geanonimiseerde informatie op een zodanig geaggregeerd niveau in het onderzoek gepresenteerd worden dat bedrijfsspecifieke gegevens niet af te leiden zijn en gebruikt zal worden in het onderzoek dat gepubliceerd wordt op de TU Delft Education Repository.
10. Ik geef toestemming om mijn antwoorden, ideeën of andere bijdrages anoniem te quoten in resulterende producten, mits het geen bedrijfsspecifieke informatie bevat.
11. Ik geef toestemming om de geanonimiseerde getranscribeerde data die middels mij verzameld wordt enkel voor dit onderzoek gebruikt zal worden en tot maximaal een maand na publicatie van het onderzoek op de TU Delft Education Repository op het persoonlijke TU Delft Onedrive account van de auteur opgeslagen wordt.

C.2. Interview guide

Een aantal dagen voor een interview hebben de geinterviewden een mail gekregen met mijn onderzoeksvraag en 2 tot 4 centrale vragen, afhankelijk van het stakeholder type van de geinterviewde. Deze centrale vragen luiden als volgt:

- Centrale vraag 1: Hoe worden investeringsbeslissingen in (CO2-vrij) regelbaar vermogen in de praktijk gemaakt?
- Centrale vraag 2: Wat zijn de grootste uitdagingen voor investeringen in CO2-vrij regelbaar vermogen?
- Centrale vraag 3: Welke beleidsinstrumenten zouden deze uitdagingen aan kunnen pakken en investeringen stimuleren? Wat voor effect hebben ze?
- Centrale vraag 4: Wat zijn criteria waar de beleidsinstrumenten aan zouden moeten voldoen?

Voorbeeld van introductie tijdens interview:
Mijn onderzoek komt voort uit de uitdaging om het elektriciteitssysteem betrouwbaar te houden, gelijktijdig met het streven om in 2035 een CO2 vrije elektriciteitssector te realiseren. Een belangrijke component hiervan is de flexibiliteit van het systeem. Ik heb een korte analyse gemaakt van de vier meest relevante technologieën voor flexibiliteit: opslag, demand response, interconnecties en CO2-vrije regelbare productievermogen. In deze laatste heb ik mijn kennis lacune gevonden. Er is veel literatuur over investeringen in traditionele elektriciteitsmarkten, en ook hier is niet altijd consensus over de optimale balans van investeringen. Nu, midden in de energietransistie onderzoek ik investeringen in CO2 vrij regelbaar productie vermogen in de praktijk, met name gericht om de onzekerheden die gepaard gaan met de energietransitie en de beleidsinstrumenten die zouden kunnen helpen om deze onzekerheden tegen te gaan en investeringen te stimuleren.

In mijn onderzoek richt ik me op gascentrales die worden omgebouwd naar waterstofcentrales, zowel bijmenging als 100% waterstof (via groene of blauwe waterstofroute met Steam Methane Reformers) en gascentrales met post combustion CCS. Mijn focus ligt op het identificeren van de onzekerheden die investeringen in CO2 vrij regelbaar vermogen belemmeren en hoe we ervoor kunnen zorgen dat deze investeringen wel tot stand komen. Hierbij doe ik dus de aanname dat er investeringen nodig zijn, zowel in ombouw als mogelijk in nieuwbouw, om in 2035 een CO2 vrije of neutrale electriciteitssector te hebben.

D

Collection of objectives

Viable business case (carbon-free) dispatchable generation capacity	**Optimal system reliability**	**High sustainability**	**High affordability**
Low investment risk/uncertainty	High system flexibility	Low carbon emissions	High policy instrument cost effectiveness
High expected IRR on investment	Low market intervention	Low emission transfer effects	Low system costs
	High (international) competition	Low hydrogen ’theft’ from sectors that use it more efficiently	Relatively stable electricity end-user prices*
	(International) level playing field		

Table D.1: Long list of objectives for assessing policy instrument effectiveness
*Not commonly agreed on

E

Cognitive map: hydrogen blending mandate

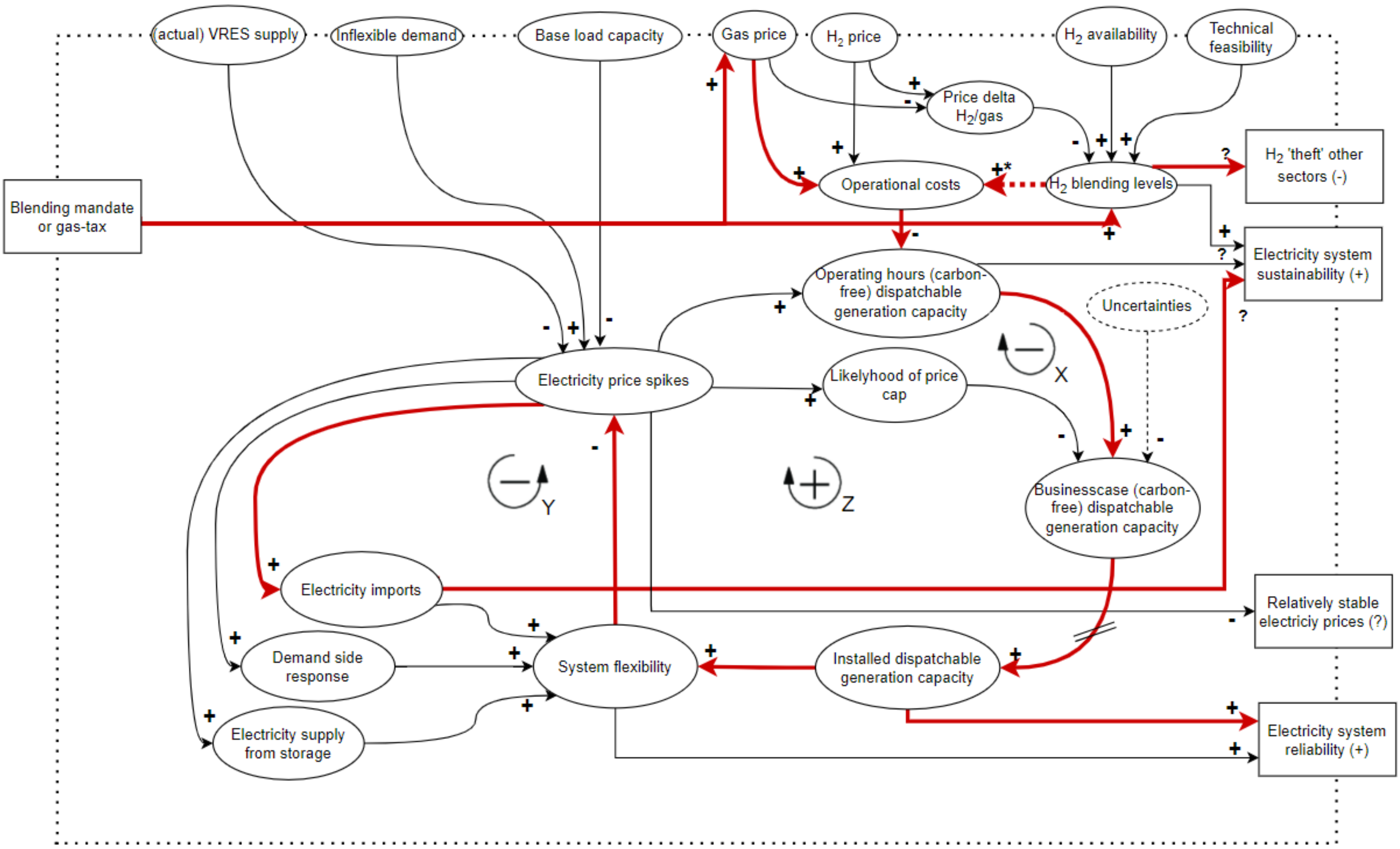

Figure E.1: Cognitive diagram presenting lines of reasoning against hydrogen blending mandate