POLITECNICO
MILANO 1863

Politecnico di Milano
Department of Electronics, Information, and Bioengineering
Doctoral Programme In Science, Technology, and Policy for Sustainable Change

---

Development of a Techno-Economic Methodology for the Analysis of Flexible Nuclear Hybrid Energy Systems

Doctoral Dissertation of:
Guido Carlo Masotti

Supervisor:
Prof. Stefano Lorenzi

Tutor:
Prof. Massimo Tavoni

The Chair of the Doctoral Program:
Prof. Andrea Castelletti

Year 2026 – Cycle XXXVIII

Acknowledgments

I would like to express my sincere gratitude for the opportunities and collaborations that have shaped this work over the past three years. In particular, I had the opportunity to contribute to the Euratom-funded TANDEM project. I am deeply thankful to the TANDEM consortium for the fruitful cooperation and stimulating exchanges, which have significantly contributed to the development of this thesis.

I am particularly grateful to Stéphanie Crevon for hosting me at CEA Grenoble for a three-month research internship. Beyond the valuable technical training on the PEGASE and PERSEE tools within the TANDEM framework, I greatly appreciated her openness, guidance, and continuous support throughout this period.

I would also like to express my sincere appreciation to Dr. Francesco Ganda for the opportunity to work under his supervision during my four-month stay at the International Atomic Energy Agency. I am particularly thankful for his trust, availability, and insightful feedback during our discussions on the development of the FRAMES code, which made this experience both professionally and personally enriching.

Finally, I would like to thank the reviewers of this thesis, Dr. Richard Boardman and Dr. Michael Fütterer, for their careful evaluation of my work. I would like to acknowledge the time and expertise they have dedicated to reviewing this manuscript, as well as their valuable comments and suggestions, which have contributed to improving the quality and clarity of this thesis.

Abstract

IN the context of the energy transition, rising shares of variable renewables and the need to decarbonise sectors that are hard to abate call for energy systems capable of providing both flexibility and low-carbon electricity, heat, and fuels. Nuclear Hybrid Energy Systems (NHES), where nuclear reactors are tightly integrated with other energy sources, storage devices and non-electric applications, are attracting growing interest, but their implementation presents strongly interconnected technical, economic, regulatory and policy challenges.

This thesis work develops a holistic methodological framework to analyse NHES from a system level to their role in broader energy systems, for instance, in long-term decarbonisation strategies. The approach starts from a context analysis that characterises local requirements and demands, as well as policy and market conditions, and uses it to define scenarios for NHES deployment. Considering this background, physics-based models are developed to represent NHES architectures, with particular attention to thermal interconnections, and are applied to assess the flexible operation, control strategies, transient behaviour, and safety-relevant aspects of the integrated systems. In particular, safety analysis is enabled by coupling the dynamic simulators with thermal-hydraulic system codes for the primary loop to evaluate transients and safety margins, with the aim of supporting regulators and safety authorities to define guidelines for the deployment of hybridised reactors. Moreover, the tools are embedded into techno-economic optimisation schemes that determine optimal layouts and dispatch strategies under different boundary conditions, accounting for operational constraints resulting from the system dynamics captured through the aforementioned simulators. Finally, nuclear cogeneration and an archetypical NHES configuration, characterised through the detailed system-level models, are integrated into country-level long-term energy planning frameworks to explore if and how NHES can contribute to decarbonisation pathways.

Applications to illustrative case studies highlighted the importance of having an interdisciplinary framework for NHES analyses that integrates technical, economic and policy dimensions. In this work, these systems were analysed from a progressively broader point of view, ranging from subsystem-level investigations to their integration into country-level energy system models. Overall, the case studies indicate that nuclear cogeneration and NHES could represent a viable option for providing low-carbon heat and hydrogen while enhancing system flexibility and supporting grid stability. The resulting technically grounded framework is applied to derive policy-relevant insights and recommendations. In particular, if these systems emerge as cost-competitive options, policymakers should consider creating an enabling environment, for example, by adapting regulatory and licensing frameworks, so that the potential deployment of NHES architectures can be appropriately assessed.

Keywords: Nuclear Hybrid Energy Systems, flexibility, nuclear cogeneration, techno-economic analysis, decarbonisation.

Abstract in lingua italiana

NEL contesto della transizione energetica, le crescenti quote di fonti rinnovabili aleatorie e la necessità di decarbonizzare i settori *hard-to-abate* richiedono sistemi energetici in grado di fornire sia flessibilità sia elettricità, calore e combustibili a basse emissioni. I sistemi energetici ibridi, che prevedono l'integrazione dei reattori nucleari con altre fonti energetiche, sistemi di accumulo e applicazioni non elettriche, stanno attirando un interesse crescente nel dibattito energetico; la loro implementazione, tuttavia, presenta sfide fortemente interconnesse di natura tecnica, economica, regolatoria e di policy.

Questo lavoro di tesi sviluppa un quadro metodologico integrato per l'analisi dei sistemi ibridi, che spazia dalla scala del singolo impianto fino al loro ruolo all'interno di sistemi energetici più ampi, ad esempio nell'ambito di strategie di decarbonizzazione a lungo termine. L'approccio parte da un'analisi di contesto che caratterizza i requisiti e le domande locali, nonché le condizioni di policy e di mercato, e utilizza tali elementi per definire possibili scenari d'implementazione di questi sistemi energetici. Nell'ambito dell'analisi sono stati sviluppati modelli fisici per rappresentare le architetture di sistemi ibridi, con particolare attenzione alle interconnessioni termiche; tali modelli dinamici sono stati successivamente integrati in simulatori del sistema complessivo, impiegati per valutare l'operazione flessibile, le strategie di controllo, il comportamento transitorio e gli aspetti rilevanti per la sicurezza dei sistemi integrati. In particolare, l'analisi di sicurezza si basa sull'accoppiamento dei simulatori con codici termoidraulici di sistema per il circuito primario, al fine di va-

lutare i transitori e i margini di sicurezza e con l'obiettivo di supportare i regolatori e le autorità di sicurezza nella definizione di linee guida per il dispiegamento di reattori inseriti in configurazioni ibride. Inoltre, i simulatori sono stati integrati in schemi di ottimizzazione tecnico-economica che determinano le configurazioni e le strategie di dispacciamento ottimali in diversi scenari, tenendo conto dei vincoli operativi derivanti dalla dinamica del sistema. Infine, la cogenerazione nucleare e una configurazione archetipica di sistema ibrido, caratterizzate mediante i modelli dettagliati a livello di impianto, sono integrate in modelli di pianificazione energetica di lungo periodo su scala nazionale, per esplorare se e in che misura i sistemi ibridi possano contribuire alle strategie di decarbonizzazione.

Le applicazioni della metodologia proposta a casi di studio hanno evidenziato l'importanza di disporre di un quadro interdisciplinare per l'analisi di sistemi ibridi che integri le dimensioni tecnica, economica e di policy. In questo lavoro, tali sistemi sono stati analizzati da un punto di vista progressivamente più ampio, che comprende le indagini a livello di singolo componente fino alla loro integrazione in sistemi energetici su scala nazionale. Nel complesso, i casi studio indicano che la cogenerazione nucleare e i sistemi ibridi possono rappresentare un'opzione valida per la fornitura di calore e idrogeno a basse emissioni di carbonio, contribuendo al contempo ad aumentare la flessibilità del sistema e a supportare la stabilità della rete. Il quadro metodologico risultante, fondato sulle basi tecniche presentate nel lavoro, è applicato per derivare indicazioni e raccomandazioni rilevanti per le policy energetiche. In particolare, qualora tali sistemi emergano come opzioni economicamente competitive, i decisori politici dovrebbero considerare la creazione di un contesto abilitante, ad esempio adattando i quadri regolatori e di licensing, affinché il potenziale dispiegamento di configurazioni di sistemi ibridi possa essere adeguatamente valutato.

Parole chiave: Sistemi energetici ibridi, flessibilità, cogenerazione nucleare, analisi tecnico-economica, decarbonizzazione.

Summary

An energy transition to low-emissions energy systems is underway. Nowadays, this transformation has been largely driven by the widespread deployment of Variable Renewable Energy (VRE) sources, such as wind and solar, whose decreasing generation costs and low associated emissions have established them as central pillars of decarbonisation strategies. However, high penetrations of VRE raise several system-level challenges. Their intermittent nature complicates power system operation and planning, requiring sufficient energy storage and dispatchable power sources to ensure that demand is met and grid stability is maintained regardless of environmental conditions. Moreover, in the European Union, the power sector represents only around 24% of primary energy consumption and accounts for approximately one-third of total energy-related emissions, with the remainder generated from hard-to-abate sectors such as industry and transport. These sectors remain heavily reliant on fossil fuels, thereby giving rise to substantial, yet untapped, decarbonisation potential. While a substantial share of their decarbonisation needs can be addressed through electrification, important challenges remain for some processes and end-uses.

In this context, nuclear power can contribute in two ways: by providing dispatchable electricity that supports deeper VRE penetration and grid stability and by supplying low-carbon heat to decarbonise hard-to-abate processes. However, this requires moving beyond the conventional paradigm of the nuclear power plant as primarily an electricity-only, baseload generator toward flexible combined heat and power production. This is also

motivated by the growing interest in a tighter integration of energy systems across sectors and energy vectors to increase overall system flexibility and efficiency. In this regard, nuclear reactors could be integrated into so-called Nuclear Hybrid Energy Systems (NHES), also referred to as integrated energy systems, in which they are tightly coupled to other energy sources, storage technologies and non-electric applications such as district heating, industrial process steam supply, and hydrogen production. Such configurations face several challenges related to the design and operation of the integrated architecture, arising mainly from the strong interdependencies between subsystems. For instance, the specific requirements in terms of temperature levels, operating limits, and reliability of supply, among others, must be met simultaneously for each subsystem. These translate into technical, economic and regulatory challenges that are essential to address before NHES can be considered as options in long-term decarbonisation strategies.

The primary goal of this work is to develop a holistic methodological framework for the analysis of NHES, with particular focus on light-water cooled Small Modular Reactors (SMRs) used in cogeneration mode. The framework combines context analysis, system-level modelling, safety assessment, techno-economic optimisation, long-term energy planning, and policy analysis, with each domain being strongly interconnected with the others. The ultimate objective is to provide technically grounded approaches and tools that can assist policymakers, regulators and involved stakeholders in assessing the conditions under which NHES could effectively contribute to decarbonisation pathways and which barriers and enabling factors should be considered in policymaking.

Methodology

The methodological framework, illustrated schematically in Figure 1, is organised into several interconnected domains. First, the *context analysis* aims at assessing how territorial, infrastructural and policy characteristics can shape the design of NHES architectures. It identifies potential end-users, available infrastructure, deployment timelines, and relevant policy drivers, which are then translated into scenarios and boundary conditions for the technical and economic analyses. *NHES modelling* focuses on the physics-based representation of the integrated system. In this domain, thermodynamic analyses are used to define suitable steam cycle configurations and extraction points that meet end-user temperature requirements while minimising power conversion losses. In addition, dynamic models of NHES components are developed in the object-oriented mod-

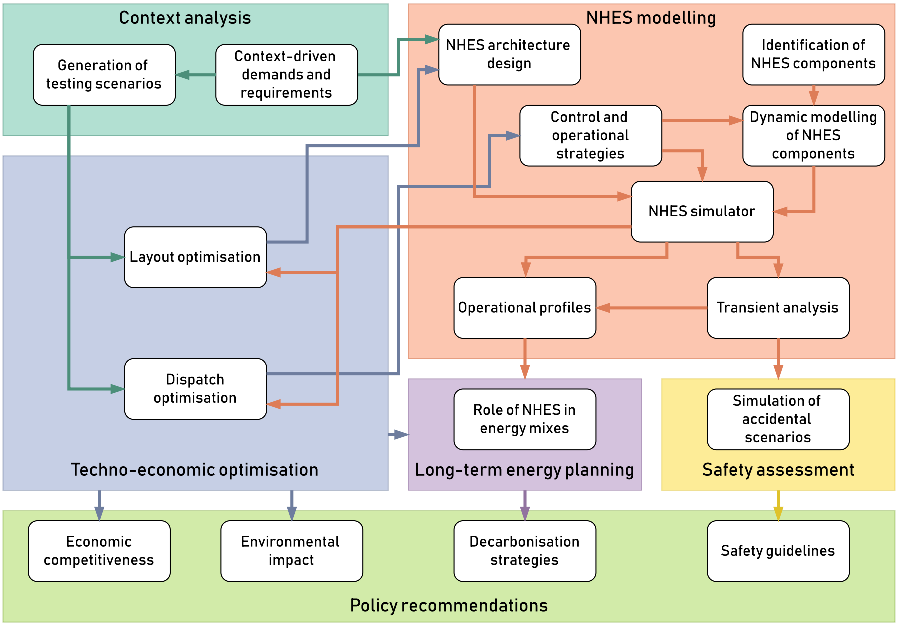

Figure 1: *Overview of the methodological framework.*

elling language Modelica and assembled through a plug-and-play approach into dynamic simulators of the overall NHES architecture. These simulators capture the transient behaviour of the coupled systems and can be used to test different control strategies, evaluate operational limits, and identify operating regions that are compatible with the constraints of each interconnected subsystem. These simulators can be applied for specific investigations, such as *safety assessments*. In this regard, a modelling framework that couples thermal-hydraulic system codes for the primary loop with the dynamic Modelica-based simulator of the steam cycle and cogeneration systems is proposed. This tool allows the simulation of transients initiated both on the nuclear side or on the cogeneration facility, enabling the assessment of how disturbances propagate through the interconnected system and how they might affect nuclear safety. The framework is intended as a support for safety authorities and regulators when developing or updating guidelines and licensing approaches for nuclear cogeneration and NHES, with the aim of assessing if the additional coupling is not jeopardising the reactor's safe operation. Furthermore, the system-level layout and dispatch optimisation are addressed in the *techno-economic optimisation* domain. Mixed-Integer Linear Programming (MILP) models are developed to determine optimal NHES configurations and dispatch strategies under different demand, costs, and policy scenarios. A primary concern is that thermally coupled NHES exhibit non-linear dynamics, while MILP formulations require linear approximations. To address this, two coupling strategies between optimisation and dynamic simulation are explored: a soft-linked approach, where optimisation results are iteratively refined using feedback from dynamic simulations, and a hard-linked co-simulation approach, where the optimiser and simulator exchange states and setpoints during the optimisation process itself. These methods improve the consistency between optimal dispatch strategies and physics-based operating trajectories, enhancing the reliability of techno-economic results used for policy insights. Another important area in assessing the role of NHES in future energy systems concerns *long-term energy planning*. In this regard, broader energy system models, which traditionally treat nuclear as an electricity-only technology, are expanded to represent nuclear cogeneration and NHES architectures. The operational characteristics of SMRs operating as combined heat and power units and of an archetypical NHES coupling an SMR with high-temperature steam electrolysis modules are incorporated into both static and dynamic energy planning models. In the static framework, a tool with hourly resolution over a full target year is applied to determine cost-optimal capacity mixes and dispatch strategies under different policy assumptions (e.g., emission caps, gas price measures or renewable targets). In the dynamic framework, a multi-year capacity expansion model is used to investigate how investment timing, deployment limits, and cost trajectories can affect nuclear deployment. Finally, the *policymaking* domain synthesises the insights from the previous pillars into qualitative recommendations on several fronts, including flexible operation of nuclear plants in NHES, safety and licensing considerations, economic aspects and the role of nuclear cogeneration in long-term capacity planning. Rather than providing country-specific recommendations, the work aims to show how the proposed tools and approaches can be used to structure policy discussions and identify key factors that might enable or pose barriers to NHES deployment.

Highlights of the analyses

In the remainder of this section, illustrative outcomes are presented for the main methodological domains. From a system-level modelling perspective, this work developed a set of dynamic models for NHES components, collected in the open-source TANDEM Modelica library, and integrated them into simulators of the overall architecture. The models were applied to investigate novel operational strategies, such as the load-following by cogeneration mode, where the nuclear reactor remains at rated power while the allocation of thermal power between electricity production and non-electric applications is modulated according to grid or end-user requirements. As a result, this operational mode leverages the advantages of maintaining a stable operation and a high capacity factor on the nuclear side while enabling flexible electrical output through adjustments in heat extraction. Applications of the models demonstrated how load-following by cogeneration can shift the burden of flexibility from the reactor core to the steam cycle and the coupled non-electric applications. These findings indicate that, if compliant with safety requirements, nuclear units could provide greater flexibility than traditional electricity-only generators by modulating heat extraction rather than core power.

On the safety side, the coupled thermal-hydraulic system code and dynamic simulator framework represents a methodological basis for assessing abnormal transients in hybridised reactors, including initiating events on the non-nuclear side. It enables comparative analyses between conventional electricity-only operation and cogeneration modes, helping to clarify under which conditions the integration with non-electric applications does or does not affect nuclear safety margins.

In the techno-economic optimisation domain, the thesis shows that coupling between dynamic and optimisation tools can significantly improve the physical representativeness of cost-optimal dispatch strategies in thermally integrated NHES. The results highlight the trade-off between solution detail and computational burden and indicate conditions in which co-simulation or iterative refinement is particularly important (e.g., when thermal flows are indirect consequences of control actions on electricity or hydrogen production).

In long-term energy planning, the extended energy system models demonstrate how representing nuclear cogeneration and NHES explicitly changes the way nuclear technologies appear in cost-optimal decarbonisation strategies. Static energy system models, with full-year hourly resolution, detailed operational reserves, and unit commitment constraints, can capture flexibility requirements in systems with high VRE penetration and quantify under which combinations of emission constraints, fuel prices, technology costs, etc. nuclear systems prove to be competitive low-carbon options for supplying electricity, industrial heat, and hydrogen. Complementary dynamic energy system models, in turn, highlight the importance of deployment timing, construction times and cost trajectories, showing that even technologies that are effective in a target year may contribute only marginally if introduced late for specific decarbonisation objectives; however, their reliance on short representative periods and limited operational constraints can lead to dispatch strategies that are not fully consistent with real-world system operation. Overall, the outcomes indicate that nuclear cogeneration should be represented in long-term planning tools and policy analyses, since the decarbonisation needs of industrial heat and hydrogen could become key drivers for the deployment of such systems, provided they emerge as a technically and economically viable option in a specific context.

Conclusive remarks

In conclusion, it is worth emphasising that, at this stage, the proposed framework is intended to be methodological and not to provide a detailed national policy roadmap or to be restricted to a single NHES archetype, but rather as a general approach that can be adapted to different contexts, technologies and system configurations. Future work should therefore focus on extending the framework to multiple reactor concepts and end-users, enabling the exploration of a broader spectrum of configurations, strengthening model validation (especially for dynamic simulators used in safety studies), and applying the methodology to real industrial clusters and national systems to investigate detailed policy scenarios.

Within its scope, this work demonstrated that assessing if, when and how nuclear cogeneration and NHES can contribute to decarbonisation cannot be addressed by high-level energy scenarios or isolated system-level studies alone. It requires an integrated view that combines physical modelling, safety assessment, techno-economic optimisation and long-term energy planning. The methodological framework and tools developed in this work are designed to bridge the gap between technical performance, economic viability, and policy and regulatory considerations, providing a basis for such integrated analyses and offering a structured way for decision-makers to move beyond the traditional view of nuclear as a pure electricity generator towards its potential role as a flexible, multi-purpose contributor to low-carbon energy systems.

Contents

List of Figures

List of Tables

CHAPTER 1

Introduction

In the fight against climate change, the energy transition represents a fundamental pathway to reduce greenhouse gas emissions. The decarbonisation of the energy sector should be addressed by facing the so-called energy trilemma, which entails the need to ensure energy security, energy equity, and environmental sustainability [1]. As a result, energy policies are needed to promote the evolution of the energy sector to cover these three axes, i.e., ensure energy supply, provide affordable energy, and phase out fossil fuels by substituting them with low-carbon energy sources.

The European Union (EU), for instance, is proposing policies to favour investments and measures to support the decarbonisation of the energy sector, e.g., by boosting the penetration of renewable energy sources for electricity generation [2]. In the last years, the penetration of renewables surged from 21.9% in 2010 to 44.3% in 2023 [3]. This growth was largely driven by solar and wind power, whose individual contributions to the total electricity mix expanded significantly, with solar rising from 0.8% to 9% and wind growing from 4.7% to 17.4% during this period [3]. The combination of renewable generation and nuclear power, which as of today represents the largest low-carbon energy source in Europe, limited the reliance on fossil fuels for electricity generation to about 40%. However, decarbonisation efforts cannot be limited exclusively to the power sector. As shown

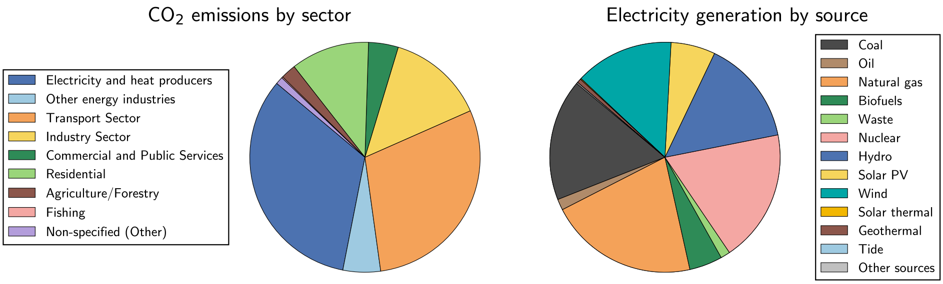

Figure 1.1: *Emissions by sector and electricity generation by source (Europe, 2022) [4].*

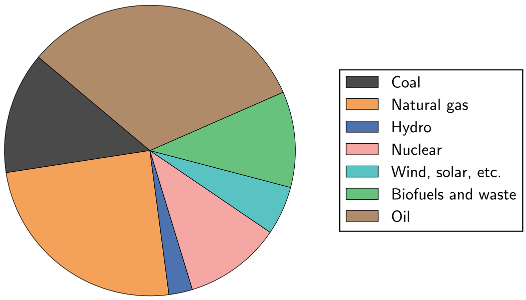

Figure 1.2: *Total energy supply by source (Europe, 2022) [4].*

on the left-hand side of Figure 1.1, this sector is responsible for about one third of total CO_2 emissions, with the remainder associated with hard-to-abate sectors such as the transport, industry, and residential sectors. This is evidenced also by the breakdown by sources of the total energy supply, reported in Figure 1.2, dominated by fossil fuels by more than 70%.

The EU introduced various energy policies to decarbonise the energy sector while seeking to remain competitive with other countries and ensuring energy security. In the European Green Deal [5], several policy areas are covered, including measures devoted to the transport and industry sectors. As for the energy sector in general, the initiative aims at promoting the deployment of renewable energy sources, improvements in energy efficiency, investments in cross-border transmission infrastructure, and the transition towards tighter interconnected energy systems. The objective of these measures is to support the Union's ambition to reduce emissions by at least 50% by 2030 and achieve climate neutrality by 2050. In this regard, each Member State is responsible for providing a comprehensive National

Energy and Climate Plan (NECP) [6], which outlines its national targets, policies, and measures for contributing to achieving these EU-level and global objectives. After the Russian aggression of Ukraine exposed the vulnerability of the European energy system and the need to enhance energy security, the European Commission proposed to integrate the Green Deal with the REPowerEU plan [7]. The set of policies proposed in this plan aims at reducing the dependence on fossil fuels by diversifying energy supply and further boosting the deployment of renewables for the production of low-carbon hydrogen to decarbonise industrial processes, among others.

Generally speaking, energy policies, combined with the low lifecycle greenhouse gas emissions and the dropping plant-level costs, are driving a massive deployment of Variable Renewable Energy (VRE) sources, such as wind and solar, in energy mixes. On the one hand, this strategy is contributing to the decarbonisation of the electricity sector, reducing the carbon footprint of power systems, and lowering electricity prices [8]. On the other hand, the intermittent nature of these sources poses significant challenges for the reliability and resilience of the power grid [9]. In particular, the progressive replacement of rotating synchronous generators (e.g., thermal power plants) by inverter-based VREs is leading to a loss in grid inertia, which in turn leads to issues in preserving grid stability [10]. Moreover, the intermittency and non-programmability of VREs translate into additional requirements in terms of flexibility provided by dispatchable power sources that are required to rapidly adjust their power outputs to ensure that power supply matches load demand. From an economic standpoint, the lower load factor of dispatchable generators translates into preferring power plants with lower fixed costs, such as gas-fired generators. Moreover, the increasing penetration of VREs translates into a drop of electricity prices when generation is high, resulting in the phenomenon of cannibalisation [11]. This effect, which can even lead to negative electricity prices, also challenges the economic profitability of programmable generators [12]. The intermittency of VREs, together with the generation uncertainties and geographical limitations, leads to so-called system costs that need to be accounted for in addition to the plant-level costs [13]. These include balancing costs to ensure grid stability through energy storage devices and backup generators, transmission and distribution costs, etc.

Despite the significant contribution of VREs to the decarbonisation of the power sector, these sources are facing challenges in effectively contributing to the decarbonisation of hard-to-abate sectors [14]. For instance, industrial processes often require a reliable and continuous energy supply, both in the form of electrical and thermal power, which is difficult to

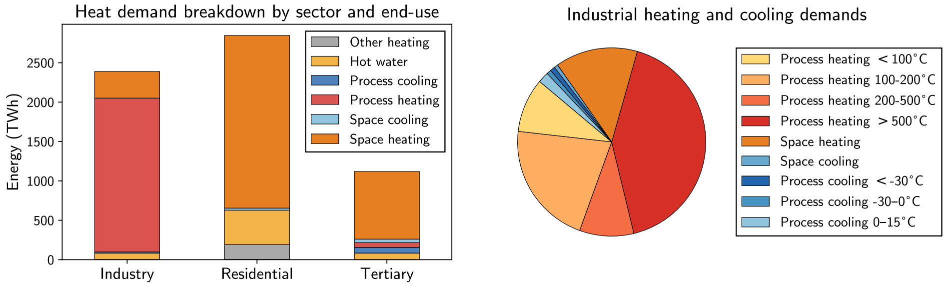

Figure 1.3: *Heat demand by sector and industrial heating demand (Europe, 2015) [17].*

meet given the intermittent nature of VRE electricity generation. Furthermore, electrifying these processes will lead to a dramatic increase in energy demand. Electrification might also not be compatible with some high-temperature industrial processes [15], which account for a large share of total process heat demand and remain difficult to supply without fossil fuels. For this reason, further solutions are required to address heating demands in the residential and industrial sectors, which are still predominantly supplied by fossil fuels [16]. In this context, low-carbon options such as hydrogen-based technologies and other energy conversion processes could contribute to meeting these requirements. As shown in Figure 1.3, the total heat demand in the EU is estimated to be almost 2400 TWh for the industrial sector and 2850 TWh in the residential sector [17], highlighting the magnitude of the challenge associated with decarbonising heat demand.

To support the decarbonisation of sectors beyond electricity generation, energy system integration has been identified as an effective pathway in the frame of the European Green Deal [18]. This strategy involves the transition from parallel, independent links between energy providers and end-users to a coordinated and strongly interconnected energy system sharing energy carriers and infrastructure. This philosophy for the management of energy systems is expected to improve the technical and economic efficiency of the overall system, supporting the path toward climate neutrality. The policies focus on increasing the overall energy efficiency by recovering waste energy and strengthening synergies between different sectors. Moreover, a larger direct electrification and the use of low-carbon fuels, such as hydrogen, are considered the solution to cover the heat demands. A key aspect of this tighter integration is the active role of consumers and end-users in the system's operation: specifically, higher flexibility can be achieved by shifting energy consumption (e.g., of industrial processes) to ensure balance between energy supply, strongly shaped by the VRE availability, and the overall demand.

As a result, the transition towards deeply decarbonised energy systems requires not only massive deployment of VREs but also complementary dispatchable sources to meet flexibility needs and sustain the decarbonisation of multiple sectors. In this context, nuclear energy, as a low-carbon and programmable source, could contribute beyond its traditional role as a baseload electricity provider, particularly when integrated into so-called Nuclear Hybrid Energy Systems (NHES), also referred to as integrated energy systems, in which the nuclear reactor is tightly coupled with other energy sources, storage devices and end-users. Such hybrid configurations represent a fundamental shift from the conventional electricity-only paradigm of nuclear power plants. However, this shift introduces a high degree of technical, operational, economic, and regulatory complexity: NHES are inherently integrated systems in which multiple processes are strongly coupled; as a result, their behaviour and performance cannot be adequately captured through isolated component-level analyses. Interactions between subsystems, operational strategies, and external boundary conditions need to be taken into account when evaluating the overall system feasibility and performance.

Moreover, existing research approaches on NHES tend to focus on individual research domains, such as techno-economic assessments, safety analysis, or energy system modelling. While these contributions provide valuable insights for the characterisation of NHES architectures, the lack of a coherent and integrated framework limits their ability to assess the actual deployment potential of NHES within decarbonisation strategies. In particular, independent studies risk being based on different assumptions across technical, economic, and policy-oriented analyses, potentially leading to inconsistent conclusions. In addition, there is the risk to sacrifice technical aspects when addressing economic or policy questions if detailed modelling of system design, operation, and constraints is not available. At the same time, limiting the analysis to purely technical considerations would not be sufficient, as economic competitiveness and policy mechanisms are critical drivers for nuclear projects. The need for a comprehensive analytical framework is also motivated by the growing interest in nuclear cogeneration within energy policies. Although nuclear energy is increasingly recognised as a low-carbon option, nuclear power plants are still predominantly considered as electricity-only generators. As a result, accounting for the hybridisation of nuclear reactors requires not only updated modelling tools capable of representing the multi-purpose nature of the plant and the potential flexible operation, but also supporting the adaptation of regulatory and licensing procedures. Furthermore, in the context of energy planning and policymaking, having an analytical framework that also encompasses NHES and the usage of nuclear heat can reduce the risk of misrepresenting the potential contribution of nuclear energy to decarbonisation strategies, particularly in terms of grid stabilisation and the use of nuclear heat for hard-to-abate industrial processes, which are often ignored.

The primary objective of this work is to develop a holistic methodological framework to address the challenges associated with integrating nuclear reactors into such multi-output energy systems. The proposed framework encompasses methodological approaches and tools across several key dimensions relevant for NHES analysis: techno-economic modelling and system-level optimisation, safety assessment and regulatory considerations, as well as long-term energy planning studies. The ultimate goal is to provide decision-makers with technically grounded tools and guidelines that can support evidence-based policymaking, e.g., by identifying policy-related barriers and enabling factors, and explore under which conditions nuclear energy (including the use of nuclear heat) can effectively support the energy transition.

Figure 1.4 provides a schematic overview of the thesis structure and the main contributions for each domain. Chapter numbers are shown in the numbered circles, while the key outcomes and main research contributions are summarised in the blocks. Specifically, Chapter 2 reviews the state of the art of non-conventional uses of nuclear technologies, including existing industrial cogeneration experiences, ongoing research initiatives and identified gaps in current practice and literature, with particular attention on NHES developments. Chapter 3 presents the methodological framework proposed in this work, emphasising the inherently interdisciplinary nature of NHES analysis and outlining how the different research dimensions are interconnected with each other. Chapters 4 through 9 then examine in detail each of the methodological domains introduced in Chapter 3, describing the adopted approaches, the developed modelling and simulation tools, and several case studies that illustrate how the methods can be applied in practice. In particular, Chapter 4 highlights the need to perform a comprehensive context and scenario analysis for NHES architectures, as it can strongly influence their design and operation. The modelling activities, described in Chapter 5, focus on the thermodynamic modelling and optimisation of power conversion systems encompassing steam extraction for cogeneration purposes and on the dynamic modelling of NHES components and architectures, resulting in dynamic simulators for multiple configurations. A key outcome for this domain is the contribution to the TAN-

DEM Modelica library, an open-source repository that collects a broad set of dynamic models for NHES analysis, including those developed within the framework of this thesis. The dynamic simulators were applied to support safety and techno-economic assessments, described in Chapters 6 and 7, by numerically coupling them to thermal-hydraulic system codes and techno-economic optimisation tools, respectively. The role of NHES within broader energy systems (e.g., at the country level) is analysed in Chapter 8 using energy modelling frameworks that have been extended as part of this thesis to represent nuclear cogeneration and NHES. Chapter 9 then translates the outcomes of the analysis and modelling activities into general policy recommendations related to NHES. Finally, Chapter 10 summarises the main findings, discusses their implications for energy policies, and outlines potential perspectives for future research efforts.

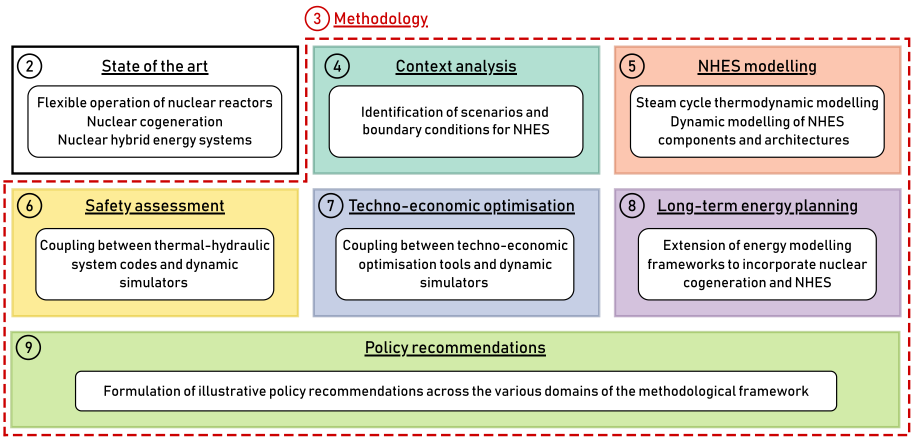

Figure 1.4: *Thesis structure.*

The methodological domains will be examined in greater depth in the following chapters, where their practical implications are explored through dedicated case studies. These studies apply the proposed approaches and tools to demonstrate how the methodological framework can support analyses that are relevant for policymaking. In particular, the case studies focus on three main applications, summarised in Figure 1.5 together with the corresponding case studies presented in each chapter. These include heat extraction and flexible operation, which address general steam extraction for cogeneration purposes (independent from specific end-user segments) and its potential contribution to the flexibility of the power plant. In addition, two illustrative non-electric applications were considered throughout the thesis: hydrogen production and district heating. It is worth noting that some tools and examples proposed in this work span over multiple applications. For instance, the TANDEM Modelica library encompasses models for the steam cycle, hydrogen production plants, and district heating networks, among others. Moreover, the extended energy system modelling frameworks were applied to investigate both steam extractions to meet exogenous heat demands and an archetypical NHES architecture incorporating hydrogen production.

Each case focuses on a light-water cooled, pressurized water-type Small Modular Reactor (SMR), considering the European SMR (E-SMR) conceptual design, developed within the Euratom-funded ELSMOR project [19], as a reference. The project provided a database of operational and geometrical data for the primary loop [20], offering a valuable basis for modelling the nuclear reactor. Most case studies consider a single E-SMR module, without addressing potential interactions in a multi-module configuration. The main design parameters of the E-SMR are summarised in Table 1.1.

Parameter	Value	Unit
Nominal thermal power	540	MW_{th}
Reference electrical power	170	MW_{el}
Primary coolant pressure	15	MPa
Steam outlet temperature	300	°C
Steam pressure	4.5	MPa
Feedwater inlet temperature	163	°C

Table 1.1: *E-SMR module design parameters [19].*

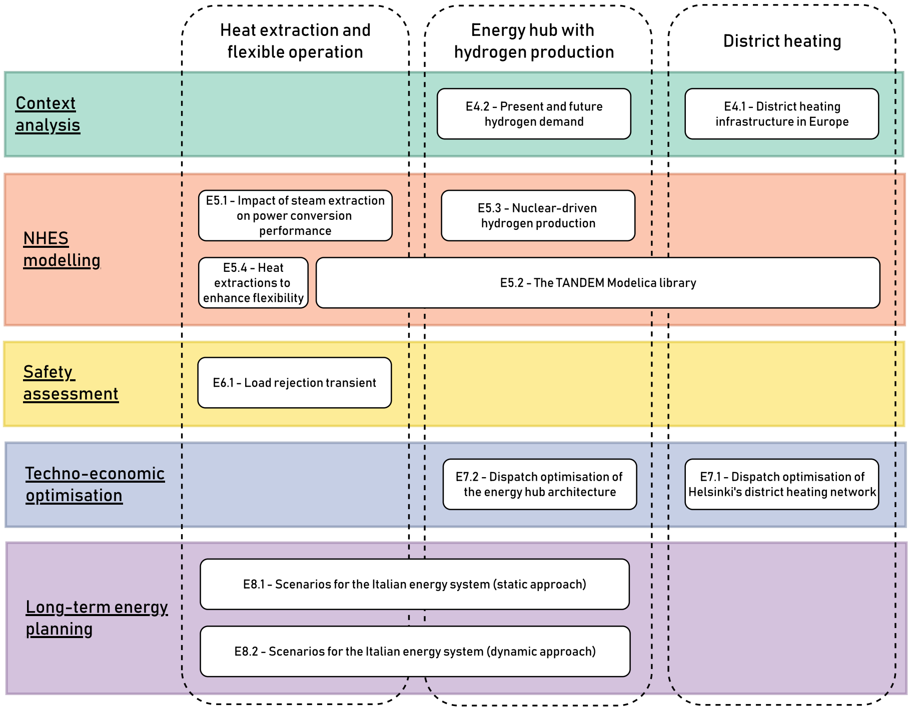

Figure 1.5: *Overview of the case studies.*

CHAPTER 2

State of the Art

This chapter provides an overview of the current and the potential future role of nuclear power in the evolving energy sector. Specifically, it addresses the contribution of nuclear power plants in providing flexibility to the electrical grid by adjusting their power production in response to renewable power generation and, in general, grid requirements. Moreover, the opportunities of directly exploiting nuclear heat to drive cogeneration applications, such as district heating and industrial processes, are discussed, providing an overview of current experiences and future prospects. A novel application of nuclear reactors involves their integration into Nuclear Hybrid Energy Systems (NHES), in which a stronger interconnection between energy suppliers and consumers is achieved. In this chapter, a general overview of these systems is provided, together with the modelling approaches and research gaps that must be addressed to inform policy decisions.

2.1 Nuclear energy in the evolving energy sector

Nuclear power, as a low-carbon and programmable heat source, can play an important role in an energy sector increasingly shaped by intermittent renewable generation and the urgent need to decarbonise industrial processes to meet climate targets. This section examines how nuclear energy can contribute to this transition through flexible electricity production, the direct exploitation of nuclear heat for cogeneration purposes, and its integration within highly interconnected hybrid energy systems.

2.1.1 Flexible operation

The increasing penetration of VREs can lead to instabilities on the electrical power grid, mainly driven by the uncertainties related to the renewable power generation that might result in mismatches with the electrical load [9]. Nuclear Power Plants (NPPs), as dispatchable and low-carbon power sources, represent a possible solution to address this issue by covering the residual load in response to renewable generation. However, traditionally, NPPs are operated as baseload generators, i.e., producing electricity continuously at their rated capacity. This operational choice is driven by both economic and technical factors. Nuclear projects are characterised by high fixed costs and rather low marginal costs, with the fuel being responsible for just 7-12% of the total operational costs, whereas this figure can rise to as much as 71% for gas-fired power plants, making these generators extremely sensitive to fuel price fluctuations [21]. Thus, achieving high capacity factors is particularly important for NPPs to maximise the return on investment. The technical advantages of keeping the reactor at its rated conditions are mainly related to reduced wear and tear of the components, as frequent power adjustments can induce thermo-mechanical stresses on the equipment [22]. Moreover, by maintaining the core power at nominal conditions, it is possible to optimise the neutron economy, as the need for external reactivity insertion through control rods, which leads to distortions in the neutron flux distribution, is minimised [22].

However, in light of the growing need for programmable generators, the flexible operation of NPPs is becoming increasingly important. In Europe, countries already modulate the reactors' power to meet load demands. An example is the French nuclear fleet, whose reactor units are designed to be operated flexibly through the use of grey rods to modulate the reactor's power in response to grid requirements, including frequency regulation [12]. As a matter of fact, NPPs can not only operate in load-following mode, i.e., in response to predicted load variations and market conditions,

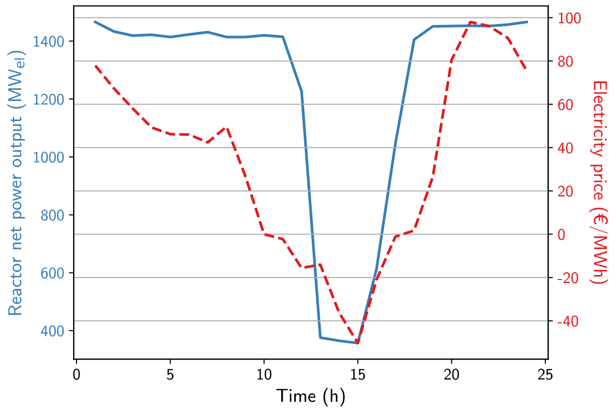

Figure 2.1: *Chooz-2 reactor operation and electricity prices in France, 10/08/2025 [24].*

but they can also provide operational reserves and other ancillary services, such as frequency regulation, to help stabilise the grid [23]. By participating in these services, operators can adjust the power plant's output, contributing to overall system reliability while taking advantage of additional revenue streams from ancillary service markets. For instance, Figure 2.1 shows an illustrative day-long operation of the Chooz-2 reactor unit in France. It can be clearly seen how the reactor power output is modulated in response to the electricity market: during the central part of the day, when solar generation is high and, consequently, when the residual load demand is low, the electricity prices fall to negative values. To reduce economic losses and respond to grid requirements, the reactor power is reduced from 100% rated power to about 25% in 1 hour. In the evening hours, when electricity prices are high, full power conditions are re-established.

Notably, the flexible operation of nuclear reactors is limited by several technical constraints, including the aforementioned neutron flux distortion through control rods. In addition, frequent adjustments in core power can be challenging for the fuel integrity and in terms of fission product poisoning [23]. These constraints are reflected in several operational limits set by regulatory authorities. The current fleet of nuclear reactors can perform load-following with ramp rates up to 5%/min of rated power and contributes to primary and secondary frequency regulation by 3% and by more than 5% of the rated power, respectively [25]. These capabilities are in line with the regulations of the European Utilities Requirements (EUR), according to which light-water cooled reactors should be able to adjust their electrical output between 50 and 100% at a rate of 3%/min, with a limit of two ramps per day or five per week [25].

It is worth noting that these flexibility requirements and limits apply to the nuclear technology that is currently more widespread, i.e., large-scale, light-water cooled reactors. Innovative and advanced nuclear reactors could have different characteristics when it comes to flexible operation. Current nuclear technology developments are mainly dedicated to Generation IV reactors [26]. Six nuclear energy systems were identified by the Generation IV International Forum (GIF), differing in terms of neutron spectrum, coolants, fuel cycle, etc. The advanced reactor designs were selected with particular attention on safety, economic viability, sustainability (e.g., in terms of environmental footprint and nuclear waste management), and proliferation resistance. The selected systems are characterised by different coolants with respect to conventional light-water cooled reactors, allowing the primary coolant to operate at higher temperatures, as summarised in Table 2.1.

Reactor concept[1]		Temperature range (°C)
Lead-cooled fast reactor	LFR	480-570
Sodium-cooled fast reactor	SFR	500-550
Supercritical water reactor	SCWR	510-625
Molten salt reactor	MSR	700-800
Gas-cooled fast reactor	GFR	850
Very high temperature reactor	VHTR	900-1000

Table 2.1: *Overview of Generation IV reactor concepts [27].*

The reactor sizes can differ from tens of MW_{el} to large-scale systems exceeding 1 GW_{el}. In this regard, generation units of smaller scale are often denoted as Advanced Modular Reactors (AMRs).

Current research efforts are exploring the viability of SMRs. They are based on innovative light-water cooled technology and have a rated power typically below 300 MW_{el} [28]. These reactors can be characterised by a loop-type design, similar to conventional large-scale reactors, or by an integral design, with the main primary circuit components packed within the reactor pressure vessel. A key feature of SMRs, as well as of AMRs, is the smaller dimension and reduced core inventory, which may facilitate siting the reactors closer to end-users for the supply of both electricity and heat. Moreover, these systems are characterised by a modular construction and deployment approach: the aim is to establish a standardised supply chain of reactor modules, manufactured in factories and assembled at the

[1]For reference, the nuclear technology considered in this work (i.e., the E-SMR) has a primary coolant temperature that reaches approximately 325°C.

construction site. In addition, multiple reactor modules could be installed in the same facility, allowing the rated power of the NPP to be scaled up as needed. From an economic perspective, SMRs rely on a different strategy with respect to conventional NPPs, as the lower power ratings lead to a loss of the economy of scale. Thanks to the modular construction approach, the SMRs competitiveness is expected to be supported by an economy of series, promoted by the standardised designs and the reduced investment risk due to the smaller size of the project [29].

The significant design evolutions with respect to conventional NPPs can lead also to differences in terms of operational limits during flexible operation. For instance, the limits driven by concerns on fuel integrity will be different in the case of MSRs or gas-cooled reactors, where the fuel is dissolved in the coolant or encapsulated in TRISO particles, respectively. For this reason, the specific design features of these advanced reactor technologies should be taken into account in future research efforts when evaluating their role in the evolving power sector. Despite the technological similarities between SMRs and conventional reactors, the former also can have some differences in terms of flexible operation. For example, some SMR concepts are based on soluble-boron-free designs, which lead to stronger inherent reactivity feedback effects and contribute to core power adjustments during load following [30]. In addition, the multi-modularity of SMRs can be exploited to adjust the electrical power output of the overall NPP by coordinating the operation of the single modules to meet the variable load demands [31, 32].

2.1.2 Nuclear cogeneration

Nuclear reactors are inherently thermal power sources; however, as of today, they are largely used exclusively for electricity generation. The direct exploitation of nuclear heat has several advantages, including improvements of the plant's efficiency, driven by a reduction in power conversion losses [27]. Moreover, the availability of large-scale, dispatchable, and low-carbon heat could support the decarbonisation of hard-to-abate sectors, especially in industries that need a reliable energy supply.

A key factor that needs to be considered for the coupling of nuclear reactors with non-electric applications is the compatibility between the temperature requirements of the heat user and the temperature levels achieved by the nuclear technology. Figure 2.2 shows a temperature range comparison including the compatibility between various non-electric applications and different nuclear reactor types, from conventional water-cooled to VHTRs. It should be noted that the temperature ranges reported in the figure refer to the peak temperature requirements of each process. However, most of these industrial applications can benefit from nuclear cogeneration even at lower temperature levels, for instance for feedstock preheating or initial steam temperature increases. In general, the steam temperature level of light-water cooled reactors, including both conventional large-scale reactors and SMRs, is limited to 300°C. On the other hand, thanks to the different technological characteristics, advanced reactors can achieve higher temperatures, up to 1000°C for the VHTR. It is worth noting that the latter temperature refers to the primary loop, meaning that some temperature drop in intermediate heat transfer processes should be accounted for when considering heat extraction from the secondary side. Nonetheless, temperature matching can also be addressed through heat-augmentation techniques that upgrade extracted heat to higher levels required by end users. For example, steam extracted at around 300°C can be boosted toward higher temperatures using heat augmentation techniques such as steam compression (with reported temperature increases up to 650°C [33, 34]), gas compression cycles, or chemical heat pumps for achieving larger temperature lifts [35]. While such approaches introduce additional equipment and power consumption, they enable heat supply at higher temperature levels (and thus exergy content) through the conversion of mechanical or chemical work. Although this inevitably leads to exergy destruction and efficiency losses at the overall system level, it can expand the addressable heat market by enabling even conventional reactor technologies to serve high-temperature end-user segments.

A significant amount of non-electric applications, e.g., desalination, district heating, hydrogen production via high-temperature steam electrolysis and process steam supply for industries requiring low-grade heat, could be potentially driven by conventional reactor technologies even without temperature boosting techniques. The deployment of advanced reactors could enable the coupling with high-temperature applications like hydrogen production via thermochemical cycles, the petrochemical industry, and steelmaking processes.

A short overview of the main processes suitable for coupling with nuclear reactors is provided below:

- *District heating*: In this application, nuclear energy is used to supply thermal power to a district heating network that distributes heat to residential, commercial, and industrial buildings for both space heating and domestic hot water production. The supply temperature of the hot water is typically limited to 150°C and can therefore be achieved by extracting steam from any NPP [36]. Notably, the heat demand

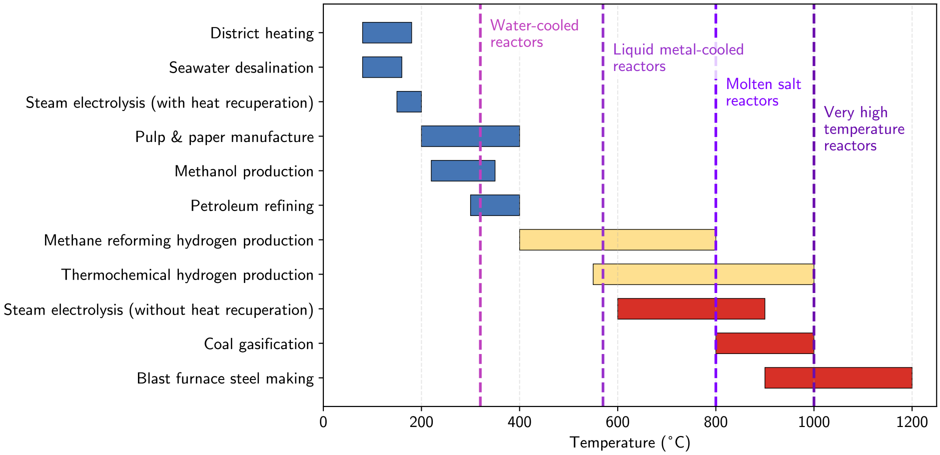

Figure 2.2: *Temperature ranges for cogeneration applications and reactor technologies (readapted from [36]).*

in this non-electric application is strongly seasonal, with higher loads in winter and almost exclusively domestic hot water demand in the summer.

- *Desalination*: Seawater desalination technologies can be classified in thermal and electricity-driven processes. As for the latter, reverse osmosis stands out as the most mature technology and would require just an electrical interconnection with the NPP. Nowadays, the predominant share of desalinated water is produced with this technology [37]. Nuclear heat could be exploited to drive thermal desalination processes, such as multi-stage flash and multi-effect distillation, reducing the electrical power requirements of the process [38]. While such applications are particularly relevant in regions facing water scarcity, nuclear-driven desalination can also be employed for the treatment of brackish water [37].

- *Hydrogen production*: Several hydrogen production technologies, characterised by different temperature requirements, could be coupled to nuclear reactors. In addition to Low-Temperature Electrolysers (LTE) (e.g., based on alkaline and proton exchange membrane technology), which would be only electrically coupled to the power plant, nuclear energy could be used to drive High-Temperature Steam Electrolysis (HTSE). In this system, the water splitting reaction occurs between 600 and 900°C, leading to significantly lower electrical power requirements compared to LTE (about 40 kWh_{el}/kg_{H_2} instead of 55 kWh_{el}/kg_{H_2}) [39]. It is important to note that an HTSE encompasses heat recuperation and temperature boosting systems to achieve the temperature levels required by the electrolyser, whereas external heat supply from the NPP is needed only for feedstock water evaporation (i.e., $<$200°C). Moreover, high-temperature reactors could support the production of hydrogen via thermochemical cycles, which require a minimal electrical power output compared to electrolysis technology. However, these cycles currently exhibit a very low technology readiness level, largely due to the challenges associated with handling highly corrosive and reactive chemical materials at high temperatures. In addition, high-temperature heat can be exploited also to support the decarbonisation of steam methane reforming, which, as of today, accounts for the overwhelming majority of hydrogen production worldwide. In this process, natural gas combustion is used to provide the required heat at about 800°C, which could be replaced by heat supplied by advanced reactors, reducing the need for gas (and, therefore, emissions) by about 35% [40].

- *Process steam supply*: Industrial process steam supply refers to the use of the heat extracted from NPPs to produce steam to drive industrial applications, which can be characterised by a wide range of temperature requirements. For instance, the paper and food industries require steam at low temperature levels, whereas chemical processing plants, refineries, steelmaking, etc. operate at higher temperature levels. In industrial processes, the reliability of the energy supply is a critical aspect. In this context, nuclear plants, with their capability to deliver a stable and continuous steam supply, could effectively meet this requirement [27].

Despite being used predominantly for electricity generation, some experiences of nuclear cogeneration exist, specifically with a fraction of the heat of large-scale reactors allocated for desalination, district heating or process steam supply. In 2021, 61 nuclear plants supplied heat to non-electric applications worldwide, representing about 14% of the operational reactor units [41]. Figure 2.3 shows the nuclear plants in Europe that are currently operating in cogeneration mode. Reactors are mainly used to supply heat to district heating networks in Eastern Europe, and there is also experience in industrial steam supply, especially in Russia. Examples of nuclear cogeneration applications are present also beyond Europe, with reactors in Japan and India used for seawater desalination, for instance. As of today, there are limited experiences of nuclear-based hydrogen generation, mainly involving small-scale production for internal uses, such as in the case of the Oskarshamn NPP in Sweden, where the produced hydrogen is used for generator cooling [42]. Nevertheless, several demonstration projects are either under deployment or have been announced to showcase the viability of coupling the power plant's operation with the hydrogen production processes, including the Davis-Besse and the Prairie Island NPPs in the United States, where the coupling with LTE and HTSE, respectively, will be implemented [43]. Moreover, the exploitation of high-temperature heat of the High Temperature Engineering Test Reactor (HTTR) to reduce emissions of hydrogen production via steam methane reforming is under demonstration in Japan [40].

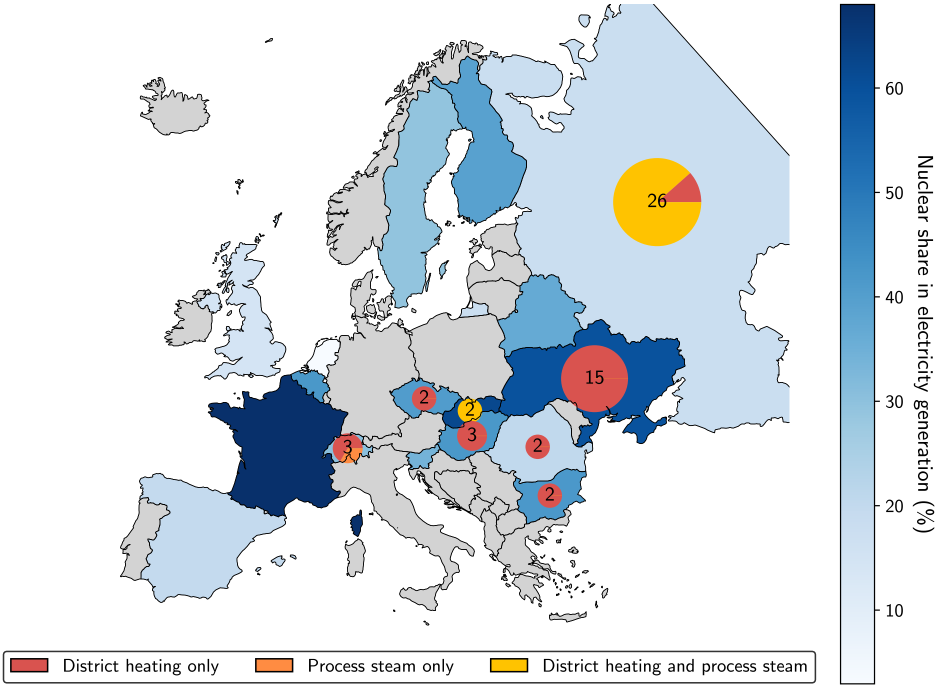

Figure 2.3: *Nuclear power in Europe: electricity supply and non-electric applications. The values indicate the total number of reactor units operating in cogeneration mode (as of 2021).*

Currently, numerous research and development (R&D) and industrial initiatives are exploring the potential applications and characteristics of nuclear cogeneration. For instance, the GIF "Non-Electric Applications and Cogeneration Applications of Nuclear Energy" Working Group (NECA WG) investigates the potential integration of advanced reactors with several non-electrical applications, leveraging the availability of high-quality heat [44]. Moreover, the International Atomic Energy Agency (IAEA) launched the Coordinated Research Project *Role of Nuclear Cogeneration within the Context of Sustainable Development* in 2023 [45]. The goal of this initiative is to support Member States to assess technologies and possible integration strategies between nuclear and cogeneration systems. As for nuclear hydrogen production, the International Energy Agency's (IEA) *Task 44 - Hydrogen from Nuclear Energy* focuses on conducting techno-economic analyses, identifying barriers, and providing guidance to policy-makers, industry, and investors to support the deployment of nuclear-based hydrogen production technologies [46]. In addition, the European Nuclear Cogeneration Industrial Initiative (NC2I), established within the framework of the Sustainable Nuclear Energy Technology Platform (SNETP), aims at facilitating the deployment of nuclear cogeneration systems by coordinating European public and private research and industrial initiatives [47]. In this framework, the NC2I-R project contributed to defining a strategic roadmap, assessing safety and licensing frameworks, and identifying research and demonstration needs for nuclear cogeneration systems in the European context [48]. Over the years, several Euratom-funded projects explored the role of nuclear cogeneration in the European context. For instance, the EUROPAIRS [49] and ARCHER [50] projects analysed the potential use of High Temperature Gas-cooled Reactors (HTGR) to supply industrial process heat, addressing technical, economic, and licensing considerations. More recently, the operation of HTGRs in polygeneration mode to reduce emissions from the industrial sector was addressed in the GEMINI+ and GEMINI 4.0 projects [51, 52]. Lastly, the NPHyCO project investigated the prospect of retrofitting existing, large-scale nuclear power plants for low-carbon hydrogen production, evaluating the techno-economic and operational viability as well as possible pilot project configurations and suitable sites [53]. From an industrial perspective, nuclear cogeneration is looked at with high interest by many SMR vendors [54]. For instance, studies are ongoing to evaluate the use of the BWRX-300 reactor design to produce hydrogen and decarbonise chemical processes in Poland. Moreover, significant advancements are ongoing for the deployment of LDR-50 reactors to supply heat to the Finnish district heating system. Another example in the European context is the French NUWARD design, which is specifically conceived for combined heat and power, providing both electricity and heat for hydrogen production, district heating, and desalination [55]. Many HTGR concepts, including the French Jimmy HTR and the Polish HTGR-POLA, also foresee the coupling with non-electric applications, leveraging their higher operating temperatures. Beyond Europe, the HTR-600S project in China targets steam supply for petrochemical applications, while in the United States X-energy and Dow are advancing the deployment of high-temperature reactors to provide reliable process heat to industrial facilities [54].

2.1.3 Nuclear hybrid energy systems

The aforementioned cogeneration applications operate as stand-alone, vertically integrated systems, directly coupling the nuclear reactor to the cogeneration facility. In contrast, Nuclear Hybrid Energy Systems (NHES) introduce a novel operational paradigm, integrating the nuclear reactor into a highly interconnected energy system with other generation sources (e.g., renewables), energy storage devices, and non-electric applications [56]. This tight coupling allows exploiting synergies between generation sources to optimise resource utilisation and revenue streams from different commodities by flexibly allocating the power flows within the system according to end-user requirements and market dynamics [56]. NHES can feature different levels of integration, ranging from purely electrical interconnection through the power grid to a tight coupling via electrical and thermal interconnections within the plant itself. A key strength of NHES architecture is flexibility, achieved by coordinating the various NHES subsystems (both energy producers and consumers) to regulate commodities production [56].

An illustrative schematic of a NHES architecture is shown in Figure 2.4. As aforementioned, it can encompass several power sources, storage devices, industrial processes and/or cogeneration applications. Therefore, the integrated system can produce different commodities needed in the end-user sectors reported on the right-hand side. Several non-electric applications could be coupled to the system, including those described before (district heating, hydrogen production, desalination, process steam supply, etc.). These technologies can differ in terms of energy requirements; for instance, LTE-based hydrogen production requires only electricity, whereas thermally coupled systems may require only heat (e.g., district heating) or both electrical and thermal energy, as in HTSE hydrogen production plants. Moreover, the system can supply net electricity to the national transmission network, coordinating on-site generation and consumption to maximise flexibility and support grid stability. Overall, the commodities produced by the NHES can contribute to the decarbonisation of hard-to-abate sectors, not only the power sector. For instance, the production of hydrogen and, eventually, of low-carbon fuels could play an important role in the industrial and transport sectors. Moreover, the heat produced by the sys-

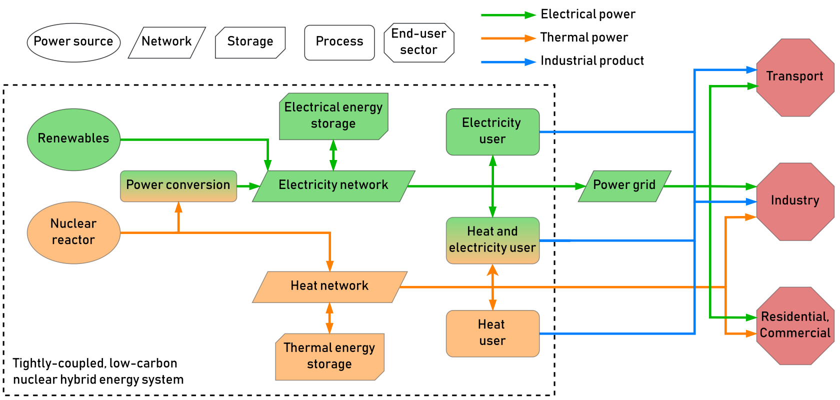

Figure 2.4: *General schematic of a NHES architecture.*

tem could contribute to satisfying the process steam and residential district heating demands.

The design and operation of NHES is characterised by several benefits and challenges, driven mainly by the strong interdependencies between NHES subsystems. A noteworthy operational mode for the nuclear reactor is the so-called load-following by cogeneration mode, where the reactor is maintained at rated conditions while flexibly allocating its thermal power either for power conversion or to drive non-electrical applications [57]. This operational mode allows leveraging the advantages mentioned in Section 2.1.1 of keeping the reactor stable while meeting flexibility and grid requirements by adjusting the fraction of thermal power delivered to non-electrical applications and/or a thermal energy storage system. For instance, when load demand or electricity prices are low (e.g., due to high renewable generation), the electricity production of the NHES could be minimised by delivering a higher amount of thermal energy to produce commodities beyond electricity, thereby diversifying revenue streams of the integrated system. However, when designing and operating a NHES, several challenges must be considered as well, such as the compatibility and coordination of NHES subsystems. For instance, the industrial process might need a stable supply of energy, which could constrain the system's capability to provide the flexibility needed for variable grid requirements. As a result, it is fundamental to define an operational mode that is compliant with the technical constraints of each NHES subsystem. In addition to operational considerations, NHES design also entails significant challenges, as integrating nuclear reactors with industrial processes or other subsystems requires compatible design standards and safety requirements, as well as properly engineered thermal and electrical interfaces [56].

Currently, several research efforts focus on the investigation of NHES. One example is the Integrated Energy System (IES) programme, a U.S. Department of Energy initiative coordinated by the Idaho National Laboratory [58]. This initiative is based on three pillars: (i) system simulation, which aims at analysing the techno-economics of NHES through modelling tools; (ii) an electrically heated experimental demonstration testing system, called DETAIL, to test the integrated operation of electrically and thermally interconnected components; and (iii) a nuclear demonstration project based on retrofitting an existing plant. Moreover, TANDEM (Small Modular ReacTor for a European sAfe aNd Decarbonized Energy Mix) is a Horizon Europe project funded under the Euratom scheme that was active between 2022 and 2025 [59]. The project focused on the possible hybridisation of light-water cooled SMRs in integrated energy systems, with the aim of assessing how such systems can contribute to meeting climate targets in Europe. As part of the project, tools and methodologies were developed to investigate the couplings from several standpoints, including techno-economics, safety, stakeholder engagement, as well as gaps and opportunities in education and training. Overall, the outcomes of the project aim at supporting R&D activities to assess the integration of SMRs into NHES.

Recent review articles on NHES agree that these systems can offer significant benefits in terms of flexibility, resource utilisation efficiency, revenue streams, and in the support of deep decarbonisation [60–62]. In particular, Arent et al. [60] highlighted the importance of leveraging the availability of multiple energy carriers to optimise the operation of the system in compliance with operational constraints. However, technical and economic challenges need to be considered, especially when it comes to the different types of interconnections and co-location of nuclear and industrial facilities [61]. Besides technical and economic considerations, general strengths, weaknesses, opportunities and threats, including aspects like social acceptance and policies, were addressed by El-Emam et al. [62]. Overall, the reviews emphasised the importance of conducting system-level techno-economic studies to assess the competitiveness of NHES in realistic, country-specific market conditions, demonstrating the safety of having an industrial process that is tightly coupled to NPPs, and developing control and operational strategies to manage power flows within the NHES to meet demands and requirements of the various produced commodities.

2.2 Modelling NHES in decarbonisation strategies

This section aims at describing the main modelling approaches for NHES available in literature, identifying current research gaps, and discussing the implications for policymaking. Due to the novelty of such integrated energy systems, the modelling and simulation phase is critical for assessing their potential in different decarbonisation scenarios. Consequently, modelling tools, such as physics-based, techno-economic, detailed thermal-hydraulic, and energy planning models, will be instrumental for decision-makers in the global evaluation of NHES. For instance, they can be applied to explore technically and economically viable configurations of NHES and provide policymakers insights about their deployment potential in synergy with renewables, considering uncertainties and different market assumptions, among others. Moreover, modelling of NHES architectures can support the definition of the optimal coupling and control strategies for the integrated system design and operation, identifying also safety-related challenges that need to be considered by policymakers in the regulations and in the licensing process.

The aforementioned review studies stressed the importance of modelling NHES to support the investigation of the design and operation of integrated architectures. In literature, there are several examples proposing dynamic models to test the operation of NHES, mainly applied to evaluate control strategies and identify operational constraints arising from system integration. For instance, the dynamics of a NHES modelled in the object-oriented language Modelica were investigated by Kim et al. [63], who demonstrated that such systems could support grid stability by regulating the power allocated for hydrogen production. Similarly, Jacob and Zhang [64] proposed a dynamic model of a NHES, encompassing a light-water cooled SMR, HTSE, as well as VREs, and presented a control strategy to coordinate subsystem operations based on grid requirements, showcasing the flexibility of the integrated system. Moreover, Garcia et al. [65] conducted a dynamic analysis of two NHES architectures tailored to regional characteristics, considering one integrating chemical production in Texas and the other fresh water production in Arizona. The study demonstrated that both architectures can effectively accommodate high levels of VRE penetration and rapidly adjust outputs to provide operating reserves and ancillary services to the electric grid. Other studies have focused on modelling the economic and environmental aspects of NHES, particularly assessing the benefits of accessing multiple markets and optimising economic dispatch, as well as the advantages in terms of emissions reduction. For example, Chen et al. [66] optimised the dispatch strategy of the NHES architectures proposed by Garcia et al. [65], highlighting the pivotal role that participation in markets beyond electricity can have on the profitability of the integrated system. Moreover, Epiney et al. [67] presented a methodology to optimise both subsystem capacities and dispatch strategy while accounting for the stochastic nature of boundary conditions, such as load demand and VRE availability. Their study demonstrated that the optimal configuration of the system is highly dependent on the considered context. Overall, these works emphasise that the economic viability of NHES is strongly scenario- and assumption-dependent, underlining the need to consider uncertainties in techno-economic parameters and to adopt realistic market- and site-specific conditions when evaluating system performance. Lastly, another important research area concerns the assessment of the role of nuclear power within broader energy systems. In this regard, most long-term decarbonisation studies that include nuclear energy still limit its role to the electricity sector [68]. A notable exception is the work by Matthews et al. [69], in which nuclear-driven hydrogen production is explicitly modelled in decarbonisation pathways. The authors show that nuclear could not only support high penetrations of VRE but also supply heat and electricity for hydrogen production when renewable availability is high, thereby reducing reliance on gas in both the power and hydrogen sectors.

In general, the models of NHES architecture proved to be instrumental in identifying risks, barriers, and enabling conditions for NHES deployment. Nonetheless, several gaps and challenges remain, arising mainly from the complex and tightly interconnected nature of such systems. This aspect complicates the development of highly representative models, which would require a detailed set of parameters for each interconnected component, and the resulting model complexity could lead to a significant computational burden when performing simulations [70]. As a result, a simplified modelling approach is often adopted for broader energy system analysis, e.g., for techno-economic analyses, whereas a physical representation of the most important systems is used for rather local or short-timescale operational assessments. The main challenge is then to integrate the outputs from these two levels into a comprehensive NHES modelling framework. As previously discussed, dynamic models are often adopted to simulate the behaviour of the overall system. Also in this case, the heterogeneity of the coupled systems can introduce considerable modelling complexities, resulting in the need for a multi-physics modelling strategy. Achieving computationally feasible simulations may necessitate simplifying certain components, though this can limit the acceptability of the results. For instance, a simplified modelling approach for the nuclear reactor can undermine the value of the simulations for safety assessments, limiting the acceptance of the models for regulatory and licensing purposes. In addition, this challenge is reinforced by the difficulty of establishing model accuracy, since validation is constrained by the limited experimental data and operational experience available for NHES. The complex architecture of NHES also creates hurdles for plant-level techno-economic optimisation, particularly due to interactions with multiple markets (e.g., electricity, hydrogen, heat), each governed by different regulations that are difficult to represent in optimisation frameworks [71]. For such integrated energy systems, it is also essential to account for spatial variability, for example, in renewable resource availability, local energy prices, or infrastructure constraints, all of which are subject to uncertain future developments. In addition, thermal couplings between subsystems can introduce non-linear effects that are hardly captured by conventional linear optimisation tools and thus require more advanced modelling approaches. However, one of the most significant research gaps regarding NHES lies in their representation within long-term energy system planning analyses. Capturing the role of NHES in these models is particularly challenging, as such systems can be characterised by multiple configurations, strong interactions between subcomponents, and simultaneous participation in multiple commodity markets [72]. Most established energy system modelling frameworks treat NPPs predominantly as electricity-only generators, with limited capability to represent their potential to supply heat or serve non-electric applications. Moreover, in the context of dispatch optimisation, only a limited number of energy system models explicitly represent operating reserves and other flexibility requirements needed to maintain grid stability [73]. When adequately represented, these elements, together with transmission, balancing, system integration costs, etc., contribute to the total system cost, which offers a more representative figure of merit for assessing decarbonisation pathways, particularly in scenarios with increasing penetration of VREs [74].

Overall, NHES models should support decision-makers in assessing the potential deployment of such systems within decarbonisation pathways, accounting not only for emission reductions but also factors such as energy security, reliability, and flexibility to contribute to grid stability. In addition to the previously discussed modelling gaps, a fundamental limitation is the lack of integration between the technical, economic, and policy dimensions. Specifically, addressing this need requires an interdisciplinary approach, with modelling tools designed to respond to a range of policy requirements and gaps, including regulatory frameworks, stakeholder engagement, social acceptance, and climate and energy policies. As a result, it is fundamental to align the NHES modelling strategies to real-world policy needs to ensure that the outputs are relevant and supportive for decision-making.

CHAPTER 3

Methodology

This chapter presents the methodological framework developed in this thesis for the analysis of NHES and, in general, nuclear-driven cogeneration systems. The approach integrates six interconnected domains: context analysis, NHES modelling, safety assessment, techno-economic optimisation, long-term energy planning, and support for policymaking, with each pillar relying on dedicated simulation and optimisation tools. Together, these domains enable a consistent treatment of technical performance, safety implications, economics and the integration of NHES within broader energy systems across different deployment scenarios. The chapter also presents how the resulting framework can be used to inform regulatory developments and evidence-based energy policies regarding the hybridisation of nuclear reactors.

The global objective of this research is to propose a holistic methodology for the analysis of NHES in different scenarios. The proposed methodology follows a structured, multi-domain approach that links contextual analysis, physics-based system modelling, safety assessment, and techno-economic optimisation with long-term energy planning and policymaking. These domains are integrated to provide a comprehensive representation of NHES architectures and their operation in different scenarios, with the aim of providing policymakers with technically grounded tools and methodologies for the evaluation of NHES configurations. Figure 3.1 shows a schematic of the proposed framework: it encompasses several domains, underlining the importance of an interdisciplinary approach in NHES research for shaping evidence-based policies. In this chapter, a brief overview of the methodology is provided, mentioning the fundamental aspects of each domain and how they are interconnected with each other. Following that, each pillar will be addressed in a dedicated chapter, delving into the specific methodological approaches, the relevant tools, and case studies to showcase their practical application and how the integrated framework can be applied to evaluate NHES architectures in different scenarios.

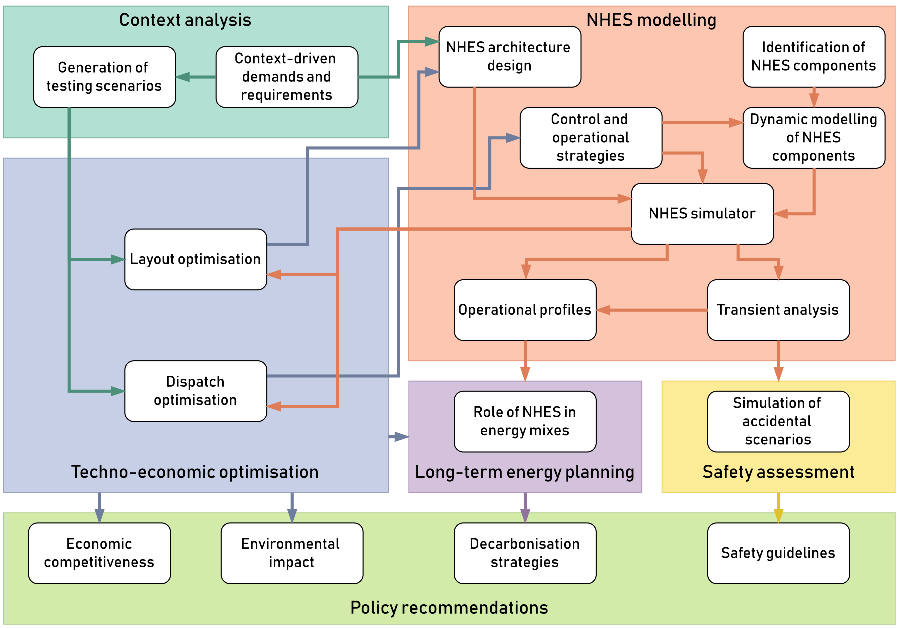

Figure 3.1: *Overview of the methodological framework.*

Context analysis

The design, operation, and optimisation of NHES architectures are strongly dependent on the considered context, including location and deployment timeline. For instance, the territories can vary in resource potential, existing infrastructure, and governing policies, among others. As a result, it is fundamental to investigate local requirements, market demands, and other factors that can affect the structure of energy systems. Consequently, understanding the context needs helps define the design of the NHES architecture during the modelling phase, e.g., by identifying the technologies and processes best suited for integration with nuclear heat based on the specific characteristics of the area. In addition, the performance of a NHES design will be driven by the testing scenarios, e.g., depending on commodity demands and market conditions. Therefore, to fully understand the potential role of these systems under future uncertainties, it is crucial to develop and analyse a broad range of scenarios based on projections and existing or anticipated policies. The underlying assumptions of these generated scenarios must be guided by the local needs and conditions of the areas where the potential NHES deployment is being investigated, ensuring that the analysis reflects realistic conditions. Moreover, the selected scenarios play a fundamental role in techno-economic optimisations, allowing for the assessment of the optimal design and operation of the integrated system in response to the specified boundary conditions.

NHES modelling

Firstly, potential components, including non-electric applications, specific technologies, etc., that are suitable for integration into NHES need to be identified. As for the overall architecture, the design phase can be supported through steady-state thermodynamic modelling of the power conversion system and the interconnection with the non-electric application in order to define viable steam extraction points in terms of temperature and pressure levels and assess their impact on power conversion performance. The selected components are then simulated through dynamic models, which can be characterised by different levels of modelling detail according to the purpose of the model and the scope of the analysis. Moreover, the dynamic models are combined in a simulator of the overall NHES architecture, based on the design identified from the context analysis and the techno-economic optimisation of the system's capacities. A fundamental aspect for both the single subsystems and the overall NHES architecture is the definition of control and operational strategies. As a matter of fact, the operation of single subsystems needs to be controlled to maintain critical variables within the allowed limits and, at the same time, their operation coordinated to enable the integrated system to meet different commodity demands efficiently. In this regard, the techno-economic optimisation of the system can provide indications on which commodities to prioritise according to market conditions, for instance. The dynamic simulator of the NHES can be applied to explore the system response in transient scenarios and to identify operational profiles. As for the former, both normal and abnormal operating conditions can be considered, providing valuable insights to assess the safe operation of the system. The operational profiles can be used to characterise constraints and performance parameters, which play an instrumental role when evaluating the techno-economics of the system at different scales.

Safety assessment

The simulators can be applied to test the system's response under various accidental scenarios, with the objective of identifying initiating events and abnormal operating conditions that could compromise the safe operation of the nuclear reactor. By analysing such scenarios, it is possible to understand potential risks arising from the integration between the nuclear reactor and non-electric application and test design and operational measures to minimise potential hazard propagation and ensure the system meets safety and performance requirements. The goal in the frame of this work is to provide a methodological approach supported by simulation tools. It is intended to support policymakers adapting the regulatory framework and licensing procedures, accounting for operation in cogeneration mode, thereby facilitating the deployment of NHES and the coupling of nuclear reactors with industrial processes.

Techno-economic optimisation

The techno-economic optimisation domain focuses on the integrated system-level dispatch and layout optimisation. In this context, optimisation tools are used to identify the most cost-effective combination of installed capacities for the various system components under a given scenario, while dispatch optimisation determines the optimal power flows within the system to maximise overall performance. The NHES simulator supports this process by providing key information on operational constraints and technical parameters and by offering a physically representative behaviour of the system response when the optimised dispatch strategy is applied. Techno-economic optimisation plays a critical role in shaping policy recommendations. It enables an assessment of economic competitiveness, accounting for capital and operational costs, revenue streams from the production of multiple commodities, implications of market dynamics, etc. At the same time, it allows policymakers to compare NHES performance with alternative energy supply options from both economic and environmental perspectives, accounting for factors such as emissions, integration costs, and efficiency gains.

Long-term energy planning

For defining strategic investments and assessing the potential inclusion of NHES within broader energy systems at the country or regional level, it is essential to integrate these advanced nuclear applications into long-term energy planning models. Such models allow policymakers to explore how NHES may fit within evolving energy systems and how they can contribute to policy objectives. Similarly to the techno-economic optimisation domain, long-term energy planning models can rely on the technical parameters that were characterised in the detailed modelling activities. As a result, it is possible to evaluate the potential contribution of NHES to national decarbonisation strategies and to understand how they may complement other energy sources and technologies in meeting commodity demands. Such insights are crucial for policymakers, as they provide evidence on whether NHES can reduce system-wide costs and deliver environmental benefits compared to alternative pathways.

Policy recommendations

The methodologies and tools developed in this work are intended to support policymakers and regulators in the evaluation and planning of the hybridisation of nuclear reactors. By integrating detailed technical and economic aspects of NHES architectures into energy system optimisation frameworks, the proposed approach enables the assessment of their potential contribution to national decarbonisation objectives. The dynamic simulators can support safety authorities in verifying operational conditions and safety-related aspects of coupled systems under both normal and accidental conditions. Furthermore, the techno-economic analyses can inform policies to assess the sustainability of NHES in the context of the energy transition, highlighting their role, benefits, and potential deployment barriers. Overall, the developed methodology aims to connect the engineering characteristics of such novel, integrated energy systems with policymaking, thereby supporting technically grounded decision-making in the evaluation of NHES in low-carbon scenarios.

Concluding remarks

This chapter introduced the methodological framework for the assessment of NHES architectures, highlighting importance of integrating technical, economic, and policy-oriented analyses. As summarised in Table 3.1, each methodological domain delivers outputs that directly support the others, in line with the interdisciplinary nature of NHES analysis. The interactions between domains are a fundamental feature of this framework. For instance, context analysis sets the boundary conditions that are needed for modelling and optimisation activities, while NHES modelling provides the operational constraints and dynamic tools safety assessments and optimisation studies. Ultimately, by linking detailed physics-based models with system-level optimisation and broader energy planning tools, the proposed methodology aims at supporting a technically grounded evaluation of NHES deployment options and provides a structured basis for informing regulatory developments and energy policy decisions concerning nuclear cogeneration.

Domain	Outputs
Context analysis	Technologies to be integrated into the NHES architecture in the modelling phase, scenarios for techno-economic studies
NHES modelling	Operational constraints for techno-economic and energy planning studies, dynamic simulator for safety and short-term dispatch analysis
Safety assessment	Safety guidelines and modelling framework for regulatory bodies
Techno-economic optimisation	Optimal capacities of NHES components and optimal operational strategy of the integrated system
Long-term energy planning	Inclusion of nuclear cogeneration in capacity expansion models to define optimal energy mixes and deployment strategies
Policy recommendations	Examples of policy involving nuclear cogeneration and NHES

Table 3.1: *Outputs and interactions between methodological domains.*

CHAPTER 4

Context analysis

This chapter presents the methodological approach used to characterise the context in which NHES may be deployed, with particular attention to energy needs, existing infrastructure and policy drivers. It illustrates how such contextual analysis impacts the definition of NHES architectures through two examples: district heating networks and industrial hydrogen demand. The chapter further shows how these context-specific insights are translated into testing scenarios for techno-economic optimisation, dynamic simulation and long-term planning case studies. In general, these boundary conditions are fundamental for assessing NHES performance and competitiveness under realistic present and future conditions.

4.1 Local demands and requirements

The design and operation of NHES are inherently context dependent. First, nuclear and other low-carbon energy sources can be coupled to existing infrastructures to decarbonise current processes, for example, by plugging them into district heating networks, industrial steam systems or hydrogen supply chains. In addition, retrofitting an existing NPP to serve non-electric applications can open access to markets beyond electricity, potentially improving its economic competitiveness through additional revenue streams. The deployment timeline is also critical to be considered in NHES analysis, as it determines market conditions, projected technology costs, and the policy framework in place. In this sense, the goal of the analysis in this chapter is to move from a generic NHES concept to architectures that are explicitly tailored to the context of interest, accounting for local boundary conditions and policies, in order to assess their impact on NHES design, operation and deployment strategies.

A comprehensive context assessment therefore requires the collection and analysis of several site-related factors, together with their projected evolution over the long-term planning horizon. These include, first, the potential for renewable energy and the local prices of fuels such as natural gas, which can strongly influence the transition to low-carbon heat and power solutions. Secondly, the demand characteristics of different commodities must be considered, including electricity load profiles and industrial process requirements, e.g., in terms of heat temperature and supply reliability. In this context, the growing deployment of data centres is introducing large and highly dynamic electricity loads, which must be accounted for in terms of power reliability requirements and their associated impacts on the grid. Moreover, policy and market conditions can play a decisive role: different regional contexts can be characterised by distinct market regulations for electricity and for non-electric commodities, while climate policies such as renewable penetration targets or carbon taxes may favour particular technologies within NHES architectures. Finally, existing infrastructure is a key driver for the design of the architectures. As outlined in Example E4.1, several European countries already operate extensive district heating networks that currently rely predominantly on fossil fuels [75]; in these regions, NHES could be deployed via a plug-in approach to decarbonise residential heat supply. The same logic can be extended to industrial applications, leveraging existing hydrogen and gas infrastructure or co-locating NHES in established industrial energy hubs.

These contextual considerations translate directly into design decisions for the NHES architecture, which should be supported by techno-economic and safety analyses to identify the most viable and competitive configurations. Technology selection must ensure that technical requirements are met, e.g., considering the compatibility between the operating temperatures of the chosen reactor technology and those required by the coupled processes. In addition, site characteristics and operational requirements may impose constraints on the system layout, especially regarding the interconnection strategy between the NPP and industrial processes. For example, siting and regulatory constraints may require the nuclear facility to be located several kilometres away from the industrial site. Combined with the typically continuous energy demand of large industrial plants, this aspect motivates the need to investigate intermediate heat transfer loops and heat storage systems as part of the thermal interconnection design.

Within the methodological framework of this thesis, two complementary approaches are adopted to design NHES architectures. The first is a context-tailored approach, in which the NHES is directly coupled to existing infrastructure with given commodity and market requirements; this is illustrated by the district heating case presented in Example E4.1, where nuclear cogeneration can be integrated into a pre-existing network. The second approach is based on the definition of archetypical NHES configurations that could in principle be deployed across different contexts. An illustrative example is nuclear-driven hydrogen production, motivated by the widespread and growing demand for hydrogen outlined in Example E4.2. Here, the objective is to assess potential deployment opportunities for a representative NHES architecture in different conditions, for instance by evaluating its contribution to the decarbonisation of hydrogen production and its role in providing flexibility services to the power system. This archetype-based perspective is particularly relevant for long-term energy planning, where a well-characterised NHES configuration could be considered in decarbonisation pathways alongside other energy sources and hydrogen production methods, with the aim of assessing its value and competitiveness on regional or national levels in the long term.

E4.1. District heating infrastructure in Europe

As discussed in Section 2.1.2, there is already substantial operational experience with nuclear-driven district heating in Europe. In these systems, low-temperature heat is extracted from the steam cycle and used to produce hot water for the residential and tertiary sectors. District heating itself currently plays a particularly important role in Eastern and Northern Europe, as illustrated in Figure 4.1. In particular, in Nordic countries such as Denmark, Sweden, and Finland, district heating supplies more than 40% of the heat demand in the aforementioned sectors [75]. Moreover, in Central and Eastern Europe, district heating supplies roughly 55 TWh/y in Poland and about 18 TWh/y per year in both Austria and the Czech Republic. Overall, the European district heating market is in the order of 300-400 TWh/y, representing a considerable potential market for nuclear cogeneration [38].

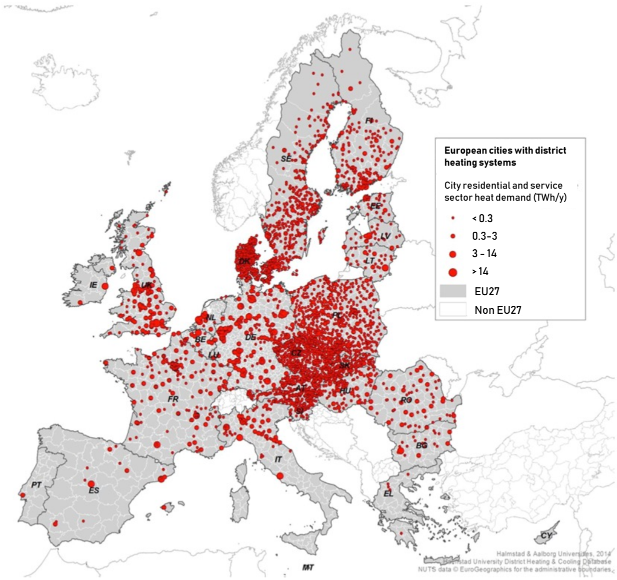

Figure 4.1: *Distribution of existing district heating networks in Europe [76].*

As of today, the large majority of heat supplied to these district heating networks is still generated from fossil fuels. Natural gas and solid fossil fuels remain dominant, with the latter playing a prevailing role in Poland and the Czech Republic. In many cases, heat is provided by Combined Heat and Power (CHP) plants, whose simultaneous production of electricity and heat is difficult to replace with conventional nuclear or renewable technologies providing exclusively electricity without compromising heat supply. Nuclear cogeneration, however, offers a viable pathway to phase out these fossil-fuelled CHP units, since it can provide both electricity and heat in a coordinated manner. In combination with renewables, heat pumps, and thermal storage, nuclear cogeneration could therefore support a deep decarbonisation of

the district heating sector, provided it proves to be economically competitive with alternative low-carbon options and is supported by an appropriate enabling framework in terms of policies and regulations. Given the extensive existing infrastructure, it is particularly attractive to explore a plug-in deployment strategy for nuclear-driven hybrid systems, where nuclear heat is integrated directly into the available district heating networks. Among the countries mentioned before, Finland stands out for its explicit interest in decarbonising district heating using nuclear energy [38]. With the exception of the Helsinki network, Finnish district heating systems are generally characterised by relatively small transmission capacities (50-100 MW_{th}). Given these limited scales, together with a power sector already dominated by low-carbon generation and relatively low electricity prices, the focus is increasingly shifting toward heat-only SMRs, such as the LDR-50 design [54], which offer a better match to the country's specific energy system requirements and market conditions remaining economically viable even at relatively low capacity factors [77].
In conclusion, European district heating networks represent one of the most promising near-term applications for NHES deployment. The combination of large-scale heat demand, existing infrastructure, and strong decarbonisation pressure creates a favourable context for nuclear cogeneration. Properly designed NHES concepts can leverage this opportunity by replacing fossil-fuelled CHP capacity, supplying low-carbon heat and operating in synergy with renewables and electrified heating technologies like heat pumps.

E4.2. Present and future hydrogen demand

Hydrogen is increasingly recognised as a fundamental energy vector in the context of the energy transition. Its potential to support the decarbonisation of several hard-to-abate sectors, including heavy industry and transportation, has placed it at the core of various international policies aimed at achieving climate change mitigation objectives, such as the net-zero emissions by 2050 target [78]. For this reason, the IEA projects a dramatic increase in global hydrogen demand, surging from around 100 Mt in 2024 to 430 Mt in 2050. This rise is largely driven by a higher penetration of hydrogen-based fuels in the transportation sector, particularly in aviation and shipping [78]. As of today, out of the 100 Mt hydrogen demand, only 1 Mt is met by producing hydrogen with low-carbon energy sources [78]. Fossil-fuel based solutions, particularly steam methane reforming, are significantly cheaper compared to low-carbon alternatives. However, for hydrogen to effectively contribute to decarbonisation objectives, the transition to low-carbon production processes is of paramount importance.

At present, hydrogen demand in Europe is concentrated primarily in refining processes and ammonia production [79]. Figure 4.2 illustrates the distribution of the main hydrogen-consuming plants in selected European countries, along with their annual consumption levels. Most of these industrial sites are characterised by relatively low demands, typically below 200 t/d, as shown in Figure 4.3. For example, the industrial hub in Fos-sur-Mer, in France, requires around 75 t/d of hydrogen, while the average hydrogen consumption of Italian industrial plants considered in this study is approximately 108 t/d.

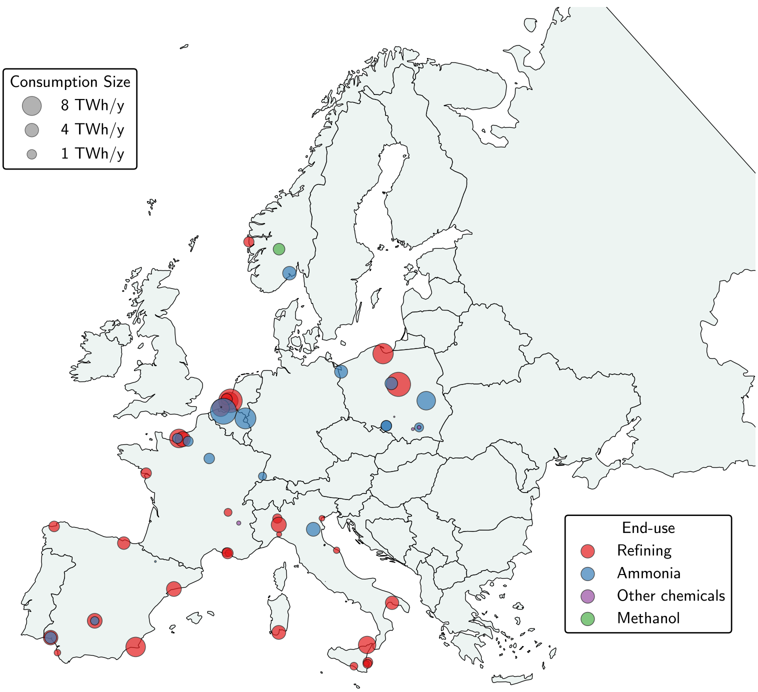

Figure 4.2: *Distribution of main hydrogen consuming plants in selected European countries [79].*

In the context of nuclear-driven hydrogen production, the distribution of the number of plants by consumption class has been compared with the hydrogen production capacity of the E-SMR, assuming that the reactor's output is fully dedicated to hydrogen production. Two low-carbon hydrogen production technologies are considered for the integrated system, namely LTE and HTSE. Under representative efficiency assumptions for these technologies [39], an E-SMR module can supply approximately 108 t/d and 77 t/d of hydrogen when coupled to HTSE and LTE, respectively. As a result, a single module would be sufficient to fully cover the hydrogen requirements of a substantial fraction of the industrial plants analysed, satisfying the total demand of roughly 56% of them in the HTSE case and about 40% in the LTE case. For larger hydrogen demands, multi-module configurations, potentially operated in synergy with other power sources, could represent a viable option to meet higher consumption levels.

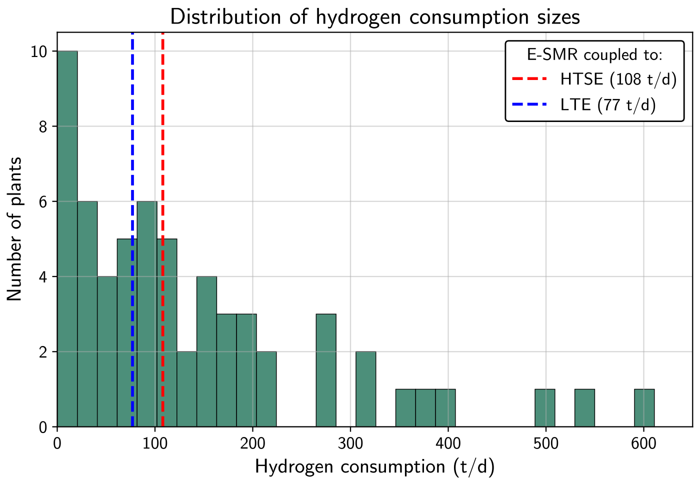

Figure 4.3: *Compatibility of hydrogen plant consumptions with the E-SMR production capacity.*

Assessing the viability of such nuclear-driven solutions requires dedicated techno-economic analyses to evaluate their competitiveness against alternative low-carbon production methods, such as renewable-driven electrolysis or fossil-fuelled systems with Carbon Capture and Storage (CCS). These assessments are essential not only to quantify cost and performance metrics at the plant level but also to inform policymakers about the system-level benefits of nuclear-based hydrogen, for example, in terms of emissions reductions, security of supply, etc. In this regard, industrial processes typically require a high degree of supply reliability, which translates, for instance, into the deployment of dedicated backup systems to mitigate unplanned interruptions. When coupling such processes with an SMR or with other energy sources, these reliability constraints must be considered not only in the economic evaluation of the system but also in the definition of operational strategies, outage planning, and maintenance scheduling. The insights from these studies can, in turn, support the design of an enabling policy and regulatory framework that recognises the contribution of nuclear cogeneration to the decarbonisation of industrial hydrogen production.

In the future, hydrogen demand in Europe is projected to increase substantially. Final hydrogen consumption is expected to grow from around 273 TWh/y in 2022 to approximately 1520 TWh/y by 2050, driven mainly by the industry and transport sectors [79]. Even the current demand level of 273 TWh/y already implies a massive decarbonisation challenge: meeting it with low-carbon hydrogen produced via the coupled E-SMR and HTSE systems would require about 208 E-SMR modules, a figure that would increase further considering realistic reactor availability and capacity factors. Nearly all EU Member States have submitted national hydrogen strategies aligned with the broader EU-level policies (e.g., EU Green Deal, EU Hydrogen Strategy, REPowerEU, etc.), outlining targets, priority sectors, and indicative trajectories for both renewable and low-carbon hydrogen deployment [80]. For instance, in Italy's *Strategia Nazionale Idrogeno* [81], the current hydrogen consumption of 17.4 TWh/y is projected to rise between 64.4 TWh/y and 122.9 TWh/y by 2050 in the proposed scenarios. In that strategy, the potential role of nuclear power in meeting part of this future demand is explicitly highlighted, as it can contribute to meeting the EU-level targets in terms of embedded greenhouse gas emissions.

4.2 Generation of testing scenarios

The performance of NHES is strongly linked to the testing scenarios selected for the assessment. These scenarios must reflect realistic conditions but also future developments in commodity demands, policy frameworks, and technology costs. Their formulation is therefore closely tied to the context analysis: local demand profiles, renewable resource availability, market dynamics, etc. all influence the assumptions that characterise the scenarios.

In this work, uncertainties in the techno-economic evaluations are addressed primarily through sensitivity analyses on key parameters. Variations in technology capital and operating costs, as well as in the demand for electricity, heat, and hydrogen, are explored to quantify the impact of different boundary conditions on system performance and NHES competitiveness. This deterministic approach provides a preliminary understanding of the parameters' impact on the optimal solution and helps identify the drivers that most strongly affect the viability of NHES configurations. From a methodological perspective, the framework could be extended to a stochastic formulation. For instance, renewable generation profiles or market prices could be treated as random variables to address their uncertainties, as proposed in literature for NHES economic analyses [67]. Moreover, the present work does not include an uncertainty quantification of the technical parameters that characterise the NHES architecture itself and how they affect the transient response of the system.

The constructed testing scenarios are integrated across the different domains of the methodological framework presented in Chapter 3. In the techno-economic optimisation, they define the system-level boundary conditions, for example, by prescribing commodity demands, renewable potential, and policy constraints such as emissions caps or hydrogen production targets. Notably, the generation of scenarios is not limited to the techno-economic analysis. In this work, illustrative scenarios are used as setpoints for the dynamic simulation tools to test the dispatch strategy of the NHES architecture. Scenario generation is also a core element of safety assessment, where initiating events and accidental conditions must be specified to verify the behaviour of the coupled system. Finally, in the long-term energy planning analyses, scenarios capture the evolution of policies, market structures, and technology costs over the planning horizon, enabling the consistent evaluation of NHES deployment strategies and competitiveness in alternative future pathways.

CHAPTER 5

Modelling of NHES architectures

This chapter presents the modelling framework developed to describe NHES to assess their performance and transient response in different contexts. It first addresses the design of NHES architectures, focusing on the thermal and electrical interconnections between the NPP and non-electric applications, and on how thermodynamic modelling can quantify power conversion losses and identify suitable coupling strategies. It then introduces dynamic models based on the Modelica language and the TANDEM library, used to build simulators of various NHES configurations through a plug-and-play approach, including nuclear-driven hydrogen production plants and integration with thermal energy storage systems. These simulators are applied to investigate flexibility, operational constraints and control strategies, providing performance indicators and physics-based transient responses that will be instrumental in safety assessments, techno-economic optimisation and long-term energy planning.

Further details on the tools and case studies presented in this chapter can be found in the following publications:

- Masotti, G. C., Cammi, A., Lorenzi, S., & Ricotti, M. E. (2023). Modeling and simulation of nuclear hybrid energy systems architectures. *Energy Conversion and Management*, 298, 117684. https://doi.org/10.1016/j.enconman.2023.117684.
- Masotti, G. C., Cammi, A., & Lorenzi, S. (2025). Assessment of pressurizer dynamic performance for nuclear hybrid energy system modelling: Comparison between equilibrium and 1D non-equilibrium approaches. *Nuclear Engineering and Technology*, 57(11), 103761. https://doi.org/10.1016/j.net.2025.103761.
- Masotti, G. C., Lorenzi, S., & Ricotti, M. E. (2025). Dynamic modelling and control of a Small Modular Reactor in load following by cogeneration mode. *Nuclear Engineering and Design*, 445, 114518. https://doi.org/10.1016/j.nucengdes.2025.114518.
- Masotti, G. C., Alpy, N., Baudoux, A., Hammadi, Y., Jouret, D., Lorenzi, S., Mathonnière, S., Simonini, G., & Vaglio-Gaudard, C. (2025). Modelling Nuclear Hybrid Energy Systems: Objectives, architecture, and applications of the TANDEM Modelica library. *Sustainable Energy Technologies and Assessments*, 84, 104695. https://doi.org/10.1016/j.seta.2025.104695.
- Masotti, G. C., Colbertaldo, P., Ficili, M., Lorenzi, S., & Ricotti, M. E. (2026). Dynamic modelling and control of a nuclear-driven high-temperature steam electrolysis plant for hydrogen and electricity production. Submitted to *Energy Conversion and Management*.
- Masotti, G. C., Lorenzi, S., Ricotti, M. E., Alpy, N., Nguyen, H. D., Haubensack, D., & Simonini, G. (2024). Simulation of flexible small modular reactor operation with a thermal energy storage system. In *Proceedings of the International Conference on Small Modular Reactors and their Applications*. International Atomic Energy Agency, Vienna, Austria.
- Masotti, G. C., Colbertaldo, P., Ficili, M., Lorenzi, S., Mauri, R., & Ricotti, M. E. (2024). Dynamic modelling of a nuclear hybrid energy system with hydrogen production via high-temperature steam electrolysis. In *Proceedings of the International Conference on Small Modular Reactors and their Applications*. International Atomic Energy Agency, Vienna, Austria.
- Simonini, G., Ferrara, V., Hammadi, Y., Hocine-Rastic, S., Lorenzi, S., Masotti, G. C., Alpy, N., Haubensack, D., Mathonnière, S., Talpin, R., Baudoux, A., Jouret, D., Pappalardo, F., & Tourneur, B. (2024). Integrating small modular reactors into hybrid energy systems: The TANDEM Modelica library. In *Proceedings of the International Conference on Small Modular Reactors and their Applications*. International Atomic Energy Agency, Vienna, Austria.
- Masotti, G. C., Lorenzi, S., & Ricotti, M. E. (2024). Small modular reactors and cogeneration: Impact of steam extraction on power conversion performance. In *Proceedings of the International Conference on Small Modular Reactors and their Applications*. International Atomic Energy Agency, Vienna, Austria.
- Masotti, G. C., Colbertaldo, P., Ficili, M., Lorenzi, S., & Ricotti, M. E. (2026). Flexible operation of a small modular reactor for combined hydrogen and electricity production. In *Proceedings of PHYSOR 2026*. Turin, Italy.
- Coita, L., Marini, S., Masotti, G. C., Lorenzi, S., & Colbertaldo, P. (2026). Thermal coupling and interface design of a hybrid nuclear system for hydrogen production. In *Proceedings of PHYSOR 2026*. Turin, Italy.
- Masotti, G. C., Lorenzi, S., Ricotti, M. E., Lopez-Velasco, J. B., Alpy, N., Haubensack, D., Hammadi, Y., Simonini, G., Rantakaulio, A., Värri, K., Meganck, V., Roosen, L., Hoxha, N., Jouret, D., Tourneur, B., Peeters, D., Van Hoeck, R., & Seynaeve, A. (2023). *TANDEM D2.1 - Modelica models requirements for the "TANDEM" library development* (Project deliverable, restricted to consortium members).
- Simonini, G., Hammadi, Y., Ferrara, V., Hocine-Rastic, S., Lorenzi, S., Masotti, G. C., Baudoux, A., Jouret, D., Tourneur, B., Pappalardo, F., Alpy, N., Haubensack, D., Mathonnière, S., & Talpin, R. (2024). *TANDEM D2.3 - Modelica models description for the "TANDEM" library* (Project deliverable).
- Martos Nogales, C., & Masotti, G. C. (2025). *TANDEM D2.5 - Hybrid system simulator description* (Project deliverable).

This chapter presents the modelling approaches adopted to analyse the design and operation of NHES architectures. First, the design of NHES is addressed through static thermodynamic modelling, with particular emphasis on the steam cycle and the definition of viable thermal interconnections (e.g., steam extraction and return points, intermediate heat transfer loops, etc.) under nominal and off-design conditions. Subsequently, dynamic modelling is adopted to capture the transient behaviour of the integrated systems and to evaluate operational profiles, control strategies, and system-level constraints that cannot be determined with steady-state tools alone.

5.1 Design of NHES architectures

The definition of the NHES architecture is a core aspect of the modelling of such integrated systems. Firstly, it is fundamental to identify the subsystems, together with the technology characteristics, to be integrated into the overall architecture. In this regard, a key requirement that needs to be accounted for in the design phase is the needed heat temperature level, which can differ significantly according to the non-electrical applications and determines the compatibility with reactor technologies, as mentioned in Section 2.1.2. Moreover, a fundamental aspect of the modelling activities is related to the design of the interconnections between NHES subsystems. For instance, the thermal interconnection design should focus on the choice of the steam extraction point, as well as on the potential deployment (and the design) of an intermediate heat transfer loop or of a Thermal Energy Storage (TES) system, as schematically shown in Figure 5.1. Considering such additional loops can be motivated by several factors, including:

- The physical separation introduced by the intermediate loop could improve the safety of the integrated system and potentially facilitate the licensing process [82]. However, the longer the distance, the higher the operational costs due to higher thermal and pressure losses.
- The additional thermal inertia of the intermediate circuit contributes to mitigating rapid transients either on the NPP or on the non-electric application side, also by managing significant power variations through dedicated control systems in the intermediate loop. This aspect is reinforced in the case of a TES, as the charging and discharging processes can decouple the thermal power exchanged between the NPP and the non-electric application.
- Using a sensible fluid avoids phase change on both the hot and cold

sides of the Intermediate Heat Exchanger (IHX), facilitating temperature regulation and heat exchanger design by preventing steam condensation on the hot side and fluid evaporation on the cold side.

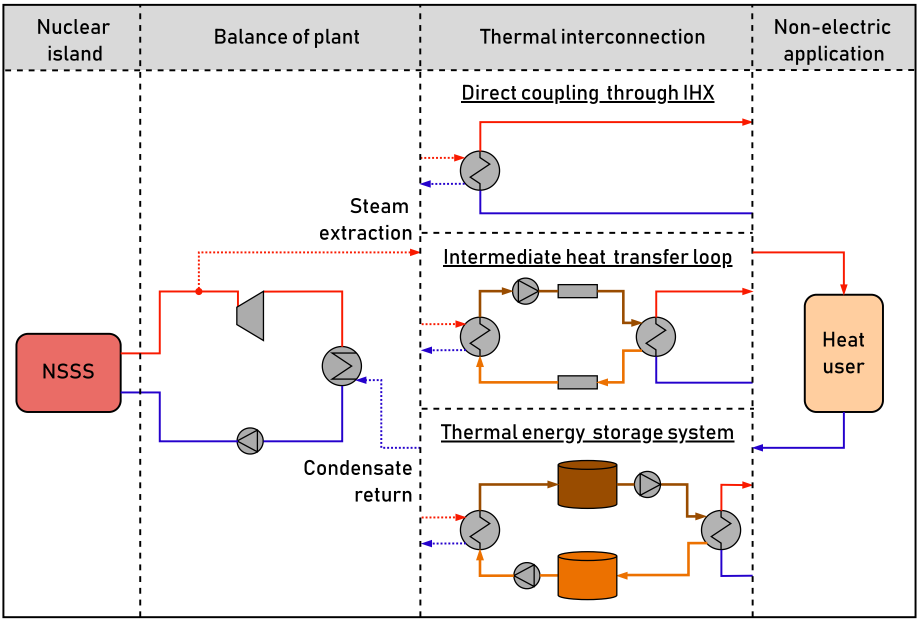

Figure 5.1: *Examples of three thermal interconnection designs.*

These will not only affect the operational strategy of the integrated system but also need to be accounted for when it comes to its design and the definition of the operational points. For instance, the introduction of the intermediate loop requires the deployment of additional heat exchangers that, in turn, lead to temperature drops, reducing the margin between supplied heat temperature and demand. Also the design of the electrical interconnection between NHES subsystems must be addressed during the design phase. For example, the NPP can be coupled with the other subsystems (e.g., renewables and industrial processes) before the connection point with the national grid, establishing an off-grid connection between the components. Conversely, an indirect interconnection is also possible, with the electricity production going through the power grid. These two coupling approaches are characterised by different benefits and challenges and will have implications not only on the design of the system but also on its operation, management structure, and stakeholder interactions [56].

Models of the integrated system are essential for these assessments. This work primarily focuses on the thermal interconnection, as it constitutes a major novelty with respect to conventional nuclear systems and introduces additional complexities compared to electrical coupling schemes [61]. The modelling to support the design of NHES architectures is strongly linked to the other pillars of the methodological framework presented in Chapter 3. For instance, the selection of technologies to be integrated in the system is largely dependent on the context, policies, and requirements discussed in Chapter 4. The capacities and deployed components, e.g., storage devices, should be defined through the techno-economic analysis of the system to define the optimal configuration in various scenarios. Moreover, the design of NHES architectures has strong implications also for the safety analysis: simulating accidental scenarios can provide indications about design gaps and possible protective measures, such as the physical separation design, to ensure the safety of both the NPP and the end-user facility.

The goal of the modelling of NHES architectures is to identify viable coupling strategies that are compatible with several requirements and design objectives, including (i) maximising overall system performance and efficiency, (ii) ensuring compatibility with the technical constraints of all coupled systems (e.g., in terms of temperature levels), and (iii) guaranteeing the safe operation of both nuclear and industrial facilities. Notably, these requirements are mainly related to the design of the architecture, but additional aspects need to be considered for the operational phase, such as flexibility, reliability of energy supply to industrial processes, etc.

In this work, particular attention has been devoted to modelling the Balance Of Plant (BOP), which represents a key component for the interface between the NPP and non-electric applications. The analysis was performed using Ebsilon Professional [83], a commercial software for simulating power plants and thermodynamic systems under both nominal and off-design conditions. This tool allows the comparison and evaluation of different thermal coupling configurations, enabling the quantification of the impact of heat extraction for cogeneration purposes on the steam cycle design. Furthermore, to enhance the physical separation between the nuclear and cogeneration systems, an intermediate heat transfer loop can be considered in the thermal interconnection design. As previously stated, the inclusion of additional heat exchangers requires a careful evaluation of the pinch points and temperature losses arising from both heat transfer effectiveness and thermal losses in the transmission pipelines. Heat exchange effectiveness must also be taken into account in off-design operation and in the definition of control requirements. Steam extraction for cogeneration purposes reduces the mass flow through the turbine, thereby lowering the machine's inlet pressure. Depending on the design of the thermal interconnection, this pressure may coincide with the pressure in the intermediate heat exchanger. In such cases, a shift to off-design conditions can reduce the saturation temperature and thus the available heat quality. This temperature drop may decrease the supply temperature of the intermediate fluid, which, in turn, could not be sufficient to meet the non-electric application requirements. It is therefore necessary to investigate alternative design and control solutions, such as the use of control valves or dedicated pressure control strategies, to ensure that the required heat quality is preserved under off-design conditions.

Consequently, these factors must be accounted for to verify that the final extracted temperature remains compatible with the temperature requirements of the non-electric applications [84]. The Ebsilon Professional tool was applied to assess the impact of steam extraction and return points on power conversion performance [85], as outlined in Example E5.1. An additional example, based on a different reactor technology, is presented in Appendix A. Heat extraction can be considered either in design or off-design conditions, according to the purpose of the integrated system, among others. For instance, if the NHES foresees a continuous steam extraction, e.g., to satisfy a constant industrial heat demand, it could be worth optimising the operational points of the BOP to have the required steam extraction at nominal conditions. This will also have an impact on the equipment cost, as the extracted steam will reduce the flow rate allocated for power conversion, thereby leading to the deployment of smaller turbines. In contrast, the system integration could be exploited to enhance the overall flexibility, with the non-electric application representing a programmable load that can be modulated to meet variable grid requirements. In this case, the steam cycle could be optimised for full power generation, allowing the turbine line to accommodate all the steam produced by the reactor. Therefore, it would be possible to regulate steam extraction to enhance flexibility, albeit at a higher efficiency cost due to the shift of the turbine operation to off-design conditions. A key outcome from this kind of analysis are the performance metrics that characterise different steam extraction points. For instance, the power loss factor provides an indication of the drop in electricity generation due to heat extraction and can be defined as follows [86]:

$$\beta = \frac{\Delta P_{el}}{P_{cog}}$$

where ΔP_{el} is the reduction in electrical power output due to the extraction of the thermal power P_{cog}. In general, extracting steam at higher enthalpies leads to higher losses compared to a low-temperature and pressure flow for the same extracted thermal power [85]. For instance, in the case of the steam cycle of a light-water cooled SMR with steam extraction in off-design conditions, the power loss factors were found to be in the order of 0.46 and 0.32 for high-temperature steam extraction at the steam generator outlet and low-temperature one at the high-pressure turbine outlet, respectively [87]. The condensate return point also influences power conversion efficiency and, therefore, the power loss factor, since the position at which the condensate is reinjected into the feedwater line affects the preheating requirements. In this regard, it is essential to define acceptable limits on the amount and conditions of heat extraction for a given BOP configuration. For example, returning condensate with a high residual enthalpy directly to the deaerator can raise its outlet temperature to an unacceptable level, potentially bringing the feedwater above saturation and causing two-phase flow at the inlet of the feedwater pump. Consequently, both in design and off-design conditions, it is necessary to verify that the required heat extractions remain compatible with the operating limits of the BOP. Overall, the power loss factor, as well as the maximal heat extraction, are fundamental parameters in the broader framework of NHES analysis, as they govern the relationship between heat extraction and electricity generation needed to describe cogeneration units in energy modelling tools such as techno-economic optimisers and long-term energy planning frameworks.

It is worth noting that the considerations mentioned above are applicable mainly to support the design phase of new systems, whereas additional challenges may arise when retrofitting an existing NPP for coupling with a cogeneration system. In such cases, the available extraction points may be dictated by the original steam cycle architecture. For instance, the Madras NPP in India was retrofitted to drive a thermal desalination plant. Despite the low temperature requirements of the plant, the only available extraction point was at the steam generator outlet, resulting in a supply temperature significantly higher than what the process actually required [36].

E5.1. Impact of steam extraction on power conversion performance

In this case study, the Ebsilon Professional tool is used to assess the impact of steam extraction and return points in a simplified steam cycle architecture. The reference non-electric application is the HTSE process, which requires an external heat input between 150 and 200°C for process water evaporation. As a result, the extraction points under investigation were selected to be compatible with this temperature

range.
The analysis is based on a simplified BOP architecture, displayed in Figure 5.2. Additional information about the configuration and the underlying assumptions used in the Ebsilon Professional model is available in a dedicated study [85]. The considered interface points are the following:

- *Extraction points:* A high-temperature extraction point (300°C, 45 bar) is located at the steam generator outlet. Steam extracted from the high-pressure turbine, at approximately 230°C and 25 bar, is referred to as the intermediate-temperature extraction point. Lastly, steam at low temperature is extracted at the high-pressure turbine outlet at 168°C and 7.7 bar. The analysis is limited to these points, as extraction at lower temperatures would not meet the HTSE requirements, especially in configurations involving an intermediate loop between the two facilities.

- *Return points:* As for the return points, the condenser, the low-pressure feedwater preheater and the feedwater tank were selected. The extracted steam is assumed to deliver heat through an intermediate heat exchanger, where it condenses to saturated liquid conditions. Each proposed return point is at a lower pressure than the extraction points, ensuring compatibility even considering pressure losses in the valve regulating steam extraction.

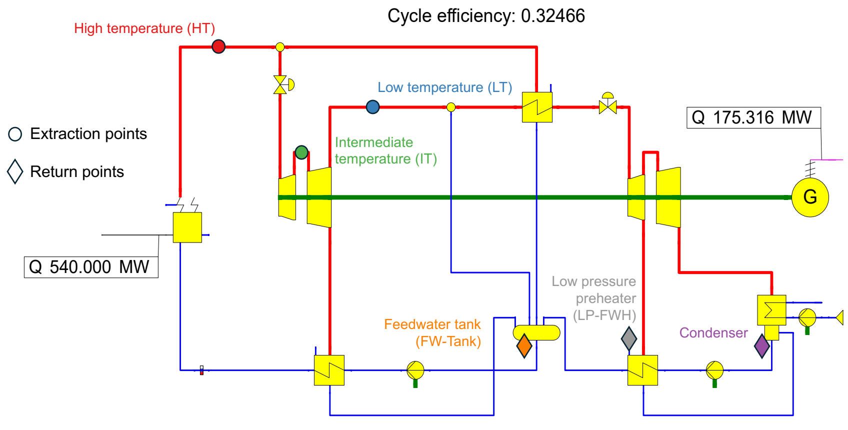

Figure 5.2: *Ebsilon Professional model of the BOP in full power mode, with steam extraction and return points [85].*

The analysis assumes heat extraction under nominal operating conditions and therefore does not address off-design behaviour. Within this framework, the steam cycle is optimised for different extraction levels by maximising power conversion efficiency. The study is limited to a thermal exchange of 36 MW_{th}, as the electrical demand of an HTSE unit is significantly higher compared to the thermal one [39]; beyond this extraction level, the net power output of the BOP would no longer be sufficient to supply the electricity required by the hydrogen production plant. The results summarising the impact of the different steam extraction and return points are shown in Figure 5.3. Overall, extracting heat at higher temperatures leads to higher conversion losses. Moreover, also the choice of the return point has a significant impact on power conversion, albeit lower compared to the extraction points. Injecting the returning flow in the condenser leads to the higher losses, due to the fact that the residual energy is discharged to the environment without contributing to the feedwater preheating phase, as in the case of return in the feedwater preheater of the feedwater tank. This recovery of energy in the feedwater line reduces the bleeding requirements from the turbine line, which translates into the fact of having more steam available for electricity production.

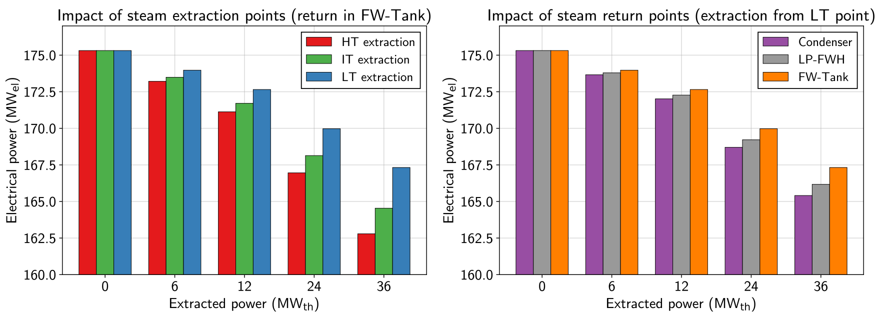

Figure 5.3: *Impact of extraction and return points on the power generated by the cycle for different thermal power extractions [85].*

In conclusion, a linear dependence of power conversion efficiency with extracted thermal power is observed when accounting for cogeneration in design conditions. Higher losses occur in off-design conditions due to the drop in turbine efficiencies, for instance. Overall, extractions at lower enthalpies lead to lower losses but can be more challenging in terms of temperature compatibility with non-electric applications, especially in the presence of intermediate heat transfer loops.

5.2 Dynamic modelling of NHES architectures

Dynamic modelling plays a central role in analysing the behaviour of tightly coupled NHES under varying operating conditions. Such models allow the assessment of system responses to changes in boundary conditions, including electrical and thermal loads, while ensuring that critical process variables remain within operational limits. Moreover, they support the identification of operational limits, such as maximal allowed ramp rates, and facilitate the investigation of different control and operational strategies to meet commodity demands and system requirements. Dynamic models can also be applied to perform quasi-static simulations, providing insight into operational profiles and performance metrics, similar to the aforementioned thermodynamic analyses of the steam cycle in off-design conditions.

The dynamic models proposed within this framework are based on the Modelica language, selected due to its versatility and suitability for complex engineering systems. Modelica is an equation-based, object-oriented modelling language that can be used in multiple simulation environments, including the open-source OpenModelica and the proprietary Dymola platform, with the latter being the primary environment used in this work. It is based on an acausal modelling approach, which enables a higher reusability and flexibility of the developed models, as inputs and outputs are not prescribed a priori, and a more intuitive representation of physical systems [88]. Modelica models are typically physics-based, relying on fundamental principles such as mass, energy, and momentum conservation. These principles are expressed as sets of Differential Algebraic Equations (DAEs), which are symbolically processed by the Modelica compiler and solved using numerical integration algorithms, such as DASSL [89]. The object-oriented structure of Modelica, through encapsulation and abstraction, allows the development of independent, interchangeable subsystem models that can be interconnected via dedicated interfaces [88]. This modularity is particularly advantageous for NHES, where subsystems (e.g., nuclear power plant, non-electric applications, etc.) can be developed and tested independently before being integrated into a comprehensive system simulator using a plug-and-play approach [90]. In addition, Modelica's compatibility with the Functional Mock-up Interface (FMI) standard supports co-simulation with models from other environments, facilitating the multi-domain investigations within the proposed methodological framework.

In this work, several NHES components were modelled, including the Nuclear Steam Supply System (NSSS) of the E-SMR, the steam cycle, district heating network components (e.g., transmission pipelines), thermal energy storage systems, and an HTSE module. The majority of the latter components is available in the open-source TANDEM Modelica library [91], presented in Example E5.2. A detailed description of the structure and modelling assumptions of the models is provided in Appendix B. These models were designed to meet several requirements [91], including the ability to provide a physically accurate representation of the integrated system over multiple timescales, e.g., from fast transients in the order of seconds to days-long simulations, and to offer a high degree of parametrisation, enabling adaptation to the users' needs. Specifically, model parameters can be obtained from literature, derived from separate calculations, or determined using specialised software tools, depending on the type of component and the available information. For example, the operational points needed to characterise the steam cycle parameters were obtained from simulations performed with the Ebsilon Professional software.

E5.2. The TANDEM Modelica library

Most of the dynamic models of NHES components developed in this work are collected in the open-source TANDEM Modelica library [91]. This tool was developed in the frame of the Euratom-funded TANDEM project to support the investigation of hybridisation strategies of light-water cooled SMRs in the European context. The library, available since mid-2024 in a freely accessible git repository[a], aims at providing the building bricks for the simulators of the two case studies identified in the frame of the project, namely the district heating and power supply and the energy hub architectures.

Figure 5.4: *Logo of the Euratom-funded TANDEM project.*

The components, listed in Table 5.1, rely on different well-established and open-source Modelica libraries, including ThermoPower [92], ThermoSysPro [93], and Buildings [94]. The compatibility between components originating from different libraries is ensured through dedicated adaptors included in the library. Table 5.1 also summarises the modelling strategy adopted for each component. A simplified approach is applied to technologies that are only electrically coupled into the NHES architecture, such as desalination and low-temperature electrolysis, while physics-based models are proposed for key thermally interconnected systems, including the NPP and HTSE. The choice of this strategy reflects the significant impact of thermal power exchanges on system dynamics, e.g., due to thermal inertia, fluid transport delays, etc., which is more pronounced than that of electrical interconnections.

Component	Supporting libraries	Modelling approach
Nuclear Steam Supply System	*ThermoPower, ThermoSysPro*	Detailed
Balance Of Plant	*ThermoPower, ThermoSysPro*	Detailed
Combined Cycle Gas Turbine	*ThermoPower*	Simplified
Heat Pump	*ThermoPower*	Simplified
Electrical Grid	*Buildings*	Detailed
District Heating	*ThermoPower*	Detailed
Thermal Storage	*ThermoPower*	Detailed
Electrical Storage	*ThermoPower*	Simplified
Desalination (Reverse Osmosis)	*ThermoPower*	Simplified
Low-Temperature Electrolysis	*ThermoSysPro, Buildings*	Simplified
High-Temperature Steam Electrolysis	*ThermoSysPro, Buildings, HTSE*	Detailed

Table 5.1: *Overview of the TANDEM library contents [91].*

The models were used to build comprehensive NHES simulators for the two case studies employing a plug-and-play approach [91,95]. In the scope of the project, the simulators were applied to test the system operation in different scenarios and were successfully coupled with other tools for techno-economic analyses and safety assessments of the integrated system.

[a] https://gitlab.pam-retd.fr/tandem/tandem

As noted above, a major advantage of the Modelica language in the context of NHES modelling is its plug-and-play structure, which allows individual models to be easily combined and interchanged to create complex hybrid system simulators [90]. This feature has been extensively leveraged in the framework of this work, enabling the development of multiple NHES simulators tailored to different applications and scenarios. These include:

- An NHES architecture integrating the NPP with a HTSE hydrogen production plant [96–98], described in Example E5.3;
- A NPP simulator to test system operation under conventional load-following and load-following by cogeneration strategies [87], introduced in Example E5.4;
- The integration of the NPP with a TES, employed for electrical peaking to enhance the flexibility of electricity production [99], also mentioned in Example E5.4;
- A dynamic simulator of the NPP coupled to the district heating network of the Helsinki metropolitan area [95,100], developed within the framework of the TANDEM project;
- A dynamic simulator of an energy hub architecture, encompassing the NPP along with other power sources, HTSE, and thermal and hydrogen storage systems [95], also developed within the TANDEM project.

In all cases, the nuclear reactor considered is the previously described E-SMR. These simulators have been employed for multiple purposes, such as the investigation of system responses under different operational scenarios, the implementation and testing of various control and operational strategies, and coupling with external tools for techno-economic and safety assessments, demonstrating the flexibility and modularity of the developed modelling framework.

E5.3. Nuclear-driven hydrogen production

In the proposed case study, a HTSE-based hydrogen production plant is thermally and electrically coupled to the E-SMR. The thermal interconnection involves extracting steam from the SMR's steam cycle and transferring it to the HTSE for water evaporation via an intermediate heat transfer loop. In this architecture, shown in Figure 5.5, the thermal power requirements of the HTSE are assumed to be met by extraction steam from the main steam line, where the flow is at 300°C and 45 bar. The steam condenses in an intermediate heat exchanger, supplying power to the thermal oil flowing in the intermediate heat transfer loop. For the latter, a transmission distance of 1 km between the NPP and the hydrogen production plant was assumed [101].

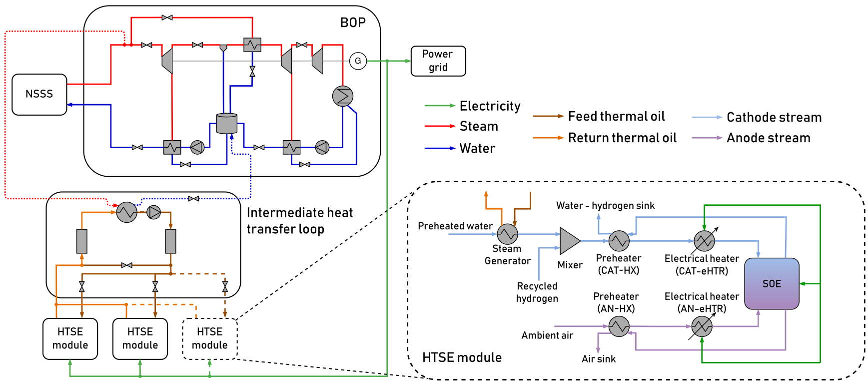

Figure 5.5: *NHES architecture for electricity and hydrogen production [97].*

Figure 5.6 shows the dynamic simulator, developed in the Modelica language, of the considered layout. It can be applied to investigate the flexibility of the integrated system, including the exploration of different control strategies and the identification of operational constraints to ensure the safe operation of both the NPP and the hydrogen production system. The simulator is built adopting a plug-and-play approach, leveraging the NPP simulator available in the TANDEM Modelica library. In addition, a detailed HTSE model, developed with particular focus on the thermal interface with the NPP, is integrated into the simulator together with an intermediate loop model. The HTSE model is based on a one-dimensional modelling approach for key components such as heat exchangers and the electrolyser, which is fundamental to capture system dynamics and temperature gradients. A single cell is modelled and assumed to be representative of the whole electrolyser behaviour. Moreover, the resulting electrochemical model is validated with respect to experimental data for the polarisation curve available in literature [102].
A detailed description of the architecture and the simulator with its underlying assumptions is available in dedicated studies [96–98], where it was applied to support the design of the configuration and verify the system response to different flexibility requirements.

Design and operational characteristics

As a first step, the dynamic simulator is applied to define the operational profiles of the nuclear and hydrogen production plants to size the NHES architecture. Specifically, the goal is to design a flexible integrated system where the SMR power can be allocated either to hydrogen production or to supply electricity to the grid. In this study, the reactor is assumed to operate in the load-following by cogeneration mode, i.e., remaining at rated conditions. The hydrogen production capacity is determined by the number of installed HTSE modules, whose behaviour is simulated by an equivalent HTSE model. In this case study, the hydrogen production plant is sized to absorb the whole power produced by the SMR in nominal conditions, i.e., there is no net electricity delivered to the grid.

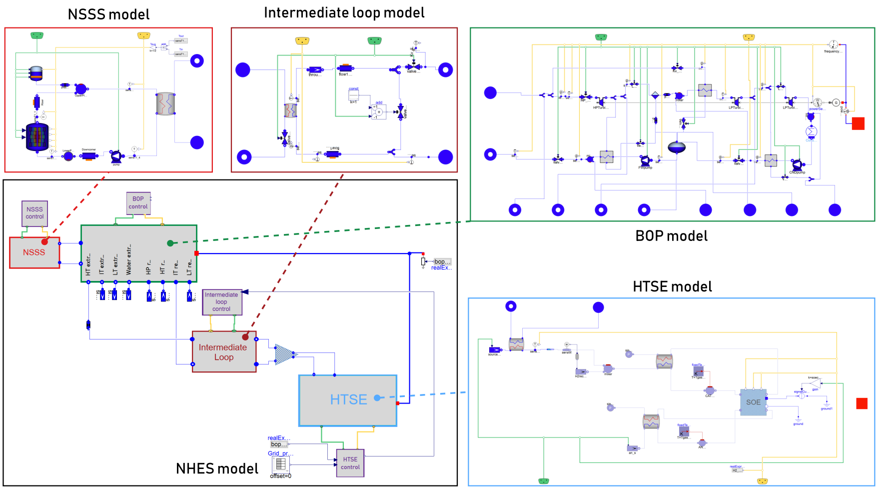

Figure 5.6: *Dynamic simulator developed in the Modelica language [97].*

To define the available electrical and thermal power that can be allocated for hydrogen production, a quasi-static simulation with the NPP simulator was performed to assess the impact of steam extraction on power conversion performance. The results, shown in the red line on the left-hand side of Figure 5.7, show a degradation in cycle efficiency corresponding to a power loss factor of about 0.46. This profile represents the upper limit for the system to be self-sufficient; operating the HTSE beyond this limit would require importing additional power. Conversely, the hydrogen production capacity is defined by multiplying the design point of a single HTSE module by the number of installed modules, resulting in the linear profile shown in blue. The intersection between the profiles defines the desired design point, whose characteristics are summarised in Table 5.2.

Parameter	Value	Unit
Number of HTSE modules	198	-
HTSE thermal power consumption	37.82	MW_{th}
HTSE electrical power consumption	159.4	MW_{el}
Hydrogen production capacity	107.7	t/d

Table 5.2: *Resulting NHES architecture capacities [97].*

The operational map during flexible operation is shown on the right-hand side of Figure 5.7, with the hydrogen production rate modulated between 20 and 100% of the plant's rated capacity. As aforementioned, during off-design conditions, the reactor remains at its rated conditions, varying the fraction of thermal power allocated for grid supply or hydrogen production. As a result, decreasing the hydrogen production rate leads to an increase in electrical power injected into the power grid. It should be noted that, by modelling an equivalent HTSE module, the analysis implicitly assumes that each unit exhibits the same behaviour. In practice, the various modules could be independently shut-down or kept in hot standby, particularly under significant load reductions. Given the relatively low thermal power extraction, limited to approximately 38 MW_{th} (about 7% of the reactor's thermal output), the resulting drop in cycle efficiency is limited, with the steam cycle output ranging between 160 and 173 MW_{el}, corresponding to efficiencies of 29.6% and 32%, respectively. Nevertheless, given the considerable amount of electrical power consumed by the hydrogen production system, the net electricity delivered to the grid can be modulated between 0 and 140 MW_{el}, corresponding to 0-80% of the steam cycle rated capacity, without any adjustments in core power.
Two operational philosophies were considered for the integrated system, which in turn translate into distinct control strategies. They differ in terms of commodities to be prioritised during flexible operation: in the *hydrogen-follows* strategy, grid requirements are prioritised, and the hydrogen production plant is adjusted accordingly. In contrast, in the *grid-follows* mode, a given hydrogen target is satisfied, and any excess electrical power is supplied to the grid.

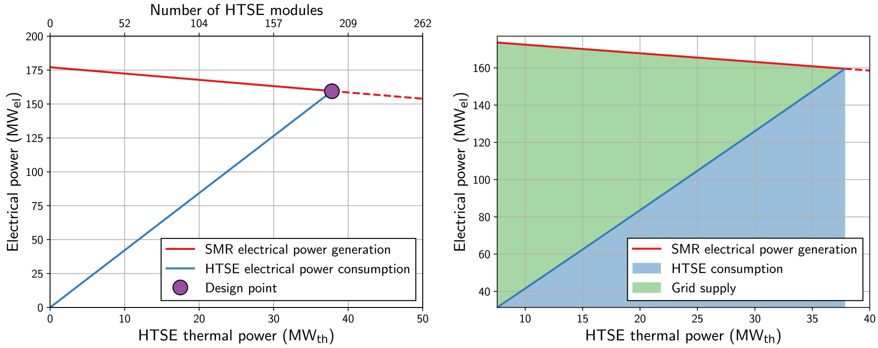

Figure 5.7: *NHES sizing results and operational map [97].*

Transient simulations and operational constraints

The integrated system has been tested in several transient scenarios, both to establish operational constraints and to showcase how it could operate in real-world scenarios.
First, a 10% stepwise decrease in the hydrogen production target, starting from design conditions, is investigated. In the proposed transient simulation, a *grid-follows* strategy is adopted and the response of the system is later compared with the *hydrogen-follows* strategy. Figure 5.8 shows the behaviour of the system in response to the aforementioned setpoint, in particular in terms of hydrogen production rate and thermal and electrical power allocation within the NHES. The reduction in hydrogen production rate translates into a rapid increase in electrical power supplied to the grid. In addition, the variation in extracted thermal power leads to a slight increase in steam cycle generation. As shown on the right-hand side panel, the thermal power of the reactor remains at rated conditions, whereas the heat allocated to the hydrogen production system adjusts to the new steady-state condition after about 600 seconds. This delay is given by the intermediate loop fluid's thermal inertia and travel time in the transmission line, which in turn leads to a delayed response of the steam cycle with respect to the hydrogen production system. However, it is important to highlight that the hydrogen production process itself is significantly more responsive, with the electrochemical system reaching a new steady-state condition in approximately 20 seconds. This faster dynamics reflects the intrinsically rapid electrochemical response of the

stack [103], which is not limited by the inertia affecting the thermal interconnection with the NPP.

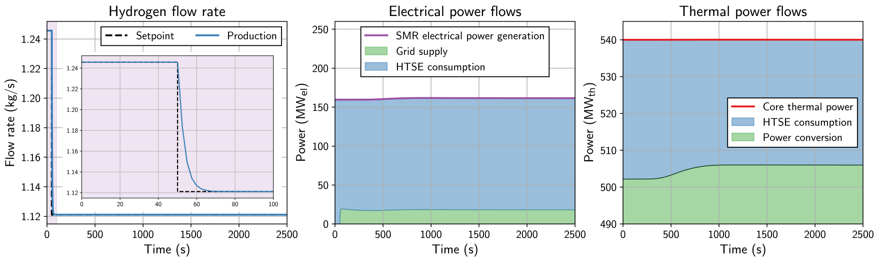

Figure 5.8: *Hydrogen production and power flows in the 10% step decrease scenario [97].*

In this operational philosophy, the NHES is controlled to meet the hydrogen production setpoint. The comparison of the system response to an alternative control strategy, the *hydrogen-follows* strategy, is shown in Figure 5.9. From this result, it can be observed how the commodities are consistent with their setpoints in the corresponding operational strategies, while the second product is regulated to ensure that the setpoint is met. It is worth highlighting that a higher flexibility could be achieved by overcoming the constraint of constant core power characterising the load-following by cogeneration mode. As a matter of fact, the reactor power could be modulated to meet both grid and hydrogen demands at the same time or together with the electrolyser operation to meet highly variable grid requirements [98].

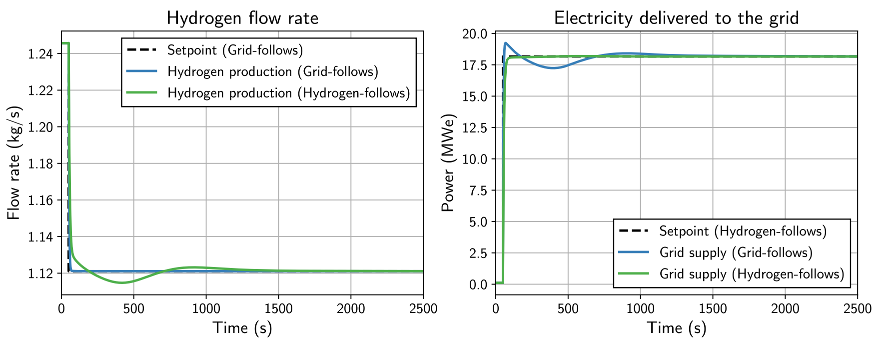

Figure 5.9: *Comparison of NHES responses considering two different control strategies [97].*

In general, with the proposed NHES architecture and considered operational philosophies, the burden of flexibility is shifted to the hydrogen production system rather than the NPP. For this reason, the one-dimensional electrolyser model is applied to investigate the thermal behaviour of the cell under different flexibility requirements. Similarly to the 10% step decrease presented before, the simulator was applied to test variations in hydrogen production rates up to 30% and at different ramping rates, ranging from 1%/min to step variations. The main limits on flexible operation for high-temperature electrolysers are dictated by temperature gradients and variation rates in the cell's solid structure, which in turn lead to thermo-mechanical stresses that challenge the structural integrity of the system. As a result, the latter indicators were selected to evaluate the possible flexible operation of the system, for which operational limits of 10°C/cm and 3°C/min, respectively, are typically considered [104–106]. Figure 5.10 shows the simulation outcomes for the maximal gradient and variation rate in each cell node. The data labels on the left-hand side of the figure refer to the settling time required to stabilise to the new hydrogen production target. The results show that the temperature gradient is mainly affected by the magnitude of hydrogen variations, and for relatively low excursions (<30%), the gradient remains within acceptable limits. In contrast, the temperature variation rate proved to be sensible to the simulated ramps, suggesting that ramp rates below 10%/min could reduce thermo-mechanical stresses on the cell.

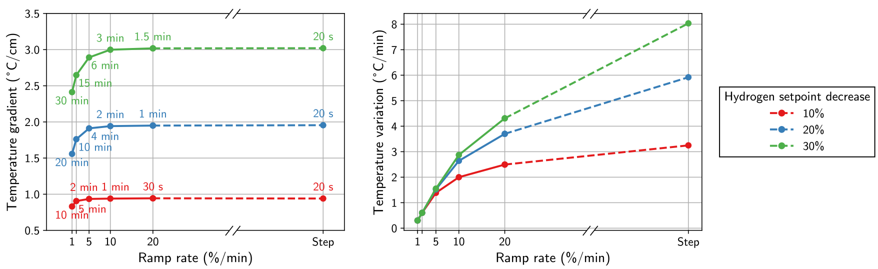

Figure 5.10: *Evaluation of temperature gradients and variation rates for different flexibility requirements [97].*

To illustrate the potential operation of the integrated system to meet grid requirements in more representative conditions, a day-long simulation with a typical load profile has been simulated. The imposed grid demand was rescaled to be consistent with the minimal and maximal power output of the system, accounting also for the minimal power requirements of the hydrogen production system. In this scenario, the NHES operated in the *hydrogen-follows* mode, with the external load profile met by regulating hydrogen production. Figure 5.11 illustrates how the power flows are allocated within the system, with constant reactor thermal power (shown on the right-hand side) and the relatively low variation in steam cycle electricity generation following the steam extraction. In this case study, high grid flexibility can be achieved (specifically, variations between 0 and 80% of the steam cycle rated capacity) mainly by regulating the hydrogen production system.

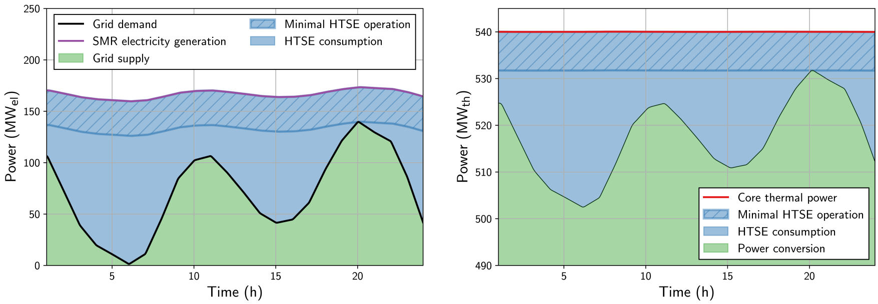

Figure 5.11: *Power flows allocation in a day-long simulation [97].*

Concluding remarks

The proposed dynamic simulator was applied to address several areas of NHES analysis, including layout considerations, identification of operational constraints, testing of different control strategies, and evaluating the system response in different scenarios. Moreover, the integrated system configuration proved to be capable of achieving high grid flexibility by regulating hydrogen production while inducing only minimal perturbations on the nuclear island. In addition, the system could produce a reliable, low-carbon, large-scale amount of hydrogen to support the decarbonisation of hard-to-abate sectors. Beyond the proposed operational strategies, which involve using the reactor in a load-following by cogeneration mode, it could also be possible to modulate both the reactor's and electrolyser's operation in response to rapidly changing grid requirements, resulting in reduced ramps on the single subsystems [98].

One of the main motivations for developing dynamic models of the NHES, particularly using the Modelica language, is the ability to test and evaluate different control and operational strategies. Such analyses support the investigation of alternative pathways to meet variable load and commodities demands. For example, they allow assessment of the benefits and challenges associated with conventional load-following versus load-following by cogeneration modes, as illustrated in Example E5.4. In terms of operational strategies, the control system can be designed to prioritise specific commodities produced by the integrated energy system while using others as additional degrees of freedom to enhance flexibility. This approach is demonstrated in Example E5.3: the thermal and electrical power flows allocated to the hydrogen production plant are modulated to satisfy variable grid requirements, while variable hydrogen production targets are met by delivering surplus electricity to the grid.

A key feature of the developed dynamic models is their plug-and-play capability, which allows different controllers to be coupled to the subsystem models without modifying the underlying components. For instance, in the dynamic model of the BOP, buses are used to collect actuator signals (e.g., valve openings and pump rotational speeds) and process variable measurements (e.g., temperatures and pressures), linking them to the user-tailored controller, as demonstrated in Figure 5.12.

The control strategies are based on a decentralised approach, with each process variable independently regulated by its corresponding control variable. Proportional-Integral-Derivative (PID) controllers are employed to regulate actuator variables in response to deviations of controlled variables from their setpoints. PID calibration was performed using the PID Tuner application in MATLAB's Control System Toolbox, which allows tuning controller performance and robustness [87]. While this tool is designed for linear models, the Modelica models are inherently non-linear. Nonetheless, the Dymola simulation environment provides a linearisation tool that enables exporting a linearised version of the model as a Linear-Time-Invariant (LTI) system around an equilibrium condition, making it compatible with the PID tuning workflow.

The modularity of the models allows testing different control strategies by varying the controlled variables and their corresponding actuator pairs. In a coordinated operation of NHES components, a supervisory control layer can be included to provide compatible setpoints for interacting subsystems to the corresponding controllers.

To quantitatively evaluate the pairing of control and controlled variables, a Relative Gain Array (RGA) analysis is performed [107]. In this proce-

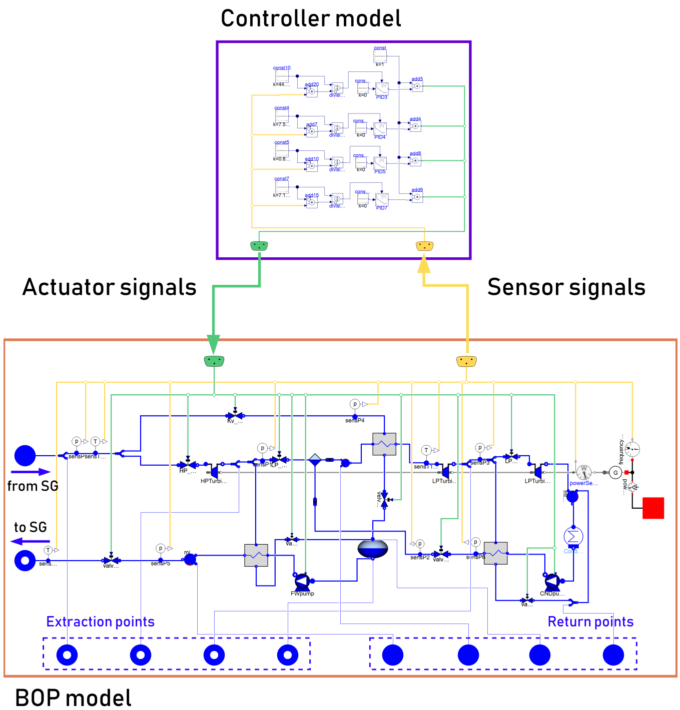

Figure 5.12: *Example of controller structure (BOP model from [87]).*

dure, a linearised version of the Modelica model is used to calculate open- and closed-loop gains in response to perturbations of the inputs on the outputs. The resulting RGA matrix provides a quantitative measure of interactions between process and control variables, ranking the variable pairs that are most suitable for the decentralised control strategy [87].

E5.4. Heat extractions to enhance flexibility

The dynamic models were also applied to investigate how heat extraction for cogeneration purposes can support the increased flexible operation of NPPs. First, the capabilities of the SMR to satisfy a variable load demand are investigated, considering two strategies: the classical load-following mode and load-following by cogeneration. In the conventional method, based on the sliding-pressure approach [22], the core power is adjusted to meet the variable grid requirements. In contrast, in load-following by cogeneration, the core power remains constant, and excess thermal power is allocated for cogeneration pur-

poses.
Illustrative results from a dedicated study [87] are shown in Figure 5.13. In the configuration in cogeneration mode, thermal power is extracted at two points: one high-temperature point at the steam generator outlet and one low-temperature point at the high-pressure turbine outlet. The same BOP model is adopted for each configuration, but different control schemes are implemented, with the corresponding controllers defined and tuned according to the outcomes of the RGA analysis. The analysis shows that regulating the distribution of thermal power extraction can substantially reduce core power fluctuations. This, in turn, decreases thermo-mechanical stresses on the core structure and improves fuel utilisation, among other advantages [22].

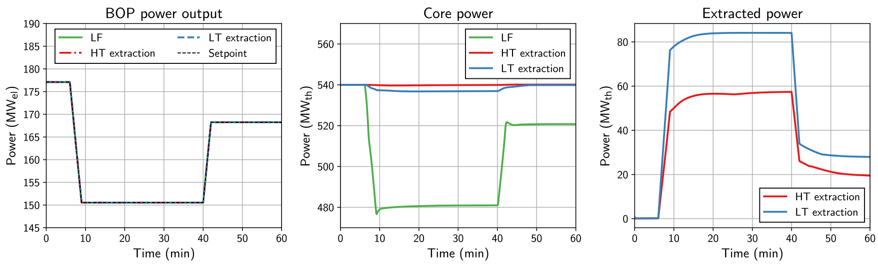

Figure 5.13: *System response comparison between conventional load-following and load-following by cogeneration mode [87].*

In another study, the flexible capabilities of the NPP were tested by considering its integration with a TES employed to perform electrical peaking [99]. A schematic of this coupled architecture is shown in Figure 5.14. A two-tank sensible heat storage system is considered, charged by thermal power exchanged with steam extracted from the steam generator outlet. During electrical peaking, the stored thermal energy is discharged to produce additional steam, which is injected into the low-pressure turbine to increase the electrical output beyond its nominal value. This additional steam is generated by pumping water from the feedwater tank to the discharging heat exchanger. It should be noted that, in this configuration, the low-pressure turbine must be oversized to accommodate the increased steam flow, which might lead to increased equipment costs.

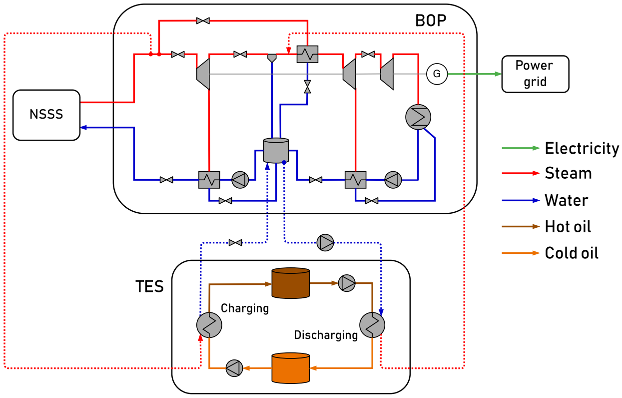

Figure 5.14: *Coupled architecture with a TES employed as electrical peaking unit.*

The operation and control strategy of the system was evaluated by constructing two load profiles estimated qualitatively from energy price trends, which are strongly influenced by the availability of renewable generation, for an illustrative weekday and a weekend day. The results, shown in Figure 5.15, demonstrate that the variable load demand can be met with minimal perturbations on the primary side, as the observed fluctuations are mainly related to thermal feedback effects rather than external interventions through control rods. The full variability of the load demand is accommodated by controlling the charging and discharging of the TES, which results in corresponding changes in the sensible fluid levels in the two tanks, as shown in the lower part of Figure 5.15.

In conclusion, heat extractions for cogeneration purposes or TES charging can significantly contribute to the flexibility of the system, as grid requirements could be met with minimal perturbations on the nuclear island. As a result, it could be worthwhile testing the system response to more rapid load ramps (i.e., $>$ 5%/min). If the nuclear island remains unaffected by such rapid load variations, i.e., the core remains at rated power, and provided that all safety requirements are met, it could be possible to relax regulatory flexibility limits, enabling the system to respond more rapidly and frequently to variable grid demands.

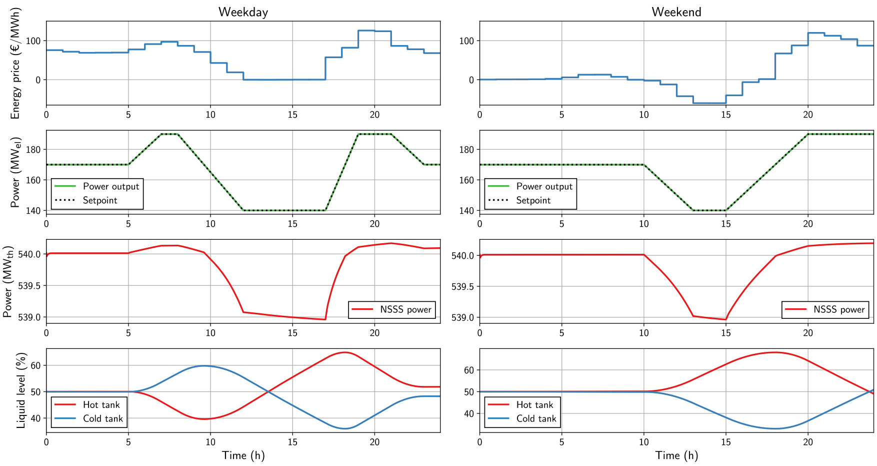

Figure 5.15: *Transient results obtained by meeting flexibility requirements through the TES [99].*

5.3 Concluding remarks

In conclusion, this chapter presented a modelling framework for the analysis of NHES in terms of both design and operation. On the one hand, a thermodynamic modelling tool was employed to guide the definition and optimisation of coupling configurations, particularly at the steam cycle level, by quantifying the impact of steam extraction and return strategies, intermediate heat transfer loops, and off-design effects on power conversion performance. On the other hand, dynamic modelling proved essential to capture the strong interactions shown by tightly coupled NHES, which cannot be adequately represented using purely static or quasi-static tools, and to characterise flexibility and operational limits under varying boundary conditions. A key methodological outcome of the dynamic modelling activity is the delivery of a set of NHES component models, collected in the open-source TANDEM Modelica library. By adopting a plug-and-play approach, these models can be combined to develop multiple NHES simulators tailored to different architectures and control philosophies, without the need to modify the single submodels. This approach facilitates the testing of alternative configurations, operational strategies, and control schemes by exploiting the reusability of the developed models.

To showcase the capabilities of the methodological approach, several NHES simulators were proposed and applied to investigate the integrated system response in different scenarios. The results demonstrated that a NHES could achieve high degrees of flexibility, e.g., from the electrical grid perspective, by modulating the interconnected systems (storage units, hydrogen production, etc.) rather than regulating the nuclear reactor operation. Shifting the burden of flexibility to the non-electrical applications, however, makes it essential to identify the operational constraints of these subsystems and ensure that their operation remains within the allowed limits. The dynamic models developed in this work supported this assessment for the flexible use of HTSEs, for example, by identifying ramping constraints that restrict their capacity to follow rapid load variations. In addition, the modelling activities enabled the computation of performance indicators that characterise system design and operation, such as the power loss factor. Overall, these simulators can support policymakers in evaluating possible NHES architectures. By providing a physics-based representation of the integrated system, these tools enable quantitative assessments of design choices, operational strategies, and the overall feasibility of different configurations. Moreover, the modelling framework could help update operational requirements and constraints, such as electrical grid-related flexibility metrics, to ensure they remain consistent with the actual flexibility potential observed for NHES. Since the reactor can operate steadily at rated power while flexibility is delivered by the interconnected subsystems, the system's allowable operating range could be substantially increased compared to the current limits set for conventional NPPs. As a result, the NHES architectures could provide faster and more frequent power adjustments while still complying with the safety margins of the nuclear island.

CHAPTER 6

Safety assessment

This chapter examines the safety implications of the hybridisation of SMRs. It discusses regulatory and licensing challenges, the need to harmonise nuclear and industrial safety frameworks, and the specific design and operational issues arising from the interface between the nuclear and industrial facility, including new initiating events and hazard propagation pathways. A co-simulation methodology is then presented, coupling validated nuclear thermal-hydraulic system codes with dynamic NHES models to analyse safety-relevant transients, such as load rejection scenarios, in configurations with steam extraction for cogeneration. The resulting framework is intended as a tool for regulators and policymakers to assess whether SMR-driven NHES can maintain safety levels comparable to stand-alone NPPs and to support the development of NHES-specific safety requirements and guidelines.

Further details on the tools and case studies presented in this chapter can be found in the following publications:

- Olita, P., Masotti, G. C., De Angelis, A., Ambrosini, W., & Alpy, N. (2025). *TANDEM D4.4 - Report of operational Design Basis Accident case studies for a SMR with cogeneration* (Project deliverable).

Safety assessments for SMR-driven NHES must address both the extensive use of flexible NPP operation to cope with VRE intermittency and the specific coupling aspects with non-electric applications. According to IAEA's SSR-2/1 *Requirement 35: Nuclear power plants used for cogeneration of heat and power, heat generation or desalination*, the global safety objective of a NPP coupled to a cogeneration system is to prevent any pathway that could transport radioactive material from the nuclear island to the user facility under both operational and accidental conditions [108]. Another key risk that must be considered concerns the propagation of hazards or disturbances from the cogeneration unit to the NPP, which could lead to transients in the nuclear island [27]. This chapter aims at providing an overview of the policy gaps and challenges of integrating a SMR into a NHES from a safety standpoint, addressing licensing and regulatory aspects, design and operational considerations, as well as safety assessment methodologies. Subsequently, the modelling approach developed in the framework of this work is presented, together with an illustrative case study involving a safety-relevant transient.

6.1 NHES safety requirements and challenges

Currently, several gaps and challenges are present in licensing and regulatory frameworks. For sites where NPPs are co-located with industrial facilities (e.g., hydrogen production plants), clear licensing standards, a well-defined division of responsibilities between plant owners and/or operators, enhanced risk assessment methods, and a comprehensive regulatory framework encompassing both nuclear and industrial safety need to be established [109]. In this context, it is fundamental to consider that industrial facilities are subject to their own regulatory regimes (e.g., the European Seveso legislation for controlling industrial hazards and preventing accidents involving releases of chemical substances [110]). In the context of NHES, these directives must be compatible with nuclear safety requirements and aligned with nuclear regulatory frameworks. From a licensing standpoint, the NPP and the cogeneration facility are governed by different safety and design standards. These regulatory differences need to be coordinated in the licensing of the coupled system and considered in the interface design so that the interconnection does not compromise nuclear safety and remains consistent with both regulatory regimes. Generally speaking, licensing SMRs is more challenging than conventional reactors because SMRs often incorporate novel technologies and design features that require an adaptation of existing regulatory and licensing requirements (e.g., reliance on passive safety systems) [28]. This challenge becomes even more pronounced when SMRs are conceived for cogeneration uses or NHES integration, where additional interfaces and operational modes that must be assessed and approved are introduced. Another aspect that can complicate licensing and regulatory aspects is multi-module SMR deployments, where several reactor units may share common systems, be coupled to industrial processes, or operate under coordinated load-following strategies. Such multi-module configurations introduce additional system-level interactions and potential propagation of failures to multiple reactor units, which require dedicated safety assessments beyond those performed for conventional NPPs. Overall, the novel nature of SMRs and their envisaged deployment in NHES architectures implies that experiences from large-scale NPPs coupled to industrial processes cannot simply be extrapolated; instead, SMR-specific safety demonstrations, addressing the technological characteristics, are needed [109].

Safety in SMR-driven NHES also critically depends on the design of the coupled system, especially the interconnection between the NPP and the non-electric application. In this context, the BOP constitutes the key physical interface between the nuclear island and the non-electric applications, and its design, e.g., in terms of additional steam extraction lines for cogeneration purposes and associated control and protection equipment, must be configured so that electrical and industrial load variations can be accommodated without driving any system outside its prescribed safe operating range [109]. Protective measures commonly implemented in the interconnection design can include intermediate heat exchangers, intermediate heat transfer loops, and additional isolating valves that provide physical and functional separation between the nuclear and industrial facility. Moreover, the deployment of a TES, which can act as a buffer to accommodate demand transients on both the nuclear and non-electric application sides, may also contribute as a protective measure and in managing deviation from normal operating conditions. It is worth highlighting that the main components required for the thermal interconnection with cogeneration systems, such as heat exchangers and circulation pumps, are typically located in the turbine hall of the NPP and are usually classified as normal non-safety systems, which has implications for their design and qualification, among others [109]. Overall, physical separation and appropriate safety distances between the NPP and the industrial facility represent a key design choice for safety assessments. The definition of these barriers is strongly dependent on the configuration of the integrated system: for instance, in the case of the production of chemicals like hydrogen, the physical separation between the facilities must guarantee that the NPP remains protected against storage tank explosions [111].

The design of interconnection, in turn, is strongly dependent on the site and infrastructure in which the coupled system will be deployed. Siting decisions must account for the presence of dangerous industrial hazards, the distance from densely populated centres, and the availability of suitable infrastructure, while considering that an excessive separation between the NPP and the industrial facility can decrease the efficiency and economic attractiveness of cogeneration because of increased transport losses and additional interconnection costs, including protective measures to prevent line breaks of the transmission system. Safety distance criteria for co-located nuclear-industrial facilities must be supported by quantitative analyses of accident scenarios, accounting for the characteristics of the industrial process. In this regard, a risk analysis focusing on the coupling between an NPP and an HTSE-based hydrogen production plant has shown that locating the hydrogen plant at distances greater than 1 km can ensure that potential hydrogen detonations do not compromise the safety of the nuclear plant, thereby illustrating the role of separation distance as a key protective system in siting strategies [112].

From an operational perspective, safety aspects for NPPs integrated into NHES are closely linked to the plant's ability to manage load-following and transients induced from the cogeneration facility. For instance, the operational implications of coupling a NPP to an industrial facility include the need to accommodate rapid changes in the thermal or electrical power absorbed by the non-electric application, both under normal operation and in accidental conditions, while keeping both plants within safe operating limits [113]. In particular, an abrupt loss of heat demand from the cogeneration facility requires the NPP either to accept more steam in the turbine line, if feasible, or to reduce reactor power; if not properly analysed and mitigated, the resulting transients may challenge the safe operation [113]. In particular, anomalies on the heat transmission line or within the industrial facility can translate into a loss of heat sink for the secondary circuit of the NPP, which must be managed without compromising safety. As aforementioned, NHES can respond to the intermittency of VRE; however, the associated need for extensive flexible operation can have safety-relevant implications. In the load-following mode, safety concerns involve pellet-cladding interactions and the formation of hot spots due to axial power distortions, which translate into thermo-mechanical stresses [22]. As a result, the flexible operation of NPPs is strictly regulated, e.g., by imposing limits on ramping rates, as described in Chapter 2. In this regard, an open question is whether load-following by cogeneration can mitigate these effects compared with conventional load-following. However, in both conventional load-following and load-following by cogeneration, it is fundamental to account for operational constraints on BOP components, such as allowable temperature variation rates in heat exchangers and piping, and turbine operating limits (e.g., minimum steam flow rate) [109]. In load-following by cogeneration, in particular, the BOP and its associated control scheme need to manage the whole burden of flexibility by allocating steam between power conversion and cogeneration application. Previously, the role of a TES was discussed from a design perspective, considering it as part of the thermal interconnection between the NPP and the cogeneration unit. In addition, a TES can serve as an operational protection device, reducing the impact of thermal transients and acting as a heat sink in accidental scenarios, for instance.

In safety assessments for nuclear cogeneration systems and NHES, the identification of hazards and potential initiating events are key elements. For such configurations, safety analyses should identify new types of initiating events arising from the specific technologies adopted and from the integrated system configuration, including hazards such as hydrogen explosions and release of toxic substances [113]. In cogeneration configurations, additional steam extraction lines and associated equipment introduce further initiating event possibilities, for example, failures of steam lines, intermediate heat exchangers and valves connected to non-electric applications, as well as malfunctions of equipment governing the thermal interconnection between the NPP and the heat user. Moreover, in case of co-location between the nuclear and industrial facility, additional hazard sources include the storage and transport of chemical products and of radioactive material. More generally, for coupled systems, the bidirectional interactions between the NPP and the cogeneration facility must be assessed explicitly in the hazard analysis: on the one hand, the potential propagation of industrial hazards toward the NPP (e.g., fires, explosions, releases of hazardous chemicals), and on the other, transport of radioactive material from the nuclear island to the non-electric application.

Safety assessment and demonstration for SMR-driven NHES configurations require an integrated methodological approach and a broad set of modelling tools. A comprehensive safety demonstration should combine deterministic thermo-hydraulic studies, probabilistic safety assessments, hazard analyses, and failure evaluations in order to quantify both the likelihood and consequences of accidents in the integrated system [109]. Several European and international projects have addressed the safety of nuclear cogeneration, particularly for gas-cooled reactors, and have developed methodologies and initial insights that can be adapted to SMR-driven NHES [111]. Moreover, risk assessment studies for nuclear-hydrogen coupling have shown that, under suitable siting and design assumptions, co-location can be feasible from a risk perspective [112, 114]. Similarly, a study performing a probabilistic safety assessment for pressurized and boiling water reactors coupled to HTSE-based hydrogen production plants indicated that current licensing approaches are still applicable, as risk indicators such as core damage frequency remain comparable to those of the reference plant without coupling in the considered configuration [82]. Within the Euratom projects GEMINI+ and GEMINI 4.0, dedicated work packages and tasks addressed the safety aspects of nuclear poly-generation systems, with the objective of adapting and extending conventional nuclear safety consideration to integrated energy systems. In this context, studies have been conducted to assess the potential propagation of hazards from the cogeneration facility to the coupled NPP. For example, CFD-based simulations have been carried out to model hydrogen detonation and blast-wave propagation, enabling the assessment of overpressure loads on the reactor building, as well as the evaluation of different safety distances and mitigation measures such as protective barriers [115].

In summary, a central requirement for NHES is to demonstrate that interactions between the NPP and the coupled cogeneration systems do not reduce the safety level relative to a stand-alone NPP, either in normal operation or under accidental conditions. When the reactor operates in cogeneration mode, the BOP assumes a critical role, as it represents the primary interface between the nuclear island and the non-electric applications; consequently, it should be considered in safety assessments as a potential source of initiating events, rather than focusing exclusively on the nuclear island. Existing safety studies on nuclear cogeneration, largely focused on conventional large reactors, generally indicate that risks can be maintained comparable to those of reference plants without coupling when appropriate design, siting and protection measures are implemented [82]. However, safety guidelines for SMR-driven NHES remain less mature: SMRs introduce both potential advantages, such as passive safety systems and lower inventories of fission products that may enable reduced emergency planning zones, and additional challenges related to multi-module deployment, for instance. From a regulatory and policy perspective, this highlights a clear gap in the current treatment of nuclear cogeneration and NHES within safety frameworks. There is a need to further develop and harmonise regulatory approaches between the nuclear and industrial facilities, including siting criteria, interface design requirements, and coordinated licensing processes for co-located facilities. In addition, safety analysis methodologies must be extended to include scenarios with nuclear cogeneration and NHES design and operation, capturing a broad range of initiating events and transients arising from system coupling. Establishing such an integrated safety assessment framework is therefore a key enabling factor for the deployment of NHES.

6.2 Modelling approach

In this work, a simulation framework to address the safety challenges associated with coupling SMRs to non-electric applications in NHES configurations is introduced. The main objective is to analyse, from a deterministic safety assessment perspective, how the hybridisation of the SMR can affect the safe operation of the system and potentially introduce new initiating events. To this end, the framework is based on the numerical coupling between the dynamic simulators and validated nuclear thermal-hydraulic system codes, with the aim of representing the interactions with the cogeneration systems and assessing the impact on the NSSS behaviour. This approach is motivated by the need to simulate in detail the SMR response to a range of accidental scenarios that are influenced by cogeneration. Many of these scenarios, such as rapid variations in heat demand or failures in the thermal interconnection, can hardly be represented exclusively by thermal-hydraulic system codes, as they are conceived primarily for the modelling of the nuclear island and the associated safety systems. For this reason, the safety analysis is extended beyond the nuclear island to the full NHES architecture, investigating interactions between the NPP, the BOP, and other coupled components, with the NHES subsystems beyond the nuclear island represented through dynamic models implemented in Modelica. The simulation setup can be applied to simulate sudden variations in thermal or electrical energy absorbed by end-users and to generalise these perturbations into new initiating events that can be triggered in the cogeneration system or in the interconnection infrastructure.

The nuclear island is modelled using validated thermal-hydraulic system codes that are accepted by safety authorities for licensing applications and probabilistic safety assessments, among others [116]. In the framework of the TANDEM project, the NSSS of the E-SMR design was implemented in the ATHLET [117] and CATHARE [118] system codes. ATHLET, developed by GRS, can be applied to normal operating conditions, Design Basis Accidents (DBA) and beyond-DBA transients for various reactor types. The CATHARE code, developed by CEA, EDF, Framatome, and IRSN, offers a modular representation of reactor components which has been extensively validated against integral- and separate-effects tests [118]. In TANDEM, dedicated E-SMR models were developed in both codes, as documented in the corresponding project reports [119, 120].

These NSSS models were specifically prepared for coupling with the BOP and NHES dynamic models developed in Modelica and described in Chapter 5. The coupling relies on the FMI standard: the Modelica-based BOP and corresponding control systems are exported as Functional Mock-up Units (FMUs), which are then imported into a supervisory environment and co-simulated together with the thermal-hydraulic system code. In this co-simulation scheme, multiple FMUs can be imported into the same environment (e.g., adopting Dymola, OpenModelica or Python as supervisor), each preserving its own numerical solver. The coupling algorithm is implemented in the supervisor: in the present studies, an explicit coupling strategy is adopted, where each time step is computed once without iterative convergence between codes. Although implicit schemes can improve numerical robustness at the cost of higher computational effort, an appropriate choice of the global time step proved to be sufficient to avoid numerical instabilities, making explicit coupling a suitable approach for the investigated transients [121]. Variable exchange between the tools is achieved through a fluid-coupling approach, as illustrated in the schematic in Figure 6.1. In this configuration, the exchanged variables are the steam generator inlet and outlet fluid conditions in terms of pressure, enthalpy, and mass flow rate. This setup allows the BOP side to impose dynamic boundary conditions (e.g., perturbed by steam extraction for cogeneration purposes) on the nuclear side while receiving the corresponding response from the detailed NSSS model. Alternatively, a thermal-coupling concept, in which the exchanged variable is represented by the thermal power exchanged between the primary and secondary side of the steam generator, was also discussed in the frame of the TANDEM project but not applied in simulation examples [122].

Within TANDEM, the coupled framework was applied to investigate normal operation, Anticipated Operational Occurrences (AOOs) and DBAs in the case of steam extractions for cogeneration purposes. Specifically, the simulation framework with the ATHLET code focused on an AOO triggered by abrupt changes in thermal power exchanged with the non-electric application, including thermal load rejection scenarios. These scenarios are classified as an AOO because substantial changes in heat demand from the cogeneration system are expected to occur with non-negligible frequency

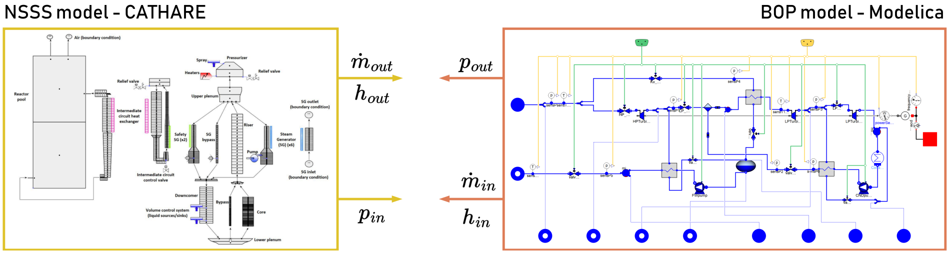

Figure 6.1: *Coupling approach between thermal-hydraulic system code and dynamic simulator (NSSS model from [121]).*

over the plant lifetime. For this study, the ATHLET E-SMR model was coupled to a Modelica BOP model described in the previous chapter and to a simplified thermal interconnection, consisting of an intermediate heat exchanger that transfers heat to a sensible heat transfer fluid and a valve regulating steam extraction for cogeneration purposes. This interconnection model was designed to generate boundary conditions representative of a NHES architecture and was coupled to ATHLET in a co-simulation environment. The detailed description of the coupling setup and the simulation results is provided in Deliverable D4.3 of the TANDEM project [123]. From a methodological standpoint, the co-simulation setup proved to be capable of tracking the plant response to abrupt changes in the cogeneration boundary conditions, confirming the suitability of the framework for safety demonstrations. Moreover, the simulation outcomes indicated that sudden increases in thermal demand can lead to core power overshoots above the nominal value if electrical power is not reduced simultaneously, highlighting the need for additional control strategies to keep power excursions within acceptable limits.

In the application with the CATHARE code, the same overall coupling concept was adopted: the CATHARE E-SMR model was linked to the Modelica BOP and to an analogous simplified thermal interconnection model with an intermediate heat exchanger and a steam extraction valve. This setup was used to analyse the impact of cogeneration on both normal operation transients and a DBA sequence. The normal operation case focused on a load rejection transient, with a detailed discussion of boundary conditions and results provided in a dedicated deliverable of the TANDEM project [121] and summarised in Example E6.1. In addition, a loss of off-site power scenario was simulated as an illustrative DBA event. The results showed that, once the NSSS is isolated from the BOP, the influence of cogeneration becomes negligible. These examples are presented, together with a more extensive discussion of the coupling methodology and of the specific impact of cogeneration on initiating events, in the aforementioned report [121].

In conclusion, the applications developed within the TANDEM project demonstrate the feasibility and value of a co-simulation framework that couples nuclear thermal-hydraulic system codes with dynamic models of the broader, integrated energy system. This framework enables the transient response of NHES to be analysed under both normal and accidental conditions, capturing the role of cogeneration in terms of initiating events and abrupt power variations. The work presented in this chapter represents a first step towards safety studies of NHES, as the cogeneration system has been represented solely through boundary conditions at the BOP. To support a more comprehensive safety assessment, additional NHES components should be integrated into the simulation framework so that the propagation of anomalies from specific NHES subsystems to the nuclear island can be evaluated. For instance, disturbances in an HTSE-based hydrogen production plant may affect both the exchanged thermal and electrical power; therefore, in the context of safety assessments, it is essential to verify that the BOP control scheme can accommodate such combined variations while maintaining the nuclear island within the allowed operating limits, accounting also for the characteristics of the thermal interconnection.

E6.1. Load rejection transient

To illustrate the capabilities of the proposed co-simulation framework, this section summarises an application to a normal operation transient, namely a load rejection scenario. A comprehensive description of the case study and the coupling technique is presented in the dedicated report [121], whereas the aim of this example is to provide a brief overview of the methodological approach. In the context of TANDEM, it was assumed that the power allocated to cogeneration purposes was limited to 10% of the core thermal power, meaning that the SMR is predominantly used for electricity generation. Under this assumption, a severe transient on the electrical side is expected to have a stronger impact on reactor behaviour than a disturbance triggered from the heat extraction system, resulting in load rejection as a particularly relevant scenario to investigate. In this example, the NSSS is modelled with the CATHARE thermal-hydraulic system code, while the dynamic model of BOP in Modelica is based on the same architecture introduced in Chapter 5, with a control scheme adapted to this specific case study [121]. The two models are coupled using Python as the master environment, in which both the CATHARE and BOP models are imported as FMUs in co-simulation mode. In the following sections, the sequence of events characterising the load rejection transient is first outlined, followed by a discussion of the results obtained for both fully electric and cogeneration operating modes.

Case study description

A load rejection transient can be triggered by disturbances on the electrical grid that compromise the possibility of exporting power from the NPP. Since the auxiliary systems of the plant rely on external power, a load rejection procedure is initiated in response to such disturbances to ensure continued safe operation. In this scenario, the NPP is isolated from the grid, leading to an abrupt loss of external electrical load. From that moment, the power produced by the NPP is used exclusively to supply the auxiliary systems, including the reactor coolant pumps. The disconnection from the external grid implies that the pumps are now directly driven by the turbo-generator shaft, which accelerates given the sudden loss of resistive torque. The BOP control system, in particular the turbine frequency control scheme, reacts to this acceleration by closing the turbine admission valves to reduce the power output. As a consequence, steam accumulates in the secondary side of the steam generators, increasing the secondary pressure. When the pressure excursion exceeds the allowed threshold, the turbine bypass system is actuated and diverts excess steam directly to the condenser, thereby stabilising the secondary pressure level.
The closure of the turbine admission valves reduces the heat removal from the primary side, causing an accumulation of energy in the reactor coolant system and a corresponding increase in primary temperature and pressure. Reactivity feedback effects contribute to reducing the core power as the primary temperature rises, following the load reduction on the secondary side. In addition, the average core coolant temperature control program further decreases the power level through control rod insertions in response to the increase in average core temperature. In this scenario, two outcomes are possible:

- In a successful load rejection, the reactor stabilises at a reduced power level of about 30% of the nominal value. The generated power is then partly used to feed the auxiliary systems, while the remaining fraction is rejected to the environment through the condenser, and the reactor can later be ramped back to full power once grid conditions are restored.

- In an unsuccessful load rejection, operational limits are violated (e.g., through primary system overpressure) during the transient, triggering the shutdown of the reactor. If external power is not available, a loss of offsite power scenario occurs [121].

Two initial operating conditions are compared: a fully electric configuration, in which all steam is directed to the turbine, and a cogeneration configuration, in which a fraction of the steam is extracted for heat supply. In the latter case, high-temperature steam is extracted at the steam generator outlet and supplies a thermal power of 25 MW_{th} to a sensible heat transfer fluid through an intermediate heat exchanger.

Simulation results

The main results of the coupled simulations are reported in Figures 6.2 and 6.3. Figure 6.2 compares the time evolution of core power in the fully electric and cogeneration cases. In both scenarios, the reactor starts from its rated power. Once the load rejection transient is initiated, the core power exhibits a rise above nominal conditions, driven by the increase in primary coolant flow induced by the acceleration of the reactor coolant pumps, whose speed is shown in the top-left panel of Figure 6.3, and the associated temperature feedback effect. Subsequently, the increase in primary coolant temperature, displayed in the bottom-left panel of Figure 6.3, combined with external reactivity control actions, leads to a gradual reduction of the core power towards a new steady state of about 150 MW_{th}, corresponding to approximately 30% of nominal power.
A comparison between the fully electric and cogeneration cases, where the latter is represented by the red curve, shows that the power peak is lower in the cogeneration scenario. Similarly, the excursions in other key NSSS variables, such as primary coolant temperature and pressure, are less pronounced in cogeneration mode. In addition, the amount of steam bypassed to the condenser is smaller in the cogeneration case, indicating that a portion of the excess thermal power is redirected to the heat extraction line rather than being entirely rejected to the environment.

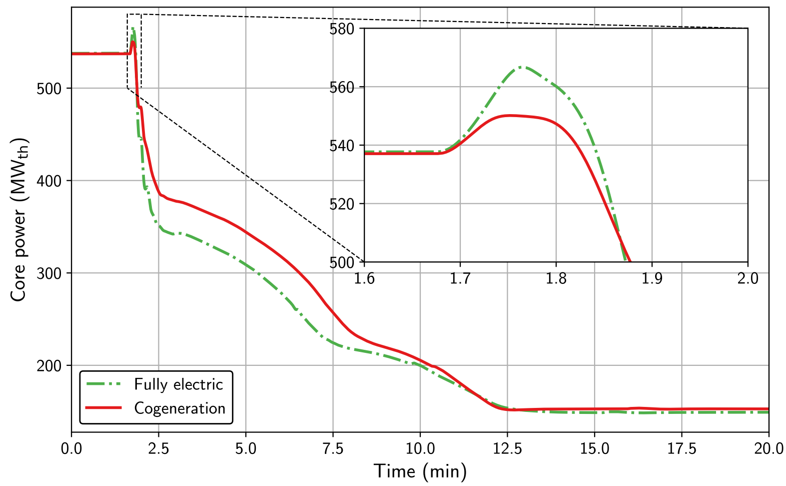

Figure 6.2: *Comparison of core power behaviour.*

As outlined by Olita et al. [121], this behaviour can be attributed to two main factors: (i) the presence of an additional steam line at the steam generator outlet, which provides an additional path for removing excess steam together with the turbine bypass to the condenser; and (ii) the lower initial electrical output in the cogeneration mode (approximately 164 MW_{el}, and 177 MW_{el} in the fully electric case), due to the steam already allocated to heat production. Consequently, the effective loss of electrical load experienced by the plant at the beginning of the transient is smaller, resulting in a reduced acceleration of the turbine shaft and milder transients in the primary system.
In conclusion, for this specific load rejection scenario, the availability of a steam extraction line for cogeneration proved to be beneficial, as it mitigated the severity of the transient on the nuclear island by providing an additional heat sink. However, this result cannot be generalised to all initiating events [121], for instance, when cogeneration systems are also electrically coupled to the NPP and are themselves affected by load rejection or grid disturbances. For a comprehensive safety demonstration, the proposed co-simulation framework should therefore be applied to a broader range of operating regimes, plant configurations, and accidental scenarios in order to characterise how different non-electric applications and interface configurations can affect nuclear safety margins.

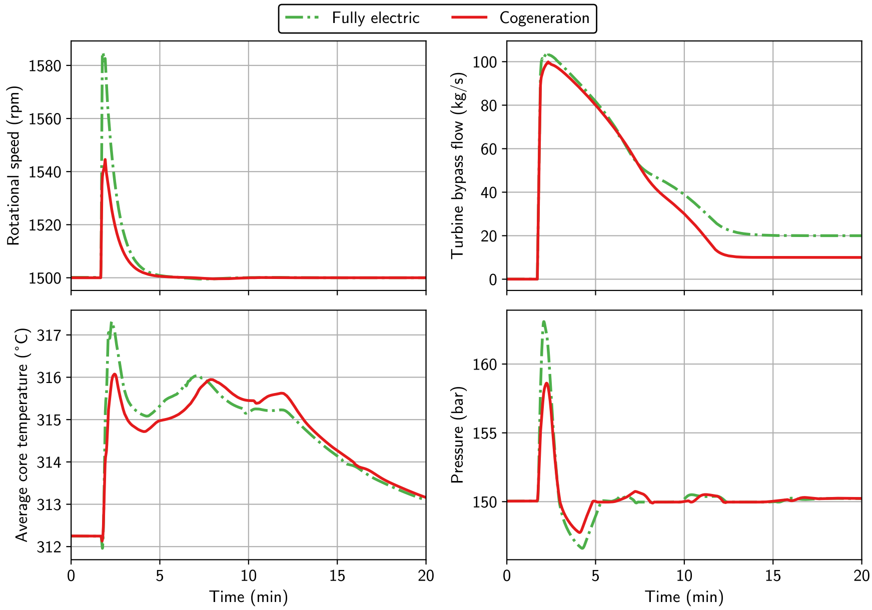

Figure 6.3: *Comparison of main NSSS and BOP variables.*

6.3 Concluding remarks

In the context of SMRs and NHES, the main deployment challenges are not only technical and economic but also from a safety standpoint. Existing policies and licensing frameworks were largely developed for conventional, electricity-only large reactors and therefore need to be updated to address the specific features of SMR-driven cogeneration and NHES. A central requirement in this evolution is to demonstrate that integrating SMRs with non-electric applications and broader NHES architectures does not jeopardise the safety of the NPP with respect to conventional nuclear uses. Consequently, safety assessments become a key enabling factor, and thus a policy priority, for the deployment of NHES. Only once a clear and integrated regulatory framework is defined, within which nuclear and industrial safety standards can coexist and interact consistently, it is possible to plan NHES deployment in a credible way, for instance, as part of national decarbonisation strategies.

In this regard, this chapter has highlighted several challenges that need to be addressed in policymaking on safety requirements for NHES. First, the increased complexity associated with tight thermal and electrical interconnections, additional initiating events, and potential hazard propagations must be acknowledged when formulating safety requirements for coupled systems. Second, an integrated regulatory framework is needed to harmonise the different requirements applicable to nuclear and industrial installations, addressing inconsistencies in safety criteria and the alignment of risk assessment methods. Within such a framework, particular attention must be devoted to the components that characterise the (thermal) interconnection between subsystems, since these elements are located at the interface between regulatory regimes. At the same time, a clear allocation of responsibilities for both regulatory bodies and plant operators is essential so that no gaps arise in the oversight or management of safety-relevant functions at the integrated system.

In this work, a co-simulation framework that couples nuclear thermal-hydraulic system codes, used to model the nuclear island, with dynamic simulation tools for the BOP and other NHES components is discussed. This framework has been applied in the Euratom TANDEM project to investigate safety-relevant scenarios such as thermal and electrical load rejections and loss of offsite power. The primary objective of these modelling activities is to provide a transparent tool that can support regulators and policymakers in the evaluation of nuclear cogeneration applications, for example, those proposed by SMR vendors. By simulating a wide range of accidental and safety-relevant scenarios, including initiating events originating in the cogeneration system, the co-simulation framework can be used to verify that safety margins remain respected. Moreover, these analyses can support the design of physical and operational barriers that protect both the nuclear and non-nuclear parts of the system and can be used to test the effectiveness of potential NHES-specific regulatory limits, such as constraints on flexible operation, minimum separation distances between coupled facilities, or constraints on the heat extracted for cogeneration. In this perspective, the proposed framework aims to provide a technical basis for developing safety guidelines and for addressing regulatory, licensing and policy gaps that could otherwise hinder the deployment of NHES or SMRs operated in cogeneration mode.

CHAPTER 7

Techno-economic optimisation

This chapter develops a system-level techno-economic optimisation framework to assess the cost-effectiveness and operation of NHES architectures. Mixed-Integer Linear Programming (MILP)-based layout and dispatch optimisation are combined with detailed dynamic simulators so that operational strategies are checked against physics-based technical and flexibility constraints. Two coupling methods between the tools are explored, soft-linked and hard-linked, showing that explicit feedback between economic and physical models is essential to avoid unrealistic dispatch strategies and to provide a more reliable description for policy and planning decisions on NHES deployment.

Further details on the tools and case studies presented in this chapter can be found in the following publications:

- Masotti, G. C., Haubensack, D., Ikonen, J.-P., Lindroos, T. J., Lorenzi, S., Pavel, G. L., & Ricotti, M. E. (2024). Dynamic modelling and optimisation of a Small Modular Reactor for electricity production and district heating in the Helsinki region. In *Proceedings of the 2024 International Congress on Advances in Nuclear Power Plants (ICAPP)*, Las Vegas, NV, United States. https://doi.org/10.13182/T130-44218
- Masotti, G. C., Crevon, S., Lorenzi, S., & Ricotti, M. E. (2025). Optimising a nuclear hybrid energy system's dispatch strategy: Coupling dynamic and techno-economic optimisation tools. In *Proceedings of the 2025 International Congress on Advances in Nuclear Power Plants (ICAPP)*, Antibes, France.
- Masotti, G. C., Lorenzi, S., Crevon, S., Ikonen, J.-P., & Lindroos, T. (2025). *TANDEM D3.4 - Assessment of the control and flexibility constraints on system components by the hybrid system simulator coupled with an optimizer* (Project deliverable).
- Martos Nogales, C., Crevon, S., & Masotti, G. C. (2025). *TANDEM D3.5 - Cross-comparison of simulation results between PERSEE, the Modelica simulator and ECOSIMPRO for the energy hub configuration* (Project deliverable).

This chapter addresses the techno-economic optimisation of NHES architectures from an architecture-level perspective. In this regard, two dimensions need to be considered:

- Layout optimisation, which determines the optimal installed capacities within the NHES architecture, such as VRE deployment, storage sizes, hydrogen production capacity, etc.
- Dispatch optimisation, which governs the allocation of power and heat flows within the integrated system over time to satisfy commodity demands while respecting technical and operational constraints.

The objective of these optimisations is to minimise total system costs, or maximise revenues, to define the economic competitiveness of NHES architectures compared to other alternatives.

The dispatch problem is particularly challenging in NHES, especially when strong thermal interconnections are present, as the operating conditions of each subsystem are tightly interdependent with the others. Furthermore, the optimisation outcomes are highly sensitive to the assumed boundary conditions and input data, including technology cost parameters, fuel prices, emission constraints and commodity demand profiles. A comprehensive context analysis is therefore essential to define realistic scenarios.

The techno-economic optimisation can be performed with dedicated tools, e.g., based on the Mixed-Integer Linear Programming (MILP) technique. This chapter explores how these tools can be integrated into the methodological framework of this work to provide a more physically representative estimation of the system's economic performance.

7.1 Modelling approach

The techno-economic optimisation of NHES configurations in this work is carried out with the aforementioned MILP-based optimisation tools. Moreover, the analysis addresses both economic and environmental aspects: typically, the objective function minimises the costs, while environmental considerations are incorporated through constraints on total emissions, for instance. In this way, the optimisation problem delivers cost-optimal designs and operating strategies that are consistent with decarbonisation policies.

A central point of the chapter is how to connect techno-economic optimisation tools with more detailed, physics-based representations of the NHES architecture. Standard MILP optimisation tools cannot fully capture the non-linear behaviour and strong interdependencies that characterise

NHES architectures, such as fluid travel times, inertial effects, variations of the operational points in off-design conditions, etc. For this reason, different coupling strategies between optimisation tools and dynamic simulators are explored. The primary goal is to obtain dispatch strategies that are also consistent with the behaviour predicted by more detailed physical models, thus providing a more reliable assessment of the economic performance and technical feasibility of the operation of the considered NHES configurations.

In this work, layout optimisation is first used to determine the system's installed capacities, which then serve as inputs for parameters of the dynamic simulators. As for the dispatch strategy, two main coupling approaches are investigated [124]:

- In the soft-linked approach, the parameters of the optimisation model are adjusted according to the feedback of the dynamic simulator, and the resulting optimal dispatch is then tested a posteriori by running the corresponding setpoints with the dynamic model. This allows assessing whether the optimal dispatch strategy can be implemented without violating any technical or operational limits of the NHES components.
- In the hard-linked approach, the dynamics of the system are integrated into the optimisation process: the optimiser receives feedback from the dynamic simulators and updates the dispatch decisions during the optimisation itself at a user-defined frequency. In this way, the optimal solution incorporates the non-linear response of the NHES simulator.

The studies proposed in this work are based on different optimisation tools. Backbone, developed by VTT and implemented in GAMS, focuses on the optimisation of energy flows with particular emphasis on district heating networks, treating electricity mainly as a secondary product [125]. Moreover, PERSEE[1], developed by CEA, is a software based on a modular C++ MILP core that can be used to optimise the flow of multiple energy vectors (e.g., electricity, heat, hydrogen, etc.) on different scales with the aim of supporting the decarbonisation of local energy needs [126]. Lastly, the PEGASE platform, also from CEA, is used as a co-simulation environment in which PERSEE can be coupled with the detailed dynamic simulator of the system, developed through the methodological approach outlined in Chapter 5, through the FMI standard. In this configuration, PEGASE is used to implement a Model Predictive Control (MPC) scheme, enabled by

[1] As part of its open-source release, PERSEE (oPtimizER for System Energy management) has been renamed to Cairn and is now available at https://github.com/CEA-Liten/CairnOpen.

the hard-linking between the techno-economic optimisation models and the simulators in the Modelica language.

Optimisation studies based on the techno-economic models in Backbone and PERSEE, documented in TANDEM Deliverable D3.2 [127], identified the most cost-effective configurations considering decarbonisation targets in different European contexts. These include, for example, replacing fossil-fuelled district heating plants with the E-SMR or shifting from Combined Cycle Gas Turbines (CCGT) and hydrogen production via Steam Methane Gas Reforming (SMGR) towards nuclear-driven electricity and hydrogen for industrial hubs. The study is complemented by Deliverable 3.3 [128], which provides sensitivity analyses on key techno-economic parameters and assumptions.

7.1.1 Soft-linked optimisation

In the soft-linked optimisation approach, the MILP-based model governing parameters are refined using operating conditions and constraints derived from the more detailed Modelica simulator of the system. This is implemented through an iterative procedure that aims to ensure consistency between the optimised profiles produced by the optimisation tool and the transient behaviour predicted by the dynamic simulator. At each iteration, the optimal profiles obtained from the optimiser are imposed as setpoints in the Modelica model; the dynamic simulation then indicates whether these trajectories can be followed without violating operational limits or inducing unrealistic system responses. Any significant discrepancies identified in this step are used to update the optimisation model, for example, by tightening ramp-rate constraints or adjusting other operational limits.

The soft-linked optimisation approach has been implemented through the following steps, summarised in the schematic in Figure 7.1:

1. First, consistency between the tools is ensured in terms of operational modes of the various components (e.g., imposing constant reactor core power in the load-following by cogeneration mode).

2. Moreover, the dynamic simulator is used to construct representative operational profiles and to extract key parameters such as power loss factors or flexibility limits, as those presented in the case studies in Chapter 5, which are then embedded in the techno-economic optimiser.

3. Lastly, iterations between the techno-economic optimisation and the dynamic simulation are carried out by re-running the optimisation

with updated constraints, testing the new optimal profiles in the dynamic simulator, and further modifying the optimiser whenever relevant mismatches appear.

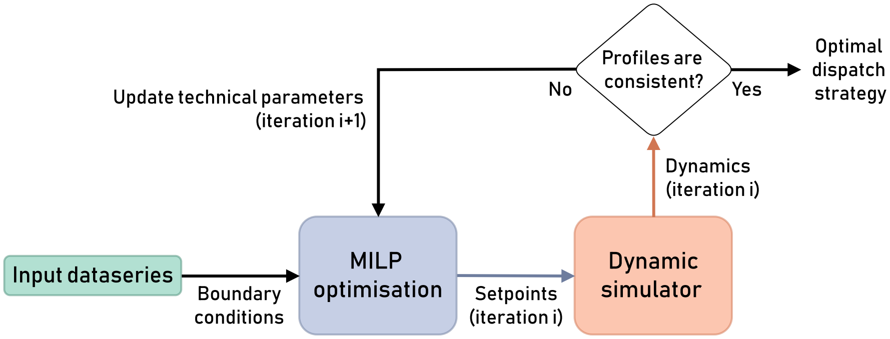

Figure 7.1: *Workflow for the soft-linked optimisation.*

An illustrative application of this soft-linked approach is presented in Example E7.1, while Example E7.2 showcases a comparison with the hard-linked optimisation approach. Overall, the soft-linked methodology represents a compromise between model representativeness and computational effort, enabling the optimisation framework to better reflect real system dynamics without incorporating the full complexity of the dynamic models directly into the techno-economic optimisation process as in the hard-linked approach.

E7.1. Dispatch optimisation of Helsinki's district heating network

This case study focuses on the contribution of an E-SMR for decarbonising heat supply in the Helsinki metropolitan district heating system, which is still largely reliant on fossil fuels [129]. In this analysis, the E-SMR is deployed in a two-module configuration, with each module treated as an independent unit equipped with its own BOP. Moreover, this example focuses exclusively on the heating part of cogeneration, with the reactor's electrical power output considered as a secondary commodity. In particular, the E-SMR is assumed to operate in a load-following by cogeneration mode, extracting low-temperature steam to feed the district heating network, which requires rather low-temperature heat ($<$150°C) also in winter. The thermal output from the reactor is coordinated with other heat sources, such as large heat pumps and fossil-fuelled units, to satisfy the season-dependent district heating demand across the interconnected urban areas of Espoo, Vantaa, Helsinki East and Helsinki West. Two main modelling tools are used. First, a dynamic simulator, shown in Figure 7.2, is employed to represent a simplified physical model of the system, including one-dimensional models for heat exchangers and transmission pipelines as well as the control system to regulate heat flows within the district heating network [95]. On the NPP side, the model also includes a cogeneration valve that modulates steam extraction in response to the required heat output.

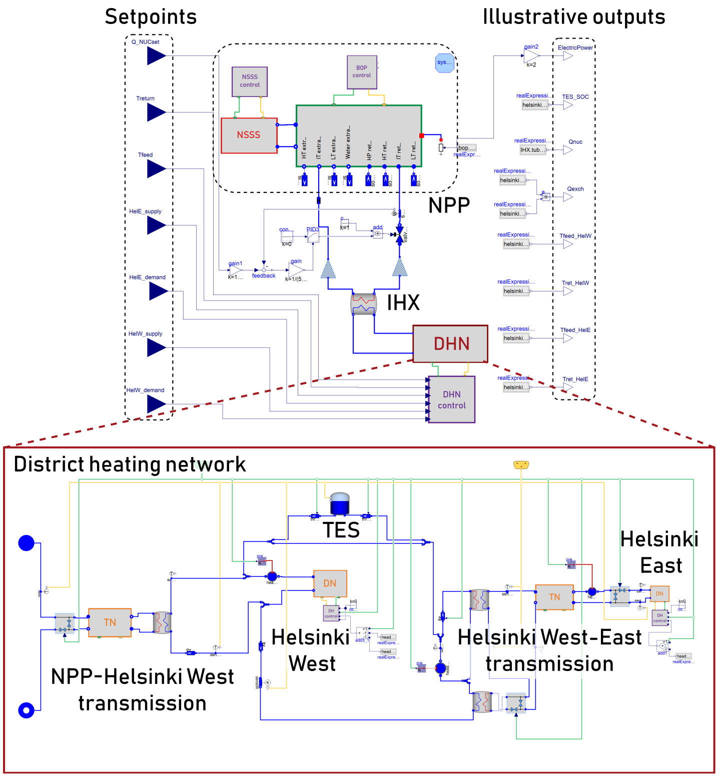

Figure 7.2: *Dynamic simulator of the district heating architecture [95].*

Secondly, the techno-economic optimisation model developed with Backbone is used to optimise the operational strategy of the system. Time series for heat demand and feed and return temperature setpoints in the different municipal areas are provided as input data, and the optimisation problem identifies the combination of units, capacities and operating strategies that maximises the Net Present Value (NPV) of the district heating system over a one-year horizon. In this case study, the two tools are coupled with each other through a soft-linked approach. Illustrative simulation results, intended to showcase the application of the methodology, are provided in the following section. For a more detailed description of the case study and of the modelling approach, the reader can refer to the dedicated deliverable of the TANDEM project [124].

Simulation results

The previously described soft-linked optimisation procedure is applied iteratively to define a more physically representative dispatch strategy. In a first step, Backbone is run with the E-SMR operating in load-following by cogeneration mode. The resulting optimal setpoints (in terms of thermal power extracted from the NPP and heat supplied by other sources) are then applied to the Modelica-based dynamic simulator, which computes the transient response of both the reactor and the district heating system. In this initial comparison, reported in Figure 7.3, significant discrepancies between the optimised profiles and the dynamic simulation outcomes were observed, particularly in the electrical power output of the E-SMR and in the heat exchanged between the interconnected subnetworks. These mismatches translate into deviations of the district heating return temperatures from their target values, as shown in the bottom-left panel.

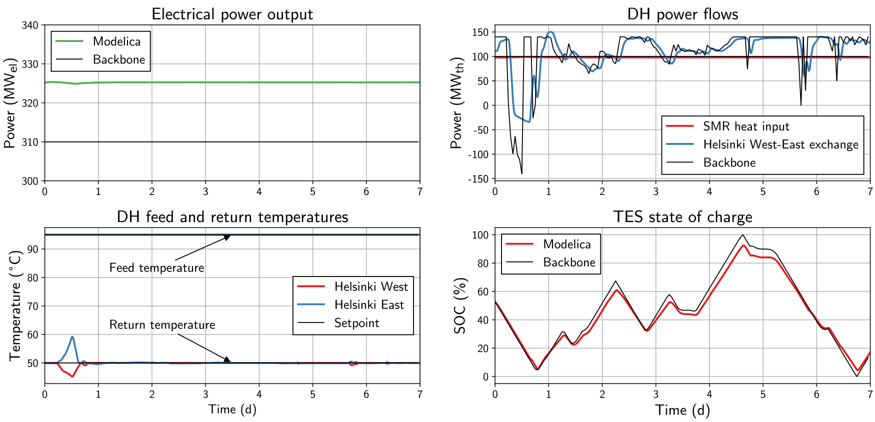

Figure 7.3: *Comparison between dynamic and linear optimisation tools - First iteration.*

Based on these findings, a second iteration is performed in which the representation of the E-SMR and the interconnection in Backbone are refined. In particular, the operational map linking the extracted thermal power to the electrical output (i.e., through the power loss factor) and maximal allowed heat extraction rate are derived from the dynamic simulation and implemented into the optimisation mode. In addition, constraints on the maximum rate of change of heat transfer and on the transmission capacity between the urban subnetworks are reduced to reflect the physical limits observed in the modelled architecture. With these updated parameters, and despite the intrinsic delays associated with fluid travel times in the transmission pipelines, the optimised heat exchange profiles between the different municipal areas show a better agreement with the simulator results. Moreover, the TES state of charge profile shows only marginal variations with respect to the first iteration, with its trend remaining consistent with the profile predicted by the Backbone optimisation.
Overall, this application shows that soft-linked optimisation provides a practical way to calibrate a linear techno-economic model so that it remains consistent with a more detailed, physically representative dynamic simulator. At the same time, the dynamic model enables the monitoring of critical variables for assessing the feasibility of the proposed dispatch strategy, such as the impact of steam extraction on the primary loop, which are not accounted for in stand-alone optimisation methods.

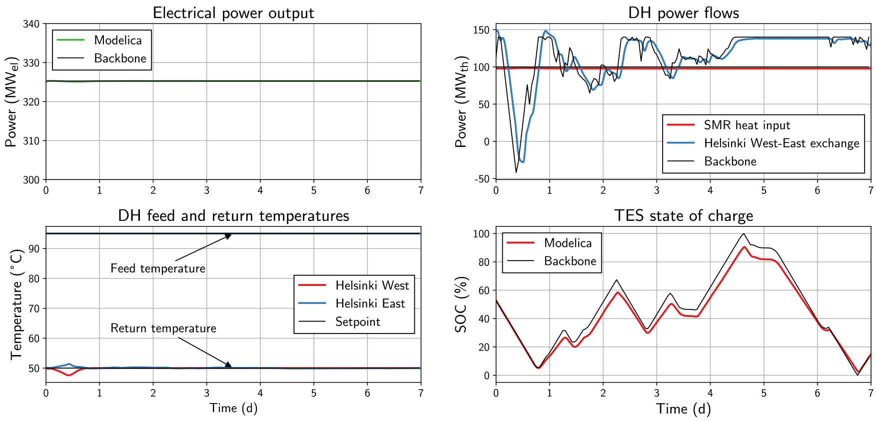

Figure 7.4: *Comparison between dynamic and linear optimisation tools - Last iteration.*

7.1.2 Hard-linked optimisation

Also in the hard-linked optimisation approach, the first step is to ensure full consistency between the operational assumptions adopted in the dynamic simulator and those used in the optimisation tool, both in terms of operational philosophies and key governing parameters. This optimisation approach focuses on the dispatch strategy, following the schematic shown in Figure 7.5, and uses the PEGASE co-simulation platform to link PERSEE and the Modelica simulators within a single environment. In this configuration, an explicit coupling scheme is adopted: given the relatively long optimisation horizons of interest (days to weeks) and the corresponding time resolution (minutes to hours), it is not considered necessary to introduce the additional complexity and computational cost of an implicit coupling scheme. As in the stand-alone optimisation cases [127], PERSEE defines the system optimal setpoints using external time series, e.g., for VRE availability, as well as electricity and hydrogen demands. For a given optimisation horizon, PERSEE first computes the optimal dispatch profiles and sends the corresponding setpoints to the dynamic Modelica model, encapsulated in a FMU in the co-simulation environment. The FMU is then simulated over the same time interval, and the resulting system state (represented, for instance, by the State Of Charge (SOC) of energy storage devices) at the end of the period is used as the starting point for the next optimisation cycle. In other words, each new optimisation phase in PERSEE starts not from the state computed by the linear optimiser itself, but from the state calculated by the dynamic simulator, thus accounting for non-linear effects and dynamics that the MILP model cannot fully capture.

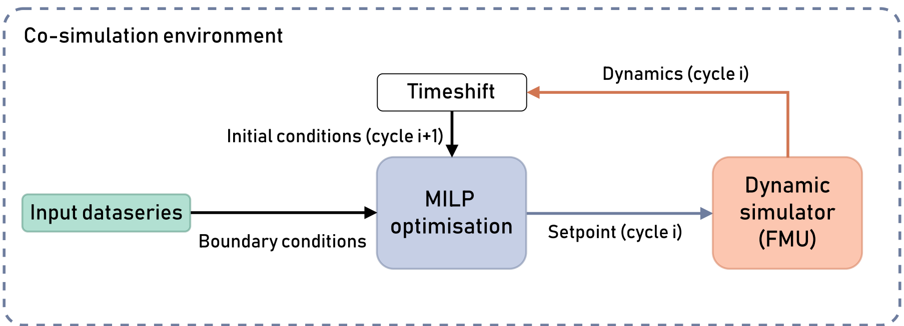

Figure 7.5: *Workflow for the hard-linked optimisation.*

A key element in this coupling scheme is the so-called timeshift parameter, implemented in PEGASE through the *Timeshift* module. This module

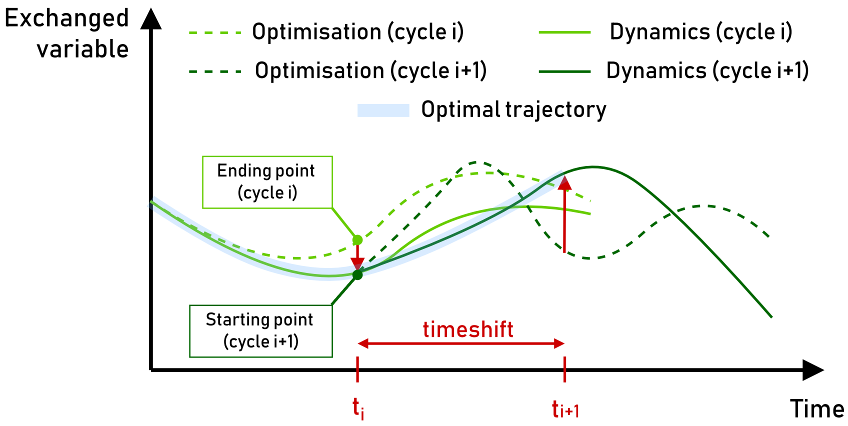

Figure 7.6: *Role of timeshift in the hard-linked optimisation [124].*

controls how often the variables between the codes are exchanged, as illustrated in Figure 7.6. Over time, significant discrepancies can arise between the PERSEE state variables and those computed by Modelica. Reducing the timeshift value increases the degree of coupling between the tools, leading to a closer alignment between the profiles used by PERSEE and the behaviour simulated in Modelica, and thereby improving the physical representativeness of the resulting optimal dispatch strategy. In summary, the hard-linked optimisation framework allows dynamic system behaviour to be encompassed directly in the optimisation process, yielding dispatch strategies that are both cost-optimal and consistent with the operational behaviour captured by the physical NHES simulator.

E7.2. Dispatch optimisation of an energy hub architecture

This case study is based on the NHES configuration shown in Figure 7.7, which will also be referred to as *energy hub* architecture. The reference location is aligned with the industrial district of Fos-sur-Mer, in France, whose characteristics inspire the demand profiles and other boundary conditions considered in the analysis [127]. The system comprises an E-SMR-driven plant (encompassing two reactor modules), CCGT units, VREs, HTSE for hydrogen production, a two-tank sensible TES unit and a hydrogen storage system. The E-SMR is the only unit operated in cogeneration mode, specifically in load-following by cogeneration with high-temperature steam extraction. The integrated system powers an industrial district, assumed to be characterised by constant electricity and hydrogen demands which cannot be satisfied exclusively by the NPP. In this configuration, the TES is used to decouple steam extraction, primarily adjusted to modulate electrical power output, from the heat requirements of the HTSE plant, which are satisfied by discharging the TES. In addition, the hydrogen storage provides a buffer between the variable hydrogen production target and the stable end-user demand.

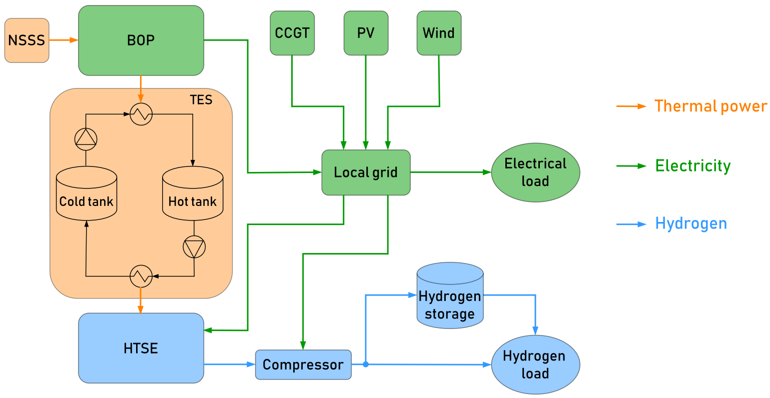

Figure 7.7: *Simplified schematic of the considered NHES architecture (adapted from [95]).*

Also in this case, a dynamic simulator provides a detailed representation of all thermally interconnected components, including the E-SMR primary and secondary loops, TES, and HTSE, while purely electrical components such as CCGT and VRE are treated in a simplified way or as boundary conditions [95]. Moreover, a PERSEE model, shown in Figure 7.8 simulates the same architecture in a MILP framework for techno-economic optimisation.

Simulation results

The optimal installed capacities of all technologies, obtained by PERSEE using operational maps derived from the dynamic model, are summarised in Table 7.1. During the coupled simulations, the optimiser provides the dynamic simulator with time series for the hydrogen production target, the hydrogen demand and the electricity generation setpoint, while Modelica returns the SOC of the TES and hydrogen storage as a feedback to update the system state for the subsequent optimisation cycle.

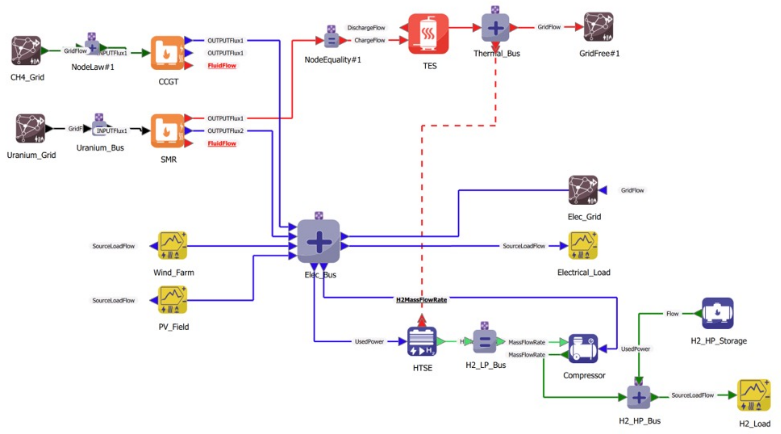

Figure 7.8: *Optimisation model in PERSEE.*

Component	Capacity	Unit
CCGT	89	MW_{el}
Wind	28.5	MW_{el}
Solar PV	200	MW_{el}
E-SMR cogeneration power (per module)*	50	MW_{th}
TES*	264	MWh_{th}
HTSE	368	MW_{el}
H_2 Storage	15088	kg_{H_2}

Table 7.1: *Optimal sizes resulting from the PERSEE optimisation. Marked values (*) are predefined [124].*

Firstly, the optimisation is performed adopting the soft-linked approach. PERSEE is run over a full year with an hourly time step, and the resulting optimal setpoints for an illustrative week are then imposed in the Modelica model. According to the results, the optimal dispatch strategy involves a continuos modulation of hydrogen and electricity production, with the setpoint for the latter carrier met by operating the reactor in a load-following by cogeneration mode. Hydrogen production exhibits significant variability, resulting in an annual load factor of 0.87 [124]. It should be noted that such continuous fluctuations could accelerate degradation of plant components, potentially increasing maintenance costs and reducing component lifetimes, and should therefore be explicitly considered in a more detailed techno-economic assessment of the system. As shown in the top row of Figure 7.9, the control strategy implemented in the dynamic simulator is capable of meeting the hydrogen production and SMR electricity generation targets, defined by the PERSEE optimisation. However, a different behaviour can be observed in the case of SOC evolutions: while the hydrogen storage, whose model is based on a simplified and static representation, remains consistent between the two tools, the TES SOC computed by Modelica progressively diverges from the trajectory assumed in the optimisation. Non-linearities, transport delays and other dynamic effects in the BOP, TES and HTSE models, which are not fully captured in the MILP optimisation, cause the TES SOC to decrease faster, ultimately driving the hot tank to the minimum level before the end of the one-week optimisation horizon and causing the simulation to fail. Alternative soft-linked configurations, in which the dynamic model control system directly regulates exchanged thermal power flows rather than hydrogen and electricity production, improve the agreement in TES SOC, but notable discrepancies still remain [130]. Generally speaking, the soft-linked results highlight that, for tightly thermally integrated architectures such as this NHES, an a posteriori iteration between the tools is not sufficient, and a stronger interaction between the optimiser and dynamic simulator is needed to ensure the definition of physically viable dispatch strategies.

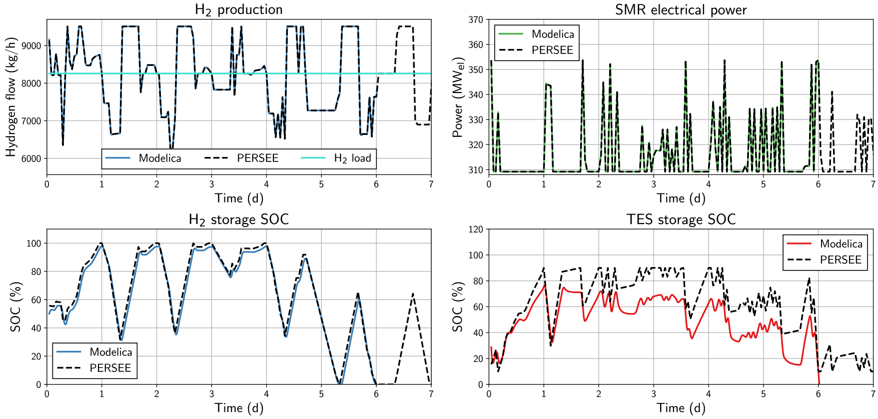

Figure 7.9: *Energy hub architecture - Soft linked optimisation.*

To address this limitation, the same scenario is simulated using the hard-linked approach within the PEGASE co-simulation platform. In this setup, PERSEE and the Modelica simulator are coupled through the FMI standard, and the optimisation cycle is carried out over shorter rolling horizons (e.g., 24 hours) rather than assuming perfect foresight over the entire year. A key parameter in this framework is the timeshift, which defines how often the optimisation is restarted using the current state of the system provided by Modelica. Two configurations are examined: a timeshift of 12 hours and a more frequent update every 3 hours. For the 12-hour case, shown in Figure 7.10, PERSEE produces optimal profiles for electrical power and hydrogen production in day-long cycles. Modelica then simulates the corresponding dynamics, and after each 12-hour interval the TES and hydrogen SOCs computed by Modelica are used as feedback to PERSEE to update the initial conditions for the next optimisation cycle. This periodic re-initialisation prevents the drift in TES SOC observed in the soft-linked setup and keeps the discrepancy between the two tools limited.

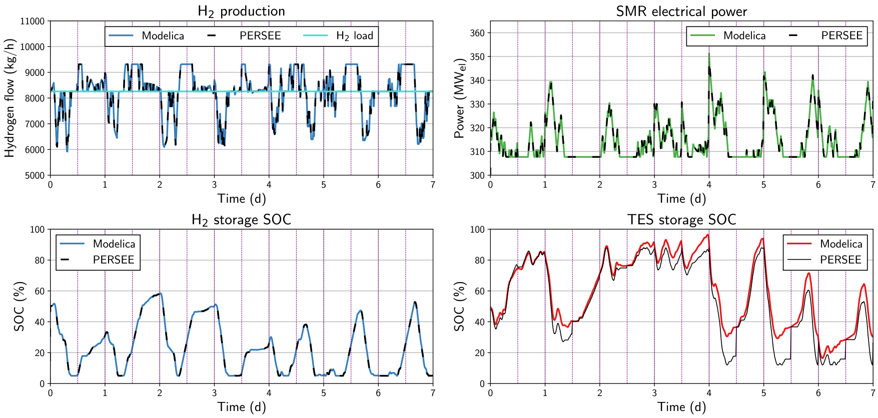

Figure 7.10: *Energy hub architecture - Hard linked optimisation, 12-hour timeshift [124].*

Reducing the timeshift to 3 hours increases the frequency of communication between PERSEE and Modelica and thus tightens the coupling. In this case, the dispatch strategy differs noticeably from both the soft-linked case and the 12-hour hard-linked case, driven by both the update of the SOCs and the different future horizon. With a shorter timeshift, the agreement between the TES SOC computed by PERSEE and by the dynamic simulator is further improved over the weekly horizon. The choice of the timeshift, however, involves a trade-off: reducing it increases the physical consistency and robustness of the resulting dispatch strategy but requires more frequent optimisation cycles and therefore higher computational effort. As a matter of fact, the 3-hour timeshift configuration required 2.4 hour CPU time, significantly higher compared with 1.6 hours for the 12-hour timeshift case and 2.89 seconds for the PERSEE stand-alone optimisation. In practice, the timeshift should be selected according to the scope of the study: short-term analyses of operational strategies over hours to a few days, with time steps of the order of minutes, should generally favour short timeshifts, whereas long-term simulations over months or years should rely on longer timeshifts, potentially up to several days or weeks, to keep the computational burden manageable. Notably, despite the boundary conditions are the same, the optimal dispatch strategy differs visibly across cases.

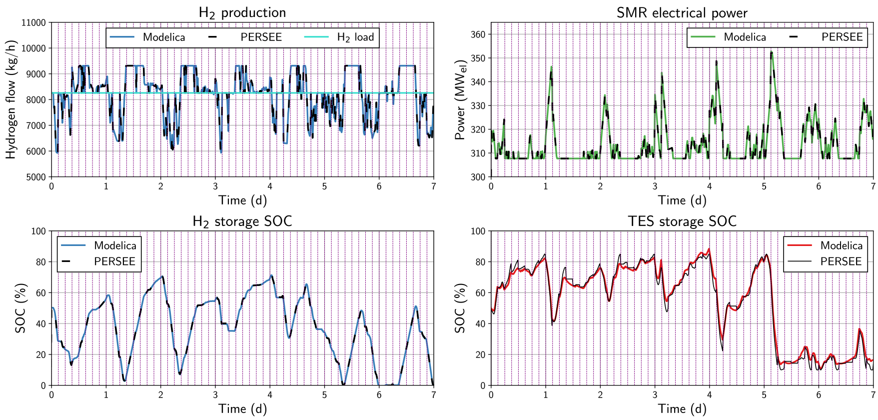

Figure 7.11: *Energy hub architecture - Hard linked optimisation, 3-hour timeshift [124].*

A quantitative comparison of the different coupling strategies, including weekly energy balances and selected techno-economic indicators, is reported in Table 7.2 [124]. At the weekly scale, the three coupling strategies lead to a very similar techno-economic performance. The electrical energies consumed or produced by the HTSE, CCGT and SMR units differ only marginally between the soft-linked case and

the two hard-linked cases, and curtailment remains low in all configurations. Likewise, TES charging and discharging energies are almost identical across the three setups.
The main discrepancies concern the TES SOC corrections in the hard-linked simulations. The net TES SOC corrections of 290 MWh_{th} for the 12-hour timeshift and 140 MWh_{th} for the 3-hour timeshift correspond to relative corrections of 1.09 and 0.53, respectively. In other words, given that the TES thermal capacity is 240 MWh_{th}, a correction of 290 MWh_{th} is essentially equivalent to adding more than one full charging cycle's worth of "free" thermal energy into the optimisation for the 12-hour timeshift case. Since this additional energy enters the PERSEE optimisation without any associated cost, it effectively acts as cost-free heat made available to the system. Over a one-week horizon this has only a negligible impact on the economic indicators, as reflected by the almost identical OPerational EXpenditures (OPEX). In principle, however, incorporating the additional operational constraints arising from the dynamic model should restrict the feasible operating space and therefore lead to a solution that is less cost-effective than the outcome of the stand-alone optimisation. In the present setup, this effect cannot be properly observed because of the "free" heat injection. Notably, if similar corrections were to accumulate over longer simulation horizons, such as months or years, this additional energy effect could significantly bias the economic assessment and lead to misleading conclusions regarding cost-effectiveness.

Variable	Unit	Soft-linked	12-h timeshift	3-h timeshift
HTSE electrical energy	GWh_{el}	53.36	53.48	53.45
CCGT electrical energy	GWh_{el}	6.63	6.99	6.87
SMR electrical energy	GWh_{el}	52.68	52.81	52.74
Curtailed electrical energy	GWh_{el}	1.02	1.34	1.19
TES charging energy	GWh_{th}	13.95	13.69	13.83
TES discharging energy	GWh_{th}	14.05	14.08	14.09
Net TES-SOC correction	GWh_{th}	N/A	0.29	0.14
Relative TES-SOC correction	–	N/A	1.09	0.53
Net H_2-SOC correction	tons	N/A	-0.03	-0.01
Relative H_2-SOC correction	–	N/A	-0.002	-0.0007
Undiscounted Net OPEX	M€	1.4	1.39	1.4

Table 7.2: *Comparison of techno-economic variables in the weekly optimisation of the decoupled energy hub [124].*

Concluding remarks

In conclusion, these results indicate that the selected NHES architecture can be operated to meet the constant hydrogen and electricity demands of an industrial hub. Soft-linked optimisation provides a useful first step, but for tightly integrated NHES configurations, a hard-linked framework, for instance encompassing the coupling of the PERSEE techno-economic optimiser with the Modelica dynamic models in the PEGASE environment, provides operational strategies that are more consistent with a physical representation of the system. At the same time, the resulting economic indicators must be carefully interpreted, e.g., by accounting for the feedback from the dynamic simulator in the cost evaluation to avoid biases such as "free" energy corrections (or, in different scenarios, net removal of stored thermal energy) accumulating over longer horizons.

7.2 Concluding remarks

From a system perspective, the techno-economic analysis of NHES reveals that current optimisation approaches present limitations for the analysis of tightly coupled architectures that include nuclear cogeneration. In particular, the thermal interconnection between subsystems can lead to dynamic effects and significant non-linearities that are not captured by standard MILP optimisers. This creates a methodological gap for the system-level analysis of NHES: dispatch and sizing decisions for integrated architecture can appear optimal in the optimisation model but could be incompatible with the actual dynamics and operating limits of the considered configuration.

The work developed in this chapter addresses this gap by proposing and showcasing the application of an optimisation framework that links layout and dispatch optimisation to the feedback of a physics-based dynamic simulation, namely through a soft- or hard-linked approach. The case studies confirm that the presence of nuclear cogeneration units, TES and other thermally interconnected components can strongly affect the optimal dispatch strategy. Moreover, they demonstrate that dispatch strategies obtained from stand-alone techno-economic optimisation can lead to unrealistic trajectories and infeasible operation once transport delays, thermal inertia and non-linearities are accounted for. Hard-linked optimisation mitigates this by aligning state variables such as storage SOCs between the two tools. However, the trade-off between physical consistency and computational burden must be accounted for, together with a limited representativeness of the economic outcomes due to the state variables' corrections according to the simulator's feedback.

These findings have direct implications for how system-level optimisation of NHES should be used to support policy and regulatory decisions. The results suggest that optimisation studies informing policies on NHES should not rely solely on conventional MILP-based tools but should be supported by at least a calibrated soft-linked setup and, where strong thermal couplings are present, by hard-linked or equivalent feedback-based schemes. In this sense, the methodological approach presented in this chapter can be applied to future studies on different NHES architectures, providing a technically grounded definition of operational strategies and informing decision-makers on how such systems can be operated while respecting key technical constraints.

CHAPTER 8

Long-term energy planning

This chapter investigates how long-term energy system models can be used to quantify the role of nuclear energy in future low-carbon energy systems, focusing on the possible utilisation of nuclear heat. Specifically, using technical parameters derived from the system-level analyses in earlier chapters, existing planning tools are expanded to treat nuclear power not only as an electricity-only source but also to consider advanced applications like SMRs operating in cogeneration mode and an NHES archetype. Within this framework, nuclear units can supply both electricity and non-electric commodities such as low-temperature heat and hydrogen, and their deployment is assessed under alternative policy assumptions. The extended models are applied to illustrative decarbonisation scenarios for the Italian energy system, primarily to demonstrate how different long-term planning tools can be used to inform policymakers about the potential contribution of nuclear cogeneration and NHES configurations operating in synergy with VREs. The analyses show that the decarbonisation needs of industrial heat and hydrogen demand could become a key driver for nuclear-driven cogeneration, as fully decarbonising these energy needs exclusively through VRE deployment could be more challenging and more expensive.

This chapter examines how long-term energy system models can be used to evaluate the role of nuclear cogeneration in present and future energy systems. Long-term planning tools are essential to quantify how nuclear integrates within decarbonisation strategies, to assess its contribution under different policy and market conditions, and to identify how it can support higher penetrations of VREs. In this context, they help clarify evolving system requirements such as flexibility and the decarbonisation of non-electric energy vectors, which are essential aspects to be considered when comparing nuclear power with other low-carbon alternatives.

One major uncertainty in assessing nuclear contributions to decarbonisation pathways concerns the future deployment of advanced nuclear technologies and applications [68], such as SMRs, cogeneration applications, and NHES. Long-term energy system optimisation frameworks can support the exploration of these novel systems, enabling the identification of conditions under which nuclear represents a cost-competitive solution for the decarbonisation of both the power and non-electric sectors through the production of commodities beyond electricity (e.g., heat and hydrogen).

In this work, existing long-term energy system models are extended to include nuclear cogeneration and NHES, characterised by technical parameters derived from the system-level analyses presented in the previous chapters. This extension is necessary because most planning tools traditionally treat nuclear exclusively as an electricity-only technology and therefore cannot capture its potential role in a multi-purpose configuration for providing low-carbon heat and hydrogen. In the considered scenarios, SMRs are allowed to operate in cogeneration mode or as part of NHES architectures, while conventional, large-scale reactors are treated as electricity-only units. In practice, large-scale reactors could also be operated in cogeneration mode; however, this work restricts cogeneration and NHES deployment to SMRs in line with the aforementioned advantages of coupling them to non-electric applications.

The chapter is organised as follows. First, the modelling approach and mathematical formulation used to integrate nuclear cogeneration and NHES into long-term planning tools are presented. Then, an overview of modelling tools is provided, together with practical applications focusing on decarbonisation pathways and policies for the Italian energy system. Finally, the chapter concludes with a discussion of the relevance and limitations of the proposed framework for informing decision-makers on advanced nuclear applications, including NHES deployment.

8.1 Nuclear cogeneration and NHES in energy system models

As discussed above, the objective of this work in the frame of long-term energy planning modelling is to explicitly represent nuclear cogeneration and NHES in decarbonisation strategies. To support the discussion of how these advanced nuclear applications are integrated with other technologies and energy carriers, a simplified reference energy system schematic is presented in Figure 8.1. For the electricity generation side, the system includes fossil-fuelled thermal plants such as CCGTs, both in conventional configurations and equipped with CCS. VREs are represented by wind and solar power, while hydropower is modelled as a dispatchable renewable resource. Moreover, energy storage is provided by Battery Energy Storage Systems (BESS) and Pumped Hydro Storage (PHS). In addition to thermal power plants operating in cogeneration mode, heat requirements can be met by heat pumps, representing an electrified heating option. Hydrogen production technologies considered in the system include SMGR, with and without CCS, as well as electrolysers.

Within this framework, the main purpose of the schematic is to illustrate how SMRs, operated as CHP units, as well as an archetype of NHES configuration, can be integrated into the broader system. In the example shown, the NHES consists of a light-water cooled SMR coupled to an HTSE-based hydrogen production plant, consistent with the architecture analysed in Chapters 5 and 7. These two subsystems are assumed to be interconnected upstream of the grid connection points, resulting in an internal heat and electricity network that allocates the reactor power either to the global electrical grid or to the hydrogen production plant, depending on the optimal dispatch strategy for the overall energy system.

It should be emphasised that this is a simplified representation built around a limited set of illustrative technologies. Real, country-level power systems typically include a wider range of power sources, such as biomass, geothermal plants, and coal-fired generators, alongside additional coupling options between energy carriers, for example, hydrogen blending in gas turbines or direct use of hydrogen or electricity to supply high-temperature industrial heat. The representation of heat demand in the schematic is also strongly simplified. As discussed in Chapter 2, industrial and residential heat demands span over a wide range of temperature levels, which are not necessarily compatible with any given heat source. In this example, only low-temperature applications (e.g., below 200°C) are considered, assumed to be compatible with heat extracted from light-water cooled reactors and industrial heat pumps. For higher-temperature requirements, in addition to the aforementioned options, cogeneration from advanced reactor concepts or the direct combustion of fossil fuels (potentially with CCS), among other solutions, could also be considered.

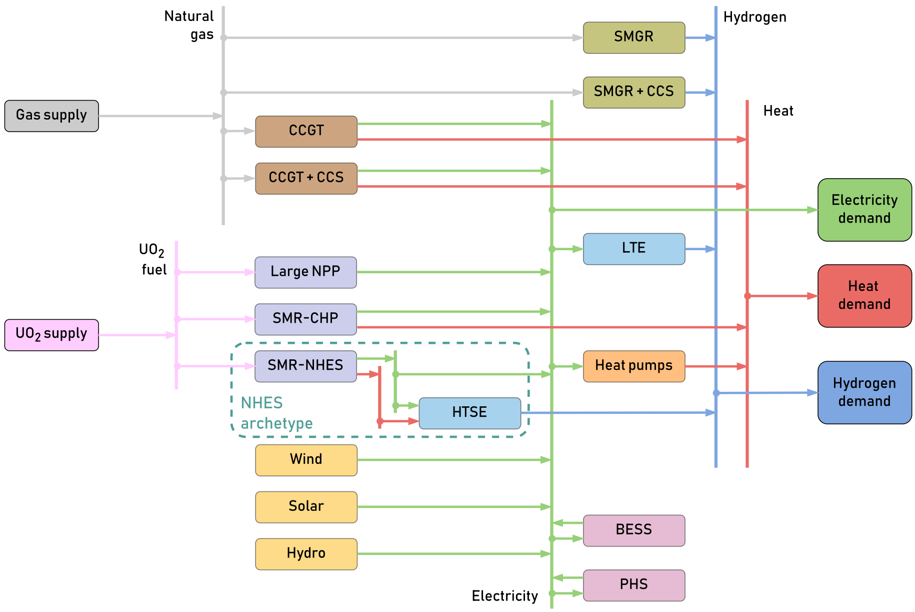

Figure 8.1: *Reference energy system comprising nuclear cogeneration and NHES architectures.*

Several constraints are introduced to characterise the operation of SMRs in cogeneration mode, giving rise to the operational map shown in Figure 8.2. Constructing such a map is essential for component modelling in long-term planning frameworks, as it allows translating the operational limits and characteristics into the linear representation needed by the model. For electricity-only generating reactors, operational constraints are required to bound the electrical power output (e.g., minimum and maximum power output, ramping limits, etc.) within the allowed operational limits. In contrast, for SMRs operated in cogeneration mode (SMR-CHP and SMR-NHES), additional constraints are required to represent how steam extraction affects power conversion performance and to enforce practical limits on the heat that can be extracted for cogeneration purposes. In particular, the electrical power generated by the unit is given by

$$P_{el} = \eta\, P_{th} - \beta\, P_{cog}$$

where η is the cycle efficiency in electricity-only operation, P_{th} the core power, β the power loss factor, and P_{cog} the thermal power allocated for cogeneration purposes. In this work, both η and β are assumed constant, even at partial core power conditions, despite the additional losses expected under off-design operation [87]. This simplifying assumption preserves linearity in the optimisation problem, since introducing power-dependent efficiencies would lead to non-linear constraints that are incompatible with the current modelling framework. Moreover, the maximum heat extraction is limited by a factor γ, which represents the allowable fraction of rated reactor power that can be allocated to the cogeneration systems:

$$P_{cog} \leq \gamma \, P_{th}^{nom}$$

In this work, the heat is assumed to be provided by extraction turbines, where steam extraction for cogeneration purposes is bled from the turbine line. The plant is therefore conceived mainly as an electricity-generating unit that delivers heat as an additional product rather than operating as a heat-only source, for instance. To reflect this design philosophy, a minimum power-to-heat ratio is specified through the following constraint:

$$P_{el} \geq \alpha \, P_{cog}$$

This constraint ensures that steam extraction remains limited relative to the flow driving power generation, thereby keeping the operating point within the design range of an extraction turbine. Together, these constraints define the admissible operating region highlighted in Figure 8.2. The upper boundary of the map (shown in blue) corresponds to the load-following by cogeneration mode, where the reactor operates at rated thermal power and variations in electrical output are achieved by modulating P_{cog}. Conversely, the purple curve corresponds to operating points where the reactor thermal power is reduced. Along this trajectory, the electricity generation and, as a consequence of the minimal power-to-heat ratio constraint, the heat extraction for cogeneration purposes, are reduced.

8.2 Overview of the tools

A wide range of modelling approaches has been developed for energy planning and scenario analyses, each with different levels of detail, sectoral coverage, and mathematical formulation. Several classification schemes have been proposed in the literature [131, 132], typically organising energy models according to their main purpose, analytical and mathematical approach, considered sectors, optimisation horizon, as well as time and geographical resolutions, among other criteria. A first key distinction is often

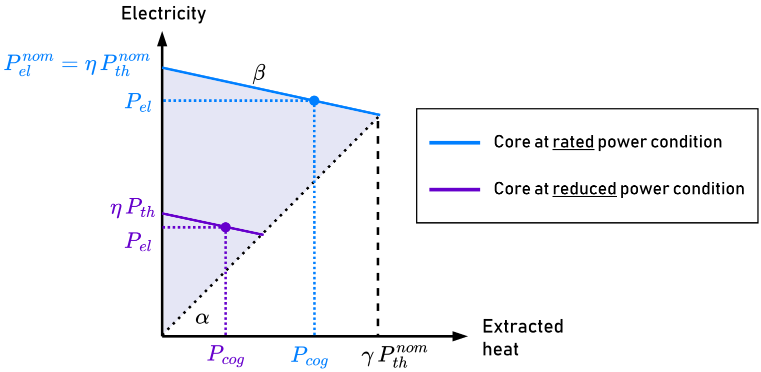

Figure 8.2: *Operational map of a SMR operating in cogeneration mode.*

given by the analytical approach, which can be divided into top-down and bottom-up. Top-down models connect the energy system to macro- and socio-economic dynamics, linking energy use to indicators such as economic growth, demographics, etc. In order to capture the broader economic system, they generally limit the representation detail of technologies and components and are therefore less suited to inform detailed, sector-specific technology or infrastructure policies in the energy sector. In contrast, bottom-up models provide a technology-centred description of the energy system, with explicit characterisation of generation, conversion, storage, and sector-coupling options. These models are particularly useful to compare alternative decarbonisation pathways, identify cost-optimal technology shares, and evaluate the impact of different policy or technology assumptions on the energy mix. However, they provide limited insights into broader macroeconomic implications.

In this work, the latter perspective is adopted, with a specific focus on the contribution of nuclear technologies to decarbonisation strategies and their interaction with other low-carbon options. Bottom-up models can be further distinguished according to their temporal formulation: Static or "snapshot" optimisation models are applied to a short horizon (e.g., a single year) to identify an optimal system configuration under the given boundary conditions. Dynamic, long-term models, by contrast, account for the temporal evolution of the system over multiple years or decades. They track investments, retirements, and capacity expansion over time and determine cost-optimal transition pathways to meet specified targets (e.g., emission constraints) over the entire planning horizon, rather than only in an isolated year. Beyond these core distinctions, long-term energy planning models can also be classified according to their sectoral coverage (e.g., power-only versus multi-sector models), geographical structure (single country, multi-region, or network-resolved formulations), methodological approach (for example, single-objective versus multi-objective optimisation), and underlying programming technique (linear, mixed-integer, etc.) [132].

The following sections describe in more detail the two modelling tools employed in the framework of this thesis, namely the static optimisation code FRAMES [133], used to explore optimal system configurations under specific policy and technology assumptions, and the dynamic framework Hypatia [134], applied to analyse long-term transition pathways and the role of nuclear cogeneration and NHES in decarbonisation scenarios.

Static energy system modelling

The static energy system model adopted in this work is FRAMES (FRAmework for Modelling Energy Systems), developed by the IAEA as a capacity expansion and dispatch optimisation tool for energy planning studies. Within the context of this thesis, FRAMES is used to explore how nuclear technologies, including cogeneration and NHES concepts, can contribute to decarbonisation strategies by providing indications on the feasibility and effectiveness of policy targets, such as emission constraints, VRE penetration levels, and deployment of programmable generators to meet flexibility requirements.

FRAMES is written in AMPL (A Mathematical Programming Language) [135] and formulated as a MILP problem. The objective function minimises the total system cost over the simulated year, subject to technical and policy constraints. Cost components include investment and fixed operational costs, variable generation costs, and detailed operational costs associated with unit commitment decisions, such as rampings, start-ups and shut-downs. Additional penalty terms can be included for non-served energy, non-served operating reserves, and, when activated, demand-side management options. Moreover, limits on carbon intensity can be imposed, which enables the assessment of decarbonisation policies and their impact on the optimal mix of technologies. Consistent with a static energy system modelling approach, FRAMES performs the optimisation over a full year with an hourly time step. This temporal resolution allows the computational effort to remain manageable while still capturing daily and seasonal variability in demand and renewable generation profiles; however, shorter time steps could be explored to better represent short-term fluctuations, such as wind stochasticity. Time series for different commodities, such as electricity, heat or hydrogen demand, as well as VRE availability profiles, are specified exogenously and provide the boundary conditions for the optimisation. The model can be used both in a greenfield or brownfield approach, with the latter treating part of the existing power generation units as fixed while optimising additional capacity. Short-term balancing needs are represented through an explicit modelling of operating reserves. FRAMES distinguishes between spinning and regulation reserves, which are required to cope with forecast errors in renewable generation and load, among others [73]. Both upward and downward reserve requirements are considered, ensuring that sufficient programmable capacity is available to increase or decrease output in response to deviations from expected operating conditions. This is particularly important in scenarios with high VRE shares, where flexibility constraints can strongly influence the optimal capacity mix. Thermal generation and storage technologies are modelled through a clustered unit commitment formulation, following the approach described by Palmintier [136]. Units with similar technical and economic characteristics are aggregated into clusters, which reduces computational complexity while retaining the essential features of plant operation, such as ramping limits, minimum up and down times, etc. From a computational standpoint, FRAMES is compatible with standard optimisation solvers. In this work, CPLEX is used to solve the MILP problem, typically with a relaxed integer formulation to reduce computational efforts. The code is under development within a dedicated IAEA Collaborative Project [137], whose initial scope included beta-testing on different case studies, validation exercises, and the collection of feedback on model performance, strengths, and limitations. These activities supported the preparation of user documentation and ultimately led to the release of the first FRAMES version in December 2025.

In this initial release, FRAMES encompasses only high-temperature process heat for hydrogen production systems, such as thermochemical cycles. In this work, the model has been adapted through several extensions tailored to the analysis of nuclear cogeneration and NHES:

- First, the adopted version of the model included an exogenous heat demand at three representative temperature levels. In this version, the constraints described in the previous section were implemented to represent the operation of SMRs in cogeneration mode.

- The technologies available in the model have also been expanded to better address the decarbonisation of the heat sector. For instance, heat pumps and thermal storage systems are introduced, enabling the analysis of synergies between electrified heating, nuclear cogeneration and VRE deployment. For hydrogen production, HTSE is added as an alternative technology, with its characteristic specific thermal and electrical consumption parameters.

- Finally, the spatial resolution of FRAMES has been generalised beyond its original two-region configuration. In the official release, the model can represent up to two interconnected regions. In this work, the formulation is extended to a multi-node setting with a user-defined number of zones. A matrix-based description is used for transmission capacities and efficiencies between zones, which enables the construction of tailored interconnection schemes corresponding to the case study of interest. In addition, imports and exports of electricity to regions outside the model boundary can be modelled, thereby capturing the influence of cross-border exchanges, which are particularly relevant in the European context.

The extended FRAMES framework is applied to a case study based on a simplified representation of the Italian energy system, in which alternative policy and technology scenarios for decarbonisation are explored. The main modelling assumptions and key results of this analysis are summarised in Example E8.1. Overall, the extended FRAMES model proved to be a flexible tool to assess the role of nuclear cogeneration and NHES in long-term decarbonisation strategies, while explicitly accounting for operational constraints and different operational modes.

E8.1. Scenarios for the Italian energy system - Static approach

The FRAMES modelling framework, including the models for SMRs in cogeneration mode and a NHES archetype, is applied to the optimisation of a simplified representation of the Italian energy system. The objective is to demonstrate the methodological approach to evaluate the competitiveness of nuclear cogeneration and NHES configurations with respect to other low-carbon alternatives, not only for the decarbonisation of the power sector but also for the supply of low-temperature process heat and hydrogen. The simplified reference energy system considered in the model is the one presented in Figure 8.1, where electricity, process heat and hydrogen demands are satisfied by a combination of technologies including VREs, fossil-fuelled generators with and without CCS, heat pumps, nuclear plants, etc.

Case study

To balance computational burden and geographical representativeness, the Italian system is divided into two regions. These correspond to a Northern macro-zone (R1) and a Southern macro-zone (R2), whose main characteristics are summarised in Figure 8.3. The modelling horizon is set to 2050, reflecting a plausible deployment target for advanced nuclear systems and deep decarbonisation targets. Consequently, input techno-economic parameters, based on literature projections and scenario studies, are defined for this target year. Further details on these parameters, together with additional sensitivity analyses, are available in Appendix C. To remain consistent with the snapshot nature of FRAMES, all cost inputs are annualised using the technology-specific lifetimes and a constant 5% discount rate.

For electricity, the projected final consumption is taken from the Italian NECP [138], equal to 478 TWh/y in 2050, significantly higher than the current value of about 315 TWh/y, mainly due to the expected electrification of end-uses. With regard to heat, the analysis focuses on low-temperature (<200°C) industrial process heat, assumed to be the most viable market for light-water cooled SMRs and estimated at around 59 TWh/y [17, 138]. High-temperature process heat, which represents the largest share of industrial heat demand, is not explicitly modelled in this work. This end-user segment could be supplied by advanced reactors, direct electrification, hydrogen or fossil combustion, but these options are outside the scope of the current analysis. Moreover, it is worth noting that the electrification of high-temperature industrial processes is already reflected in the increased electricity demand assumed for 2050 [138], so its impact is not neglected at the system level. For hydrogen, the reference demand is derived from the baseline scenario of the Italian *National Hydrogen Strategy* [81], corresponding to 64.4 TWh/y. This represents a substantial increase with respect to the current value of about 17.4 TWh/y, driven mainly by additional consumption in industry and transport. In this study, electricity demand is represented by an hourly annual profile, while the industrial heat and hydrogen demands are modelled as constant over the year, reflecting the need for a stable and reliable supply in industrial processes. This represents a simplifying assumption, as in practice some processes require variable demand profiles; a dedicated effort should therefore be devoted to constructing representative profiles, as well as considering thermal energy and hydrogen storage systems that could help accommodating this variability in planning decisions. Moreover, given the significant uncertainty in the evolution of these demands, a set of scenarios is constructed in which heat and hydrogen requirements are varied around the reference values. Total demand is allocated between the two regions according to the industrial load distribution in the territory, with approximately 75% of the industrial load located in the Northern bidding zones and the remaining 25% in Southern Italy [139].

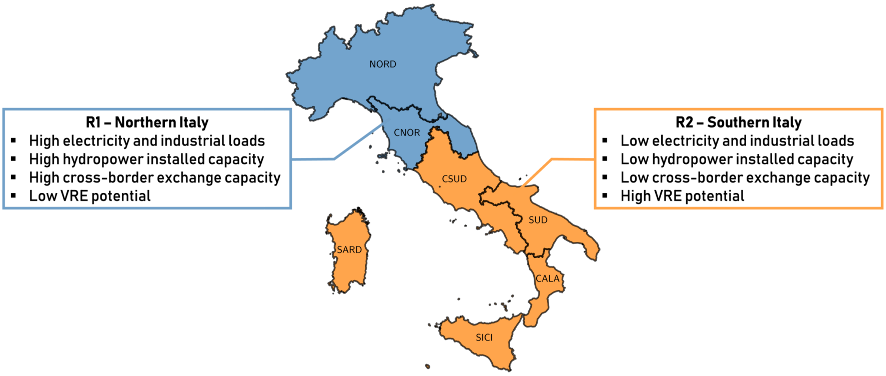

Figure 8.3: *Overview of the Italian case study.*

On the supply side, CCGT and CCGT+CCS plants are assumed to be capable of operating in cogeneration mode, without defining separate clusters for CHP units, thereby reducing decision variables and the associated computational effort. Moreover, maximal hydropower generation is imposed exogenously, based on historical profiles. This reflects the fact that this technology, including PHS, is largely saturated and cannot be scaled up significantly to achieve future decarbonisation targets. Three nuclear systems are included in the model:

- Conventional, large-scale reactors, operating as electricity-only units.
- SMRs based on the E-SMR design, operated in cogeneration mode to supply low-temperature industrial heat. In this case, steam is extracted at an intermediate stage of the turbine, and a power loss factor of 0.32 is adopted, in line with the analysis in Chapter 5.

- An NHES configuration coupling the E-SMR with a HTSE plant for hydrogen production, consistent with the architecture discussed in Example E5.3, and with the SMR operated in load-following by cogeneration mode, i.e., at rated thermal power.

On this basis, the following sections explore a variety of policy-relevant scenarios, including decarbonisation considering emission caps, alternative policies based on VRE targets and fossil-fuel price measures, together with examples of sensitivity analyses.

Decarbonisation policies through emission caps

As a first step, the model is used to determine the most cost-effective energy mix under different caps on the emission intensity of the system, defined over the combined electricity, heat and hydrogen demands. Caps ranging from 15 gCO_2/kWh to no cap are considered. Two main scenarios are analysed:

- A *no nuclear scenario*, in which decarbonisation is achieved primarily via VREs and fossil plants with CCS.
- A *nuclear scenario*, in which the model can deploy both large-scale reactors and SMRs operated in cogeneration mode and integrated into NHES.

The results, illustrated in Figure 8.4, show that for stringent decarbonisation targets (e.g., 15 gCO_2/kWh), allowing nuclear deployment reduces total system cost. For deep decarbonisation, the *no nuclear scenario* is roughly 10% more expensive than the nuclear one when comparing total system costs annualised to the target year. Furthermore, in the *no nuclear scenario*, the intermittency of VRE requires considerably higher installed capacities and large amounts of energy storage to maintain adequacy (i.e., capability to meet demand and reserve requirements) and satisfy the variable load profile. Specifically, the storage requirement is more than doubled with respect to the *nuclear scenario*. In the latter case, VRE capacity remains relatively stable as emission caps are reduced, while fossil-fuelled generation is progressively displaced by nuclear. Without any emission constraint, nuclear is not cost-competitive against a mix of gas and renewables, as both baseload and flexibility needs are met by CCGTs. Once emission caps are introduced, nuclear enters the mix and its installed capacity increases from about 11 GW_{el} (mainly SMRs in cogeneration mode) at 100 gCO_2/kWh to around 25 GW_{el} at 15 gCO_2/kWh, distributed between both large reactors and SMRs.

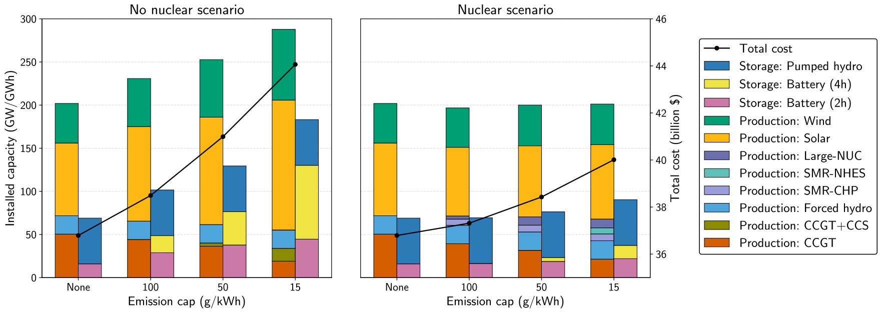

Figure 8.4: *Installed capacities and total system costs.*

Because of greater technology maturity, large reactors are assumed to have a lower CAPital EXpenditure (CAPEX) than SMRs as baseline. However, for stringent emission limits, SMRs operated in cogeneration mode become attractive as they address decarbonisation needs in the heat and hydrogen sectors that conventional reactors cannot directly serve. This can be observed in the breakdown of energy supplies for electricity, heat and hydrogen, shown in Figure 8.5. In the *no nuclear scenario*, extensive CCS deployment is required, especially for industrial heat and hydrogen, while electricity is dominated by VRE. Even in the power sector, however, renewables alone are unable to cover the entire demand, and gas plants with CCS remain necessary as programmable power sources. In both *nuclear* and *no nuclear scenarios*, heat pumps play a significant role, even though the largest fraction of heat demand is covered by dispatchable thermal power sources (i.e., CCGTs and SMRs). In the *nuclear scenario*, gas-fired generation is progressively replaced by nuclear, which reaches about 18% of total energy supply at 100 gCO_2/kWh and 38% at 15 gCO_2/kWh, while renewables remain the dominant contributor in each case. Nuclear heat applications, i.e., process steam from SMRs and hydrogen from HTSE, become increasingly important under strict emission caps. In particular, under the cost assumptions summarised in Appendix C, HTSE-based hydrogen production within NHES starts to become relevant in the 15 gCO_2/kWh cap, where the output grows to approximately 21 TWh/y, which corresponds to about one-third of total hydrogen demand, highlighting the growing importance of increasing hydrogen production efficiency when emission limits are stringent.

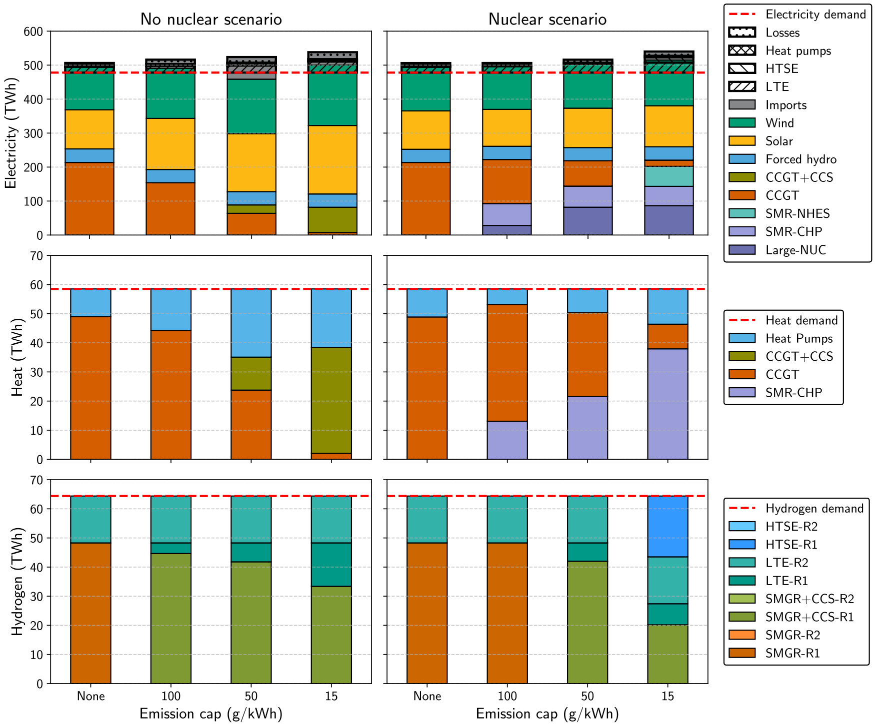

Figure 8.5: *Energy production breakdown for different carriers.*

Figure 8.6 shows the generation profiles over an illustrative week in summer. In the *no nuclear scenario*, Northern Italy exhibits substantial solar excess generation relative to demand, with surplus energy used to charge storage and drive electrolysers. During periods of low solar output, demand is met via storage discharge, CCGT generation and imports from the other region or from abroad. In Southern Italy, in contrast, wind generation remains high even at night. Considering nuclear deployment, both regions still deploy large amounts of renewables, but the dispatch in R1 changes significantly: NPPs, including both large reactors and SMRs, provide the baseload power due to lower marginal costs and more restrictive operational flexibility compared with CCGTs. As a result, nuclear generation remains stable throughout the week, with a significant ramp-down only on

Sunday in response to high solar output and low demand. Aside from this day, the output of large-scale nuclear units stays essentially constant, whereas the SMR electrical output is continuously regulated to provide flexibility. This showcases the advantages of operating nuclear units in cogeneration mode, as the SMR electrical output can be adjusted by modulating the heat extraction for cogeneration while maintaining an essentially constant core power and thus respecting the most stringent flexibility limits on the primary side.

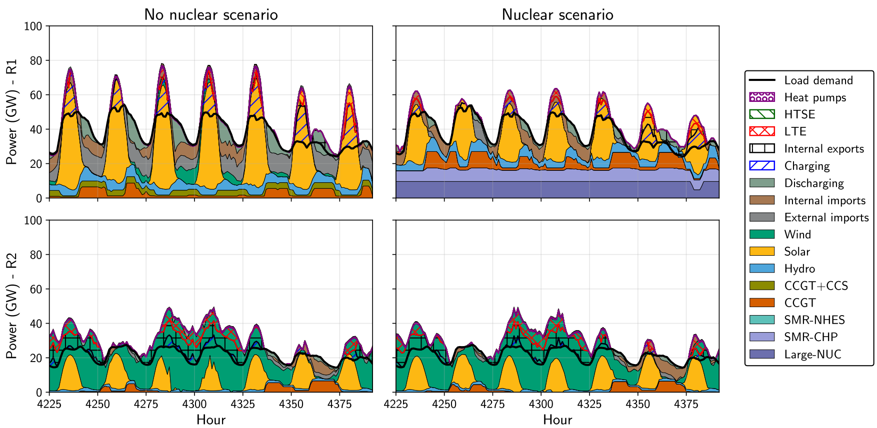

Figure 8.6: *Illustrative operation in a summer week, 50 g/kWh cap.*

Decarbonisation policies through VRE and gas price regulation

In addition to emission intensity caps, alternative decarbonisation policies are explored by acting directly on the deployment drivers of low-carbon technologies. Two main types of policy are considered:

- Renewable generation targets, expressed as a minimum share of energy demand supplied by renewables (wind, solar, hydro).
- Gas price measures, representing penalties or constraints on fossil fuel use to indirectly promote low-carbon technologies.

The former type of policy reflects current EU approaches, such as the RED III directive requiring a minimum 42.5% share of renewables in gross final energy consumption by 2030 [2], while the latter aims at representing policies related to energy security by raising the cost of gas and thus discouraging its use. As highlighted in the emission-

cap analysis, fossil fuel dependence remains substantial, particularly in the *no nuclear scenario* and especially for heat and hydrogen. This poses not only climate concerns but also risks to energy security, as evidenced by the vulnerability of the European energy system following the Russian invasion of Ukraine. Policies that constrain gas consumption can therefore contribute both to emissions reduction and to lowering exposure to such risks.
In the modelling, these policies are assumed to guide the system towards low-carbon configurations, rather than imposing explicit carbon-intensity limits. Results show that high VRE targets alone lead to slightly higher system costs and do not guarantee deep decarbonisation: even with 90% of energy demand for electricity, heat, and hydrogen supplied by renewables, the total system emission intensity remains above 50 gCO_2/kWh and at a total system cost that is 10% higher compared to the 50 gCO_2/kWh in the *nuclear scenario*. The reason is that, while the power sector is heavily decarbonised, industrial heat and hydrogen remain largely supplied by fossil fuels without CCS, and nuclear options are not incentivised by this type of policy. Conversely, scenarios where the average gas price is progressively increased exhibit a rapid decline in gas use across electricity, heat and hydrogen production, resulting in significantly lower emissions and lower total system costs than in the high VRE penetration case. Under these gas price policies, nuclear technologies are deployed primarily to decarbonise heat and hydrogen, thereby reducing the burden on renewables to provide all low-carbon energy. This underlines the importance of policy instruments that act on fossil fuel usage and carbon pricing, rather than relying solely on renewable targets.

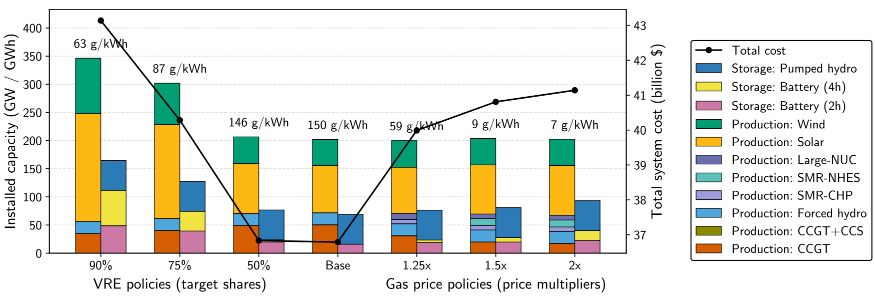

Figure 8.7: *Impact of different policies on capacity deployment .*

Scenarios on commodity demands

Given the uncertainty surrounding future industrial heat needs and hydrogen demand, additional scenarios explore the impact of these drivers on optimal technology deployment under an emission intensity cap of 50 gCO_2/kWh. The baseline low-temperature industrial heat demand is halved and doubled in the *Low Heat* and *High Heat* scenarios, respectively. For hydrogen, the *Low* H_2 scenario assumes that demand remains close to current levels, whereas the *High* H_2 case follows the "high diffusion" scenario from the national hydrogen strategy [81]. Since a fixed emission intensity limit is imposed, higher energy demands lead to higher absolute emissions. The results, reported in Figure 8.8, indicate that higher industrial heat demand substantially changes the deployment of nuclear technologies, with SMRs in CHP mode gaining a larger share when heat demand is high. In contrast, variations in hydrogen demand have a more limited influence on the electricity generation mix: hydrogen production remains dominated by steam reforming with CCS and LTE, while HTSE is not cost-competitive in the optimal solution for the 50 gCO_2/kWh cap.

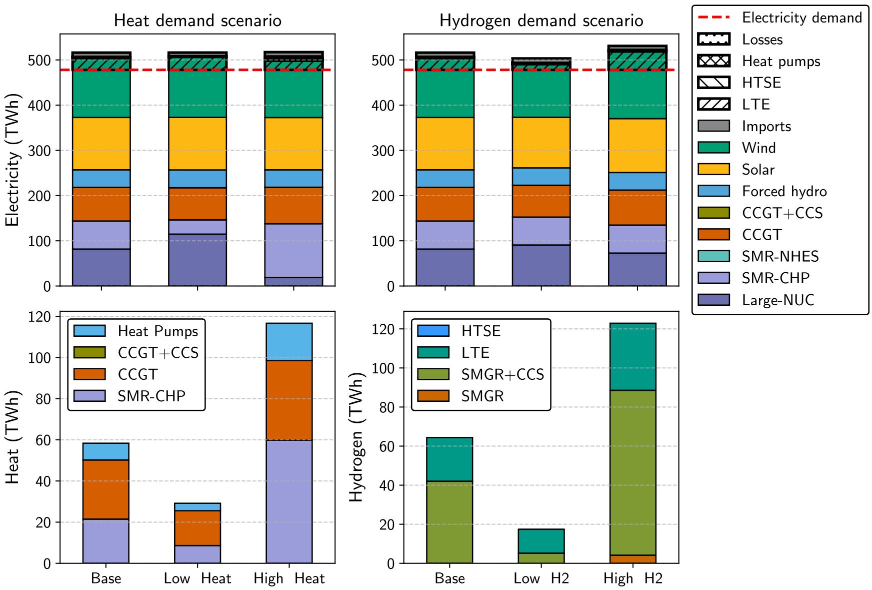

Figure 8.8: *Impact of heat and hydrogen demands on energy production.*

Sensitivity analysis

The quantitative results discussed above are sensitive to assumptions on technology parameters. Two illustrative and non-exhaustive sensitivity analyses are presented to showcase these dependencies, while further sensitivity studies are reported in Appendix C.

In the first, shown in Figure 8.9, nuclear CAPEX and average gas prices are varied under a 50 gCO_2/kWh cap. VRE penetration is relatively stable, fluctuating between roughly 40% and 55% of electricity supply even at extreme cost conditions. By contrast, nuclear cogeneration for low-temperature heat is strongly driven by gas prices: for high gas costs, SMR-based heat supply covers more than 70% of industrial heat demand and, for very low nuclear CAPEX, can rise to nearly the entire heat demand. Hydrogen production is sensitive to both nuclear and gas costs. High gas prices tend to promote electrolysis, while low nuclear costs favour SMR deployment, including integration in NHES, increasing the HTSE share of hydrogen to around 70% of total demand. For high nuclear costs, lower nuclear capacity (restricted to SMRs dedicated to decarbonising heat and hydrogen) results in a larger share for LTE. The analysis also highlights that nuclear competes primarily with gas-fired plants as dispatchable capacity and thermal power energy supplier rather than with VRE that effectively decarbonise the power sector.

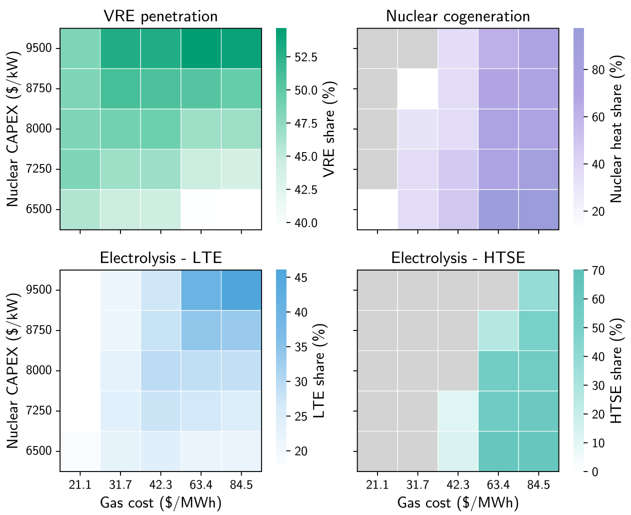

Figure 8.9: *Sensitivity analysis on nuclear and gas costs.*

In the second sensitivity analysis, the focus is on SMR techno-economic parameters. Due to uncertainties surrounding the costs of the chosen SMR design, the baseline assumes an SMR CAPEX 10% higher than that of large reactors, corresponding to a cost multiplier of 1.1. This is varied within a range, together with the maximum allowable heat extraction for SMR-CHP operation, which is set to 20% of reactor thermal power in the baseline and varied between 0% and 40%. Results show that SMR deployment is highly sensitive to their relative cost: if SMR CAPEX is equal to or lower than that of large reactors (multipliers 1.0 or 0.9), the nuclear fleet consists almost entirely of SMRs; if SMRs are more expensive (multiplier above 1.1), no units are deployed. This also affects HTSE deployment, as the deployment of NHES is driven by SMR costs, leading hydrogen to be supplied mainly by LTE and SMGR+CCS. This outcome should be interpreted with the understanding that, in this study, HTSE is assumed to be deployed only within NHES configurations, and that alternative system integration options could lead to different conclusions. The model is less sensitive to the maximum heat extraction fraction, although a lower SMR capacity can be deployed to satisfy the same fraction of heat demand in the case of higher allowable extraction levels.

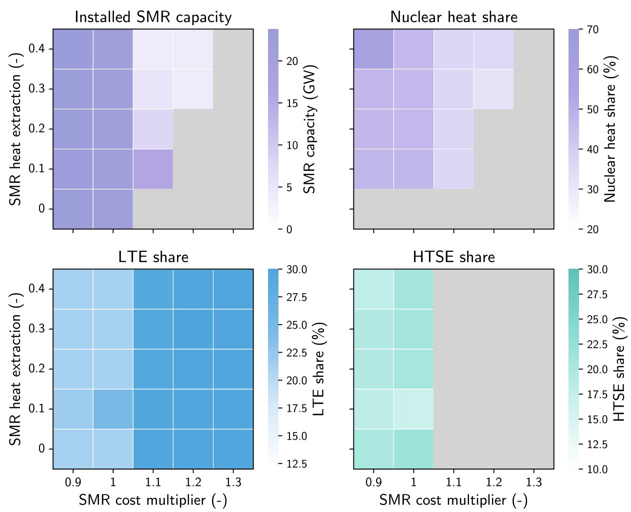

Figure 8.10: *Sensitivity analysis on SMR parameters.*

Concluding remarks

In the proposed case study, the optimisation results show that deep decarbonisation targets are met more cost-effectively when nuclear power is allowed to complement high VRE deployment, especially if SMRs in cogeneration and NHES configurations are available to decarbonise industrial heat and hydrogen demand. Similar outcomes were obtained also in other studies focusing on the pathway to net-zero of the Italian energy system, including the NECP [138] and the scenarios developed by the Italian transmission system operator Terna [140]. Policies based solely on VRE targets are comparatively more expensive and still leave substantial residual emissions for heat and hydrogen production, whereas measures that penalise fossil fuel use (e.g., via carbon pricing or measures on gas price) drive a faster and cheaper phase-out of unabated CCGT. Overall, these policy approaches should be considered complementary rather than mutually exclusive, as their combined implementation may accelerate decarbonisation across various end-user sectors. In conclusion, Italian decarbonisation strategies would benefit from an integrated policy framework that simultaneously maintains strong support for VRE to decarbonise the power sector, keeps the nuclear option open to provide grid stability and significantly reduce the need for energy storage systems, and enables the deployment of nuclear cogeneration and NHES to support the decarbonisation of industrial process heat and hydrogen production.

However, it is important to acknowledge that the snapshot optimisation framework adopted here does not describe how the system could practically evolve towards the identified optimal configuration. In particular, the model does not capture path dependencies, temporal competition for capacity expansion, or the fact that early large-scale deployment of readily available low-carbon technologies may leave limited space for nuclear technologies in later stages of the transition. Assessing these dynamic aspects requires complementary dynamic long-term planning models, which are able to represent investment trajectories and deployment constraints based on supply chain capabilities; such frameworks can provide a more complete view of how, and under which policy conditions, nuclear cogeneration and NHES could realistically be integrated into decarbonisation pathways.

Dynamic energy system modelling

As aforementioned, dynamic energy system models represent the temporal evolution of capacity deployment, allowing the analysis of how the technology mix changes over multi-year horizons. In this work, the open-source optimisation framework Hypatia [134], developed at Politecnico di Milano in the Python programming language, is used to investigate the potential role of nuclear cogeneration in cost-optimal long-term energy system planning. As a matter of fact, Hypatia supports multiple energy carriers, in particular electricity, heat and hydrogen, enabling the investigation of the various interactions between these vectors. The model is operated in planning mode, meaning that it optimises capacity expansion decisions over multiple years, considering a short-term dispatch over a representative 24-hour period per year, for instance, to ensure acceptable computational limits. In this framework, the objective function can be formulated either to minimise total system costs or to minimise emissions; in the former case, it is also possible to impose exogenous emission targets and derive the corresponding cost-optimal energy mix that satisfies the specified decarbonisation trajectory. Moreover, the user can specify time-dependent techno-economic parameters for each technology, including learning-driven investment cost reductions, deployment timelines and efficiency improvements, as well as policy constraints such as emission caps or phase-out targets for fossil-fuelled plants.

In general, dynamic planning models and static energy system models should be seen as complementary rather than competing tools, as they address different research questions. Static models with full-year hourly resolution are well suited to analyse the detailed operation of a given system configuration, capturing the variability of demand and supply over the whole year-long horizon. In contrast, dynamic planning models focus on the trajectory by which an energy system moves from a starting-year configuration toward a future objective (e.g., defined by emission targets), optimising the timing and scale of capacity expansion under evolving techno-economic conditions and policy constraints, albeit with a simplified short-term representation for the dispatch strategy.

In this work, consistently with the static modelling approach adopted earlier, SMR-driven cogeneration and NHES configurations are represented by implementing the same operational constraints presented in Section 8.1. An illustrative application of this framework, intended to demonstrate the type of insights that dynamic long-term planning models can provide without delving into a detailed discussion about the assumptions or performing an exhaustive analysis, is presented in Example E8.2.

E8.2. Scenarios for the Italian energy system - Dynamic approach

This case study examines the decarbonisation of the Italian energy system employing a dynamic capacity expansion strategy. The system is represented as a single region, with dispatch modelled over a 24-hour period for each year in the optimisation horizon spanning from 2020 to 2050. The first five years are characterised by the residual capacities of the current energy system, while subsequent years allow for endogenous capacity expansion subject to technology-specific deployment caps. As in the previous analyses, the same final demands for electricity, heat and hydrogen are considered; however, because Hypatia is a dynamic framework, trajectories must be specified over time. In this example, electricity demand follows scenario trajectories derived from decarbonisation studies of the Italian energy system [138,140], heat demand is assumed constant over the horizon, and hydrogen demand increases linearly from its current level to the 2050 target [81]. It is important to stress that the results presented here are not meant to be directly compared with those obtained from the snapshot optimisation, as the two modelling approaches serve different purposes and rely on different assumptions and sets of technologies. The dynamic framework explicitly represents time-dependent technology costs, construction and deployment times and installation caps to reflect supply chain limitations, whereas the static one assumes a single representative year, adopting a greenfield approach. The objective of this example is therefore to highlight the main drivers that shape optimal solutions in a dynamic setting, rather than to provide a direct comparison with the previous case.

In this example, decarbonisation pathways are modelled by imposing exogenous limits on the system's emission intensity, defined over the combined electricity, heat and hydrogen consumptions. These caps decrease linearly from 150 g/kWh in 2025 to 15 g/kWh in 2050. The resulting production mixes for electricity, heat and hydrogen are reported in Figures 8.11, 8.12 and 8.13, while Figure 8.14 compares the daily dispatch patterns in the current system and in the 2050 scenario. A first evident outcome is that nuclear energy plays a leading role in decarbonising low-temperature heat demand, while its impact on the electricity sector remains more limited, accounting for about 12% of total electricity production in 2050, with no deployment of large-scale reactors or of the NHES archetype. This behaviour is driven by the modelling assumptions: due to long construction times and lower technological maturity of SMRs, these units are only allowed to enter the system after 2034, with relatively high initial capital costs that gradually decrease over time as a result of assumed learning-by-doing effects. Large reactors are considered to be deployable earlier, but their even longer construction times and similarly high overnight costs, selected to reflect recent experiences in the European context, mean that their contribution to the early decarbonisation effort would not be cost-effective with respect to other clean electricity-generating options. Moreover, the fact that nuclear plants can be deployed only in the later years, combined with lifetimes significantly longer than the planning horizon, leads to the so-called "end-effect", in which investments delivering a large share of their benefits beyond the planning horizon are penalised in the optimisation [141].

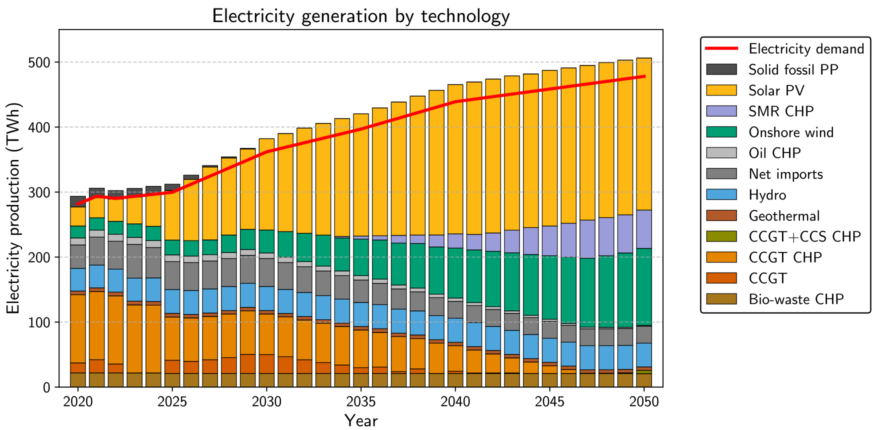

Figure 8.11: *Electricity production in Hypatia.*

As for the other energy carriers, nuclear cogeneration emerges as the primary source of low-temperature industrial heat, while heat pumps and cogeneration from CCGT+CCS account for approximately 7% and 6% of total heat supply in 2050, respectively. For hydrogen, the results show a predominance of SMGR, progressively replaced by the same technology equipped with CCS as emission caps tighten, while electrolysis does not enter the optimal solution under the assumed techno-economic conditions. The combination of limited nuclear deployment (due to timing and cost assumptions) and the higher costs of HTSE with respect to other hydrogen production technologies, particularly in the near term, implies that NHES configurations do not emerge as cost-competitive in this scenario. Notably, these results are strongly dependent on the techno-economic assumptions selected for this case study, particularly the investment costs and deployment timelines of nuclear technologies; the impact of these assumptions is further assessed in additional scenarios presented in Appendix C.

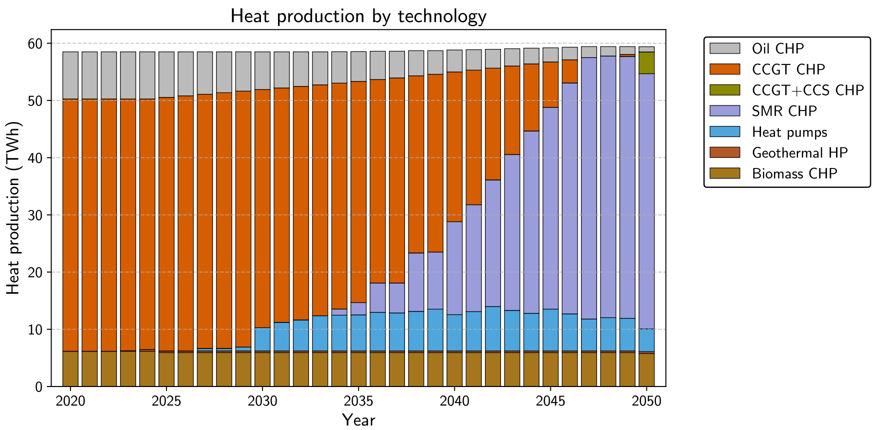

Figure 8.12: *Heat production in Hypatia.*

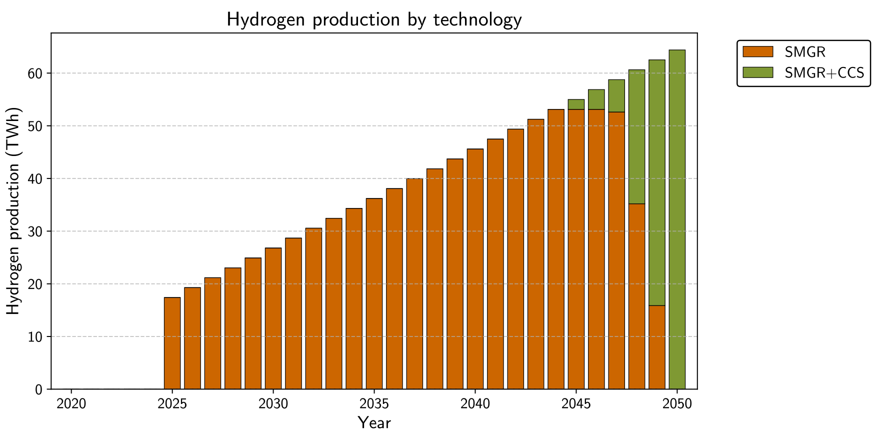

Figure 8.13: *Hydrogen production in Hypatia.*

The dispatch results in Figure 8.14 compare the operational characteristics of the optimised energy system in 2050 with those in 2025. The high penetration of solar PV (around 170 GW of installed capacity in 2050) increases the flexibility requirements on dispatchable plants and storage. In this formulation, a one-hour shut-down of nuclear units arises from the need to reproduce an average availability of 0.9 within a single representative 24-hour profile, rather than from a physically realistic operating pattern. With only one day modelled, it is not possible to represent constraints such as minimum up- and down-times, ramping limitations, etc. While this solution is mathematically feasible within the optimisation, it is not operationally realistic: nuclear units cannot shut down and restart on such short timescales, and operating the system with no dispatchable units online as reserves would be unacceptable from a grid-stability standpoint. This outcome shows that, in the absence of dedicated constraints on ramp rates, reserve requirements, start-up and shut-down behaviour, and by limiting the operation horizon to 24 hours, dynamic planning models may select dispatch strategies that are not technically feasible in practice, highlighting the need for more detailed operational models to complement them. For this reason, they should be interpreted primarily as tools to capture the long-term evolution of generation patterns and capacity mixes, rather than as providers of fully realistic dispatch strategies that can be effectively evaluated with snapshot-type models.

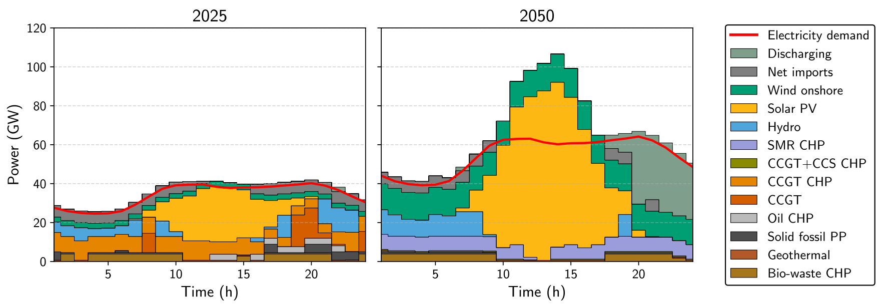

Figure 8.14: *Differences in terms of dispatch strategy in 2025 and 2050.*

In conclusion, the results of this Italian case study are not intended to analyse policy options but rather as a way to showcase the strengths and limitations of dynamic long-term energy planning models compared with static energy system models. The main strengths include the ability to capture evolving technology costs and deployment trajectories, which is particularly relevant for technologies such as VRE and nuclear power, whose investment costs and deployment times differ significantly and evolve differently over time, as also illustrated by the additional scenarios presented in Appendix C. Under the chosen assumptions, these features lead to a significant role of nuclear energy in meeting 2050 targets for the decarbonisation of heat demand. At the same time, the analysis highlighted important limitations: the 24-hour dispatch horizon does not capture weekly or seasonal patterns of demand and renewable availability, and the current formulation does not include a detailed representation of grid requirements, ramping constraints or realistic cycling limits for nuclear units. These aspects are particularly critical when assessing the integration of nuclear reactors into systems with deep VRE penetration. To provide robust and policy-relevant insights, these modelling limitations need to be taken into account, together with a comprehensive sensitivity analysis on key assumptions (e.g., nuclear costs and deployment timelines, annual deployment caps, demand trajectories and decarbonisation targets, etc.). These developments have only partially been pursued here, since a detailed investigation of these aspects would go beyond the overall scope of this work. Consequently, the present example should be viewed as an illustration of how dynamic optimisation can shape decarbonisation pathways and as a starting point for more detailed, policy-oriented analyses rather than as a representative roadmap for the Italian case.

8.3 Concluding remarks

Typically, energy system models limit the contribution of nuclear power to its role as an electricity source. This simplification is increasingly inadequate in a context where advanced nuclear technologies, including SMRs in cogeneration mode and broader NHES architectures, are being considered as contributors to decarbonisation across multiple sectors. As a result, the policy gap that drives the modelling activities presented in this chapter is therefore to be able to move beyond the traditional baseload operational paradigm in long-term energy planning and to identify the technical and economic drivers, as well as the barriers, that shape the deployment of nuclear heat utilisation in future low-carbon systems.

To address this gap, nuclear cogeneration and NHES archetypes were explicitly represented in long-term optimisation frameworks, with dedicated constraints that capture the coupling between nuclear reactors and non-electric applications. This representation was implemented in two complementary tools: a static snapshot optimisation model, FRAMES, and a dynamic planning model, Hypatia. Both codes were adapted to include SMRs in cogeneration mode and NHES and were applied to the Italian case study to explore how these technologies might contribute to cost-optimal decarbonisation pathways under different policy and techno-economic assumptions.

A comparison between the strengths and weaknesses of the two approaches, observed in the case studies presented in this work, is summarised in Table 8.1. From a spatial perspective, FRAMES adopts a multi-node structure that can represent different regions with distinct demand profiles and renewable resources, which is particularly relevant for assessing where nuclear cogeneration and NHES could be most valuable. Hypatia, as used here, is formulated as a single-node model and therefore focuses more on system-wide trajectories than on regional deployment issues. In terms of temporal resolution, FRAMES optimises over an entire single year with hourly detail, while Hypatia optimises over multiple years using a representative 24-hour profile that is scaled through time. This means FRAMES is well suited to capturing intra-year flexibility requirements and the interaction between nuclear units and variable renewables, whereas Hypatia is better tailored for questions about when investments occur and how the technology mix evolves under different policy constraints. On the flexibility side, FRAMES includes a detailed operational description with reserves, start-up and shut-down costs, ramp-rate limits and cycling constraints. This is essential to analyse how nuclear cogeneration and NHES can contribute to system flexibility in high-VRE contexts. Hypatia, conversely, does not yet provide an explicit representation of these short-term operational constraints. It can therefore indicate under which conditions NHES and SMRs are economically attractive in the long run, but it cannot on its own guarantee that the considered dispatch profiles are technically feasible without support from more detailed operational studies. From a policymaking perspective, the two tools answer different but complementary questions. FRAMES identifies the cost-optimal configuration of the energy system in a given future year, under a set of techno-economic assumptions that implicitly assume a certain level of technological and market maturity. It is therefore well suited to assessing the system value of nuclear cogeneration and NHES once these technologies are available at scale and exploring the optimal technology mix under different policy assumptions. Hypatia, instead, explores the transition from current conditions to a decarbonised system, including the timing of investments and the impact of policy measures such as emission caps and VRE incentives. This aspect also translates into different scopes for the assessment of NHES and nuclear cogeneration in long-term energy planning strategies: FRAMES is suited to answering if and how nuclear can be integrated with VREs in a given future system, accounting for realistic flexibility requirements and operating capabilities. Hypatia, in contrast, addresses factors like deployment timelines, cost trajectories, and policy measures that act as enablers or barriers for these advanced nuclear applications.

Feature	FRAMES	Hypatia
Spatial resolution	Multi-node; accounts for location-dependent demand and renewable availability	Single-node representation
Temporal resolution and horizon	Hourly resolution for the full target year	Representative 24-hour profile repeated over multiple years
Investment dynamics	Snapshot view: costs and capacities defined for a given target year	Dynamic capacity expansion with cost trajectories and deployment timelines
Flexibility modelling	Operating reserves, start-up/shut-down costs, ramping and cycling limits, etc.	Not represented
Multi-vector representation	Electricity, heat and hydrogen with hourly profile for the target year	Electricity, heat and hydrogen with evolving demand pathways
Data requirements and uncertainties	Detailed technology data and full-year time series	Long-term assumptions on demand, costs, annual deployment limits, etc.
Relevance for policymaking	Identifies cost-optimal system at a given year, assuming technologies have reached a certain maturity	Explores transition pathways and investment timing under different policy or scenario assumptions
Relevance for NHES analysis	Focus on operational advantages and impact on system integration for flexible nuclear-driven systems	Assesses deployment conditions under which NHES become part of the cost-optimal energy mix

Table 8.1: *Comparison between the key features of FRAMES and Hypatia observed in the applications considered in this work.*

The Italian case study illustrates how these methodological choices translate into different insights. The snapshot optimisation showed that when restrictive emission caps are imposed at a target year, nuclear power can reduce system costs by acting as a low-carbon dispatchable source, replacing gas-fired generation rather than renewables, and that SMRs operated in cogeneration mode can effectively support the decarbonisation of industrial heat and hydrogen. The dynamic planning analysis, on the other hand, highlighted that deployment timelines, construction times and initial cost assumptions can strongly penalise nuclear technologies, especially large-scale reactors, in the early decades of the transition, favouring earlier deployment of renewables and other low-carbon options; as a result, by 2050 nuclear plays a limited role in electricity supply, while light-water cooled SMRs emerge primarily as important contributors to the decarbonisation of low-temperature heat demand. From a policy standpoint, the preliminary analysis provided some initial insights about the role of nuclear cogeneration. First, nuclear deployment is sensitive to carbon policies, nuclear and gas cost assumptions, and explicit constraints on emissions. Policies that penalise fossil fuels and support cost reductions and risk mitigation for nuclear projects can significantly improve the competitiveness of nuclear technologies, especially when decarbonisation targets extend beyond the power sector to include heat and hydrogen. The results indicate that industrial heat and hydrogen demands, which are more difficult to electrify and decarbonise solely with VRE-based solutions, could become important drivers for the deployment of nuclear cogeneration and NHES. Moreover, the snapshot optimisation showed that nuclear plants in cogeneration mode, and in particular SMRs, can provide valuable flexibility by adjusting electrical output through modulation of heat extraction while maintaining stable core power, thereby complementing variable renewables and reducing the need for additional storage and gas-fired backup. Finally, the dynamic optimisation highlighted that if nuclear projects are introduced late in the planning horizon, combined with long construction times and high initial capital costs, they may struggle to compete with rapidly deployable low-carbon alternatives and may therefore contribute only marginally to emission reductions by 2050 under the assumed trajectories.

As a result, future modelling efforts that aim to provide policy insights on the role of nuclear cogeneration and NHES should focus on decreasing the gap between these two approaches. For snapshot models, this includes moving from purely greenfield formulations towards brownfield settings where existing capacities in fossil-fuelled plants and renewables are represented, so that the space available for future nuclear deployment reflects realistic system trajectories. For dynamic planning models, there is a need to refine the representation of grid requirements and flexible operation, within the computational limits of long-horizon optimisation, so that the potential for nuclear units to provide programmable power and grid services in high-VRE systems can be assessed more realistically.

CHAPTER 9

Policy recommendations

This chapter translates this work's results into policy recommendations for evaluating nuclear co-generation and NHES in decarbonisation strategies. It highlights that nuclear should be assessed as a multi-output, flexible provider of electricity, heat and hydrogen, using integrated safety, techno-economic and long-term planning analyses rather than representing it as an electricity-only provider. Recommendations are structured around infrastructure and markets, flexible operation, safety and licensing, system design, economics, and environmental impact, with emphasis on valuing flexibility, interfaces between the nuclear facility and the non-electric application, and using system-wide emission targets.

The outcomes of this research highlight the importance of integrating detailed techno-economic and dynamic analyses for energy policymaking in order to understand if, and under which conditions, NHES can effectively contribute to decarbonisation pathways. When nuclear cogeneration is represented consistently with safety, techno-economic and long-term planning models, it emerges as a multi-purpose, low-carbon source of electricity, heat and hydrogen that can support system flexibility and resilience, moving beyond the conventional perspective of nuclear as a baseload power generator.

Building on the insights from the different modelling approaches and case studies proposed in the methodological framework of this work, several policy-relevant recommendations can be identified, summarised in the remainder of this chapter.

9.1 Summary of policy recommendations

On the infrastructure and market characteristics

A first set of challenges concerns the characterisation of the context, e.g., in terms of infrastructure needs, market dynamics, local policies, etc., into which NHES would be deployed. In general, it is fundamental to identify a nuclear technology whose power rating and cogeneration capabilities are compatible with the size and configuration of the end-users (e.g., district heating networks and industrial hubs).

Heat and hydrogen are difficult and costly to transport over long distances, which implies that nuclear plants intended for cogeneration should be located close to their end-users or connected via dedicated infrastructure such as large-scale district heating networks, industrial steam pipelines or hydrogen networks. In this regard, existing infrastructure represents both an opportunity and a challenge. On the demand side, the potential use of existing district heating networks, and on the supply side, the possible retrofitting of current NPPs for cogeneration or NHES integration, must be carefully assessed from multiple perspectives to verify whether it represents a viable solution in terms of safety, reliability, and overall cost-effectiveness. As for market conditions, there is considerable uncertainty over the future scale of demand for relatively new commodities such as low-carbon hydrogen, as well as over how future electricity markets will value flexibility, which is increasingly important under growing VRE penetration.

This work addressed these issues by performing context evaluations and constructing realistic deployment scenarios that reflect plausible end-user sizes, geographical constraints and demand trajectories for electricity, heat and hydrogen. In particular, the analysis considered different NHES archetypes encompassing the E-SMR design, such as district heating systems, industrial hubs with both electricity and hydrogen demands, and a simplified representation of a national energy system to assess the potential integration of such systems in a broader context. As a result, the following policy recommendations emerged in the analyses:

- Policymakers should evaluate the potential deployment of NHES configurations, taking into account national and regional characteristics, for example, by identifying industrial areas where the co-location of SMRs operating in cogeneration mode could reduce transport requirements for heat and hydrogen and strengthen the coupling between energy supply and demand.
- Uncertainties in commodities demands, and thus investment risks, should be addressed by regulators and policymakers by enabling the conditions for a growing demand in low-carbon hydrogen and industrial heat. This could be achieved by introducing specific sectoral targets with the aim to reduce the reliance on fossil fuels. Moreover, electricity market reforms should ensure that support schemes for VREs are complemented by mechanisms that properly value and remunerate capacity, flexibility and system services (e.g., reserves and inertia) from dispatchable low-carbon generators, so that these units remain economically viable and high VRE penetration does not undermine grid stability.

On the flexible operation of hybridised nuclear plants

Traditional regulatory and market frameworks often implicitly treat nuclear as a pure baseload electricity source, operating at maximum power with limited flexibility. In NHES, by contrast, reactors operate in tight interaction with non-electric applications: the BOP and associated control systems must continuously allocate power between electricity production and heat supply. This introduces additional complexities in the plant design and control philosophy but also opens up new possibilities for flexible operation, particularly via load-following by cogeneration, where the electrical output is modulated by regulating heat extraction while keeping reactor power essentially constant.

In this thesis, NHES simulators and control strategies were developed to explore these new operational regimes and to quantify the technical potential and limitations of using nuclear heat to enhance flexibility. The results show that, within appropriate design limits, nuclear cogeneration can substantially increase the flexibility of the electrical output with minimal perturbations on the nuclear island, thereby allowing nuclear units to effectively respond to the increasing variability of the residual load and electricity prices. In this sense, the following policy recommendations can be formulated concerning this novel operational paradigm:

- Safety authorities and system operators should recognise the increased potential of flexible operation in integrated energy systems. In this regard, load-following by cogeneration should be treated as a viable operational strategy, but each specific reactor and NHES design must demonstrate to the safety authorities that this operating mode is technically feasible and can be carried out without compromising nuclear or industrial safety.

- Policymakers should facilitate the deployment of demonstration projects for SMRs operating in cogeneration and flexible modes, ensuring that early operational experience is collected and shared. Such demonstrators can inform the definition of new safety requirements, acceptable flexibility limits and control strategies for NHES. At the same time, it would give investors clearer evidence of the range of revenue streams available across electricity, heat, hydrogen and ancillary service markets, thereby reducing uncertainty and perceived risk for these innovative projects.

On the safety of NHES, including regulatory and licensing gaps

NHES raise specific safety and regulatory questions. The tight coupling between the nuclear power plant and cogeneration facilities introduces new types of initiating events, including those originating from the industrial process and propagating to the nuclear island, as well as potential interactions in emergency situations (e.g., loss of offsite power). Existing regulatory frameworks for nuclear installations and industrial facilities are not always aligned; overlaps and gaps may occur, for instance concerning the classification of shared systems, safety functions at the interface, or emergency preparedness. In this regard, although nuclear cogeneration projects implemented so far represent only a minor fraction of the total NPPs operating worldwide, they provide valuable operational and regulatory experience from which important lessons can be drawn when developing safety approaches and regulatory frameworks for NHES.

This thesis contributes to addressing these issues by proposing a modelling framework that can be used by safety authorities and regulators to assess the behaviour of NHES architectures under normal and accidental conditions, including the effect of coupling interfaces and new initiating events. The methodology was applied to illustrative safety-relevant scenarios, but a broader analysis of initiating events and NHES-tailored investigations would be needed for a comprehensive safety assessment. Nevertheless, the following preliminary policy recommendations emerged from the research activities:

- Legal and regulatory frameworks should clearly define the responsibilities of plant operators and regulators at the interface between nuclear and non-nuclear subsystems, including for emergency planning, accident management, and decision-making. This clarity is fundamental to avoid gaps in responsibility in the event of accidents that involve both sides of the system.
- For NHES projects, nuclear safety authorities, industrial safety regulators, environmental agencies and other involved stakeholders should be involved from the earliest stages of project development. This is essential to avoid inconsistent assessments and conflicting requirements.
- Licensing processes should explicitly address nuclear cogeneration and NHES, with clear guidance on how to treat shared systems, interfaces and initiating events originating outside the nuclear island. This may require new regulatory guides or extensions of existing ones, recognising cogeneration as an intended operational mode rather than a secondary feature.

On the design and operation of NHES

The design and operation of NHES are technically complex because of the strong electrical and thermal interconnections between subsystems. These interconnections shape both short-term dynamics (e.g., thermal delays in pipelines and storage systems, inertial effects, control interactions) and long-term configurations (e.g., changes in optimal layouts as components reach the end of life at different times). Thermal couplings are particularly challenging, as they introduce delays and non-linear effects that must be handled both in normal operation and under abnormal conditions.

In this thesis, system-level modelling tools were developed to test different NHES architectures and operational strategies, explicitly accounting for these non-linearities in the definition of short-term dispatch strategies and in techno-economic optimisation. In particular, a coupling between dynamic simulators and optimisation tools was used to ensure that cost-optimal strategies remain physically feasible, providing policymakers with a tool to understand the limitations of conventional modelling approaches and to obtain a more realistic representation of how NHES could actually be operated. These aspects translate into the following policy recommendations:

- Design studies for NHES should require system-level analyses that represent the dynamics of thermal and electrical interconnections between subsystems, rather than relying solely on steady-state performance. This allows capturing transient phenomena, delays and feedback effects that can influence both design choices and operational strategies.
- Regulatory guidelines should be developed to address the design of thermal interconnections in NHES, including minimum requirements for response times, controllability, and storage capacities to manage transients and failures without affecting nuclear safety.

On the financing and economics of NHES

The business model for conventional, electricity-only nuclear power plants is not directly applicable to multi-purpose NHES: the economic performance of these systems depends on the dynamics of the electricity, heat and other commodities markets and on the intrinsic interdependence of outputs, e.g., the loss of electrical power when heat production for cogeneration is prioritised. Moreover, assessments based purely on levelised costs are no longer sufficient, as they don't account for key factors such as environmental impact, need for flexibility, and security of supply.

This work contributed by developing techno-economic models that evaluate the competitiveness of NHES under different assumptions about costs, carbon constraints, energy prices and policy instruments. These analyses were carried out at NHES architecture-level, capturing the interdependence between commodities production and identifying cost-optimal configurations under policy-driven limits on carbon intensity. The resulting modelling tools can be used not only to compare alternative NHES designs with one another but also to assess their economic competitiveness against supply options that do not rely on nuclear energy. In this context, policy recommendations include:

- Policymakers and regulators should avoid basing decisions solely on levelised cost of production comparisons. Instead, evaluations should consider total system costs and benefits, including emissions reductions, contribution in meeting flexibility requirements, reduced exposure to fuel price volatility, etc.

- Financing frameworks and contracts should be adapted to the multi-output nature of NHES. For example, long-term Power Purchase Agreements (PPAs) for electricity could be complemented by long-term heat or hydrogen offtake contracts, with risk-sharing mechanisms between utilities and industrial end-users that could reduce the exposure associated with the high upfront investment in nuclear.

On the environmental impact of NHES

A central policy question is whether and to what extent NHES can effectively support the energy transition as low-carbon solutions.

In this work, the environmental impact was addressed by incorporating emission constraints directly into the definition of NHES architectures and into system-level techno-economic optimisations. The focus was placed on low-carbon configurations with no, or very limited, reliance on fossil fuels, and emission caps were applied across electricity, heat and hydrogen supply. This can be translated into the following policy recommendations:

- Rather than prescribing specific technologies, policymakers should set carbon intensity targets that apply to all energy carriers (electricity, heat, hydrogen, etc.). This would facilitate the deployment of all low-carbon solutions, including nuclear, VREs, and fossil-fuelled sources equipped with CCS, and allow NHES to compete based on their overall contribution to decarbonisation.

- Climate policies should explicitly address industrial heat and hydrogen use, which, as of today, are mainly satisfied by fossil-fuelled processes. Including these end-users in emission targets and carbon pricing schemes could favour solutions such as nuclear cogeneration that can provide low-carbon process heat and hydrogen at a large scale while also meeting the stringent requirements for reliability, continuity of supply and operational stability that are essential for many industrial processes. Such measures could also help unlock emissions reductions in sectors whose decarbonisation potential remains largely underexploited, particularly as the marginal abatement cost of reducing the remaining emissions in the electricity sector tends to rise sharply once the most cost-effective solutions have already been implemented.

On the role of NHES in decarbonisation strategies

Finally, the role of NHES in long-term energy planning is strongly influenced by how nuclear technologies are represented in system models. In many existing studies, nuclear is treated solely as an electricity source, and non-electric applications are not considered due to the limited operational experiences. Model outcomes are also highly dependent on assumptions about technology costs, deployment timelines, fuel prices and demand trajectories: if these assumptions are not transparent and extensively addressed through sensitivity studies, the resulting insights would provide an incomplete picture considering the underlying uncertainties.

This thesis tackled these issues by integrating nuclear cogeneration and NHES archetypes into both static and dynamic long-term optimisation frameworks, reflecting their complementary strengths. The implementation of this methodology was tested by applying the models to national decarbonisation strategies, using a country-scale case study to explore how nuclear cogeneration and NHES could, in principle, contribute to meeting long-term climate targets. However, since the primary objective of this work is not to prescribe specific policy measures for any particular national context, the policy considerations presented in this chapter are formulated at a more general level and are intended to be independent from the specific numerical outcomes of those case studies:

- Long-term planning for policy formulation should evaluate how different technology mixes affect total system costs, reliability, and flexibility, as well as cross-sector decarbonisation (e.g., through low-carbon heat and hydrogen production), rather than relying solely on the power sector or levelised cost comparisons.

- National and regional energy plans should include scenarios where nuclear is allowed to provide also commodities beyond electricity, and where its flexibility is fully represented. The case studies in this thesis show that under stringent emission constraints, nuclear cogeneration can relieve pressure on electrification, reduce reliance on fossil-fuelled backup capacity, and limit the need for extensive storage deployment, while still maintaining high levels of VRE penetration.

- Policymakers should rely on a combination of static and dynamic models. Static, high-resolution models are particularly valuable for assessing operational feasibility, flexibility, and the system value of NHES and nuclear cogeneration in specific target years. Dynamic models, in turn, are better suited to exploring policy-driven deployment pathways, cost trajectories, and the timing of investments. In all cases, key assumptions (especially on nuclear costs, deployment timelines, annual deployment caps, demand growth, etc.) should be documented and subject to sensitivity analyses.

- Dynamic frameworks highlight that nuclear technologies with long construction times and uncertain near-term costs may struggle to be deployed at scale if other low-carbon options can be introduced faster in the early years of the transition. This implies that policy decisions taken today on support for demonstration projects, licensing frameworks, and financing instruments will strongly influence whether NHES can play a meaningful role in meeting climate targets in 2050.

9.2 Concluding remarks

The policy considerations discussed in this chapter are the final building block of the methodological framework developed in this thesis. They integrate the key insights from the other domains addressed in the work: dynamic modelling of NHES, system-level techno-economic optimisation, safety and licensing considerations, and long-term energy planning. Taken together, these domains show that questions like if, when, and how nuclear cogeneration and NHES should be deployed cannot be answered solely with high-level energy scenarios or isolated component studies. They require an integrated view that simultaneously accounts for technical feasibility, operational behaviour, safety constraints, economics, and interactions between multiple energy carriers.

At the same time, it is important to stress that the policy recommendations formulated here are primarily qualitative. The core objective of this thesis was to develop and test methodological approaches and tools, not to deliver a definitive, country- or NHES-specific policy roadmap. The case studies were deliberately designed as illustrative applications of the framework, showing how different modelling tools can be coupled, how NHES archetypes can be represented, and how system-level indicators respond to changes in assumptions and policies. As emphasised throughout the work, concrete policy recommendations are strongly context-dependent: they vary with national energy mixes, industrial demands, infrastructure, regulatory constraints, and also with the specific NHES configurations under consideration (reactor type, coupling scheme, end-user characteristics, storage design, etc.). Any quantitative use of the proposed tools for policy-making would therefore require a dedicated, location- and design-specific assessment. In addition, the proposed policy recommendations should be complemented by a broader set of enabling factors that were not addressed in the proposed methodological framework but have a pivotal impact on real-world feasibility. These include, among others, the adoption of targeted measures to enable the development of robust supply chains for key

NHES components, the training of a qualified and sufficiently large workforce for the design and operation of such systems, as well as the achievement of public acceptance and stakeholder trust. Neglecting these dimensions could significantly constrain or delay deployment, even in scenarios where techno-economic and policy conditions appear favourable.

Within these limits, the chapter shows how the methodological developments of the thesis can inform policies from several perspectives. The dynamic simulators and safety-oriented tools support regulators in understanding how new operational modes, such as load-following by cogeneration, affect plant behaviour and safety margins. The techno-economic optimisation models are used to assess under which cost, policy and infrastructure conditions NHES and SMRs might become competitive and how they interact with VRE, gas and other low-carbon options at the system level. The long-term planning frameworks, in turn, highlight the importance of deployment timelines, cost trajectories, and policy measures in determining whether nuclear cogeneration emerges as a meaningful contributor to decarbonisation or remains marginal for specific climate targets. Together, these methodological elements provide a structured way for policymakers, regulators and system planners to move beyond the traditional view of nuclear as a baseload electricity provider and to evaluate innovative, integrated, multi-vector energy systems.

CHAPTER 10

Conclusions

The work presented in this thesis has focused on the investigation of Nuclear Hybrid Energy Systems (NHES), a novel application of nuclear technologies in which a nuclear reactor is tightly coupled with other energy sources, storage devices and multiple end-user segments. By design, these architectures go beyond the traditional paradigm of electricity-only nuclear plants, aiming at a tighter integration between energy supply and consumption to enhance the flexibility, efficiency and reliability of energy supply. However, the analysis and deployment of NHES involve significant technical and regulatory challenges. Their complex architectures, characterised by strong thermal and electrical interconnections between subsystems, translate into significant complications for both design and operation. In addition, nuclear reactors have traditionally been designed and licensed primarily as electricity generators, operating mostly in baseload mode under strict safety and regulatory constraints. Integrating them with non-electric applications such as district heating networks, industrial processes or hydrogen production introduces additional requirements on plant design, control systems and safety assessment. Modelling tools can play a central role in addressing these challenges. For instance, they can support the definition of new operational limits, investigate the safety implications of novel operating modes and inform long-term planning studies on the potential role of NHES in future energy systems.

In this context, the primary objective of this work has been to develop a holistic methodological framework that combines different modelling approaches and tools to provide a comprehensive description of NHES architectures and their possible role in various deployment contexts and to connect technical, economic, and policy dimensions. The framework is primarily intended as an instrument for decision-makers, providing technically grounded support for defining policies and measures that might shape deployment strategies of NHES. In particular, it can help identify technical, economic, and regulatory aspects that could represent enabling factors or barriers for their deployment in decarbonisation strategies.

From a methodological standpoint, the proposed framework for NHES analysis proved to be capable of providing a comprehensive description of NHES architectures and nuclear cogeneration across all the aforementioned domains.

The context analysis provided the boundary conditions for the various techno-economic studies, which are highly relevant for the design and operation of NHES, as well as for their deployment strategies within broader energy systems.

A key outcome of the modelling activities is the contribution to the open-source TANDEM Modelica library, which collects a wide range of dynamic models. These models can be assembled into different NHES architectures, as well as associated control schemes, by adopting a plug-and-play approach. The resulting simulators can be applied to test the dynamic response of the system under different scenarios, control and operational strategies, and to identify operational constraints relevant to flexible operation. Moreover, the simulators can be coupled with other tools, such as thermal-hydraulic system codes for safety assessments and techno-economic optimisation models, by leveraging the FMI standard.

For safety assessments, coupling the dynamic simulator of the overall NHES architecture with a detailed thermal-hydraulic system code-based model of the primary loop allows (i) the use of a detailed primary loop model based on a validated tool accepted by safety authorities, and (ii) the representation of the dynamics of the steam cycle and the non-electric application, as well as potential initiating events arising from their interconnection, among other aspects.

With regard to coupling with techno-economic optimisation codes, two approaches were investigated: a soft-linked and a hard-linked approach. In the soft-linked configuration, the optimiser runs independently, and the resulting setpoints are then tested in the dynamic simulator. In contrast, in the hard-linked configuration, the optimiser and the dynamic simulator are coupled in a co-simulation environment. The optimisation is performed over shorter rolling horizons, and the resulting setpoints are updated based on the feedback from the dynamic simulator, which reflects the actual system response.

In the methodological domain related to long-term energy planning, the analysis was extended from the architecture level to the broader energy system level. Existing modelling frameworks were expanded to include nuclear cogeneration and an NHES archetype in which an SMR module is coupled with a hydrogen production plant. Dedicated constraints were implemented to represent cogeneration behaviour, informed by the thermodynamic and dynamic modelling activities presented in the previous chapters. These additional constraints were implemented in two complementary long-term planning modelling approaches, namely a static and a dynamic one.

The developed modelling tools were applied to simulate multiple NHES configurations, focusing on the coupling of a light-water cooled SMR with thermal energy storage devices, hydrogen production systems, and district heating networks, among others. The NHES simulators were used to study the transient response of the system to changes in commodity demands, for instance, and to assess whether the system remains within acceptable operating limits during such transients. Moreover, they were employed to explore different control philosophies and operational strategies, including load-following by cogeneration.

The simulators, coupled with thermal-hydraulic system codes, were also applied to showcase the applicability of the methodology to safety assessments. In this regard, the dynamic BOP model was coupled with two different thermal-hydraulic codes, and the integrated tool was applied to investigate system responses to abrupt changes in electrical and thermal loads. These studies showed that the coupled tools can capture key physical phenomena and provide insight into the interactions between core behaviour, secondary-side dynamics, and the cogeneration interface.

Regarding the coupling between dynamic simulators and techno-economic optimisation tools, the application of these strategies demonstrated that consistent agreement can be achieved between the linear optimiser and the dynamic simulators, particularly when feedback on variables strongly affected by system dynamics is incorporated. A key outcome is that the largest discrepancies arise in thermally coupled components with strong inertial effects, such as thermal energy storage systems. Furthermore, it was observed that when the dynamic model directly controls the exchanged thermal power, agreement with the optimiser improves significantly, although this may, in turn, lead to discrepancies in the resulting electrical power profiles.

In applications of the extended energy planning frameworks, the static model highlighted how nuclear cogeneration and NHES can support grid stability by providing flexibility, taking into account operating reserve requirements and realistic unit commitment constraints. The dynamic framework, on the other hand, allowed for investment timing, technology availability and cost trajectories to be represented, providing insight into whether and under which conditions these advanced nuclear applications might become part of a cost-optimal decarbonisation pathway.

Overall, the goal of this methodological domain is to translate the technical and economic insights obtained throughout the thesis into qualitative policy recommendations. The motivation was that, while NHES are attracting growing interest, there is still a lack of dedicated modelling frameworks and real operational experience. This makes it difficult for regulators to define licensing requirements and for policymakers to evaluate the potential contribution of NHES within broader energy policies. The thesis synthesised the outcomes of the various case studies into a set of policy considerations covering infrastructure and market characteristics, operational paradigms for nuclear reactors, safety and regulatory frameworks, design and operation of NHES, economic and financing aspects, environmental implications and the role of NHES in long-term planning. These recommendations were intentionally formulated at a qualitative and technology-agnostic level so that they would not be tied to a specific NHES configuration or deployment context.

For each methodological domain, the following future developments can be identified:

- *Context analysis*: Further developments could focus on making scenario generation less dependent on modeller choices. This includes generalising the formulation of scenarios and explicitly accounting for the stochastic nature of boundary conditions such as renewable availability, commodity prices and demand profiles. This would strengthen the robustness and provide a more reliable basis for evaluating NHES architectures.

- *NHES modelling*: Additional work is required on model verification and validation, including the establishment of comprehensive regression tests to ensure robustness. Moreover, extending the library to additional reactor designs and non-electric applications would further increase both the applicability and the reliability of the framework across a broader range of NHES configurations.

- *Safety assessment*: Starting from these illustrative case studies, future developments should aim at extending the coupling to the entire NHES simulator rather than only the BOP, thereby enabling a more complete analysis of failure propagation from non-nuclear facilities. Further work is also needed to identify initiating events relevant to NHES, to support different types of safety assessments (including probabilistic safety analysis), and to use simulation outcomes to inform design choices and regulatory guidance, for example, in terms of minimum safety distances or interface design criteria, as well as the definition limits concerning flexible operation.

- *Techno-economic optimisation*: The modelling framework should be refined by updating techno-economic indicators, such as costs and emissions, based on dynamic trajectories rather than solely on optimiser profiles. In addition, quantitative metrics should be defined to measure discrepancies between optimisation and simulation, along with acceptable thresholds, so that convergence between optimisation and physics-based models can be assessed in a systematic way.

- *Long-term energy planning*: Future research could generalise the formulation to encompass multiple NHES archetypes, thereby enabling a broader exploration of possible configurations. Moreover, extensive sensitivity analyses on key assumptions (such as costs, deployment limits and policy targets) are necessary to quantify uncertainties. Finally, synergies between static and dynamic approaches should be addressed, for instance by feeding capacity expansion trajectories from dynamic models into static models for a more detailed operational assessment.

- *Policy recommendations*: Building on these methodological approach, future work should aim to develop more quantitative policy instruments, for example, by deriving operational limits, deployment targets or support mechanisms that are tailored to specific contexts where NHES deployment appears promising.

In conclusion, the methodological framework developed in this thesis has shown its ability to address several key challenges that need to be tackled to enable the deployment of NHES. By integrating context analysis, detailed thermodynamic and dynamic modelling, safety assessment tools, techno-economic optimisation and long-term planning models, the framework provides a set of tools to analyse NHES architectures from component-level behaviour up to their energy system-level role. In particular, the proposed methodology provides a structured way to link the different domains. Context analysis is needed to define modelling assumptions and boundary conditions; thermodynamic and dynamic models provide parameters and operational constraints to techno-economic and planning tools; and the outcomes of system-level studies are instrumental for safety and policy considerations. In this sense, the framework can serve as a bridge between techno-economic analyses and decision-making for NHES deployment.

Starting from this work, several directions for future development can be identified. First, the modelling tools should be extended to cover different nuclear technologies, including advanced reactor concepts and alternative cogeneration schemes. Moreover, the framework could be applied to real industrial systems and concrete deployment proposals, for example, by analysing specific industrial clusters or district heating systems. This would require closer collaboration with utilities, industrial partners and regulators and would provide a more realistic basis for quantitative policymaking. Lastly, the tools proposed in this methodology could be refined by integrating indicators to directly test policy instruments and measures (e.g., market reforms, incentives for low-carbon heat and hydrogen, regulatory constraints for cogeneration, etc.) to have a direct quantitative estimation of the added value that NHES deployment could have in different contexts.

Overall, the thesis has shown that, under appropriate conditions, flexible NHES may provide a meaningful contribution to decarbonisation across electricity, heat and hydrogen supply, while also enhancing system flexibility. More importantly, it has provided a methodological foundation to study these systems, adopting an interdisciplinary approach, and to inform future technical, regulatory and policy developments aimed at assessing whether, and under which conditions, they could play a role in future low-carbon energy systems.

APPENDIX A

AMR steam cycle analysis

This appendix provides an additional example of how the methodological approach adopted for NHES design described in Section 5.1 can be extended to AMRs. In particular, the example focuses on the lead-cooled fast reactor technology, coupled to an HTSE-based hydrogen production plant. In the following sections, the selected case study is described, with particular emphasis on the steam cycle, which is modelled using the Ebsilon Professional tool. The model is then used to assess potential design solutions for the coupled LFR-HTSE system.

A.1 Case study

The reference reactor technology considered in this study is ALFRED (Advanced Lead-cooled Fast Reactor European Demonstrator), a lead-cooled fast reactor with a thermal power of 300 MW_{th} [142]. The reactor is assumed to be coupled to the hydrogen production plant through an intermediate heat transfer loop adopting thermal oil as sensible medium.

The example focuses on the steam cycle and on the intermediate loop, which together constitute the interface between the NPP and the HTSE modules. Consequently, the thermal power delivered by the nuclear reactor and the process fluid conditions entering the HTSE module steam generator are treated as boundary conditions for the BOP model. These boundary conditions are defined according to the parameters summarized in Table A.1.

Parameter	Value	Unit
Nominal thermal power	300	MW_{th}
Steam outlet temperature	450	°C
Steam pressure	185	bar
Feedwater inlet temperature	335	°C
Process fluid inlet temperature	95	°C
Process fluid outlet temperature	150	°C

Table A.1: *ALFRED steam cycle boundary conditions [142, 143].*

A.2 Steam cycle modelling

The steam cycle architecture modelled using Ebsilon Professional is illustrated in Figure A.1. The reference configuration is inspired by the architecture developed within the framework of the Euratom-funded ANSELMUS project [143].

In this work, the operating conditions of the steam cycle are first optimised for electricity-only operation, envisaging the transition to cogeneration mode under off-design conditions. The optimisation procedure focuses on the selection of the pressure levels along the turbine stages and the feedwater line with the objective of maximising the gross electrical power output. This optimisation results in a net electrical output exceeding 120 MW_{el}, corresponding to an overall power conversion efficiency of approximately 40%.

When steam extractions are introduced to supply thermal power for cogeneration purposes, the plant operation inherently departs from the nominal design point and enters off-design conditions. In the present analysis, a set of key variables that are critical for the integrity and proper functioning of specific components is maintained at their design values even during off-design operation. These controlled variables include the steam generator outlet and inlet conditions, as well as the pressure levels in the reheating line and in the deaerator. In addition, the thermal power delivered to the intermediate heat transfer loop is regulated by adjusting the opening of the cogeneration valve, with the target to maintain the intermediate loop's hot leg temperature at its nominal value. All remaining design and operating parameters are allowed to vary consistently with the off-design behaviour of each steam cycle components. This includes, for instance, the turbine performance, which is modelled using the Stodola cone law for the turbine stages, as well as the degradation of isentropic efficiencies associated with off-design operation.

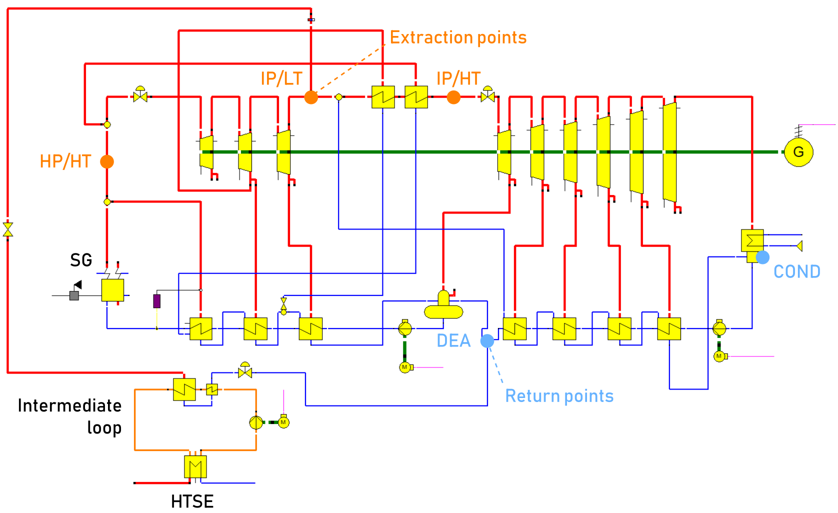

Figure A.1: *Steam cycle architecture with illustrative extraction and return points.*

A.3 AMR-driven NHES sizing

Several steam extraction and return points, included in the schematic in Figure A.1, were considered in the analysis in order to assess their impact on the performance of the integrated nuclear-driven hydrogen production system. Steam extraction was first investigated at the steam generator outlet, where the steam is available at high pressure and high temperature (HP/HT), namely 183 bar and 450°C. In addition, two extraction points along the reheating line at intermediate pressure (IP) were identified, corresponding to low- and high-temperature conditions upstream and downstream of the reheaters, respectively. These points are characterised by an extraction pressure of 37 bar, with steam temperatures of 246°C upstream of the reheaters and 353°C at the reheater outlet. Concerning the return points, two alternatives were analysed, namely the condenser (COND) and the deaerator (DEA), operating at pressures of 0.09 bar and 18 bar, respectively. In both cases, the return flow was assumed to be subcooled to a temperature of 200°C. The main results of the analysis are summarised in

Figure A.2 and Table A.2.

The system sizing is defined by assuming a hydrogen production module capable of absorbing the entire power output of the NPP, both in terms of electrical and thermal power. In Figure A.2, the operational points of the HTSE system are represented by the black dashed line, which is constructed starting from the values obtained from the dynamic model providing the specific thermal and electrical power consumptions [97]. However, the latter was increased to 39 kWh_{el}/kg_{H_2} in order to account for the power requirements associated with hydrogen compression and other auxiliary systems.

The sizing of the hydrogen production plant is determined by the intersection between the HTSE operational profile and the operational profiles of the steam cycle. As for the latter, different combinations of steam extraction and return points result in different power loss factors, which in turn directly affect the amount of power available to drive the hydrogen production process.

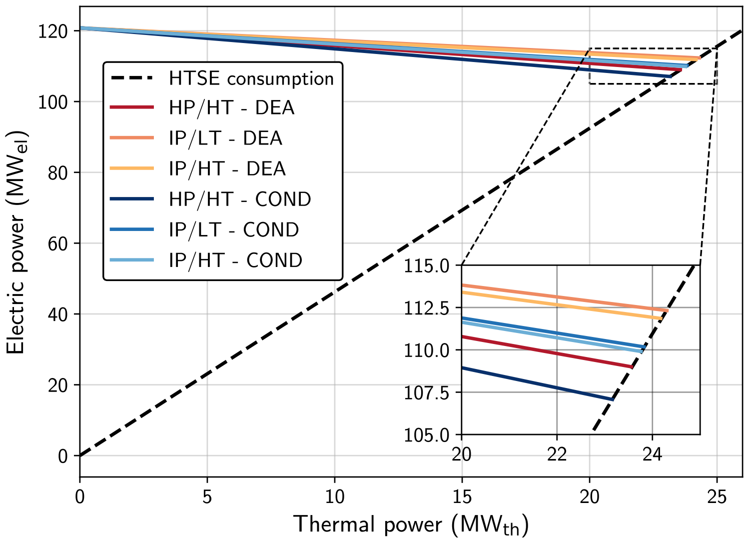

Figure A.2: *Comparison of sizing options for the integrated system.*

As discussed in Section 5.1, steam extraction at the HP/HT conditions leads to the highest conversion losses, despite the relatively lower extracted steam flow rate. For the IP extraction points, improved performance is achieved when steam is extracted at lower temperatures, as this reduces the reheating requirements along the turbine line, thereby slightly increasing the steam flow rate through the high-pressure turbine. By contrast, extracting steam downstream of the reheaters does not reduce the reheating demand. As for the return points, exploiting the residual enthalpy of the extracted flow by returning it to the deaerator reduces the low-pressure feedwater preheating requirements. This configuration therefore results in better overall performance compared to the solutions in which the return flow is directed to the condenser.

	HP/HT DEA	IP/LT DEA	IP/HT DEA	HP/HT COND	IP/LT COND	IP/HT COND
Power loss factor (-)	0.499	0.349	0.372	0.592	0.448	0.459
Extracted steam flow (kg/s)	10.86	12.95	11.03	10.98	13.07	11.16
HTSE electric demand (MW_{el})	109.0	112.3	111.8	107.1	110.1	109.9
HTSE heat demand (MW_{th})	23.58	24.29	24.18	23.16	23.82	23.76
H_2 production capacity (t/h)	2.79	2.88	2.87	2.75	2.82	2.81

Table A.2: *Potential design points of the LFR-HTSE coupled system for different steam extraction and return points [84].*

A.4 Concluding remarks

The best performance in terms of steam cycle efficiency (i.e., hydrogen production capacity) of the integrated system is achieved by the IP/LT-DEA configuration. While similar steam temperatures could also be obtained with a light-water reactor, this would require steam extraction further upstream in the turbine line, leading to a significantly higher degradation of the power conversion efficiency compared to the steam cycle of the AMR considered in this example. Furthermore, although the power loss factor varies significantly among the different configurations, the absolute impact on the power conversion efficiency remains limited because of the relatively low thermal energy demand of the HTSE process when compared to its electrical energy requirements.

APPENDIX B

Dynamic models of key NHES components

This appendix provides a description of the structure and underlying assumptions of the dynamic models developed in the Modelica language. Most of the presented models are available in the open-source TANDEM Modelica library, whose public repository[1] also includes dedicated documentation for each module, encompassing models and test cases descriptions [144]. Additional details and practical applications of the models are available in the publications referenced at the beginning of Chapter 5.

B.1 Nuclear Steam Supply System

The NSSS represents the central subsystem of nuclear-driven hybrid energy systems. In this work, the NSSS associated with the reference reactor technology, namely the E-SMR, has been modelled.

Within the TANDEM Modelica library, multiple versions of the NSSS model are available. These variants differ with respect to the level of modelling detail (such as the inclusion of bypass flows) as well as the type of the interface with the secondary system, which may be implemented either through fluid or thermal power exchange with the BOP, and supporting Modelica libraries. For instance, Figure B.1 shows the detailed configura-

[1] https://gitlab.pam-retd.fr/tandem/tandem

tion featuring a fluid-based interface with the steam cycle modelled with components stemming from the ThermoPower library. To support model verification, a benchmark comparison with respect to an independently developed NSSS model of the same reactor design, implemented using components from a different Modelica library, is included in the library documentation [144].

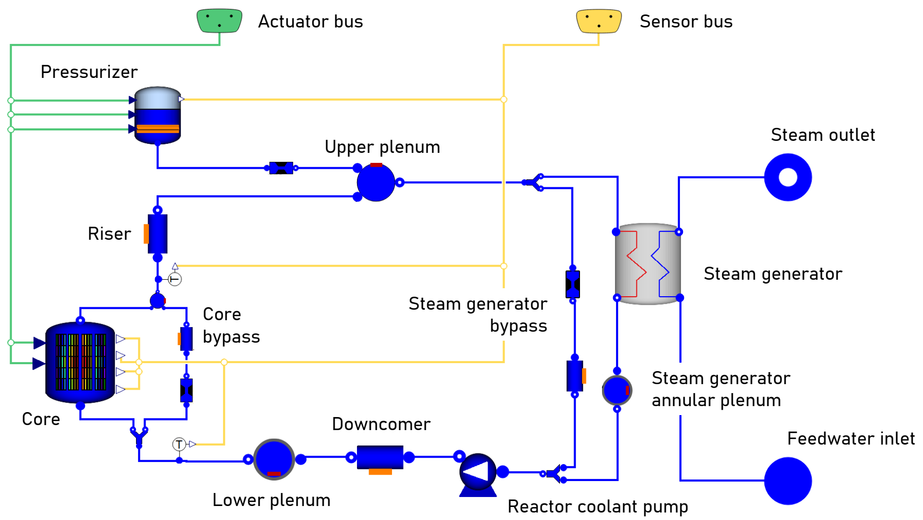

Figure B.1: *Dynamic model of the NSSS [87].*

The core, pressurizer, and steam generator models have been developed specifically for the proposed NSSS model. By contrast, the other components used to represent the primary coolant circuit, such as the riser, upper and lower plena, and downcomer, are drawn from the *Water* package of the ThermoPower library.

- The reactor core model is composed of three coupled submodels: the thermal-hydraulic representation of the coolant flow through the core channels, the neutronics module, and the fuel thermal model. The thermal-hydraulic submodel is derived from the ThermoPower `Flow1DFV` component and has been adapted to provide the coolant average temperature to the neutronics block. Moreover, heat exchange between the fuel rods and the coolant is represented through a dedicated thermal connector linking the coolant model to the fuel model. Neutronic behaviour is described using point kinetics equations, accounting for both externally imposed reactivity insertions, e.g., through control rods regulation, and reactivity feedback mechanisms. These feedbacks include xenon poisoning effects, modelled via the decay chains of iodine-135 and xenon-135, as well as temperature-dependent reactivity contributions arising from changes in fuel and moderator temperatures. The neutronics module receives the relevant temperature signals from the thermal-hydraulic and fuel models and computes the time evolution of the fission power, which is subsequently supplied to the fuel thermal model as a internal heat source. The thermal behaviour of the fuel rods is modelled through a user-defined axial and radial discretization of the fuel pellets, complemented by energy balances for the gap and cladding regions. The fuel domain is subdivided into control volumes of equal size, and its transient response is governed by the time-dependent Fourier heat equation, including the fission heat source term.

- Two alternative modelling approaches have been investigated for the pressurizer: a non-equilibrium formulation and a simplified equilibrium model [145]. The non-equilibrium approach distinguishes between liquid and vapour phases by discretizing the pressurizer volume in the axial direction, thereby enabling a more detailed description of the temperature distribution and of the fluid dynamics in the pressurizer. The equilibrium model, by contrast, assumes a homogeneous mixture within the pressurizer volume. While the former offers increased physical detail, it also entails higher computational cost. In the context of NHES modelling, where overall model complexity and computational efficiency are critical, the equilibrium pressurizer model was selected, as it has been shown to adequately reproduce the relevant pressure dynamics while maintaining acceptable simulation performance [145].

- The steam generator component is based exclusively on component stemming from the ThermoPower library. The primary and secondary sides are represented by the `Flow1DFV` and `Flow1DFV2ph` components, respectively, while the thermal inertia and resistance of the metal structure are captured through the `MetalWallFV` model. Counter-current flow conditions are represented using the `CounterCurrentFV` component. The parameters required by these models are derived from the specific steam generator design under investigation. For the E-SMR design, a Printed Circuit Heat Exchanger (PCHE) encompassing rectangular channels, is adopted. Geometric characteristics such as channel dimensions are therefore used to calculate the hydraulic diameter, flow area, and other thermal-hydraulic parameters required by the aforementioned models.

The NSSS is equipped with a dedicated controller addressing both pressure regulation and core average temperature control. Pressure control is implemented through the actuation of pressurizer heaters, sprayers, and the relief valve. Electrical heaters are activated when the system pressure falls below a predefined threshold, whereas sprayers are activated when the pressure exceeds allowable limits. In addition, a constant average core temperature control program is implemented by means of external reactivity insertions driven by control rods displacement. A PID controller is used to regulate reactivity to maintain the average core temperature at its prescribed setpoint, with the option to include a dead zone to prevent excessive control activity.

B.2 Balance Of Plant

The TANDEM Modelica library includes three alternative BOP models, which differ in terms of underlying modelling assumptions and supporting libraries [144]. Out of these options, the BOP configuration proposed in the frame of this work has been developed to include dynamic and inertial aspects of key BOP components, such as heat exchangers.

The overall architecture and nominal operating conditions of the BOP are derived from a thermodynamic analysis performed with the CYCLOP optimisation tool [146] in the framework of the TANDEM project. Subsequently, the steady-state thermodynamic results obtained from this analysis are used to define the main design parameters of the various submodels of the BOP simulator, such as the turbines' Stodola coefficient. Compared to conventional NPPs, the modelled BOP is based on a simplified layout. In particular, the reheating stage and the low- and high-pressure feedwater preheating sections are represented by equivalent heat exchangers rather than by the typical train of preheaters. This modelling choice allows capturing the thermal behaviour of the cycle while maintaining an acceptable level of computational complexity.

A key feature of this BOP model, shown in Figure B.2, is the inclusion of multiple control valves. These valves enable the implementation and testing of different control philosophies, including conventional load-following as well as load-following by cogeneration. Moreover, to facilitate the coupling with non-electric applications, the BOP model encompasses several steam extraction and return points. These interfaces allow simulating heat extractions at different thermodynamic conditions without modifying the BOP layout in each case study, which proved to be instrumental to build different NHES simulators through a plug-and-play approach. When these interfaces are not required, such as in electricity-only studies, the corresponding connectors can be closed using plug components that enforce zero mass flow. The available extraction points include high-temperature steam at the steam generator outlet, intermediate-temperature steam at the high-pressure turbine outlet, low-temperature steam at the low-pressure turbine, and liquid water extracted from the feedwater tank. Return points are provided at the low-pressure turbine inlet (to be used, for instance, in electrical peaking configurations), the steam generator inlet, the feedwater tank, and the condenser.

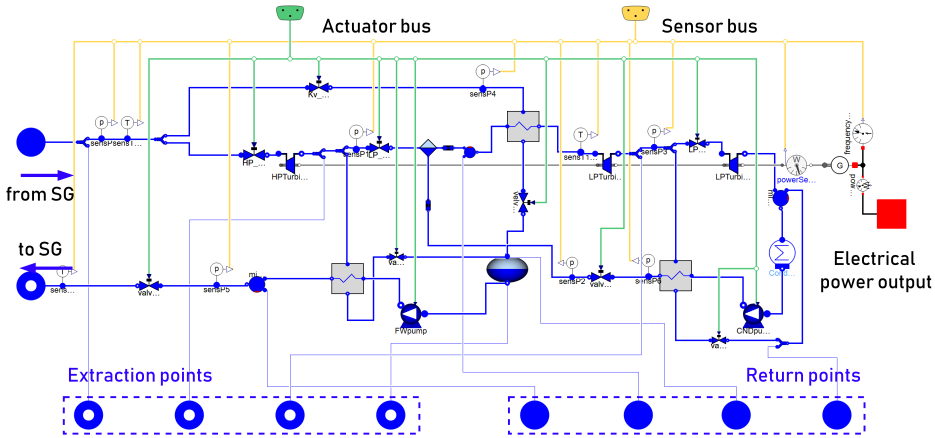

Figure B.2: *Dynamic model of the BOP (adapted from [87]).*

The BOP subcomponents are implemented using models from the ThermoPower library. In particular:

- Control valves for vapour and liquid flows are represented using `ValveVap` and `ValveLiq` components, respectively.
- Turbine stages are modelled using an extended version of the `SteamTurbineStodola` component, including additional loss mechanisms such as wetness losses, accounted for through Baumann's rule, as well as flow-related losses [87].
- Both the high- and low-pressure pumps are modelled using the ThermoPower `Pump` component, which employs a quadratic characteristic curve to describe pump behaviour.
- The condenser (`PrescribedPressureCondenser`) is represented as an ideal component, enforcing saturated liquid conditions

at its outlet, with a prescribed condensation pressure.

- Similarly, the moisture separator is treated as ideal, assuming complete separation of the liquid phase from the two-phase mixture [87].

- The feedwater tank is modelled through dynamic mass and energy balance equations and supports a user-defined number of inlets and outlets, allowing it to accommodate multiple extraction and return streams in a flexible manner.

- Electrical power generation is represented using the ThermoPower `Generator` component, which converts mechanical shaft power into electrical power while accounting for the rotational inertia of the turbo-generator.

- The reheater and the high- and low-pressure feedwater preheaters are modelled as dynamic, one-dimensional shell-and-tube heat exchangers. These components are sized on the basis of the nominal operating conditions obtained from the CYCLOP analysis. Both the shell and tube sides are discretized using a finite volume approach, relying on the `Flow1DFV2ph` and `Flow1DFV` components for two-phase and single-phase flows, respectively, adopting the same model structure described for the NSSS steam generator.

As far as the control system is concerned, the BOP model is designed to be compatible with a wide range of control strategies. This is enabled by the implementation of dedicated actuator and sensor buses, which allow users to implement customized control schemes without modifying the model structure. In its current version, the model includes a predefined set of process and control variables, summarized in Table B.1.

Process variables	Control variables
Steam generator inlet temperature	Steam generator admission valve
Steam generator outlet temperature	HP-turbine admission valve
Steam generator pressure	HP-turbine outlet control valve
HP-turbine outlet extraction pressure	Reheater hot side flow control valve
LP-turbine inlet temperature	LP-turbine extraction valve
LP-turbine outlet extraction pressure	HP-pump rotational speed
Feedwater tank pressure	LP-pump rotational speed
BOP power output	HP-preheater control valve

Table B.1: *Predefined actuator and sensor variables in the BOP model [144].*

B.3 Thermal Energy Storage System

The TES technology selected in the frame of the TANDEM project is based on a two-tank sensible heat storage concept. In this configuration, thermal energy is stored and released by a heat transfer fluid (e.g., thermal oil) flowing between a cold tank and a hot tank. During the charging phase, thermal power is transferred from an external heat source, in this case the steam extracted from the BOP, to the sensible loop through a dedicated charging heat exchanger. As a result, the heat transfer fluid is pumped from the cold tank to the hot tank, where it accumulates at an higher temperature. The charging power level directly influences the mass flow rate circulating between the tanks, with higher charging power translating into to higher flow rates. In the discharging process, the thermal energy is delivered to the end-user by pumping the hot fluid through a discharging heat exchanger before it returns to the cold tank.

The sensible loop architecture, illustrated in Figure B.3, is composed of two `Tank` components representing the hot and cold storage devices, two pump models derived from the ThermoPower `Pump` component, and control valves used to regulate the flow between the tanks according to the charging and discharging requirements.

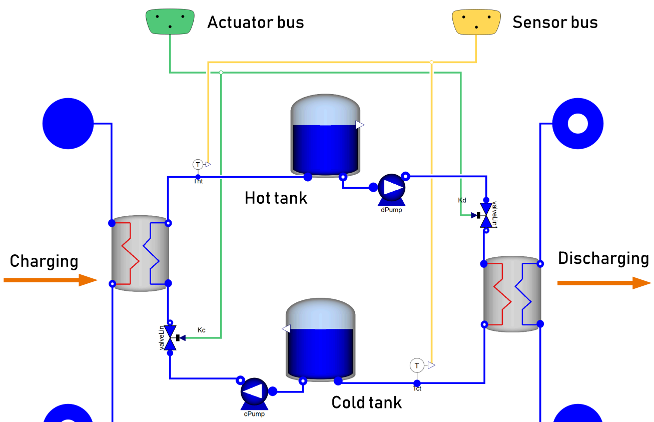

Figure B.3: *Dynamic model of the TES.*

Charging and discharging power levels are determined by the heat transfer occurring within the respective heat exchangers. Within the TANDEM library, multiple versions of the sensible loop model are available. These differ in the level of detail used to represent the heat exchangers: the user may select between simplified, quasi-static heat exchangers and fully dynamic models implemented using ThermoPower components, similarly to those described in the previous sections. The `Tank` component is specifically designed to represent the accumulation of sensible heat. Its formulation is based on dynamic mass and energy balance equations. The pressure at the liquid free surface is assumed to be constant and is specified by the user, as in the presence of a cover gas. Within the liquid volume, the pressure distribution follows Stevino's law. The model also allows for the inclusion of thermal losses to the environment. These are computed by accounting for convective heat transfer between the tank wall and both the internal fluid and the surrounding ambient, as well as conductive heat transfer through the tank wall material. When required, heat losses can be neglected through a dedicated flag.

From a control standpoint, the flow from one tank to the other is regulated through dedicated control valves. These can be actuated according to the evolution of different process variables, such as the sensible fluid temperatures at the outlet of the heat exchangers [99]. As a result, the heat transfer medium flow is regulated according to the power transferred in the heat exchanger, and the temperature levels in the two tanks are maintained close to their nominal value.

B.4 District Heating Network

The key models used to simulate the dynamic behaviour of a district heating network, available in the TANDEM library and shown in Figure B.4, are the transmission and distribution networks. The former comprises supply and return pipelines used to provide heating water from the power plant to one or more distribution networks. The latter represents the pipeline ramification in urban areas, intended to supply the heat to the final end-users. Moreover, it allows accounting for the potential contribution of auxiliary heat sources, such as conventional combined heat and power units or heat pumps, and for heat exchanges with other distribution networks that are not included in the simulator's boundaries.

All classes included in this package are constructed using components from the ThermoPower library. The distribution network model captures the inertia associated with the pipelines typically found in urban areas where heat consumers are located. The structure of this model is illustrated on the left-hand side of Figure B.4. A key element is the `Inertia` component, shown in the center of the figure, which represents a closed water volume exchanging mass with the transmission line through two Ther-

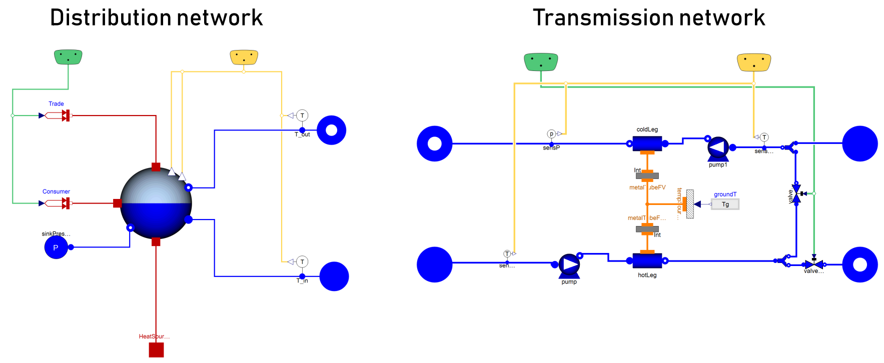

Figure B.4: *Dynamic model of the district heating components.*

moPower `Flange` connectors. A third flange provides a connection to a pressure sink, which enforces the nominal operating pressure within the distribution network. Thermal interactions within the distribution volume are represented through three `HeatPort` connectors from the Modelica Standard Library. These ports are linked to ideal heat source components (`PrescribedHeatFlow`) that convert control system signals into exchanged thermal power. Each connector corresponds to a distinct heat flow contribution, including the heat demand of the connected users and the potential thermal exchange with other distribution networks. An additional `HeatPort` connector is used to simulate the thermal power supplied by external heat sources. The signal bus collects key process variables, such as supply and return temperatures, which can be exploited in the definition of different control schemes. In the transmission network model, pumping stations are modelled using the ThermoPower `Pump` component, with two pumps placed at the inlets of the hot and cold legs of the transmission line. The pipelines themselves are described using a one-dimensional finite-volume formulation, implemented through the `Flow1DFV` component. Thermal coupling between the fluid and the pipe walls is accounted for using `MetalTubeFV` components, which allows simulating the thermal resistance and heat capacity of the metallic structure. Heat losses to the environment are represented by connecting the external wall interface to a `TempSource1DFV` component that prescribes the outer temperature.

To facilitate the control of the thermal power delivered to the distribution network, two control valves are included in the transmission line. These valves regulate the flow either toward the distribution network or through a bypass connecting the hot and cold legs. For instance, an increase in the thermal power supplied to the users can be achieved by opening the admission valve to the distribution network while simultaneously closing the bypass valve. In this regard, a control scheme could be implemented to regulate the opening of these valves in response to temperature deviations in the distribution network, which might result from mismatches in heat supply and demand.

B.5 High-Temperature Steam Electrolysis

Despite the availability of an HTSE model in TANDEM library based on the ThermoSysPro supporting library, an additional HTSE model has been developed in this work [97]. The primary motivation for this effort is to facilitate a more detailed investigation of the dynamic behaviour and operational limits of the electrolyser under flexible operating conditions. The resulting dynamic model of the HTSE module is shown in Figure B.5. The core element of the HTSE system is the Solid Oxide Electrolyser (SOE), which is represented through a detailed, physics-based model. Each electrolyser cell is described by the Positive electrode-Electrolyte-Negative electrode (PEN) structure, connected to the anode and cathode gas channels and the interconnect. The latter provides mechanical support to the cell and, in the model, it is thermally connected to the other electrolyser components. Between the gas channels and the cell's solid structure, mass transfer also needs to be considered, as it arises from the water-splitting reaction. In particular, steam flowing through the cathode channel is reduced to hydrogen within the PEN, with the produced hydrogen joining the cathode gas stream and the oxygen ions migrating through the electrolyte toward the anode.

The SOE model adopts a one-dimensional spatial discretisation. The PEN, interconnect, and both anode and cathode channels are subdivided into a user-defined number of control volumes, within which mass and energy balance equations are implemented. This approach enables the representation of axial gradients in temperature, composition, and reaction rates along the cell. The PEN model incorporates an electrochemical description of the steam electrolysis process, linking hydrogen production, electrical power consumption, and operating temperature [97]. The interconnect is modelled as a solid plate separating the anode and cathode channels from adjacent cells. Its thermal behaviour is governed by convective heat transfer with the gas streams flowing in the channels and by radiative heat exchange with the PEN. The anode and cathode gas channels are implemented by adapting the ThermoPower `Gas.Flow1DFV` component. Each channel model solves one-dimensional mass, energy, and mo-

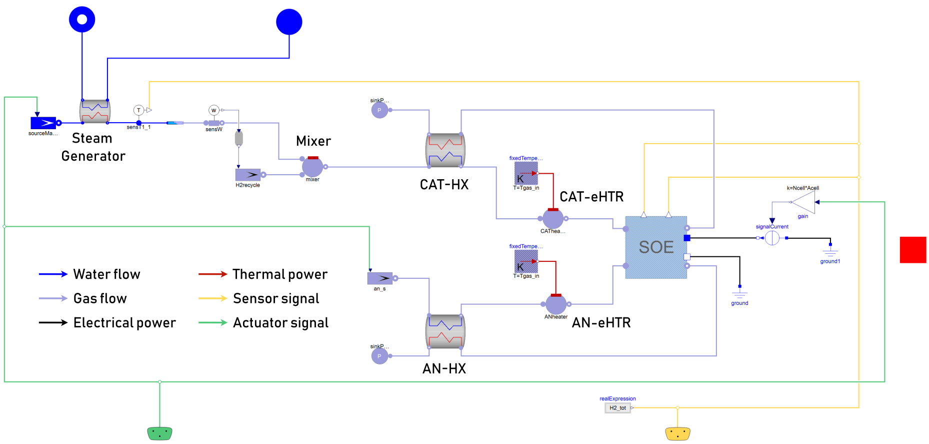

Figure B.5: *Dynamic model of the HTSE module.*

mentum balance equations using a finite-volume formulation. The model in the ThermoPower library has been modified to include additional mass exchange terms representing the interaction with the electrochemical cell. For the cathode channel, the mass balance accounts for the consumption of steam and the generation of hydrogen associated with the electrolysis reaction, whereas the anode channel model incorporates the influx of oxygen produced within the PEN. A set of recuperative heat exchangers is deployed to raise the flow temperatures close to the required cell's inlet conditions. These components follow the same modelling approach adopted for other heat exchangers in the TANDEM library and are built using ThermoPower elements. The reference design considered for these recuperators is based on the PCHE configuration. Additional components are included to complete the representation of the HTSE plant layout. A shell-and-tube heat exchanger is employed, adopting the same model described in the previous sections. Electrical heaters are represented using a simplified approach: the outlet temperature of the heated gas stream is imposed through the `PrescribedTemperature` component from the Modelica Standard Library, while the gas distribution is handled using the ThermoPower `Gas.Header` model. As a result, the thermal power required to achieve the prescribed temperature is supplied implicitly by the model. Other auxiliary elements, such as flow sources, sinks, and fluid mixers from the ThermoPower library, are used to complement the HTSE simulator.

The modelling approach adopted for the control system is analogous to the TANDEM library models, with a set of actuator and sensor signals that aim to facilitate the implementation of different control strategies. These signals provide access to key thermal, electrical, and mass flow variables and are summarized in Table B.2.

Process variables	Control variables
Steam utilisation factor	Process water flow
Anode outlet oxygen concentration	Air flow
Electrolyser inlet temperatures	Electrical heaters power
Steam generator outlet temperature	Oil flow
Hydrogen production rate	Current density

Table B.2: *Predefined actuator and sensor variables in the HTSE model [97].*

APPENDIX C

Italian decarbonisation scenarios - Additional results

C.1 Static energy system model

C.1.1 Main techno-economic parameters

Key techno-economic parameters, together with the corresponding references, are summarised in Tables C.1 and C.2. In this regard, it is worth highlighting that hydropower and pumped hydro storage are not included in these tables, as their installed capacities are assumed to remain fixed at current levels and hydropower's energy production is constrained consistently with historical trends. Sensitivity analyses were carried out on key techno-economic parameters, with particular emphasis on those governing the decarbonisation of heat demand, since in the baseline solution this sector is the main driver for SMR deployment. For instance, the impact of natural gas price (42 \$/MWh in the baseline, consistent with the 2023 average in Italy [147]), selected SMR governing parameters, heat pump investment costs, etc. on the solution was explored. Overall, in the FRAMES model, all cost data reported in the techno-economic tables are annualised, taking into account the assumed technology lifetimes and a discount rate of 5%.

Technology	Item	Value	Unit	Ref.
		Variable renewables		
PV	CAPEX	683	$/kW	
	Fixed OPEX	12.8	$/kW/yr	[148]
	Lifetime	25	yr	
Onshore wind	CAPEX	1115	$/kW	
	Fixed OPEX	25.2	$/kW/yr	[148]
	Lifetime	25	yr	
Offshore wind	CAPEX	3132	$/kW	
	Fixed OPEX	70	$/kW/yr	[148]
	Lifetime	25	yr	
		Nuclear technologies		
Nuclear (large)	CAPEX	8000	$/kW	
	Fixed OPEX	106	$/kW/yr	[149, 150]
	Variable OPEX	9.33[1]	$/MWh	
	Lifetime	60	yr	
Nuclear (small)	CAPEX	8800[2]	$/kW	
	Fixed OPEX	106	$/kW/yr	[149, 150]
	Variable OPEX	9.33	$/MWh	
	Lifetime	60	yr	
		Fossil-fuelled plants		
CCGT	CAPEX	1000	$/kW	
	Fixed OPEX	25	$/kW/yr	
	Variable OPEX	2	$/MWh	[151, 152]
	Efficiency	63	%	
	Lifetime	30	yr	
	Power loss factor	0.21	–	
CCGT + CCS	CAPEX	2400	$/kW	
	Fixed OPEX	60	$/kW/yr	
	Variable OPEX	4	$/MWh	
	Efficiency	55	%	[151, 152]
	CO_2 capture efficiency	88.5	%	
	Lifetime	30	yr	
	Power loss factor	0.21	–	

Table C.1: *Techno-economic parameters for the power generation technologies (projections to 2050).*

Storage technologies				
Battery (4 hours)[3]	CAPEX	1036	\$/kW	
	Fixed OPEX	22.5	\$/kW/yr	
	Power/energy ratio	0.25	–	[148, 153]
	Efficiency	0.86	%	
	Lifetime	15	yr	
Battery (2 hours)	CAPEX	709	\$/kW	
	Fixed OPEX	14.62	\$/kW/yr	
	Power/energy ratio	0.5	–	[148, 153]
	Efficiency	0.86	%	
	Lifetime	15	yr	
Hydrogen production				
SMGR	CAPEX	711	$\$/kW_{H_2}$	
	Fixed OPEX	32.7	$\$/kW_{H_2}/yr$	[154, 155]
	Lifetime	25	yr	
SMGR + CCS	CAPEX	1230	$\$/kW_{H_2}$	
	Fixed OPEX	43.5	$\$/kW_{H_2}/yr$	[154, 155]
	Lifetime	25	yr	
LTE	CAPEX	450	$\$/kW_{el}$	
	Electrical power input	50	kW_{el}/kg_{H_2}	[39, 155]
	Lifetime	25	yr	
HTSE	CAPEX	500	$\$/kW_{el}$	
	Electrical power input	36	kW_{el}/kg_{H_2}	[39, 155]
	Thermal power input	10	kW_{th}/kg_{H_2}	
	Lifetime	25	yr	
Other parameters				
Heat pumps	CAPEX	840	\$/kW	
	COP	3	–	[156]
	Lifetime	20	yr	
Transmission	Import capacity (R1/R2)	10.9/2.3	GW	
	Import cost	100[4]	\$/MWh	
	Efficiency	94	%	[140, 157]
	R1-R2 capacity	7.6/8.3	GW	

Table C.2: *Techno-economic parameters of storage technologies, hydrogen production methods, and other system components (projections to 2050).*

[1] Includes fuel and waste management cost.

[2] A cost multiplier of 1.1, subject to a sensitivity analysis, was assumed with respect to conventional reactor technologies.

C.1.2 Additional sensitivity analyses

As aforementioned, additional sensitivity analyses were conducted to assess how key parameters affect the optimal system configuration. In a first set of sensitivity analyses, different values of nuclear investment costs were combined with progressively more stringent carbon intensity caps. The results, shown in Figure C.1, indicate that nuclear CAPEX has a strong influence on the optimal solution. In the absence of emission constraints and for high nuclear costs ($\geq$ 8000 \$/kW), nuclear power is not competitive with other technologies and is therefore not deployed. Conversely, when nuclear costs are low and stringent emission caps are imposed, nuclear deployment increases substantially, reaching a maximum of about 30 GW_{el} of installed capacity (including large reactors, SMRs and NHES) in the most extreme case. Under these conditions, SMRs in cogeneration mode supply about 80% of the low-temperature heat demand, while NHES configurations provide about 50% of hydrogen demand through HTSE. In contrast, the deployment of LTE is less sensitive to these parameters, with its share varying between 22% and 36%. This behaviour is linked to the fact that hydrogen demand in Southern Italy is always met by LTE, regardless of nuclear costs or emission caps, due to the high renewable potential in that region. As a result, LTE acts as a flexible electrical load that reduces curtailment. Depending on the combination of nuclear costs and emission constraints, hydrogen production from fossil fuels is shifted either towards HTSE (for low nuclear CAPEX, which favours NHES deployment) or towards LTE.

A second set of sensitivity analyses was designed to compare two competing low-carbon options for decarbonising the heat sector, which emerged as the main driver for SMR deployment in the baseline case. Specifically, the optimal technology mix was evaluated for different heat pump and SMR cost assumptions, under a fixed emission intensity cap of 50 g/kWh. The results, reported in Figure C.2, show that the optimal configuration is almost independent from variations in heat pump costs. For low SMR costs, heat supply is dominated by nuclear cogeneration, with heat pumps contributing to maximal 14% of total heat demand. When SMR costs are high, no SMRs are built and heat pumps expand significantly; in the extreme case of low heat pump CAPEX and high SMR costs, heat pumps supply around 50% of the heat demand with approximately 6.6 GW_{th} of installed capacity. Hydrogen production follows a similar behaviour to that observed in the

[3] The analysis is limited to technologies of this duration as they are commonly considered for grid-scale in planning studies [158].

[4] Assumed.

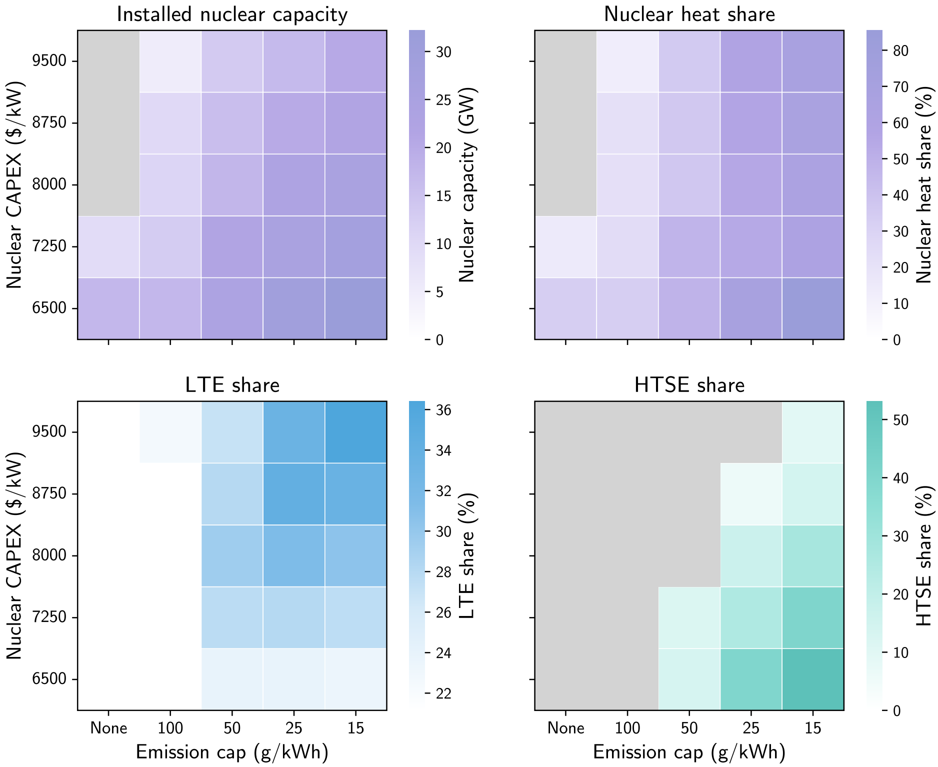

Figure C.1: *Sensitivity analysis on nuclear CAPEX and emission cap.*

previous sensitivity analysis: low SMR costs favour HTSE-based hydrogen and thus the deployment of NHES, whereas high SMR costs shift hydrogen production towards LTE. It is worth noting that, with an SMR cost multiplier of 1.1 with respect to large reactors, NHES configurations are not cost-competitive with alternative hydrogen production methods, while SMRs operating in CHP mode remain part of the optimal mix and still provide a substantial share of heat demand.

C.2 Dynamic energy system model

In this example, long-term planning strategies are explored by comparing optimal transition pathways under different deployment conditions for conventional large nuclear reactors and SMRs. In addition to the baseline configuration, two further scenarios are defined: an optimistic and a pessimistic nuclear case, intended to reflect differing levels of policy support and supply chain readiness for nuclear new-build. The scenarios differ in terms of

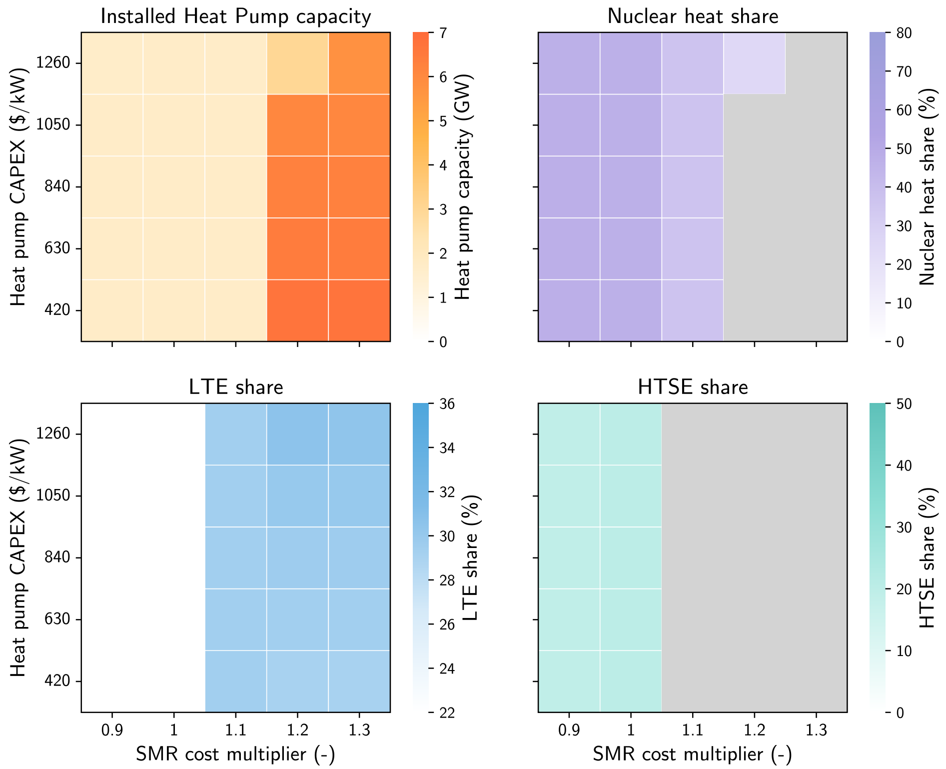

Figure C.2: *Sensitivity analysis on SMR cost multiplier and heat pump cost.*

the investment costs assumed for nuclear installations and the time required for their deployment, as summarised in Table C.3. In all cases, the CAPEX at the year of technology availability is taken to be the same for SMRs and for conventional large reactors. Beyond the technology availability year, technology costs follow learning-by-doing trajectories derived from the literature for both large reactors [159] and SMRs [160], so that SMRs tend to remain more expensive than large units because their cost reductions begin later in the optimisation horizon. The effective deployment time is determined by the assumed construction period and by the technology availability year: once a technology becomes available, its first contribution to the system can only appear after the corresponding construction time has elapsed. These scenarios are therefore intended primarily to illustrate how assumptions on nuclear costs and deployment schedules influence the optimisation outcomes, while a comprehensive assessment would require a systematic exploration of all other key parameters, including technology-specific deployment caps, cost trajectories for competing options and demand pathways.

Parameter		Optimistic nuclear	Baseline	Pessimistic nuclear
Nuclear CAPEX ($/kW)		7600	9500	11400
Time of construction	Large-Nuc	7	9	12
	SMR	3	4	7
Technology availability	Large-Nuc	2025	2025	2025
	SMR	2027	2030	2035

Table C.3: *Assumptions for the nuclear technology scenarios.*

C.2.1 Additional scenarios

The resulting production mix and installed capacities for the three scenarios are shown in Figure C.3 and Table C.4. Overall, nuclear deployment is driven mainly by the need to decarbonise low-temperature heat demand so that only SMRs operating in cogeneration mode are included in the optimal solution. Under the assumptions of the baseline and optimistic nuclear cases, SMR cogeneration is more cost-competitive than alternative low-carbon options and thus becomes the primary source of industrial heat. In the pessimistic nuclear scenario, by contrast, SMRs are never deployed; heat demand is instead decarbonised primarily through electrification with heat pumps and by cogeneration from CCGTs equipped with CCS. Hydrogen production remains dominated by fossil-fuelled technologies in all cases, except in the pessimistic nuclear scenario where the large expansion of renewable capacity and associated surplus electricity makes low-temperature electrolysis attractive. Moreover, under the assumed cost trajectories for SMRs and HTSE, the NHES configuration combining these technologies is not competitive with the other technologies in any of the scenarios. This suggests that dedicated policy measures may be required to reduce fossil fuel dependence in hydrogen supply, not only for climate reasons but also from an energy security perspective, since the relatively low cost of these hydrogen production methods constitutes a significant barrier to the deployment of NHES architectures and, in general, of electricity-driven techniques.

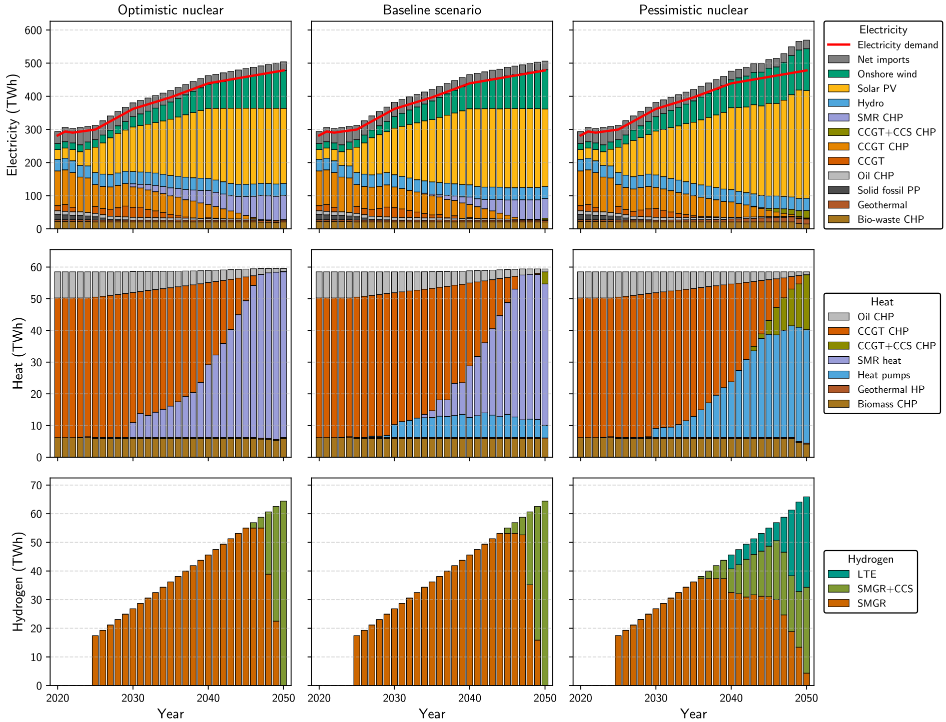

Figure C.3: *Impact of nuclear costs and deployment assumptions on optimal decarbonisation strategies.*

Parameter	Unit	Optimistic nuclear	Baseline	Pessimistic nuclear
Nuclear capacity	GW_{el}	11.22	9.18	0
Solar capacity	GW_{el}	166	172	240
Wind capacity	GW_{el}	68	70	75
Storage capacity	GWh_{el}	192	203	233
Heat pumps capacity	GW_{th}	0	1.08	6.64
Electrolyser capacity	GW_{H_2}	0	0	12.77
Fossil fuel dependence – Electricity	%	0.3	1.3	4.5
Fossil fuel dependence – Heat	%	1.7	7.9	31.2
Fossil fuel dependence – Hydrogen	%	100	100	52.1

Table C.4: *Summary of system configuration and fossil fuel dependence across scenarios.*

Bibliography

[1] Masoud Shirazi. Assessing energy trilemma-related policies: The world's large energy user evidence. *Energy Policy*, 167:113082, 2022.

[2] The European Parliament and the Council of the European Union. Directive on the promotion of the use of energy from renewable sources (RED). Official Journal of the European Union L 328/82, 2018.

[3] Eurostat. Gross production of electricity and derived heat from non-combustible fuels by type of plant and operator, 2025. DOI: https://doi.org/10.2908/NRG_IND_PEHNF.

[4] International Energy Agency. World Energy Statistics and Balances, 2025.

[5] European Commission. The European Green Deal. Communication from the Commission COM(2019) 640, European Commission, Brussels, 2019. Adopted 11 December 2019.

[6] European Parliament and Council of the European Union. Regulation (EU) 2018/1999 on the governance of the energy union and climate action. Official Journal of the European Union L 328/1, Dec 2018.

[7] European Commission. REPowerEU Plan. Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions COM(2022) 230 final, European Commission, Brussels, May 2022.

[8] Ember. European Electricity Review 2025, 2025. Annual Report.

[9] Njabulo Mlilo, Jason Brown, and Tony Ahfock. Impact of intermittent renewable energy generation penetration on the power system networks - A review. *Technology and Economics of Smart Grids and Sustainable Energy*, 6(1):25, December 2021.

[10] Sajeeb Saha, Muhammad I. Saleem, and Tushar K. Roy. Impact of high penetration of renewable energy sources on grid frequency behaviour. *International Journal of Electrical Power & Energy Systems*, 145:108701, February 2023.

[11] Lina Reichenberg, Tommi Ekholm, and Trine Boomsma. Revenue and risk of variable renewable electricity investment: The cannibalization effect under high market penetration. *Energy*, 284:128419, December 2023.

[12] Jesse D. Jenkins, Zhi Zhou, Roberto Ponciroli, Richard B. Vilim, Francesco Ganda, Fernando De Sisternes, and Audun Botterud. The benefits of nuclear flexibility in power system operations with renewable energy. *Applied Energy*, 222:872–884, July 2018.

[13] Nuclear Energy Agency. *The Costs of Decarbonisation: System Costs with High Shares of Nuclear and Renewables*. OECD NEA, January 2019.

[14] International Energy Agency. The Challenge of Reaching Zero Emissions in Heavy Industry, 2023.

[15] International Energy Agency. Achieving Net Zero Heavy Industry Sectors in G7 Members, 2022.

[16] *Policy support for heating and cooling decarbonisation – Roadmap*. Publications Office of the European Union, 2022.

[17] Tobias Fleiter et al. Heat Roadmap Europe D3.1: Profile of heating and cooling demand in 2015, 2017.

[18] European Commission. Powering a climate-neutral economy: An EU Strategy for Energy System Integration. Communication from the Commission COM(2020) 299, European Commission, Brussels, Jul 2020.

[19] Sylvain Lansou et al. ELSMOR - towards European Licensing of Small Modular Reactors: Methodology recommendations for light-water small modular reactors safety assessment. *Open Research Europe*, 3:158, September 2023.

[20] Ville Tulkki, Marton Szogradi, Fares Alblouwy, Rebekka Komu, and Riku Tuominen. Using open SMR datasets E-SMR and LDR lite for research and training purposes. In *Proceedings of the International Conference on Small Modular Reactors and their Applications*, Vienna, Austria, 2024. IAEA.

[21] Nuclear Energy Agency and International Energy Agency. *Projected Costs of Generating Electricity 2010*. OECD Publishing, Paris, 2010.

[22] *Non-baseload Operation in Nuclear Power Plants: Load Following and Frequency Control Modes of Flexible Operation*. Number NP-T-3.23 in IAEA Nuclear Energy Series. International Atomic Energy Agency, Vienna, 2018.

[23] Roberto Ponciroli, Y. Wang, Z. Zhou, A. Botterud, Jesse Jenkins, Richard B. Vilim, and Francesco Ganda. Profitability Evaluation of Load-Following Nuclear Units with Physics-Induced Operational Constraints. *Nuclear Technology*, 200(3):189–207, December 2017.

[24] Réseau de Transport d'Électricité (RTE). RTE Open Data Portal. https://data.rte-france.com, 2025.

[25] Nuclear Energy Agency. *Technical and Economic Aspects of Load Following with Nuclear Power Plants*. Nuclear Development. OECD, December 2021.

[26] Generation IV International Forum. GIF website. https://www.gen-4.org/, 2026. Accessed: 2026-03-02.

[27] *Guidance on Nuclear Energy Cogeneration*. Number NP-T-1.17 in IAEA Nuclear Energy Series. International Atomic Energy Agency, Vienna, 2019.

[28] Nuclear Energy Agency. *Small Modular Reactors: Challenges and Opportunities*. OECD Publishing, Paris, 2021.

[29] *Approaches for Assessing the Economic Competitiveness of Small and Medium Sized Reactors*. Number NP-T-3.7 in IAEA Nuclear Energy Series. International Atomic Energy Agency, Vienna, 2013.

[30] Ahmed Amin E. Abdelhameed, Xuan Ha Nguyen, Jeongik Lee, and Yonghee Kim. Feasibility of passive autonomous frequency control operation in a Soluble-Boron-Free small PWR. *Annals of Nuclear Energy*, 116:319–333, June 2018.

[31] Adeel Sabir, Dennis Michaelson, and Jin Jiang. Load-Frequency Control With Multimodule Small Modular Reactor Configuration: Modeling and Dynamic Analysis. *IEEE Transactions on Nuclear Science*, 68(7):1367–1380, July 2021.

[32] Charly Boudot, Jean-Baptiste Droin, Pierre Sciora, Yvon Besanger, Bruno Robisson, and Anne-Laure Mazauric. Small Modular Reactor-based solutions to enhance grid reliability: impact of modularization of large power plants on frequency stability. *EPJ Nuclear Sciences & Technologies*, 8:16, 2022.

[33] Václav Novotný, Junyung Kim, and Tyler Westover. Heat augmentation for process heating using light water nuclear reactors. *Energy Reports*, 13:1416–1440, 2025.

[34] NuScale Small Modular Reactor Integration for Hydrogen and Ammonia Production. Technical Report WP-178373, NuScale Power LLC, Office of Technology, 2025.

[35] Jun Soo Yoo, Carlos Eduardo Estrada Perez, Byung-Hee Choi, Vivek Utgikar, Chaithanya Balumuru, and Quinn Dodge. Investigation of heat pump technologies with potential for ultra-high temperature applications. Technical report, Idaho National Laboratory (INL), Idaho Falls, ID (United States), 09 2023.

[36] *Opportunities for Cogeneration with Nuclear Energy*. Number NR-T-4.1 in IAEA Nuclear Energy Series. International Atomic Energy Agency, Vienna, 2017.

[37] International Atomic Energy Agency. New Technologies for Seawater Desalination Using Nuclear Energy. Technical Report IAEA-TECDOC-1753, International Atomic Energy Agency (IAEA), Vienna, 2015.

[38] International Atomic Energy Agency. Nuclear Cogeneration for Climate Change Mitigation and Sustainable Development Goals. Technical Report IAEA-TECDOC-2056, International Atomic Energy Agency (IAEA), Vienna, 2024.

[39] Clean Hydrogen Partnership. Clean Hydrogen Joint Undertaking SRIA Key Performance Indicators (KPIs). Technical report, February 2022. Strategic Research and Innovation Agenda 2021-2027, Annex: KPIs.

[40] International Atomic Energy Agency. Developing a Roadmap for the Commercial Deployment of Nuclear Hydrogen Production. Technical Report NR-G-4.1, International Atomic Energy Agency (IAEA), Vienna, 2025.

[41] International Atomic Energy Agency. *Nuclear Power Reactors in the World*. International Atomic Energy Agency (IAEA), Vienna, 2021.

[42] International Atomic Energy Agency. Hydrogen Production with Operating Nuclear Power Plants. Technical report, International Atomic Energy Agency (IAEA), Vienna, 2023.

[43] Venizelos Venizelou and Andreas Poullikkas. Comprehensive overview of recent research and industrial advancements in nuclear hydrogen production. *Energies*, 17(12), 2024.

[44] Generation IV International Forum. Non-Electric and Cogeneration Applications of Nuclear Energy Working Group. https://www.gen-4.org/gif-activities/working-groups/non-electric-and-cogeneration-applications-nuclear-energy-working, 2024.

[45] International Atomic Energy Agency. Coordinated research project: Role of nuclear cogeneration within the context of sustainable development (i35008). https://www.iaea.org/projects/crp/i35008, 2023.

[46] IEA Hydrogen TCP. Task 44: Hydrogen from nuclear energy. https://www.ieahydrogen.org/task/task-44-hydrogen-from-nuclear-energy/, 2023.

[47] Sustainable Nuclear Energy Technology Platform (SNETP). European Nuclear Cogeneration Industrial Initiative (NC2I). https://snetp.eu/nc2i/, 2011.

[48] Grzegorz Wrochna, Michael A. Fütterer, and Dominique Hittner. Nuclear cogeneration with high temperature reactors. *EPJ Nuclear Sci. Technol.*, 6:31, 2020.

[49] Carmen Angulo et al. EUROPAIRS: The European project on coupling of High Temperature Reactors with industrial processes. *Nuclear Engineering and Design*, 251:30–37, 2012. 5th International Topical Meeting on High Temperature Reactor Technology (HTR 2010).

[50] Steven Knol, Michael A. Fütterer, Ferry Roelofs, Norbert Kohtz, Mathias Laurie, Derek Buckthorpe, and Walter Scheuermann. The ARCHER project (Advanced High-Temperature Reactors for Cogeneration of Heat and Electricity R&D). *Nuclear Engineering and Design*, 306:208–214, 2016. 7th International Topical Meeting on High Temperature Reactor Technology (HTR 2014).

[51] Michael A. Fütterer, Raimondas Pabarcius, Sebastian Hübner, Ludwik Pieńkowski, Wojtek Brudek, Piotr Darnowski, Michał Pawluczyk, Błażej Chmielarz, and Martin Šilhan. Nuclear process heat application options: Highlights from the European GEMINI+ project. *Nuclear Engineering and Design*, 396:111879, 2022.

[52] Canet Serin, Martin Glückler, Michel Pasquet, and Claire Vaglio-Gaudard. Outcomes of three Euratom projects on cogeneration of electricity, heat and hydrogen. *EPJ Nuclear Sci. Technol.*, 11:12, 2025.

[53] Eduard Diaz-Pescador, Marco Viebach, Wolfgang Lippmann, Florian Gamaleja, Antonio Hurtado, Oleksandr Mazurok, Cecilia Herrero-Moriana, Martin Glückler, Stéphanie Crevon, Pavla Lukášová, Michael A. Fütterer, Mathijs Hijlkema, Gabriele Firpo, Jessica Johnson, and Clemens Heitsch. The Euratom NPHyCo project: Conceptualization, technical work plan and current status. *Progress in Nuclear Energy*, 185:105731, 2025.

[54] Nuclear Energy Agency. *The NEA Small Modular Reactor Dashboard: Third Edition*. OECD Publishing, Paris, 2025.

[55] Cedric Terrier, Alexandra Menges, and Jean-François Dhedin. NUWARD SMR Cogeneration Services. In *Proceedings of the International Conference on Small Modular Reactors and their Applications*, Vienna, Austria, 2024. IAEA.

[56] *Nuclear-Renewable Hybrid Energy Systems*. Number NR-T-1.24 in IAEA Nuclear Energy Series. International Atomic Energy Agency, Vienna, 2023.

[57] Giorgio Locatelli, Andrea Fiordaliso, Sara Boarin, and Marco E. Ricotti. Cogeneration: An option to facilitate load following in Small Modular Reactors. *Progress in Nuclear Energy*, 97:153–161, May 2017.

[58] Shannon M. Bragg-Sitton, Richard Boardman, Cristian Rabiti, and James O'Brien. Reimagining future energy systems: Overview of the US program to maximize energy utilization via integrated nuclear-renewable energy systems. *International Journal of Energy Research*, 44(10):8156–8169, August 2020.

[59] Claire Vaglio-Gaudard, M. T. Dominguez Bautista, Michele Frignani, Michael Fütterer, Andrei Goicea, Eric Hanus, Thorsten Hollands, Calogera Lombardo, Stefano Lorenzi, Joachim Miss, Gabriel Pavel, Andrea Pucciarelli, Marco Ricotti, Alain Ruby, Christophe Schneidesch, Stanislav Sholomitsky, Giorgio Simonini, Ville Tulkki, Konsta Värri, Lubor Zezula, and Nina Wessberg. The TANDEM Euratom project: Context, objectives and workplan. *Nuclear Engineering and Technology*, 2023.

[60] Douglas J. Arent, Shannon M. Bragg-Sitton, David C. Miller, Thomas J. Tarka, Jill A. Engel-Cox, Richard D. Boardman, Peter C. Balash, Mark F. Ruth, Jordan Cox, and David J. Garfield. Multi-input, Multi-output Hybrid Energy Systems. *Joule*, 5(1):47–58, January 2021.

[61] Mark F. Ruth, Owen R. Zinaman, Mark Antkowiak, Richard D. Boardman, Robert S. Cherry, and Morgan D. Bazilian. Nuclear-renewable hybrid energy systems: Opportunities, interconnections, and needs. *Energy Conversion and Management*, 78:684–694, February 2014.

[62] Rami S. El-Emam, Alina Constantin, Rupsha Bhattacharyya, Haris Ishaq, and Marco E. Ricotti. Nuclear and renewables in multipurpose integrated energy systems: A critical review. *Renewable and Sustainable Energy Reviews*, 192:114157, March 2024.

[63] Jong Suk Kim, Richard D. Boardman, and Shannon M. Bragg-Sitton. Dynamic performance analysis of a high-temperature steam electrolysis plant integrated within nuclear-renewable hybrid energy systems. *Applied Energy*, 228:2090–2110, 2018.

[64] Roshni Anna Jacob and Jie Zhang. Modeling and control of nuclear-renewable integrated energy systems: Dynamic system model for green electricity and hydrogen production. *Journal of Renewable and Sustainable Energy*, 15(4):046302, 08 2023.

[65] Humberto E. Garcia, Jun Chen, Jong S. Kim, Richard B. Vilim, William R. Binder, Shannon M. Bragg Sitton, Richard D. Boardman, Michael G. McKellar, and Christiaan J. J. Paredis. Dynamic performance analysis of two regional Nuclear Hybrid Energy Systems. *Energy*, 107:234–258, 2016.

[66] Jun Chen, Humberto E. Garcia, Jong Suk Kim, and Shannon M. Bragg-Sitton. Operations Optimization of Nuclear Hybrid Energy Systems. *Nuclear Technology*, 195(2):143–156, August 2016.

[67] Aaron Epiney, Christian Rabiti, Paul Talbot, and Andrea Alfonsi. Economic analysis of a nuclear hybrid energy system in a stochastic environment including wind turbines in an electricity grid. *Applied Energy*, 260:114227, February 2020.

[68] John Bistline, Shannon Bragg-Sitton, Wesley Cole, Brent Dixon, Erich Eschmann, Jonathan Ho, Augustine Kwon, Laura Martin, Caitlin Murphy, Christopher Namovicz, and Andrew Sowder. Modeling nuclear energy's future role in decarbonized energy systems. *iScience*, 26(2):105952, 2023.

[69] Juan Matthews, William Bodel, and Gregg Butler. Nuclear cogeneration to support a net-zero, high-renewable electricity grid. *Energies*, 17(24), 2024.

[70] Athanasios Ioannis Arvanitidis, Vivek Agarwal, and Miltiadis Alamaniotis. Nuclear-driven integrated energy systems: A state-of-the-art review. *Energies*, 16(11), 2023.

[71] Mark Ruth, Dylan Cutler, Francisco Flores-Espino, and Greg Stark. The Economic Potential of Nuclear-Renewable Hybrid Energy Systems Producing Hydrogen. Technical Report NREL/TP-6A50-66764, 1351061, April 2017.

[72] John Bistline, Andrew Sowder, Shannon Bragg-Sitton, Brent Dixon, Wesley Cole, Jonathan Ho, Caitlin Murphy, Augustine Kwon, Laura Martin, Christopher Namovicz, et al. Nuclear Energy in Long-Term System Models: A Multi-Model Perspective. Technical report, National Renewable Energy Laboratory (NREL), Golden, CO (United States), 04 2022.

[73] Bryan S. Palmintier and Mort D. Webster. Impact of operational flexibility on electricity generation planning with renewable and carbon targets. *IEEE Transactions on Sustainable Energy*, 7(2):672–684, 2016.

[74] Nuclear Energy Agency. *The Costs of Decarbonisation: System Costs with High Shares of Nuclear and Renewables*. OECD, January 2019.

[75] ENTSO-E. Study on Power and Heat Sectors: Interactions and Synergies. Technical report, European Network of Transmission System Operators for Electricity (ENTSO-E), Brussels, 2023.

[76] Urban Persson, Bernd Möller, and Sven Werner. Heat Roadmap Europe: Identifying strategic heat synergy regions. *Energy Policy*, 74:663–681, 2014.

[77] Jussi-Pekka Ikonen, Tomi J. Lindroos, and Pauli Hiltunen. Feasibility of small modular reactors for decarbonizing district heating systems: a case study of the Helsinki metropolitan area. *Nuclear Engineering and Design*, 442:114262, 2025.

[78] International Energy Agency. Global Hydrogen Review 2024. Technical report, International Energy Agency (IEA), Paris, 2024.

[79] European Hydrogen Observatory. The European Hydrogen Market Landscape. Technical report, Clean Hydrogen Joint Undertaking, Brussels, 2025.

[80] European Hydrogen Observatory. The European hydrogen policy landscape. Technical report, Clean Hydrogen Joint Undertaking, Brussels, 2025.

[81] Ministero dell'Ambiente e della Sicurezza Energetica. Strategia Nazionale Idrogeno. Technical report, Ministero dell'Ambiente e della Sicurezza Energetica (MASE), Rome, Italy, 2024.

[82] Kurt G. Vedros, Robby Christian, and Courtney Mariko Yang Hui Otani. Probabilistic Risk Assessment of a Light-Water Reactor Coupled with a High-Temperature Electrolysis Hydrogen Production Plant. Technical report, Idaho National Laboratory (INL), Idaho Falls, ID (United States), 11 2022.

[83] Iqony System Technologies GmbH. EBSILON®Professional: Innovative software for thermodynamic cycle processes.

[84] Luca Coita, Stefano Marini, Guido C. Masotti, Stefano Lorenzi, and Paolo Colbertaldo. Thermal coupling and interface design of a hybrid nuclear system for hydrogen production. In *Proceedings of PHYSOR 2026*, Turin, Italy, 2026.

[85] Guido C. Masotti, Stefano Lorenzi, and Marco E. Ricotti. Small Modular Reactors and cogeneration: impact of steam extraction on power conversion performance. In *Proceedings of the International Conference on Small Modular Reactors and their Applications*, Vienna, Austria, 2024. IAEA.

[86] Dragan Urošević, Dušan Gvozdenac, and Vojin Grković. Calculation of the power loss coefficient of steam turbine as a part of the cogeneration plant. *Energy*, 59:642–651, 2013.

[87] Guido C. Masotti, Stefano Lorenzi, and Marco E. Ricotti. Dynamic modelling and control of a Small Modular Reactor in load following by cogeneration mode. *Nuclear Engineering and Design*, 445:114518, December 2025.

[88] Sven E. Mattsson and Hilding Elmqvist. Modelica - An International Effort to Design the Next Generation Modeling Language. *IFAC Proceedings Volumes*, 30(4):151–155, 1997. 7th IFAC Symposium on Computer Aided Control Systems Design (CACSD '97), Gent, Belgium, 28-30 April.

[89] Antonio Cammi, Marco E. Ricotti, Francesco Casella, and Francesco Schiavo. New Modelling Strategy for IRIS Dynamic Response Simulation. In *Proceedings of the 5th International Conference on Nuclear Option in Countries with Small and Medium Electricity Grids*, pages 1–15, Dubrovnik, Croatia, 2004.

[90] Guido C. Masotti, Antonio Cammi, Stefano Lorenzi, and Marco E. Ricotti. Modeling and simulation of nuclear hybrid energy systems architectures. *Energy Conversion and Management*, 298:117684, December 2023.

[91] Guido C. Masotti, Nicolas Alpy, Augustin Baudoux, Youssef Hammadi, Dorian Jouret, Stefano Lorenzi, Sylvain Mathonnière, Giorgio Simonini, and Claire Vaglio-Gaudard. Modelling Nuclear Hybrid Energy Systems: Objectives, architecture, and applications of the TANDEM Modelica library. *Sustainable Energy Technologies and Assessments*, 84:104695, 2025.

[92] Francesco Casella and Alberto Leva. Modelling of thermo-hydraulic power generation processes using Modelica. *Mathematical and Computer Modelling of Dynamical Systems*, 12(1):19–33, February 2006.

[93] Baligh El Hefni and Daniel Bouskela. *Modeling and Simulation of Thermal Power Plants with ThermoSysPro: A Theoretical Introduction and a Practical Guide*. Springer International Publishing, 01 2019.

[94] Michael Wetter, Wangda Zuo, Thierry S. Nouidui, and Xiufeng Pang. Modelica Buildings library. *Journal of Building Performance Simulation*, 7(4):253–270, 2014.

[95] Casto Martos Nogales and Guido C. Masotti. TANDEM D2.5 - Hybrid system simulator description. Technical report, TANDEM Project, 2024.

[96] Guido C. Masotti, Paolo Colbertaldo, Marco Ficili, Stefano Lorenzi, Riccardo Mauri, and Marco E. Ricotti. Dynamic modelling of a nuclear hybrid energy system with hydrogen production via high temperature steam electrolysis. In *Proceedings of the International Conference on Small Modular Reactors and their Applications*, Vienna, Austria, 2024. IAEA.

[97] Guido C. Masotti, Paolo Colbertaldo, Marco Ficili, Stefano Lorenzi, and Marco E. Ricotti. Dynamic modelling and control of a nuclear-driven high-temperature steam electrolysis plant for hydrogen and electricity production. Submitted to *Energy Conversion and Management*, 2026.

[98] Guido C. Masotti, Paolo Colbertaldo, Marco Ficili, Stefano Lorenzi, and Marco E. Ricotti. Flexible operation of a Small Modular Reactor for combined hydrogen and electricity production. In *Proceedings of PHYSOR 2026*, Turin, Italy, 2026.

[99] Guido C. Masotti, Stefano Lorenzi, Marco E. Ricotti, Nicolas Alpy, Huynh D. Nguyen, David Haubensack, and Giorgio Simonini. Simulation of Flexible Small Modular Reactor Operation with a Thermal Energy Storage System. In *Proceedings of the International Conference on Small Modular Reactors and their Applications*, Vienna, Austria, 2024. IAEA.

[100] Guido C. Masotti, David Haubensack, Jussi-Pekka Ikonen, Tomi J. Lindroos, Stefano Lorenzi, Gabriel L. Pavel, and Marco E. Ricotti. Dynamic modelling and optimisation of a Small Modular Reactor for electricity production and district heating in the Helsinki region. In *Proceedings of the 2024 International Congress on Advances in Nuclear Power Plants (ICAPP)*, Las Vegas, NV, United States, 2024.

[101] Daniel S. Wendt, Lane Todd Knighton, and Richard D. Boardman. High temperature steam electrolysis process performance and cost estimates. Technical report, Idaho National Laboratory (INL), Idaho Falls, ID (United States), 03 2022.

[102] Konrad Motylinski, Michal Wierzbicki, Jakub Kupecki, and Stanislaw Jagielski. Investigation of off-design characteristics of solid oxide electrolyser (soe) operating in endothermic conditions. *Renewable Energy*, 170:277–285, 2021.

[103] Zhikuan Zhu, William T. Gibbons, Nicholas J. Kane, and Michael C. Tucker. Dynamic testing of solid oxide electrolysis cells standard operating procedure. *Frontiers in Energy Research*, Volume 13 - 2025, 2025.

[104] Patricia Aguiar, Claire S. Adjiman, and Nigel P. Brandon. Anode-supported intermediate-temperature direct internal reforming solid oxide fuel cell: Ii. model-based dynamic performance and control. *Journal of Power Sources*, 147(1):136–147, 2005.

[105] Lukas Wehrle, Yuqing Wang, Aayan Banerjee, Nigel Brandon, and Olaf Deutschmann. Dynamic modeling of reversible solid oxide cells. *Chemie Ingenieur Technik*, 91(6):833–842, 2019.

[106] Zhaojian Liang, Shanlin Chen, Meng Ni, Jingyi Wang, and Mengying Li. A novel control strategy to neutralize internal heat source within solid oxide electrolysis cell (soec) under variable solar power conditions. *Applied Energy*, 371:123669, 2024.

[107] Edgar Bristol. On a new measure of interaction for multivariable process control. *IEEE Transactions on Automatic Control*, 11(1):133–134, 1966.

[108] International Atomic Energy Agency. *Safety of Nuclear Power Plants: Design*. Number SSR-2/1 (Rev. 1) in IAEA Safety Standards Series. International Atomic Energy Agency, Vienna, 2016. IAEA Safety Standards Series No. SSR-2/1 (Rev. 1).

[109] Joachim Miss, Christophe Herer, Emmanuel Wattelle, Oliviee Baudrand, Luca Coita, Michele Frignani, Franck Morin, Andrea Pucciarelli, Walter Ambrosini, Alessandro De Angelis, Giorgio Simonini, Franck David, Oleksandr. Sevbo, and Thorsten Hollands. TANDEM D4.2 - Identification of potentially impacted safety margins and methodology for safety analysis of a SMR integrated in a hybrid system. Technical report, TANDEM Project, 2023.

[110] Directive 2012/18/EU of the European Parliament and of the Council of 4 July 2012 on the control of major-accident hazards involving dangerous substances, amending and subsequently repealing Council Directive 96/82/EC. Official Journal of the European Union, L 197, 24 July 2012, p. 1–37, 2012. Seveso III Directive.

[111] Andrea Pucciarelli, Alessandro De Angelis, Walter Ambrosini, Thorsten Hollands, Sebastian Buchholz, Andreas Wielenberg, J. Caruso, Olivier Baudrand, Joachim Miss, Oleksandr Sevbo, Claire Vaglio-Gaudard, and Michele Frignani. TANDEM D4.1 - Status report on safety analysis in Europe from the operational flexibility and cogeneration viewpoint. Technical report, TANDEM Project, 2023.

[112] Austin Michael Glover, Austin Ronald Baird, and Dusty Marie Brooks. Hydrogen Plant Hazards and Risk Analysis Supporting Hydrogen Plant Siting near Nuclear Power Plants. Final report. Technical report, Sandia National Laboratories (SNL-NM), Albuquerque, NM (United States), 07 2020.

[113] International Atomic Energy Agency. Safety Demonstration for Innovative Technologies in Nuclear Power Plants. Technical Report DS537, International Atomic Energy Agency, Vienna, 2025. Draft Safety Guide, Step 8.

[114] Austin Michael Glover and Dusty Marie Brooks. Risk Analysis of a Hydrogen Generation Facility near a Nuclear Power Plant. Technical report, Sandia National Lab. (SNL-NM), Albuquerque, NM (United States), 08 2023.

[115] Laura Gastaldo, J.-C. Latché, and M. Sanz. CFD simulations of a detonation of a hydrogen/air mixture in a hydrogen production facility coupled with a nuclear reactor. Technical report, GEMINI 4.0 Project, 2025.

[116] Alessandro Petruzzi and Francesco D'Auria. Thermal-Hydraulic System Codes in Nulcear Reactor Safety and Qualification Procedures. *Science and Technology of Nuclear Installations*, 2008(1):460795, 2008.

[117] Andreas Wielenberg, Liviusz Lovasz, Peter Pandazis, Angel Papukchiev, Livia Tiborcz, Philipp J. Schöffel, Claus Spengler, Martin Sonnenkalb, and Andreas Schaffrath. Recent improvements in the system code package AC2 2019 for the safety analysis of nuclear reactors. *Nuclear Engineering and Design*, 354:110211, 2019. Special Issue on Trends and Perspectives in Nuclear Thermal-Hydraulics.

[118] Philippe Emonot, Annick Souyri, Jean-Luc Gandrille, and François Barré. CATHARE-3: A new system code for thermal-hydraulics in the context of the NEPTUNE project. *Nuclear Engineering and Design*, 241(11):4476–4481, 2011. 13th International Topical Meeting on Nuclear Reactor Thermal Hydraulics (NURETH-13).

[119] Sebastian Buchholz, Fabian Weyermann, and Artur Hashymov. TANDEM D2.7 - ATHLET SMR model description. Technical report, TANDEM Project, 2024.

[120] Calogera Lombardo, Massimiliano Polidori, Marco E. Ricotti, Guido C. Masotti, Alessandro De Angelis, and Andrea Pucciarelli. TANDEM D2.6 - CATHARE SMR model description. Technical report, TANDEM Project, 2024.

[121] Paolo Olita, Guido C. Masotti, Alessandro De Angelis, Walter Ambrosini, and Nicolas Alpy. TANDEM D4.4 - Report of operational Design Basis Accident case studies for a SMR with cogeneration. Technical report, TANDEM Project, 2025.

[122] Paolo Olita, Walter Ambrosini, Oleksandr Sevbo, Calogera Lombardo, and Thorsten Hollands. TANDEM D2.2 - Identification of the modelling/simulation strategy - Modelling requirements for safety codes. Technical report, TANDEM Project, 2023.

[123] Sebastian Buchholz and Alessandro De Angelis. TANDEM D4.3 - Report of operational transient safety case studies for a SMR with cogeneration. Technical report, TANDEM Project, 2025.

[124] Guido C. Masotti, Stefano Lorenzi, Stéphanie Crevon, Jussi-Pekka Ikonen, and Tomi J. Lindroos. Tandem d3.4 - assessment of the control and flexibility constraints on system components by the hybrid system simulator coupled with an optimizer. Technical report, TANDEM Project, 2025.

[125] Niina Helistö, Juha Kiviluoma, Jussi Ikäheimo, Topi Rasku, Erkka Rinne, Ciara O'Dwyer, Ran Li, and Damian Flynn. Backbone-An Adaptable Energy Systems Modelling Framework. *Energies*, 12(17):3388, September 2019.

[126] Alain Ruby, Pimprenelle Parmentier, Stéphanie Crevon, Yacine Gaoua, Antoine Piguet, Thibaut Wissocq, Gabriele Leoncini, and Gilles Lavialle. PERSEE, a single tool for various optimizations of multi-carrier energy system sizing and operation. In *ECOS 2024 - 37th International Conference on Efficiency, Cost, Optimization, Simulation and Environmental Impact of Energy Systems*, Rhodes, Greece, June 2024.

[127] Gilles Lavialle, Stéphanie Crevon, Jussi-Pekka Ikonen, Tomi Lindroos, Lubor Zezula, and Filip Vobr. TANDEM D3.2 - Presentation of dynamic techno-economic analysis for each case study. Technical report, TANDEM Project, 2024.

[128] Jussi-Pekka Ikonen, Tomi J. Lindroos, Stéphanie Crevon, and Gilles Lavialle. TANDEM D3.3 - Sensitivity of the hybrid system techno-economic analysis to uncertain key parameters. Technical report, TANDEM Project, 2024.

[129] Esa Pursiheimo, Tomi J. Lindroos, Dennis Sundell, Miika Rämä, and Ville Tulkki. Optimal investment analysis for heat pumps and nuclear heat in decarbonised Helsinki metropolitan district heating system. *Energy Storage and Saving*, 1(2):80–92, June 2022.

[130] Casto Martos Nogales, Stéphanie Crevon, and Guido C. Masotti. TANDEM D3.5 - Cross-comparison of simulation results between PERSEE, the modelica simulator and ECOSIM-PRO for the energy hub configuration. Technical report, TANDEM Project, 2025.

[131] Nicole van Beeck. Classification of Energy Models. FEW Research Memorandum 777, Tilburg University, Faculty of Economics and Business Administration, Tilburg, 1999.

[132] Matteo Giacomo Prina, Giampaolo Manzolini, David Moser, Benedetto Nastasi, and Wolfram Sparber. Classification and challenges of bottom-up energy system models - A review. *Renewable and Sustainable Energy Reviews*, 129:109917, 2020.

[133] International Atomic Energy Agency. FRAMES – FRAmework for Modelling Energy Systems, 2025. Proprietary model, developed and maintained by the IAEA.

[134] Negar Namazifard and Mohammad A. Tahavori. SESAM-Polimi/Hypatia: Release v0.1.1, 2022.

[135] Robert Fourer, David M. Gay, and Brian W. Kernighan. *AMPL: A Modeling Language for Mathematical Programming*. Duxbury Press, 2003. Second edition.

[136] Bryan S. Palmintier. *Incorporating Operational Flexibility into Electric Generation Planning: Impacts and Methods for System Design and Policy Analysis*. Phd thesis, Massachusetts Institute of Technology, Cambridge, MA, 2013. PhD Dissertation, Engineering Systems Division.

[137] International Atomic Energy Agency. Terms of Reference for the INPRO Collaborative Project on Developing the FRAMES Tool (FRAmework for Modelling Energy Systems). Internal Terms of Reference document, 2024. INPRO Collaborative Project on Developing the FRAMES Tool.

[138] Ministry of the Environment and Energy Security. Italy – Final Updated NECP 2021–2030. National energy and climate plan, Government of Italy, 2024. Submitted to the European Commission.

[139] Terna S.p.A. Terna Open Data Portal. https://dati.terna.it/, 2025.

[140] Terna S.p.A. Prospettive di sviluppo del sistema energetico 2050: Copertura della domanda elettrica. Technical report, Terna S.p.A., 2025.

[141] Venkat Krishnan and James D. McCalley. Building foresight in long-term infrastructure planning using end-effect mitigation models. *IEEE Systems Journal*, 11(4):2040–2051, 2017.

[142] Alessandro Alemberti, Marco Caramello, Michele Frignani, Giacomo Grasso, Fabio Merli, Giulia Morresi, and Mariano Tarantino. Alfred reactor coolant system design. *Nuclear Engineering and Design*, 370:110884, 2020.

[143] Marcos Celador Lera, Alfonso Junquera Delgado, Michele Frignani, and Marco Ricotti. ANSELMUS D5.2 - LFR BOP Main Components Definition: Definition and Sizing of the Main Components, Including Sensitivity Analysis of Both BOP Configurations. Technical report, ANSELMUS Project, 2023.

[144] Giorgio Simonini, Youssef Hammadi, Viola Ferrara, Sarah Hocine-Rastic, Stefano Lorenzi, Guido C. Masotti, Augustin Baudoux, Dorian Jouret, Bernard Tourneur, Fabrizio Pappalardo, Nicolas Alpy, David Haubensack, Sylvain Mathonnière, and Raphaël Talpin. TANDEM D2.3 - Modelica models description for the "TANDEM" Library. Technical report, TANDEM Project, 2024.

[145] Guido Carlo Masotti, Antonio Cammi, and Stefano Lorenzi. Assessment of pressurizer dynamic performance for nuclear hybrid energy system modelling: Comparison between equilibrium and 1D non-equilibrium approaches. *Nuclear Engineering and Technology*, 57(11):103761, 2025.

[146] David Haubensack, Caroline Thévenot, and Patrick Dumaz. The Copernic / Cyclop Computer Tool: Pre-Conceptual Design of Generation 4 Nuclear Systems. pages 1–11, Beijing, 2004.

[147] Gestore dei Mercati Energetici GME. MGP-GAS Market – Summary Statistical Data, 2023. Average Italian gas price for 2023, MGP-GAS market.

[148] National Renewable Energy Laboratory. Annual Technology Baseline (ATB) 2024: Electricity Technologies. https://atb.nrel.gov/electricity/2024/technologies, 2024.

[149] European Commission. Commission Staff Working Document Accompanying the Document Communication from the Commission "Nuclear Illustrative Programme" Presented under Article 40 of the Euratom Treaty for the Opinion of the European Economic and Social Committee, 2025.

[150] Nuclear Energy Agency. *NEA System Cost Analysis for Integrated Low-Carbon Electricity Systems: A Guide for Stakeholders and Policymakers*. OECD Publishing, Paris, 2024.

[151] International Energy Agency. Global energy and climate model, 2025.

[152] Roberto Lacal Arantegui, Arnulf Jaeger-Waldau, Marika Vellei, Bergur Sigfusson, Davide Magagna, Mindaugas Jakubcionis, Maria Del Mar Perez Fortes, J. Carlsson, Stavros Lazarou, Jacopo Giuntoli, Eveline Weidner Ronnefeld, Giancarlo De Marco, Amanda Spisto, and Carmen Gutierrez Moles. ETRI 2014 - Energy Technology Reference Indicator projections for 2010-2050. Scientific analysis or review LD-NA-26950-EN-N, Luxembourg (Luxembourg), 2014.

[153] European Commission, Directorate-General for Energy, Fraunhofer Institute for Systems, Innovation Research ISI, Guidehouse, McKinsey & Company Inc., TNO, Trinomics, and Utrecht University. *Study on energy storage*. Publications Office of the European Union, 2023.

[154] IEAGHG. Low-Carbon Hydrogen from Natural Gas: Global Roadmap. Technical Report 2022-07, IEA Greenhouse Gas R&D Programme (IEAGHG), 2022.

[155] Nuclear Energy Agency. *The Role of Nuclear Power in the Hydrogen Economy*. Paris, 2023.

[156] Danish Energy Agency. Technology Data for Industrial Process Heat, 2024.

[157] ENTSO-E and ENTSOG. TYNDP 2024 Scenarios Methodology Report. Technical report, European Network of Transmission System Operators for Electricity (ENTSO-E) and European Network of Transmission System Operators for Gas (ENTSOG), 2025.

[158] IRENA. Renewable Power Generation Costs in 2024. Technical report, International Renewable Energy Agency, Abu Dhabi, 2025.

[159] Ryan Spangler, Sunming Qin, Levi Larsen, Chandu Bolisetti, Abdalla Abou-Jaoude, Mehdi Asgari, Koroush Shirvan, William Stewart, James Krellenstein, and Garrett Wilkinson. Potential Cost Reduction in New Nuclear Deployments Based on Recent AP1000 Experience. Technical Report INL/RPT-25-84701, Idaho National Laboratory, Idaho Falls, ID, USA, 2025.

[160] Jonas Kristiansen Nøland, Martin Hjelmeland, and Magnus Korpås. Cost projections of small modular reactors: A model-based analysis. In *Proceedings of the International Conference on Small Modular Reactors and their Applications*, Vienna, Austria, 2024. IAEA.

Glossary

AMR Advanced Modular Reactor.

AOO Anticipated Operational Occurrence.

BESS Battery Energy Storage System.

BOP Balance Of Plant.

CAPEX CAPital EXpenditure.

CCGT Combined Cycle Gas Turbine.

CCS Carbon Capture and Storage.

CHP Combined Heat and Power.

DBA Design Basis Accident.

E-SMR European SMR.

EU European Union.

FMI Functional Mock-up Interface.

FMU Functional Mock-up Unit.

GIF Generation IV International Forum.

HP High-Pressure.

HTGR High-Temperature Gas-cooled Reactor.

HTSE High-Temperature Steam Electrolysis.

IAEA International Atomic Energy Agency.

IEA International Energy Agency.

IHX Intermediate Heat Exchanger.

LP Low-Pressure.

LTE Low-Temperature Electrolysis.

MILP Mixed-Integer Linear Programming.

MSR Molten Salt Reactor.

NECP National Energy and Climate Plan.

NHES Nuclear Hybrid Energy Systems.

NPP Nuclear Power Plant.

NSSS Nuclear Steam Supply System.

OPEX OPerational EXpenditure.

PCHE Printed Circuit Heat Exchanger.

PEN Positive electrode-Electrolyte-Negative electrode.

PHS Pumped Hydro Storage.

PID Proportional-Integral-Derivative.

PV Photovoltaic.

R&D Research & Development.

RGA Relative Gain Array.

SMGR Steam Methane Gas Reforming.

SMR Small Modular Reactor.

SOC State Of Charge.

SOE Solid Oxide Electrolyser.

TES Thermal Energy Storage.

VHTR Very High Temperature Reactor.

VRE Variable Renewable Energy.