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Arthur Lynch

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Arthur Lynch. Nuclear in decarbonized power systems with renewable energy : Flexibility assessment, modeling framework, and role in the French and Western European electric transition. Electric power. Université Paris-Saclay, 2022. English. NNT : 2022UPAST147 . tel-04346156

HAL Id: tel-04346156

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Nuclear in decarbonized power systems with renewable energy: Flexibility assessment, modeling framework, and role in the French and Western European electric transition

*Le nucléaire dans les systèmes électriques décarbonés avec des énergies
renouvelables : Analyse de sa flexibilité, cadre de modélisation et rôle
dans les transitions électriques françaises et ouest-européennes*

Thèse de doctorat de l'université Paris-Saclay

École doctorale n°573 : interfaces : matériaux, systèmes, usages (INTERFACES)
Spécialité de doctorat : Ingénierie économique
Graduate School : Sciences de l'ingénierie et des systèmes.
Réfèrent : CentraleSupélec

Thèse préparée dans l'unité **Laboratoire Génie Industriel (Université Paris-Saclay,
CentraleSupélec)**, sous la direction de **Gilles Mathonnière**, HDR

Thèse soutenue à Paris-Saclay, le 13 décembre 2022, par

Arthur LYNCH

Composition du Jury

Membres du jury avec voix délibérative

Pascal DA COSTA Professeur, CentraleSupélec	Président
Patrice GEOFFRON Professeur des universités, Université Paris Dauphine	Rapporteur et Examineur
Rodica LOISEL Maître de conférences HDR, Université de Nantes	Rapporteuse et Examinatrice
Patrick CRIQUI Directeur de recherche émérite, Université Grenoble-Alpes, CNRS	Examineur
Jesse JENKINS Professor, Princeton University	Examineur
Olivier MASSOL Professeur, ENSPM-IFP School	Examineur

Titre : Le nucléaire dans les systèmes électriques décarbonés avec des énergies renouvelable : Analyse de leur flexibilité, cadre de modélisation et rôle dans les transitions électriques françaises et ouest-européens

Mots clés : Nucléaire, Energie renouvelable, Flexibilité, Modélisation de systèmes électriques

Résumé : Dans le contexte de la décarbonation des systèmes électriques français et européens, les énergies renouvelables, notamment les technologies solaire et éoliennes, sont destinées à assurer une part grandissante de la demande d'électricité. Cette transition va fortement impacter le système électrique, en particulier augmenter les besoins de flexibilité pour maintenir l'équilibre constant entre offre et demande. Ainsi, les réacteurs à eau pressurisée, majoritairement utilisés à pleine puissance pour recouvrir leurs coûts fixes élevés, devront participer à ces besoins de flexibilité et concourir face aux autres sources disponibles (hydraulique, batteries, flexibilité de la demande...).

Cette thèse présente tout d'abord les contraintes de flexibilité des réacteurs à eau pressurisée et se focalise sur les phénomènes influençant le calendrier de fonctionnement des réacteurs et l'évolution de leur puissance minimale de fonctionnement au cours de leur cycle d'irradiation, qui déterminent en partie la capacité de flexibilité des réacteurs. L'analyse de la littérature montre que ces contraintes de flexibilité sont rarement considérées par les modèles de simulation de systèmes électriques visant à déterminer la capacité et le fonctionnement des réacteurs dans des systèmes à forte part d'énergies renouvelables. L'absence de représentation de ces contraintes mésestime le potentiel de flexibilité des réacteurs, ce qui pourrait impacter les résultats de simulation, donc l'évaluation du rôle du nucléaire dans les futurs systèmes électriques décarbonés.

Afin de déterminer l'impact de la non représentation de ces contraintes sur les résultats des modèles de simulation, cette thèse propose ensuite une méthode permettant de les implémenter dans un modèle de système électrique simplifié dont la part de la demande couverte par les renouvelables varie de 0% à 80% selon les cas de sensibilités. Les résultats de simulation permettent de déterminer que dans les

cas où la pénétration des énergies renouvelables dans le système est élevée, la représentation de ces contraintes diminue l'estimation des coûts du système, mais aussi le niveau des émissions, et l'écrêtement des renouvelables. Ainsi, l'inclusion du calendrier de fonctionnement et de l'évolution de la puissance minimale des réacteurs dans les pratiques de modélisation semble déterminante pour l'évaluation de mix électriques combinant de fortes parts de renouvelables et du nucléaire.

Dès lors, la dernière partie de la thèse étend cette approche en incluant les contraintes de flexibilité dans un modèle d'optimisation des capacités de production visant la décarbonation d'un système électrique détaillé, basé sur une représentation de l'Europe en 2050. Le modèle permet l'investissement en capacités de production décarbonées, dont renouvelables et nucléaire, et en interconnexions entre pays, en visant un coût complet minimal de fonctionnement du système. Ces simulations concluent que la majorité de la production serait assurée par les renouvelables, ces capacités étant peu chères et à fort potentiel de développement. Le reste de la demande est en partie complétée par des nouveaux programmes nucléaires qui apparaissent comme « sans-regret » puisque de réacteurs sont installés même dans le scénario de dérive des coûts du nucléaire le plus défavorable. En dehors de ce scénario, le potentiel de développement nucléaire est maximisé, ce potentiel étant limité par les durées de construction, les chaînes d'approvisionnement et la volonté des pays à considérer de nouveaux réacteurs. Dans de tels mix de production, les réacteurs fonctionneraient de manière flexible, avec un facteur de charge réduit et un nombre de manœuvres de puissance plus conséquent. La thèse conclue quant à la viabilité technique et économique d'un tel mode de fonctionnement pour les réacteurs à eau pressurisée.

Title : Nuclear in decarbonized power systems with renewable energy: Flexibility assessment, modeling framework, and role in the French and Western European electric transition

Keywords : Nuclear, Renewable energy, Flexibility, Power system modeling

Abstract : Due to the decarbonization of the French and European electricity systems, renewable energies, especially solar and wind capacities, are expected to ensure an increasing share of the electricity demand. Such a transition will substantially impact the electricity system, particularly by increasing the need for flexibility to maintain a constant balance between supply and demand. Thus, pressurized water reactors, primarily used as baseload to recover their high fixed costs, will have to participate in the system's flexibility requirements and compete with other sources (hydroelectricity, batteries, demand side response...).

The present thesis first summarizes the flexibility constraints of pressurized water reactors. It then focuses on the phenomena influencing a nuclear fleet operational schedule and each reactor's minimum power evolution throughout their irradiation cycle, as these two parameters partly determine the flexibility capacity of reactors. A literature analysis shows that power system simulation models rarely consider these flexibility constraints to determine the capacity and operation of reactors in systems with a high share of renewable energy. The lack of representation of these constraints misestimates the flexibility potential of reactors, which could impact the simulation results. Thus, the role of nuclear power in future decarbonized power systems could be misevaluated.

This thesis then proposes a method to implement flexibility constraints in a simplified power system model where the share of demand covered by renewables varies from 0% to 80% depending on the sensitivity case, aiming to determine the impact of the non-representation of these constraints on the results of simulation models. The simulation results show that in cases where the penetration of renewables in the system is high,

the representation of these constraints decreases the evaluation of system costs, emissions levels, and renewables curtailment. Thus, the inclusion of reactors' operational schedule and minimum power evolution in modeling practices seems to be decisive for evaluating power mixes combining high shares of renewables and nuclear.

Therefore, the last part of the thesis extends this approach by including flexibility constraints in a capacity optimization model aiming to decarbonize a complex power system based on a representation of Europe in 2050. The model allows for investment in decarbonized generation capacities, including renewables and nuclear, and interconnections between countries, aiming at a minimum full system cost. The simulation results conclude that renewables would provide most of the electric demand, as these technologies are cost-competitive and have high development potential. The residual demand is partly ensured by new nuclear programs, the implementation of which is cost-optimal even in the most unfavorable nuclear scenario that assumes consequent cost overruns. Apart from this scenario, the nuclear development potential is maximized, as the number of installable reactors is limited by construction durations, supply chain constraints, and countries' willingness to pursue a future nuclear program. In such production mixes, nuclear reactors would operate flexibly, with a reduced load factor and a higher number of power maneuvers. The thesis concludes by discussing the technical and economic viability of such an operating mode for pressurized water reactors.

À mon grand-père Lucien.

REMERCIEMENTS

Il est ardu d'exprimer ma gratitude envers toutes celles et ceux qui m'ont accompagné ces trois précédentes années tout au long de mon travail de thèse qui arrive aujourd'hui à sa conclusion. Sans eux, ce présent travail n'existerait pas et il serait ainsi de bon ton d'adresser à chacun une complète page d'éloge. Je suis néanmoins contraint dans la longueur de ces remerciements et suis condamné à être bref. Je voudrais alors en préambule remercier toutes les personnes que je ne peux citer ici et que j'ai eu la chance de rencontrer durant la réalisation de mes travaux de thèse, de proche comme de loin. Nos échanges, vos conseils et plus généralement vos soutiens ont été des sources d'inspiration et d'encouragement continues. Merci donc, à vous qui m'avez brièvement croisés au hasard d'une conversation ou cotoyés chaque jour.

Plus particulièrement, mes premiers sentiments de gratitude s'adressent à mon encadrante Sophie Gabriel et mon directeur de thèse Gilles Mathonnière. C'est grâce à votre suivi quotidien qu'il me fut possible de répondre à mes questions de recherche. Vos remarques tout comme votre patience face à mon obstination vous honorent et il convient de vous en créditer. J'ai eu un grand plaisir à travailler sous votre direction. Je souhaiterais également remercier Yannick Perez pour son suivi de thèse et les précieux conseils qu'il m'a dispensés. J'ai beaucoup appris, notamment quant à la méthodologie de recherche, à ses côtés. Merci également à Pascal Da Costa d'avoir suivi mes travaux et d'avoir accepté de présider mon jury.

Je remercie profondément mes rapporteurs Rodica Loisel et Patrice Geoffron, ainsi que mes examinateurs Jesse Jenkins, Patrick Criqui, et Olivier Massol d'avoir accepté de faire partie de mon jury et de lire mon manuscrit. J'espère qu'il les intéressera.

Merci à l'I-tésé et au CEA de m'avoir soutenu financièrement mais également offert un cadre convivial au sein duquel j'ai énormément progressé. Sous la direction d'Elisabeth Le Net puis de Bertrand Charmaison, j'ai pu échanger avec une équipe compétente et joviale que j'espère avoir honorée avec ce travail de thèse. J'ai hâte de contribuer à développer l'équipe et les thématiques de recherche une fois ce doctorat terminé. Je souhaiterais également remercier le département SERMA/DM2S du CEA et en particulier Karim Ammar dont l'aide technique et matérielle ont grandement contribué aux travaux de modélisation présentés ici. Merci également aux équipes de RTE pour la mise open-source du modèle ANTARES qui fût la base des modélisations ici présentées.

Je tiens également à remercier le laboratoire LGI où j'ai pu rencontrer des professeurs passionnés et à l'écoute ainsi que des doctorants pleins d'avenir. Je pense qu'il est crucial de pouvoir échanger sur notre apprentissage commun de la recherche, nos succès et nos peurs, d'autant plus lorsque tout fût perturbé par l'expérience inédite qu'a été la récente pandémie. Vous avez été pour moi cette soupape et je vous en suis reconnaissant.

Il me faut remercier Camille Cany dont les travaux de thèse m'ont en premier intéressés au sujet de la flexibilité des réacteurs à eau pressurisée. De même, je me dois de remercier Alexis Lebeau qui m'a permis d'effectuer mon premier stage dans ce domaine au sein d'EDF R&D, stage m'ayant convaincu d'approfondir ce sujet de recherche. Je te souhaite le meilleur pour la réalisation de ta thèse en cours. Merci également à Valentin Satgé dont les travaux exploratoires sur le modèle ANTARES durant son stage au sein d'I-tésé auront permis d'achever une

modélisation ambitieuse du système électrique européen présentée en dernière partie du manuscrit. Enfin, je souhaiterais souligner l'apport tant technique qu'émotionnel de mon ami Sergio-Léo Vargas-Aranda. Ton arrivée au sein de l'équipe il y a deux ans a été un facteur déterminant pour la finalisation de ce manuscrit.

Je finirai ces remerciements par une pensée à ma famille, en particulier mes parents qui ont eu la gentillesse et la patience de me soutenir tout au long de mes études. Merci également à ma sœur et mon frère pour leur tolérance face à mon obsession à parler d'énergie lors de nos repas de famille. En définitive, je voudrais sincèrement remercier tous mes amis sans qui ces années auraient été bien tristes. S'il n'est pas possible de tous vous citer ici, je ne manquerai pas de vous exprimer ma gratitude de vive voix.

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CHAPTER 1. GENERAL INTRODUCTION AND CONTEXT OF THE THESIS

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1. DECARBONIZATION BY ELECTRIFICATION: TOWARDS INCREASED FLEXIBILITY NEEDS

The overall context of this manuscript is the concerns surrounding climate change and its impact on humanity. The impact of human activities, notably the massive release of greenhouse gases in the atmosphere, has been extensively documented in the scientific literature and the six Assessment Reports of the Intergovernmental Panel on Climate Change [1]. Among others, climate change will likely result in increased heatwave frequency, increased severity of storms and droughts, warmer and rising oceans, biodiversity loss, decreasing agricultural yields, increasing occurrence of pandemics, overall increased poverty and displacement of populations, and so on. Such changes will likely impact all regions in the world at some point, although their historical responsibilities regarding greenhouse gas emissions are not equivalent [2]. Similarly, countries are not equally developed, and facing those adverse effects will be varyingly challenging depending on the region and its development level. More than ever, joint action from all over the world will be needed to mitigate climate change and limit its consequences.

Broadly, the principal metric discussed among countries to negotiate climate measures is the progressive global temperature increase that has been measured since pre-industrial times, as seen in Figure 1.1. Implicitly, this relates to the greenhouse gases concentration in the atmosphere that has increased conjointly with the use of fossil fuels since the industrial revolution. Bound by the 21st session of the Conference of the Parties to the United Nations Framework Convention on Climate Change in Paris, a record 196 parties pledged to act toward limiting global warming to 2°C above pre-industrial levels- 1.5°C being preferable. In terms of emissions reduction, limiting global warming under 1.5 °C corresponds to a 45% decrease of current emissions until 2030 and reaching net zero by 2050, meaning that all remaining emissions are re-absorbed by the environment (for instance, oceans or forests).

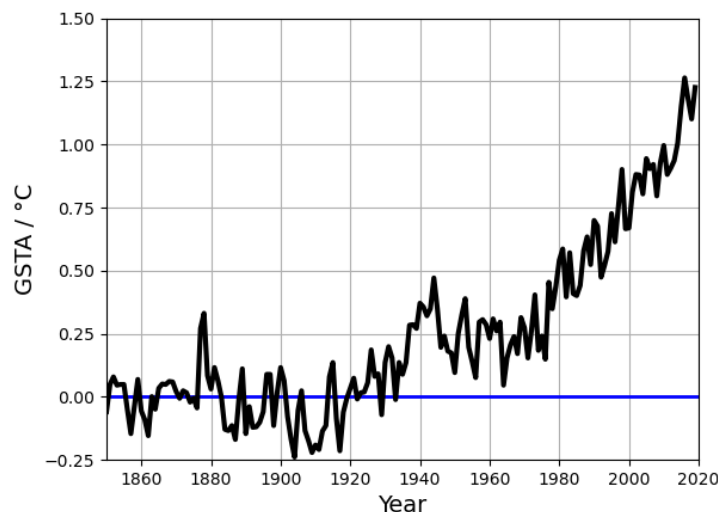


Figure 1.1: Global Surface Temperature Anomalies (GSTA) relative to 1850-1900 [1]

Namely, such pledges aim to decrease the concentration of greenhouse gases in the atmosphere by halting their emission or increasing their capture to lessen their global warming effect. Although commitments made by states seem to fall short of the ambitious 2°C global

temperature increase, as [3] notes, “*the number of countries that have pledged to reach net-zero emissions by mid-century or soon after continues to grow.*”. Hence, climate plans across the world are ambitious and will shape the future of human societies.

As energy use represents about two-thirds of global greenhouse gas emissions from human activities [4], it is a significant focus of parties’ strategies to limit global warming. The objective is to replace the three primary carbonized energy sources, petroleum, coal, and natural gas, with decarbonized energy. In most countries, such strategies rely on high electrification of most economic sectors, such as transportation (electric vehicles), industrial processes (decarbonized gas and heat), or domestic heating. Hence, countries aim to decarbonize electric generation, replacing fossil plants as the most important means of electric generation (63.3% of global electricity generation in 2019¹). In that sense, most countries have committed to the expansion of variable renewable technologies like onshore and offshore wind, solar photovoltaic, and concentrated solar power (e.g., 42% variable renewable energy (VRE) by 2050 in the United States [5], 40% by 2030 in the European Union (Fit For 55), 25% for China, representing 1200 GW of combined wind and solar capacity, in its Nationally Determined Contribution sent to the IPCC) [6]. Those goals were recently heightened in the context of the covid crisis, the Russian-Ukrainian conflict, the energy prices increases, and the overall high inflation rates following those events. For example, the European council announced in June 2022 that it aims to ensure 45% of its energy consumption with renewable sources in 2030 as a part of a broader effort to reduce the European Union’s reliance on foreign fuel (REPowerEU²). Conjointly, the recently voted Inflation Reduction Act in the United States aims for a 43% decrease in emissions by 2030 compared to 2005 levels and \$370 billion in climate and clean energy investments, a consequent part being allotted to renewable energy deployments. For the 2050 threshold, even though most countries do not define how they will reach net-zero emissions levels, renewable energy should become the primary source of electric generation, as highlighted in [3].

In the French context, the main legislative text that frames the pathways toward net zero in 2050 is the National Low-Carbon Strategy (Stratégie Nationale Bas-Carbone: SNBC), first introduced by the French Law on Energy Transition for Green Growth (Loi de Transition Energétique pour la Croissance Verte: LTECV). It is France's roadmap against climate change, providing guidelines for achieving the transition to a low-carbon, circular and sustainable economy in all sectors of activity. It defines a trajectory for reducing greenhouse gas emissions until 2050 and sets short- and medium-term objectives: carbon budgets. The overall objective is dual: first, reaching carbon neutrality by 2050, and second reducing the carbon footprint of French consumption. Alongside the National Low-Carbon Strategy, the Pluriannual Energy Program (Programmation Pluriannuelle de l’Energie: PPE) expresses the guidelines and priorities for action of the public authorities for the management of all forms of energy in mainland France. Its objectives must then comply with the National Low-Carbon Strategy. Specifically, the PPE fixes renewable energy targets for 2028, namely at least 38.4 GW of wind capacity and 35.1 GW of solar capacity, and other objectives linked to renewable gas and heat

¹ <https://ourworldindata.org/electricity-mix>

² https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal/repowerEU-affordable-secure-and-sustainable-energy-europe_en

that are not detailed here. Those goals should be heightened in the face of the REPowerEU commitments when debating the new PPE in 2023.

2. VARIABLE RENEWABLES AND DEMAND VARIABILITY AN INCREASED NEED FOR FLEXIBILITY

As defined in [7], flexibility is “*the ability of a power system to cope with variability and uncertainty in both generation and demand while maintaining a satisfactory level of reliability at a reasonable cost, over different time horizons.*” This definition will be used throughout this manuscript. This manuscript will also refer to generating unit flexibility –or maneuverability– broadly defining plants' ability to modify their output over time.

The transition toward a high-renewable French power system will significantly change the flexibility requirements of power systems. VRE technologies are characterized by high capital with negligible variable costs and a prime position in the economic ‘merit order’³ dispatch to meet electricity demand [8]. Moreover, their production level is weather-dependent and thus non-dispatchable, making it optimal to prioritize them to meet demand when meteorological conditions favor their production. Previously characterized by variable electricity demand ensured by dispatchable generators, the electricity system will likely shift toward a partly controllable demand and a consequent intermittent production share, notably solar and wind power. Such change will eventually impact the level and profile of the residual demand that must be ensured by dispatchable thermal sources of generation or storage facilities. It is then essential to characterize the main elements affecting this residual demand.

Thus, there will be a substantial increase in the need for flexibility to balance electricity supply and demand. Substantially, whether the system is sufficiently flexible will significantly influence the challenges of integrating variable renewables. Indeed, the growing difficulty of maintaining the electricity supply-demand equilibrium in the context of massive renewable capacity development creates a strong need for flexible services. By taking on the French power system as an example and the year 2015 – a standard meteorological year -the following subsections aim to characterize the variabilities that will influence the shape of future power systems’ residual demands.

2.1. Demand side variability

The first source of variability is the electrical consumption level. Indeed, the electric demand is variable at different time horizons, from several hours to interannual. It is important to characterize this variability since it conditions the generation level needed at each moment to respect the supply-demand balance of the power system. Broadly, it is possible to characterize the variability of electrical demand at three different time horizons on a daily, weekly and multi-month scale [9]. In the short term, the variations in electrical demand are linked to the human

³ The manuscript refers here to the ranking of available generating units of an electric system based on ascending order of marginal costs, with the aim of minimizing the overall generation costs of the system. Low-marginal-cost technologies then take priority over high-marginal-cost technologies in responding to the corresponding electricity demand.

and economic activity of the society, the consumption peaks taking place during periods of economic activity or domestic consumption for heating or cooking.

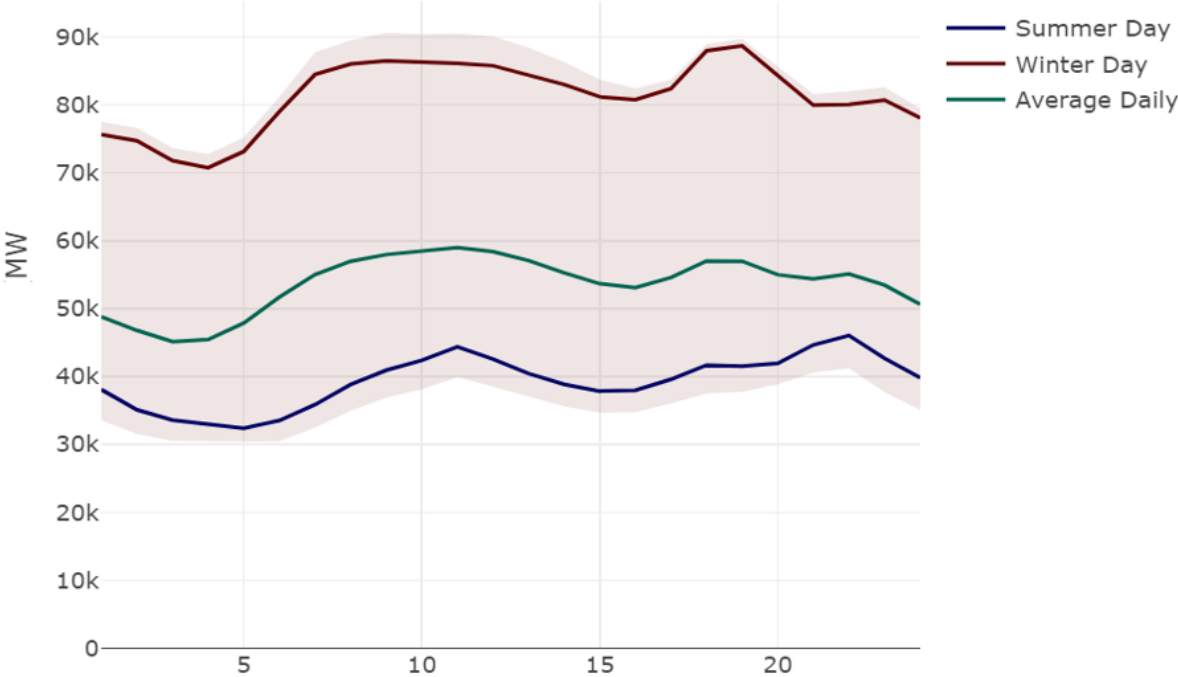


Figure 1.2: Average, winter, and summer daily electric load profile - France 2015-Entso-e data

Electricity consumption peaks occur between 8 am and 2 pm and between 5 pm and 8 pm corresponding to work periods and household consumption for electrical appliances. Inversely, low consumption periods are concentrated during the night. Thus, if there is a significant minimum of electrical consumption (about 30 GW of power at any time in the French case, as illustrated in Figure 1.2), the daily variations in demand are not negligible -13.85 GWe average daily amplitude in 2015 for France. The daily variability of demand is then the primary driver of flexibility requirements to ensure the supply-demand balancing of power systems.

Electric consumption levels also vary within one week, with a decrease in consumption on weekends compared to weekdays (see Figure 1.3).

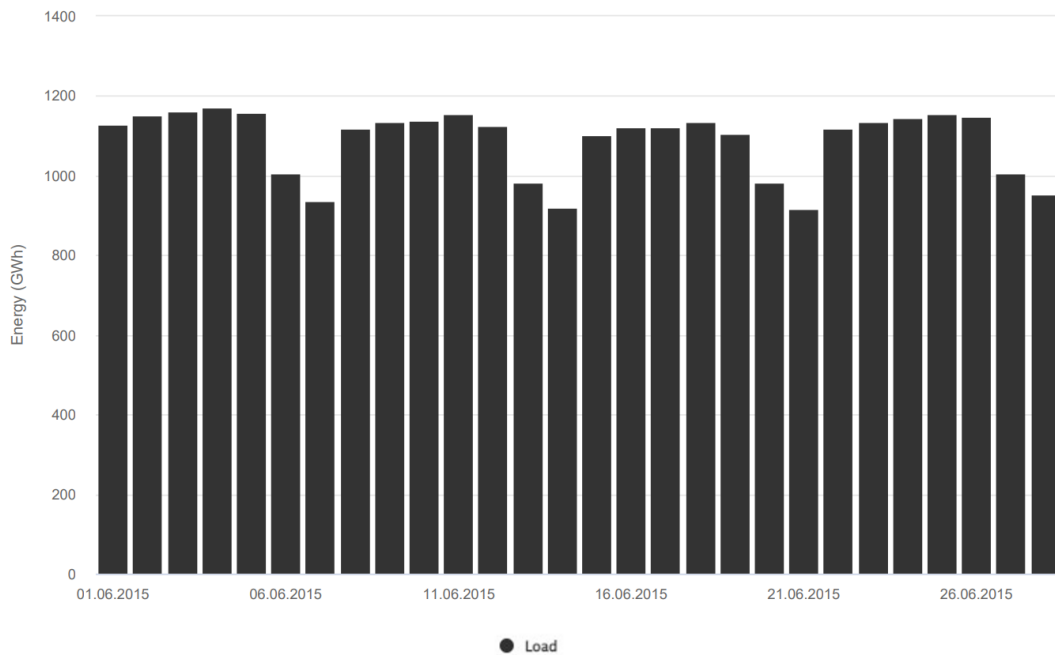


Figure 1.3: Net daily electricity load in France - June 2015 – Energy-Charts.info

While daily consumption remains substantial, there is an overall drop in demand since economic activities decrease during weekends. Thus, the production needs necessary to balance supply and demand are lower. This evolution of the power needed according to the day of the week must be considered when sizing the electrical supply-demand balance.

Demand requirements also vary according to the seasonality of electrical demand (increasing heating or lighting requirements linked to the decreasing temperature and sunshine time). In France, annual consumption peaks occur in winter, unlike summer periods when needs are lower (illustrated in Figure 1. 4). However, it is important to note that this is not the case in all countries, as the seasonal differences vary depending on the power system’s thermal sensitivity and the meteorological conditions of the countries. For example seasonal dynamics in the Italian power system are reversed compared to France, as the highest electric consumptions occur during the summer when cooling needs are higher. Due to global warming, such dynamics are more likely to occur with the increasing use of air conditioning, especially during heat waves.

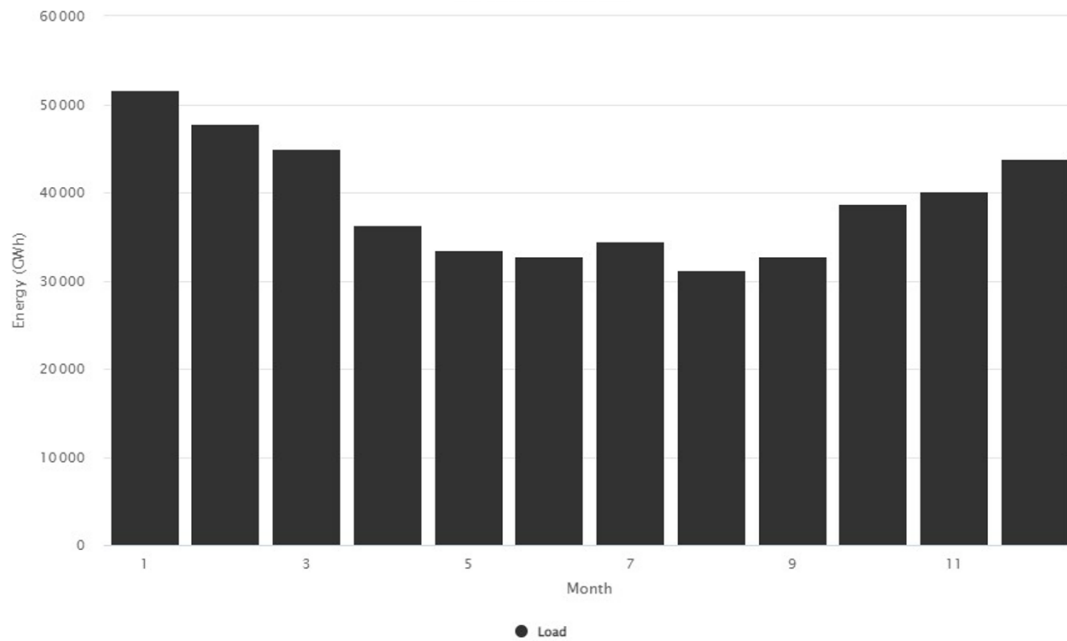


Figure 1. 4: Net monthly electricity load in France - 2015 – Energy-Charts.info

It should be noted that the annual electricity consumption level varies from one year to another, depending on economic activity, climatic conditions, or other parameters that may affect electricity demand. The example of 2020, when the pandemic caused a sharp drop in economic activity in Western Europe, is telling, as the electricity consumption was significantly lower than in previous years (443 TWh vs. 465 TWh in 2019 and 469 TWh in 2018).

The three presented time horizons (intraday, weekly and annual) highlight one of the characteristics of electrical demand: it is structurally variable since its level depends on the socio-economic and climatic conditions. As power systems necessitate maintaining a constant equilibrium between supply and demand, electric consumption variations are the primary determinant of the required flexibility from the system’s supply side.

2.2. Supply-side variability

Regarding the supply side, variable renewable energies’ output depends on meteorological conditions at a given time. Given the need to keep the electrical supply-demand balance constant, the production variability from these generation assets is a significant issue for future decarbonized electrical systems. The following sub-section aims to characterize the variability of three non-dispatchable generating technologies: solar, wind, and fatal hydroelectricity, especially run-of-river hydropower.

The primary characteristic of electricity derived from solar energy is its dependence on the irradiance level at a given time. The solar installations' production level is all the more important as the sunshine and its duration is high. Thus, the solar production curve follows a normal distribution centered around noon, with maximum production when the sun reaches its zenith and zero production during the night, without particular variations according to the day of the week.

The main variability of solar production is related to seasonal changes in the intensity and duration of irradiation due to the variation in solar exposure caused by the earth's movements around the sun. If these changes in exposure are limited for regions close to the equator, they have a real impact, particularly in more northern regions such as metropolitan France. During the summer, France benefits from prolonged and more substantial irradiance than during winter periods. The impact on production is consequent since solar installations' output is more substantial during summer, as illustrated in Figure 1. 5.

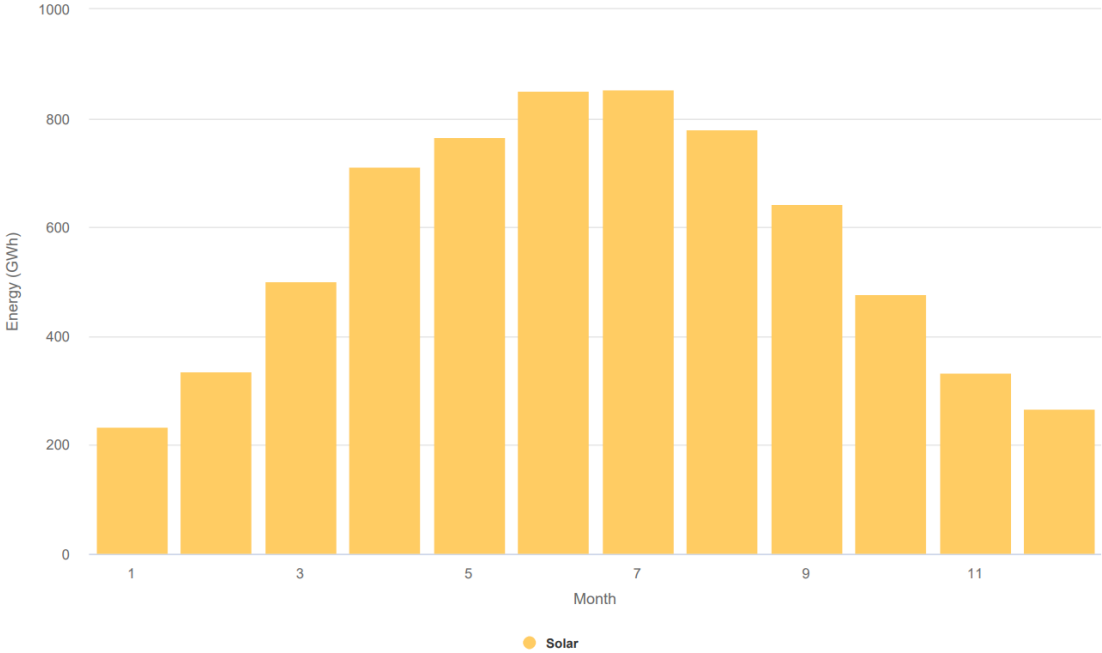


Figure 1. 5: Monthly solar production in France – 2015 – Energy-Charts.info

If the solar production level is variable, its production periods are predictable since they are linked to sunshine, whose duration and intensity are known a priori depending on the time of year. However, other sources of uncertainty exist, for example, cloud cover, which reduces the amount of energy solar installations receive. As a result, the level of production from solar energy can vary significantly over a day or week, depending on weather variations. The contribution of solar energy to the supply-demand balance can therefore vary significantly in the short term.

The intermittency of wind turbines is less than that of solar panels, although less predictable since winds are more evenly distributed across hours than solar irradiation, but also more volatile. From the analysis of the weekly production profile over the year 2015 in France, night hours appear to be periods of peak production since the drop in temperature induced by the absence of sunshine increases the average wind speed. It is then possible to observe a recurrent drop in wind production in the middle of the day for each day of the week, indicating a certain complementarity of renewable energies from the sun and wind.

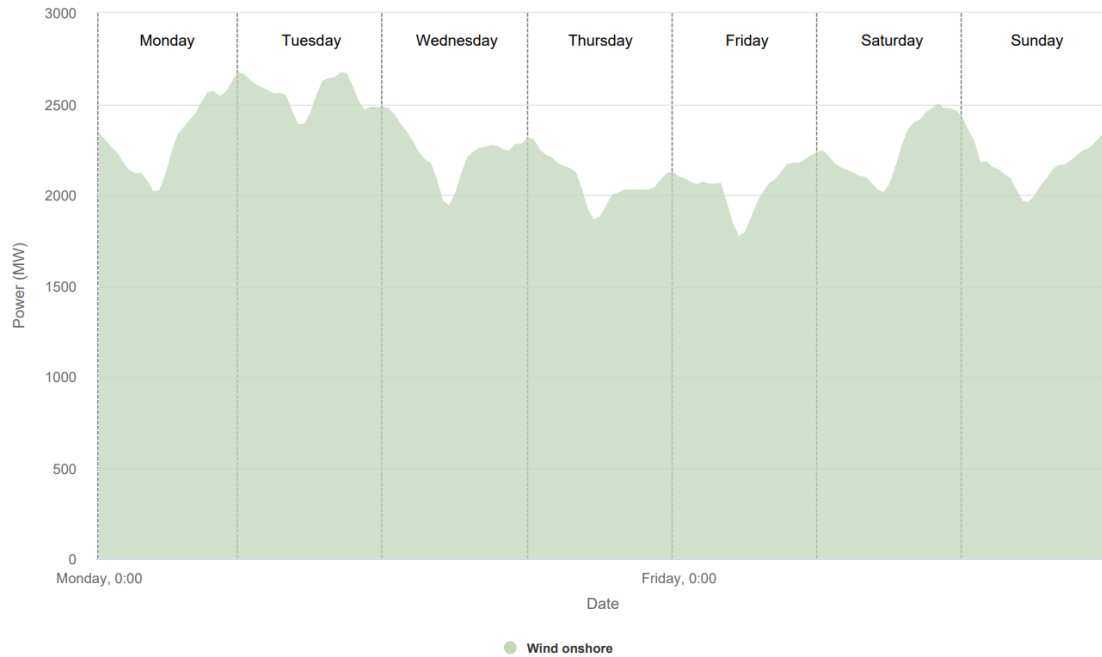


Figure 1. 6: Average daily wind onshore production in France – 2015 – Energy-Charts.info

Wind power’s thermo-sensitivity also implies a higher production during cold months, in winter. Thus, unlike solar energy, wind power production is lower during summer, as seen in Figure 1. 7. Additionally, the inter-annual variability of wind power can be substantial (for example, standard variations ranging from 5% to 12.5% of countries’ wind generation in Europe [10], [11]), as noted in [12], [13], [11], [14].

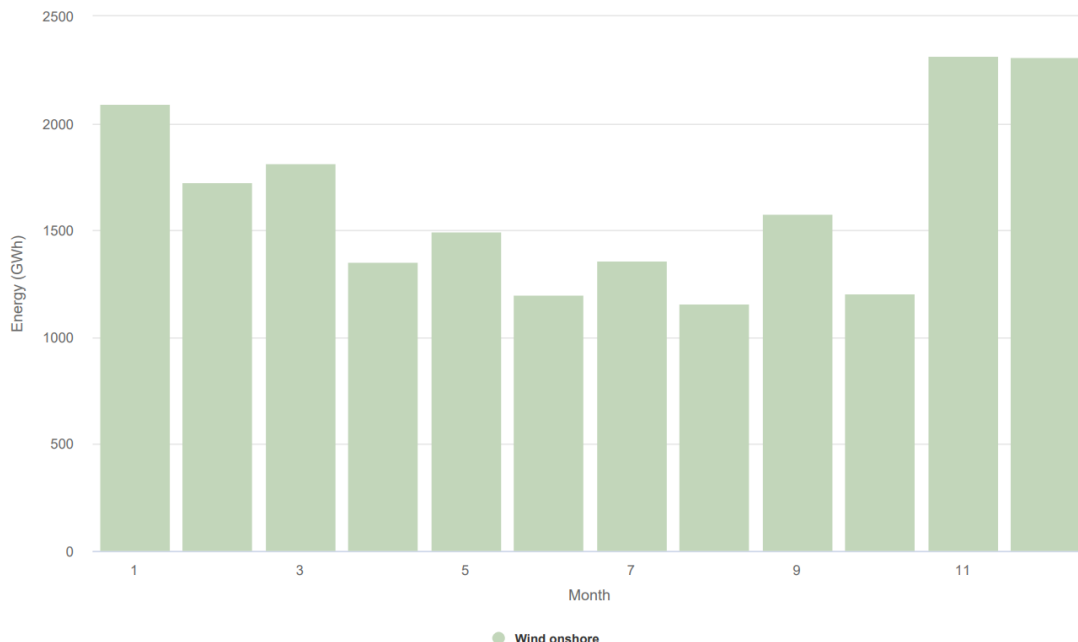


Figure 1. 7: Monthly wind onshore production in France – 2015 – Energy-Charts.info

Due to the higher speed of winds, greater consistency, and lack of physical interference that land or human-made objects may create, offshore wind turbines, whose capacity is likely to

increase in the future substantially, should benefit from lower production variability and higher capacity factor than onshore wind turbines. Notably, [15] notes that offshore winds have higher variance than onshore winds, but this increase is due to increased speed.

Hydraulic production is also subject to substantial variations linked to meteorological conditions, particularly the level of precipitation. The impact of precipitation then occurs at two levels, direct and indirect. For run-of-river “fatal” installations, the impact of precipitation is direct since the quantity of water flowing through the electricity-generating turbines cannot be controlled. Therefore, the production level of these installations is seasonal as it depends on the water inflow in the territories. The production peaks of the hydroelectric installations are therefore concentrated at the beginning of the year when precipitations and snow melts are more frequent.

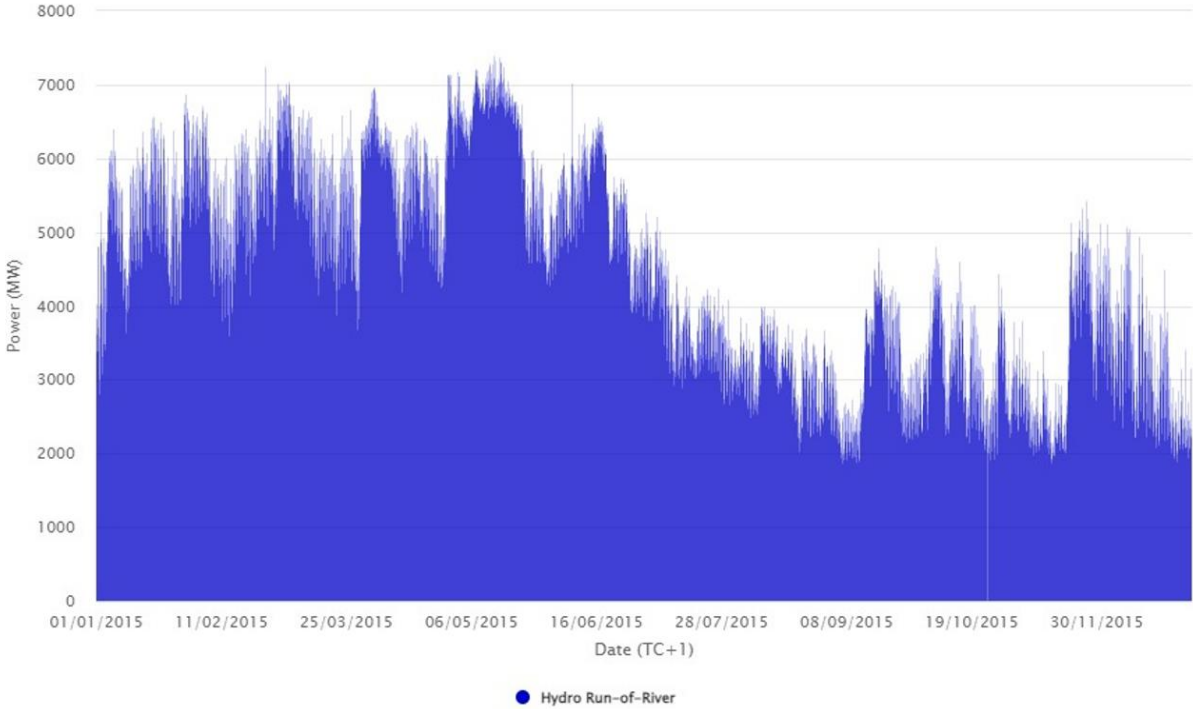


Figure 1. 8: Run-of-river generation in France – 2015 – Energy-Charts.info

Regarding other hydraulic generation facilities, namely dispatchable hydraulic facilities, the level of water inflow influences the level of stocks in dams and pumping stations and, ultimately, the strategy for planning hydraulic production to manage the production stock in these facilities. Dams are partially emptied at the end of the winter before the massive inflow of new production induced by the snowmelt. In the French case, the hydraulic peak production in winter to reduce the dam stock level corresponds to the consumption peak, which underlines the crucial role of controllable hydraulics for the security of supply.

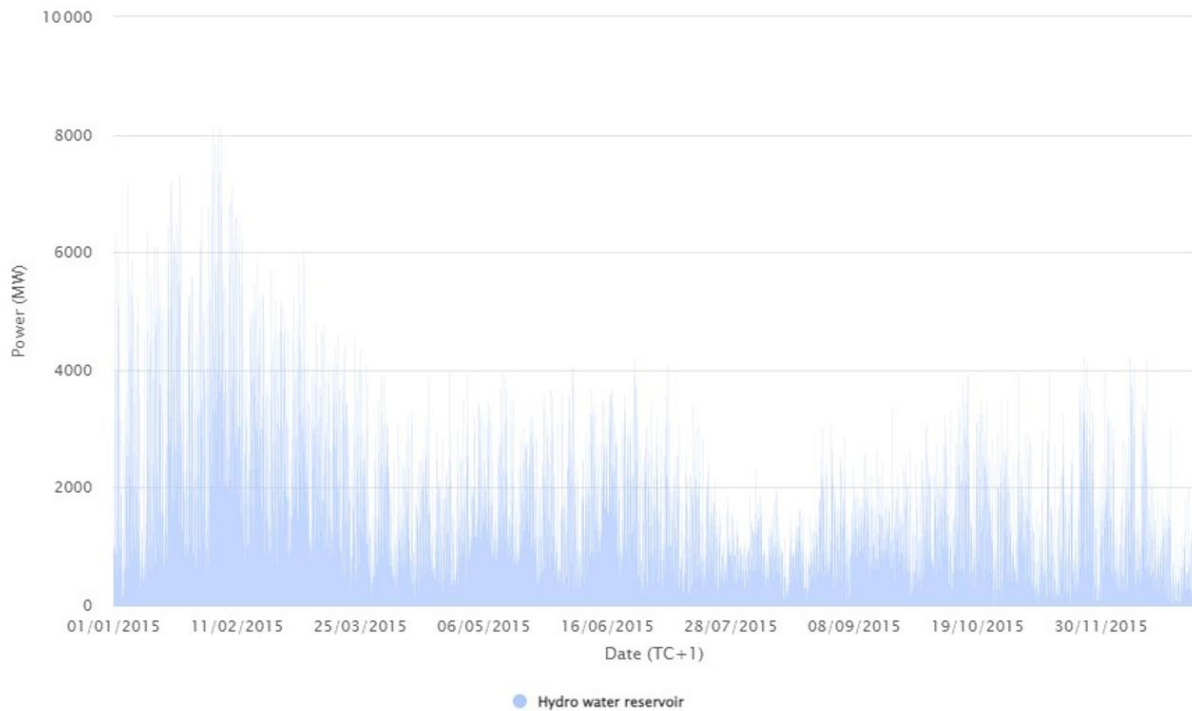


Figure 1. 9: Reservoir generation in France – 2015 – Energy-Charts.info

2.3. Impact of VRE integration on residual demand

The residual demand level and profile will change in the context of variable renewable energy development toward decarbonization of power systems. [16] summarizes the overall effect of the integration of variable renewable energy on residual demand: its level will most likely decrease as a greater share of the electric demand is ensured by VRE. Inversely, its volatility will increase due to VRE's inherent flexibility. Such a change in residual demand will influence the flexibility required from thermal generating sources and storage facilities. In this context, nuclear will need to operate flexibly to remain valuable to power systems.

Assessing the interaction between renewables capacity introduction in power systems and thermal generators is not a novel research theme. Indeed, in 2015, [17] already quantifies that a European power system with 32% wind and 8% solar results in more significant power ramps needed from dispatchable plants. The authors quantify that the occurrence of substantial residual demand ramps (defined as 20 GWe upward variations and 10 GWe downward variations) increases by 50% in such a power system. Additionally, extreme residual demand events (70 GWe power variations) start to appear.

A 2016 study on California [18] shows that, due to the expected increased solar and wind capacity in 2018 and 2023, extreme upward hourly residual demand ramps will increase during the late afternoon and early evening. Inversely, the number of extreme downward ramps increases during the morning, although less substantial. Such evolutions are linked to the predominant production share of solar energy in the California Independent System Operator (CaISO). In the morning, the increasing solar production lowers the residual demand level. Solar production decreases at the end of the day conjointly with the increase in domestic electric consumption. Hence, the upward ramping requirements to meet the demand-supply equilibrium

are challenging and must be ensured by dispatchable generation and storage units. Such a residual demand profile is characterized as a “duck curve”, as illustrated in Figure 1. 10. The magnitude of such a challenge then depends on the power system's solar penetration level. In recent years, the mid-day residual demand level has continuously decreased as solar capacity in California increased (see Figure 1. 10).

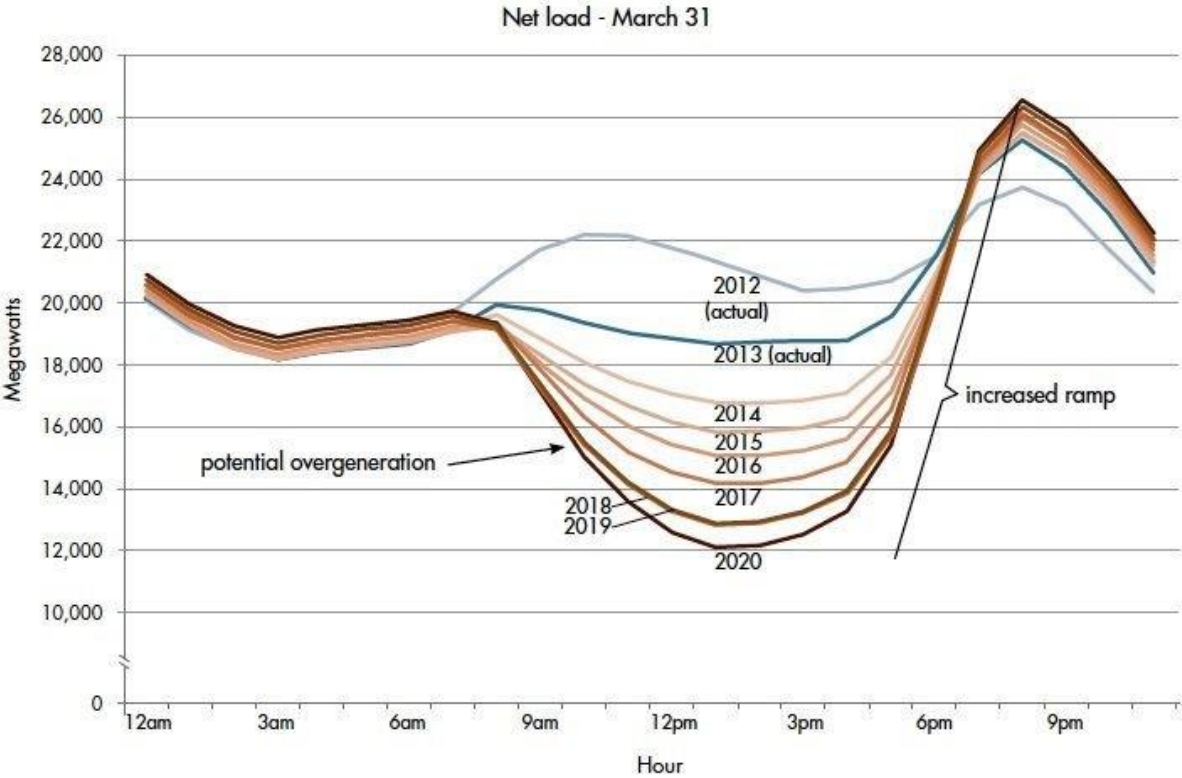


Figure 1. 10: Californian duck curve - CaISO

In Europe and France, such dynamics are weaker than in isolated power systems [17], as countries are interconnected, allowing better geographical dispersion of generation sources, thus, their overall production smoothing. Nonetheless, [19], in a study focused on the German power system, estimates that VRE integration will also significantly impact flexibility requirements. Indeed, reaching a 62% VRE penetration in the production mix should triple the maximal annual residual demand variation and the occurrence of substantial ramps (defined as 5 GWe/h variations in the study).

It is essential to note that future power systems evolutions would ease the challenges induced by a decreasing and more volatile residual demand. Indeed, [16] notes that most assessments surrounding the impacts of wind and solar integration on the temporal profile of residual demand are based on historical data, for example [17], [18], [20], thus ignoring the potential evolution of electric demand’s profile, and the technological improvements and changing geographical locations of future renewables installations. Moreover, electric vehicles may participate as storage capacities by charging and discharging at timely periods, thus participating in short-term flexibility requirements [21]. Sector-coupling, notably the use of electrolyzers to produce hydrogen, could, on the other hand, become a long-term storage source in Power-To-Gas-To-Power schemes (P2G2P) [22], [9]. Combined with flexibility from

diverse sources such as nuclear, decarbonized thermal technologies, batteries, or hydroelectricity, these new levers will contribute to balancing the electric supply and the modified demand.

3. NUCLEAR NOW AND THEN

In December 1951, at the Argonne National Laboratory in Idaho, USA, started up the Experimental Breeder Reactor EBR-1, the first nuclear reactor that produced electricity [23]. Atomic fission, whose focuses were previously fundamental research and the development of nuclear weapons in the second world war context, then found a new usage that participates in humanity's economic development. First located in the United States and the Soviet Union, nuclear power's use to produce electricity has since scattered worldwide.

As of June 2022, 440 reactors are in operation⁴, representing approximately 5% of the global primary energy consumption⁵ during the last decennia. Although marginal compared to fossils energy sources, nuclear technology has since represented a major asset as it has been the 2nd most significant source of decarbonized electricity generation after hydroelectricity for the last decades (see Figure 1. 11).

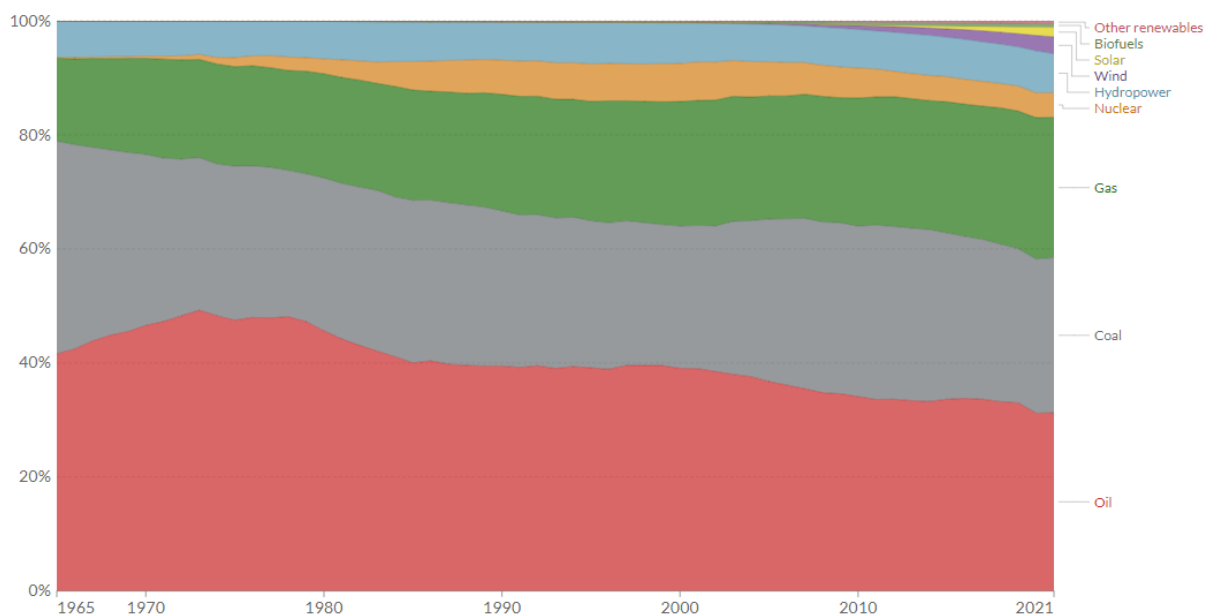


Figure 1. 11: Energy consumption by source, World - OurWorldInData.org/energy • CC BY⁶

Nonetheless, nuclear development has not been homogeneous, first geographically, as only 33 countries have used nuclear to produce electricity, but also temporally, as most nuclear reactors were built between the 70s and the start of the third millennium.

⁴<https://world-nuclear.org/information-library/current-and-future-generation/nuclear-power-in-the-world-today.aspx>

⁵ <https://ourworldindata.org/grapher/energy-consumption-by-source-and-region>

⁶ Primary energy consumption is measured in terawatt-hours (TWh). Here an inefficiency factor (the 'substitution' method) has been applied for fossil fuels, meaning the shares by each energy source give a better approximation

Several factors explain the uneven geographic distribution of nuclear power. Using nuclear power plants necessitates a skilled workforce to build the plant or maintain the safe operation of reactors. Numerous work tasks are specific to the nuclear industry, necessitating investment in long-term development programs. The entry cost is thus high, which may prohibit some countries from starting a nuclear program.

Additionally, due to non-proliferation reasons and safety concerns, countries may be reluctant to let others develop reactors. Eventually, most nuclear reactors are located in a limited number of developed countries, in Europe, Northern America, Russia, and East Asia, as seen in Figure 1. 12.

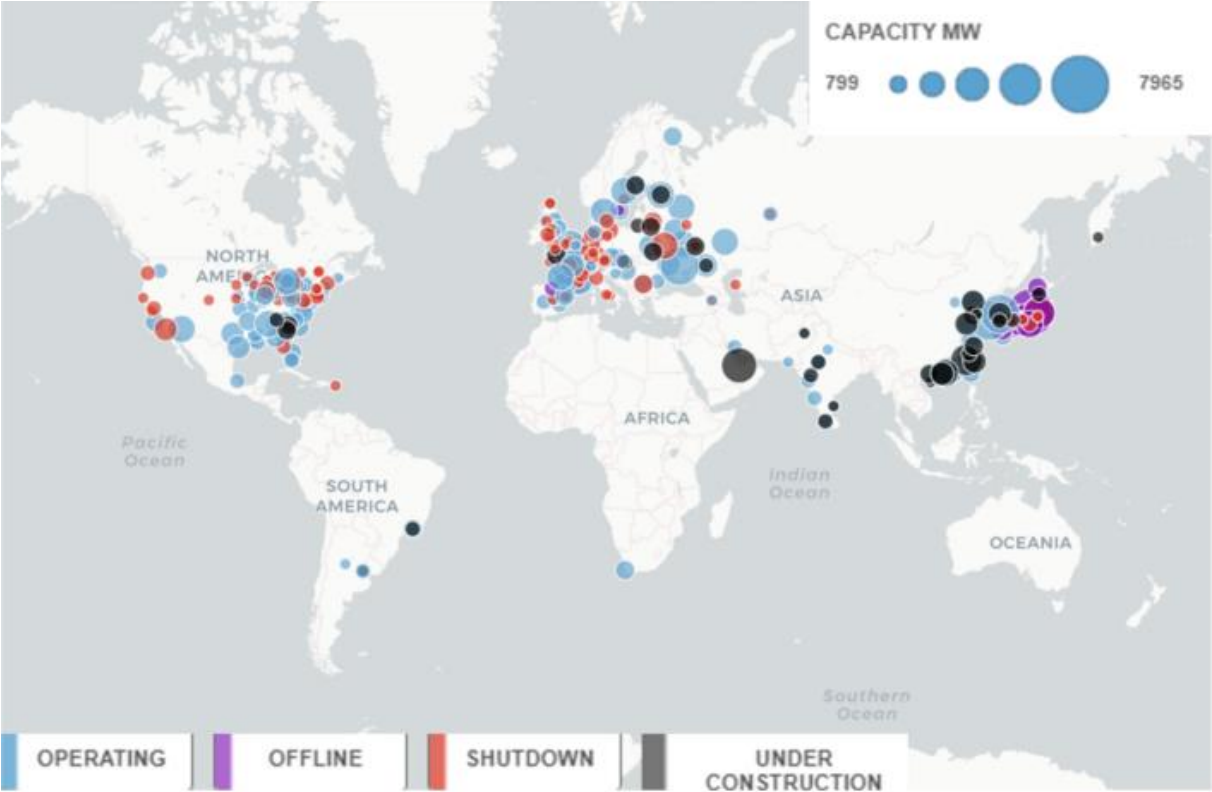


Figure 1. 12: Nuclear power plants’ location in the world⁷

Temporally, the development of nuclear power plants has also been uneven. After the development of the first commercial reactors corresponding to 1st generation reactors at the start of the 60s, consequent building programs started, increasing in the 70s following the 1973 oil shock and peaking around the 80s, as seen in Figure 1. 13. This corresponds to the building of 2nd generation reactors, mainly in Western Europe, Northern America, and the USSR. Starting from this point, the number of reactors in construction has been continuously decreasing until the mid-90s, notably after the Chernobyl accident in 1986, and plateaued for the ten following years, highlighting a decreasing interest in nuclear technology. The interest in new builds grew

of final energy consumption. 'Other renewables' includes geothermal, biomass and waste energy. Courtesy to Our World In Data.

⁷ <https://www.carbonbrief.org/mapped-the-worlds-nuclear-power-plants/>

again at the end of the 2000s with the first building of 3rd generation reactors to replace aging reactors in Europe and Northern America and the development of a novel fleet in China. However, following the Fukushima accident, the number of reactors in construction began stagnating again as some new reactor projects were abandoned, and the construction delays of 3rd generation reactors increased in Western countries. Hence, as illustrated in Figure 1. 14, most reactor new builds are currently taking place in China, which aim to quickly ramp up its electricity generation using nuclear and renewable energy. In countries with a historical fleet, the nuclear capacity tends to decrease as reactors age and political and societal oppositions emerge due to safety or waste concerns. The decreasing capacity effect is especially noticeable after Chernobyl and Fukushima, with records number of reactors shutdowns in 1990 and 2011.

Eventually, nuclear development dynamics are not chronologically linear nor coordinated between countries, and many parameters seem to influence its development speed. Broadly, the context strongly influences those developments, whether geographic, economic, political, societal, environmental, or safety-related parameters. Notably, social acceptability surrounding waste management and nuclear accidents has substantially impacted development perspectives, as in Germany or Japan. However, social acceptance levels regularly can evolve in the face of changing perceptions of nuclear, as illustrated by the restart of some reactors in Japan and the new building plans in South Korea.

The future of nuclear energy will likely remain conditioned by these contexts, with changing political and societal support depending on those parameters. The thesis work presented here acknowledges this fact. Thus, it does not aim to determine the future of nuclear energy based solely on a techno-economics analysis of its interaction with renewable energy.

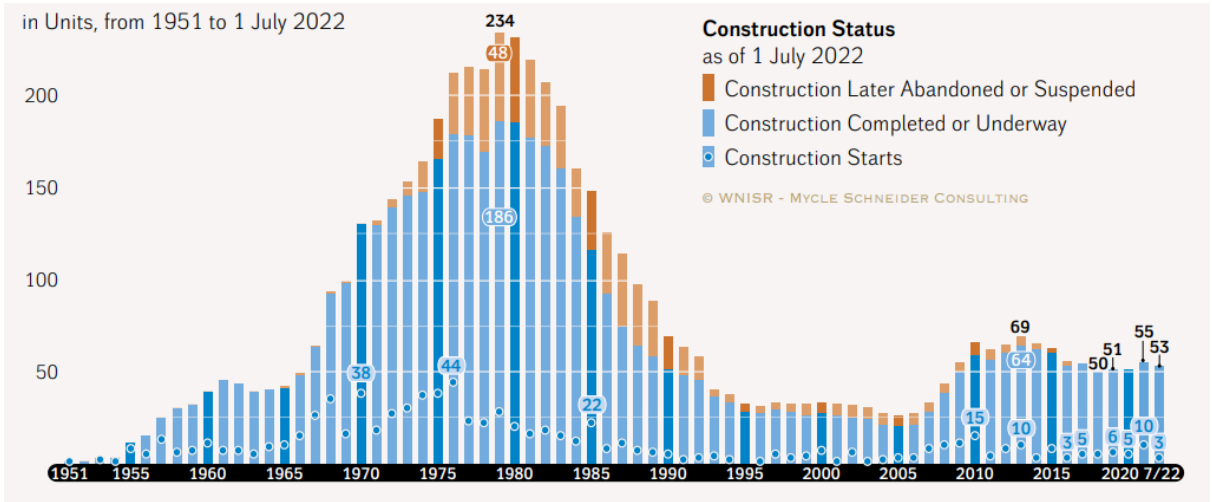


Figure 1. 13: Reactors under construction in the world ([24] and IAEA PRIS)

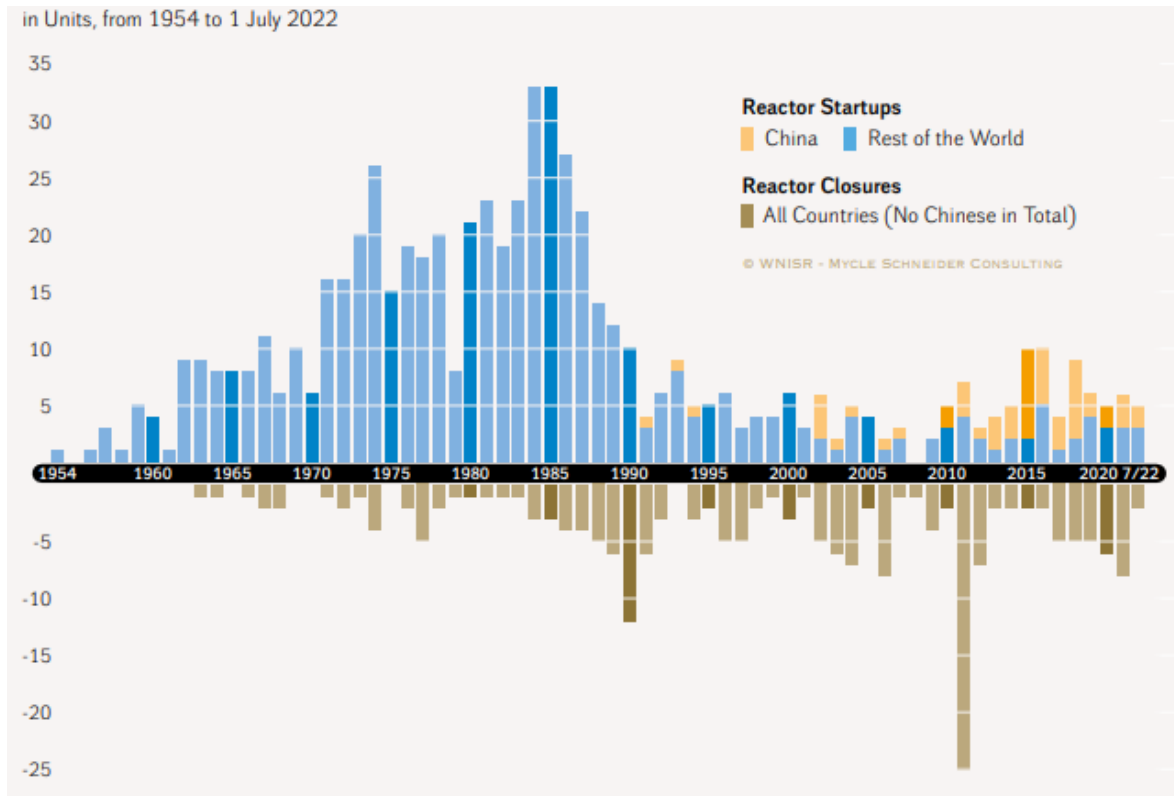


Figure 1. 14: Reactors startups and closures in the world ([24] and IAEA PRIS)

As this thesis' work focuses mainly on French nuclear and the use of its flexibility in future decarbonized power systems, it is necessary to provide some context regarding its specific history and potential future.

Nuclear has a particular role in France as it represented between 77.9 % and 68.9 % of its total electricity generation from 2015 and 2021 (as illustrated for the year 2015 in Figure 1. 15), with a slightly decreasing tendency these last years linked to the covid crisis and recent corrosions events that temporarily prohibited part of the fleet from producing (65.7% as of October 2022). Globally, France has the second largest nuclear fleet (61.3 GWe) just after the United States (94.7 GWe), soon to be the third largest as China is quickly ramping up its installed capacity.

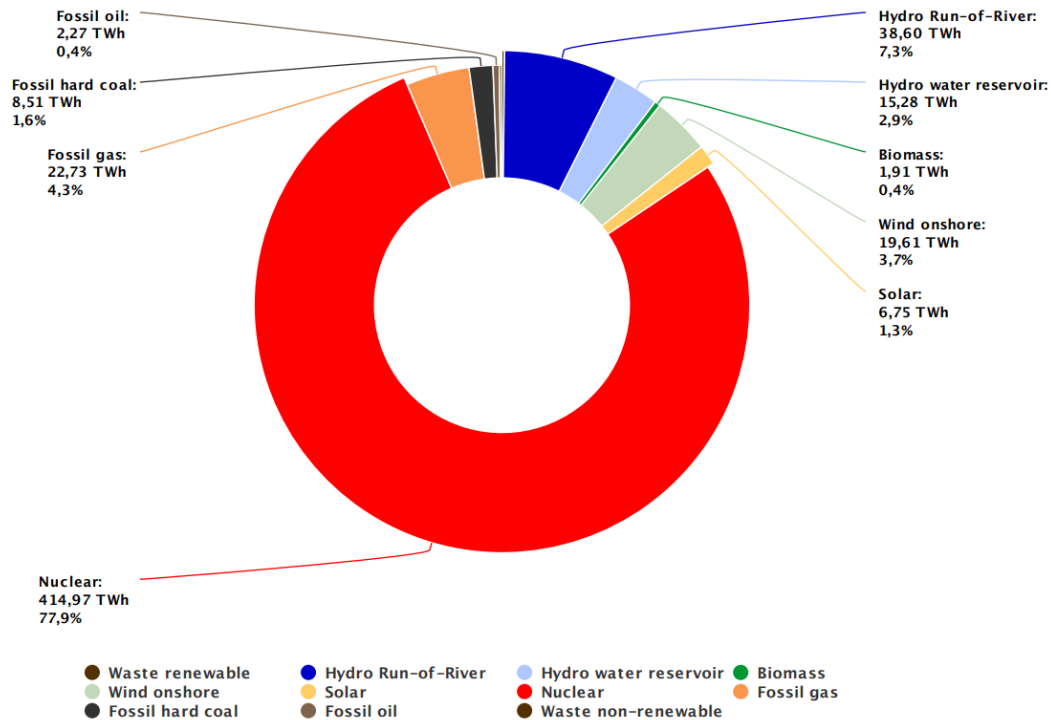


Figure 1. 15: Electricity production by sources in France - 2015

Following the Second World War, France developed a civil and military nuclear program to ensure its strategic independence and sovereignty in the face of the cold war context [25]. The first nuclear builds started with the development of a French reactor design, the Uranium Naturel Graphite-Gaz (UNGG), a graphite-moderated, carbon-dioxide-cooled, and natural uranium-fueled design. This design has been since abandoned in favor of the Westinghouse-licensed Pressurized Water Reactors (PWRs) using enriched uranium, and the nine reactors constructed are currently being decommissioned. Since then, 2nd generation reactors have made up the entirety of the French nuclear fleet, with only one 3rd generation reactor currently in construction, the Flamanville Evolutionary Power Reactor (EPR), a novel design aiming to increase the performance and safety of nuclear operation. Although France developed 4th generation nuclear reactors designs, notably Fast Breeder Reactors (FBR), current projects have been on hold since the closure of the 1242 MWe Superphoenix reactor in 1997 and the recent abandonment of the Advanced Sodium Technological Reactor for Industrial Demonstration (ASTRID) in 2019. Potential plans for nuclear in France now primarily focus on 3rd generation reactors such as EPRs, its evolved version, the EPR2, aiming to simplify construction for the benefit of quality, duration, and cost of construction without impacting on safety, according to Electricité De France (EDF)⁸, and the Nuward Small Modular Reactor (SMR), being developed by a consortium made up of EDF, TechnicAtome, Naval Group, and the French Alternative Energies and Atomic Energy Commission (CEA).

The current French nuclear is characterized by its relatively high age (average age of 35 years in 2022), as all reactors were put into service between 1977 and 2002 (see Figure 1. 16). The

⁸<https://www.edf.fr/la-centrale-nucleaire-de-penly/les-actualites-de-la-centrale-nucleaire-de-penly/lepr2-est-une-version-optimisee-et-industrialisee-de-lepr>

fleet was built in five different groups of reactors, with increasing capacity and evolutionary design. The five groups are chronologically CP0 and CPY (900 MWe – 32 reactors, 2 shut down), P4 and P’4 (1300 MWe – 20 reactors), and N4 (1450 MWe – 4 reactors). As of 2022, the total French nuclear capacity is 61.3 GWe (63.1 GWe before Fessenheim’s shutdown), distributed among 56 reactors located in 18 operating sites. The only reactor in construction is 1650 MWe EPR and should start operating commercially in 2023, according to the latest EDF plans⁹, although its original industrial commissioning was planned for 2012. Thus, the reactors in operation have or will soon exceed the 40 years life length threshold, and the question of their renewal arises. It is possible to continue operation after this threshold provided that reactors pass a specific inspection by the independent French nuclear safety authority (Autorité de Sureté Nucléaire: ASN). It is then unsure whether reactors will be able to continue operating for prolonged periods, and the perspective of their shutdowns has to be considered. As illustrated in Figure 1. 16, whatever the assumption regarding reactors’ ability to operate long-term, the existing nuclear capacity will decrease if no new builds are considered.

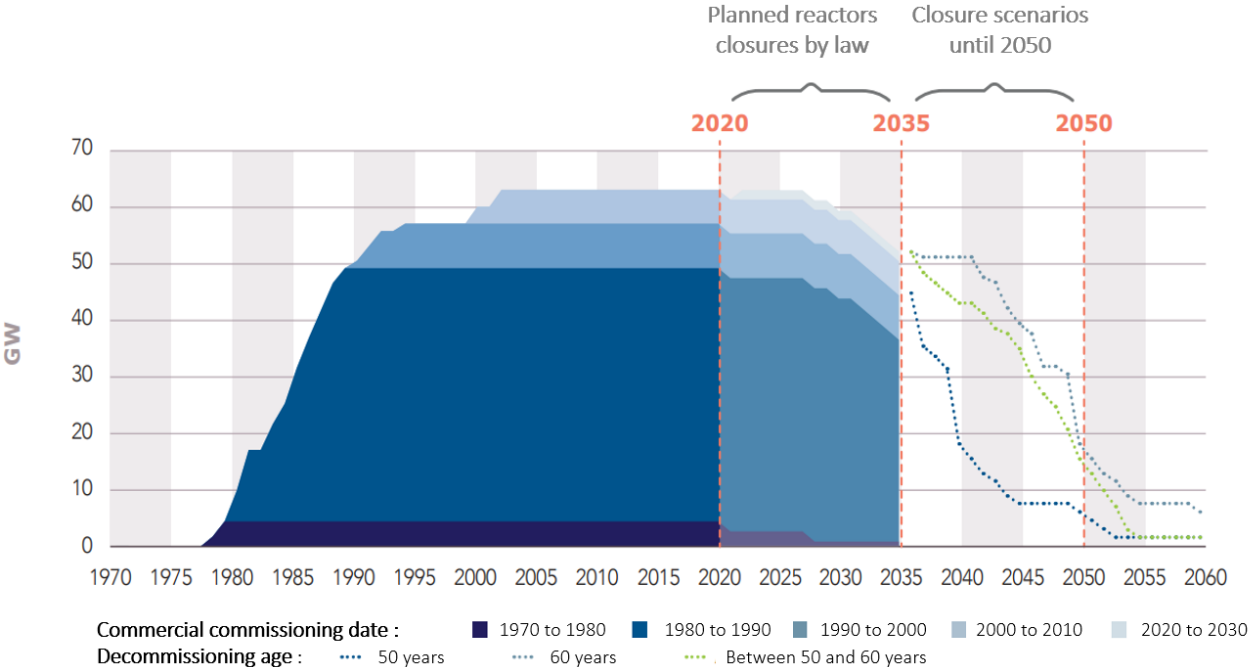


Figure 1. 16 : Existing fleet capacity scenarios [26]

Although a new energy programming law is currently being discussed in France, the current Multi-annual Energy Program (Programmation Pluriannuelle de l’Energie: PPE) voted in 2018 stipulates the closure of 12 reactors until 2035 [27]. Conjointly, the share of nuclear energy should reach 50%. Recent debates occurred on the pertinence of such goals, especially as the French Transmission System Operator (TSO) Réseau de Transport d’Electricité (RTE) released prospective reports exploring the potential future French decarbonized power mix [26], and the technical feasibility of 100% renewables power mix in collaboration with the International Energy Agency (IEA) [28]. Following those reports and the 2022 presidential election, the

⁹<https://www.edf.fr/groupe-edf/espaces-dedies/journalistes/tous-les-communiques-de-presse/point-d-actualite-sur-l-epr-de-flamanville-0>

eventuality of building 6 EPR2 reactors has been brought to public debate. Hence, nuclear in France is currently at a crosspoint with its aging fleet and the question of its potential renewal.

Eventually, the main challenges facing nuclear power in France are the aging of its fleet and the question of its renewal. Such debate is controversial, as opposition to nuclear energy has emerged due to safety concerns of the general public following the Chornobyl and Fukushima accidents and interrogations linked to nuclear's economic competitiveness illustrated by the cost overruns of the Flamanville EPR. Nonetheless, the latest opinion poll conducted in September 2022 [29] shows an increased support trend toward nuclear energy and new reactor builds in the face of energy crises, climate concerns, and the country's energy independence. Compared to the results of the same opinion poll carried out last year, support for nuclear has increased by 14 points to reach 75% of favorable opinions.

4. MAIN CHALLENGES FACING NUCLEAR ENERGY IN FRANCE AND EUROPE

This part briefly introduces the two challenges facing nuclear energy in the future. The objective is to focus on specific challenges that will be addressed in the main chapters of the manuscript, notably reactors' adaptability to the residual demand and the market design framing nuclear revenues and economic viability. It is nonetheless essential to highlight that the technology's social acceptance is a prerequisite to future developments. Additionally, the question of cost overruns and building delays is essential for future developments.

4.1. Nuclear adaptability to a decreasing and more volatile residual demand

Facing the predicted increased flexibility requirement, nuclear power plants (NPP) typically operate in 'baseload' mode, meaning that they mostly produce at their nominal power level. Nuclear has high fixed costs and low variable costs, making it economically optimal to use this operation mode. Hence, nuclear reactors operating as "baseload" do not seem to match the flexibility requirements of future decarbonized power systems. Nonetheless, countries with a higher share of nuclear capacity may be forced to maneuver their NPP output to balance electricity demand and supply. The French electric system is a case in point: NPP represent 46.6% of France's installed capacity and 70.6% of its electricity generation (2019) [30], so NPPs frequently maneuver to participate in flexibility operations, either by load-following (power variations usually higher than 10% of a reactor's nominal power to adapt to residual demand variations), primary frequency control (short-term adjustment to stabilize production and power-system demand in the timeframe of seconds) or secondary frequency control (several seconds to several minutes of automatic power adjustment aiming to restore frequency following frequency deviations) [31]–[33]. The nuclear fleet then covers a significant share of the current French flexibility requirements. Broadly speaking, part of the installed nuclear fleet was either initially designed to operate flexibly [32] or can be adapted to this regime through re-design work [33]. There is a dense literature on nuclear flexibility, its ability to load-follow, and the additional costs generated, i.e. wear of components, cost of retrofit and re-design, fuel, and staff costs [19], [33]–[41]. One of this thesis' objectives is to determine how flexible nuclear reactors are and how they can adapt to this changing residual demand.

Eventually, the stakes surrounding nuclear and the decreasing and more volatile residual demand relates to reactors' ability to adapt to these new flexibility requirements. Such considerations will be discussed in Chapter 2.3.

4.2. Power systems market design

In the wake of economic liberalization in the 90s, power markets were progressively liberalized in Western Europe towards a common electricity market, first through the adoption of the first energy package in 1996 that defined the rules of an internal electricity market until the third energy package in 2009 establishing national and pan-European (Agency for the Cooperation of Energy Regulators: ACER) energy regulators to ensure competition. From vertically-integrated national monopolies (right-side illustrated in Figure 1. 17), the market structure was changed toward competitive markets for generation and retailing while maintaining regulated operations for transmission and distribution as they are natural monopolies.

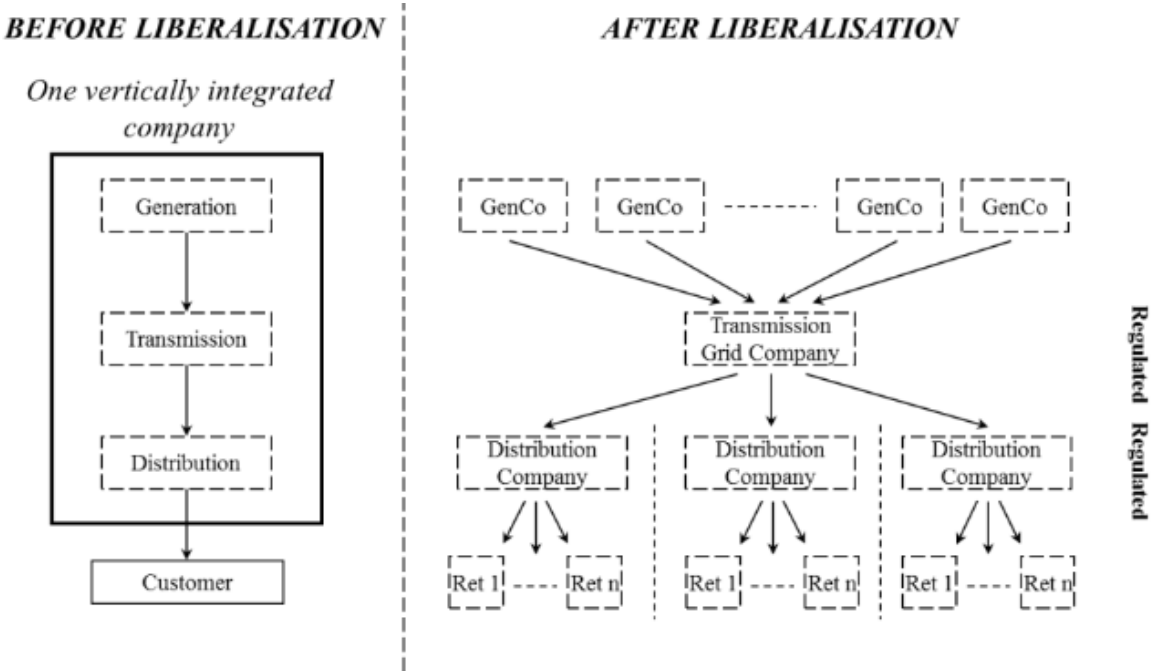


Figure 1. 17: Liberalization of the power market [42]

Such changes have been impactful as it created several related sub-market depending on their time horizons, namely forward/future (from several years to the next week), day-ahead, intraday, and balancing markets, where generators compete to sell their power production. Although prices are determined over-the-counter, driven by interest rates, and markets participants' future expectations on forward markets, and bid and ask mechanisms in future, day-ahead, intraday, and balancing markets, the underlying economic discrimination principle in perfect market conditions is the merit order, ranking technologies based on their ascending order of marginal cost. Price signals should then ensure investment in profitable capacity toward long-term null profits for all generators.

However, several market failures impact the economic optimality of such liberalized power systems. First, the introduction of consequent VRE capacity, thanks to countries' support mechanisms, impacts the overall power markets without allowing sufficient time for the supply

side to adapt to those sources. As the merit order prioritizes VRE generation characterized by its near-zero marginal costs, VRE introduction decreases the average market prices, thus endangering other generators' economic viability [42]. As noted by [43], future power markets should be characterized by increased occurrences of low prices hours, with few high prices hours where flexible generators will recover costs.

This situation is detrimental to guaranteeing the future power supply-demand equilibrium. Investors predicting increased price volatility are more averse to new capacity builds as they support more risk without additional returns. Capital-intensive such as nuclear, renewables and storage units are exponentially exposed to this phenomenon, as a higher investment is necessitated upfront. Thus, as noted by [42], apart from renewables benefiting from support mechanisms, most investments occurring since electric markets liberalization are gas plants, whose capital costs are low and can be mothballed at low costs. Eventually, the historical over-capacity of European power systems is threatened as some nuclear plants are being decommissioned, and carbonized generation sources are closed in light of climate concerns. According to [44], from 2000 to 2020, the total European Union nuclear capacity decreased by 16 GWe, coal capacity by 27 GWe, and oil capacity by 36 GWe. Conjointly, 96 GWe new gas capacity has been built.

In order to complement generators' revenues and ensure future investments, numerous capacity mechanisms have been introduced [45]. Although capacity mechanisms across countries have different designs, they have the same purpose “—to incentivize sufficient infrastructure investment to meet future electricity demand and, thus, assure mid- and long-term electricity system reliability“ [45]. The underlying principle is to complement the “energy-only” market through the remuneration of capacity availability. Then, such mechanisms may encourage investment in capital-intensive technologies. Overall, the emergence of capacity mechanisms highlights recent academic discussions about hybrid market designs [46]–[48] surrounding the need for reforms that reconcile short-term operations and long-term investment decisions.

Recent discussions have occurred in Europe in the wake of the Russian-Ukrainian conflict and related gas and power price surges. Hence, interrogations surrounding current market designs' ability to prevent short-term price increases while providing long-term investment signals have emerged, resulting in probable short-term design reforms to protect final consumers. As of this manuscript's redaction, the nature of the measures to be adopted and their sustainability are not yet fully defined; thus, they will not be discussed here.

5. SCOPE OF WORK AND RESEARCH QUESTIONS

As identified in this introductory chapter, the challenges facing nuclear in future decarbonized power systems are numerous. Then, to operate a complete analysis, one should adopt an interdisciplinary approach combining, among others, physics, economics, finance, and sociology while including risk assessment analyses that could influence nuclear energy. Such work is too vast for this thesis, whose duration is limited to three years. This work must then focus on specific research questions while acknowledging its incompleteness in solving the nuclear debate.

Hence, the thesis proposes a techno-economics approach in line with recent literature on renewables-driven power systems. As this manuscript is structured in three different chapters, the research questions are:

- What is PWRs flexibility potential, and how is it depicted in the existing modeling literature? (Chapter 2)
- How can modelers represent nuclear flexibility constraints in Mixed-Integer Linear Programming models, and what is their relevance? (Chapter 3)
- Based on cost minimization, what is the optimal mix in future decarbonized power systems considering nuclear flexibility, and how do reactors operate with renewable energy? (Chapter 4)

6. THESIS STRUCTURE

Following the research questions, the thesis is structured in three main parts after the introductory chapter, with methods and results feeding into the next.

Chapter 2 resumes the main physics principles of electricity production using Pressurized Water Reactors and presents the main components of those reactors. Then, the chapter highlights that the flexible operation of PWRs units is substantial, although constrained by technical parameters such as Pellet-Cladding Interaction, xenon transients, and refueling and maintenance of reactors. The chapter then discusses power systems modeling approaches and determines which approach ensures the best compromise between the results' accuracy and computational complexity. Lastly, it reviews the integration of nuclear flexibility constraints in the modeling literature and discusses the potential impacts of the misestimation of those constraints on models' results.

Chapter 3 builds on Chapter 2 by proposing a novel modeling framework to represent two nuclear flexibility constraints whose integration is rare in the literature: the operational schedule of nuclear power plants and reactors' minimum power evolutions linked to xenon transients dynamics in their core. The underlying model is based on a MILP approach and historical data derived from EDF's operational experience. By comparing several nuclear flexibility constraint modeling assumptions applied to simplified power system simulations (one country and one year with 8760 timesteps), the chapter aims to determine the pertinence of implementing such constraints at the cost of increased computational complexity. Hence, the results fill a literature gap by providing a modeling method for such constraints and highlighting that such constraints are of little interest when VRE penetration in power systems is low, and impactful as modelers consider power systems with a high share of renewable energy.

Chapter 4 aims to expand Chapter 3's work by integrating the previously-mentioned nuclear flexibility constraints into a broader capacity expansion model, simulating ten meteorological years scenarios with 2050-levelized power demands, the whole European power system, a higher number of generating and technologies, and investing in new decarbonized capacities in the Western European area (solar, wind, decarbonized gas, and nuclear). The model's objective is to reach a least-cost capacity mix that ensures the demand-supply equilibrium while considering installation potential constraints for VRE and nuclear reactors (limited by

countries' willingness to invest in the technology and supply-chain constraints). Hence, the chapter discusses each technology' optimal capacity, notably the predominant VRE share, as their costs are low and potentials are high. The chapter also considers nuclear cost uncertainties, with one scenario replicating Flamanville 3's costs, to discuss its optimal capacity's sensitivity to cost overruns and building delays. Eventually, the chapter focuses on the future of the French fleet and how it would operate with high shares of VRE, especially regarding its load factor, flexibility requirements, and overall revenues.

The conclusive chapter summarizes the main contributions of the thesis and discusses potential extensions of the presented work.

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1. INTRODUCTION

As mentioned in the introduction chapter, this thesis focuses on the future role of flexible use of nuclear power concurrently with renewable energy in future decarbonized power systems. Naturally, this theme draws the question of the technical feasibility of such mixes, especially regarding the ability of reactors to adapt to the variability of VRE production. Another question relates to the consideration of the technical characteristics of nuclear energy in prospective studies focusing on decarbonized energy systems.

This chapter first introduces the main principles of electricity generation derived from nuclear technology, especially Pressurized Water Reactors (PWRs). Then, it focuses on the primary flexibility limits of nuclear energy that limit its ability to adapt to the variability of electric demand and renewable sources. Finally, the chapter discusses modeling approaches to analyze the future of nuclear energy in decarbonized mixes while accounting for the technical limitations of this technology. This last part also introduces the existing modeling literature surrounding future power systems with renewable energy and the modeling practices of nuclear energy.

2. NUCLEAR FISSION AND MAIN COMPONENTS OF A PRESSURIZED WATER REACTOR

Like all other thermal generating plants, a nuclear power plant is a thermodynamic machine that generates steam to drive a turbine that drives an alternator to generate electricity. However, contrary to combustion processes in fossil or renewable fuels plants, the thermal power source is the nuclear fission reaction, in which an atom splits and releases thermal energy. Hence, the underlying principle allowing steam generation differs from other thermal plants. Such characteristic results in specific operational constraints that need to be evaluated when considering nuclear reactors' ability to operate with high shares of renewable energy.

Broadly, various types of nuclear reactor designs were developed and still coexist. As of June 2022, 440 nuclear reactors are in operation, divided into seven different reactors designs: Pressurized Water Reactors (PWRs – 307 reactors), Boiling Water Reactors (BWRs – 61 reactors), Pressurized Heavy-Water Reactors (PHWRs – 48 reactors), Light Water Graphite Reactors (LWGRs – 11 reactors), Gas-Cooled Reactors (GCRs – 10 reactors), Fast-Breeder Reactors (FBRs – 2 reactors), and High-Temperature Gas Reactors (HTGRs – 1 reactor). Conjointly, 55 nuclear reactors are currently being built, the majority being PWRs (46 units), then FBRs (4 units), PHWRs (3 units), and BWRs (2 units).

Although the underlying principle of nuclear fission does not fundamentally vary depending on the reactor design, as all existing designs rely on nuclear fission, it is crucial to consider that different designs are not subject to the same generation constraints. As this work focuses on the role of nuclear energy in the French electric transition, we chose to consider only PWRs designs, as it is the unique technology in France for existing and upcoming reactors, all historical French Gas-Cooled Reactors (UNGG) being currently decommissioned.

This part first explains the underlying principle of the chain reaction that produces thermal energy. Then, the chapter presents the main elements of a nuclear power plant allowing thermal

energy conversion into electrical energy. Finally, a brief presentation of the circuits allows us to address the issues related to cooling and regulating the chain reaction.

2.1. Nuclear fission and chain reaction principle

Nuclear fission is the basic principle of thermal energy generation in a nuclear reactor. It is the process in which the nucleus of an atom splits into two fragments, releasing a large amount of energy and some neutrons [1]. A nuclear reactor's principle is to induce nuclear fission reactions by colliding deliberately a neutron and the nucleus of a fissile isotope – as the isotope 235 of uranium. As the U-235 nucleus captures the bombarded neutron, it becomes unstable toward nuclear fission, emitting thermal energy, fission products, and two to three neutrons (Figure 2. 1). The emitted neutrons will interact with their surrounding medium, resulting in their absorption by non-fissile material, such as U-238 isotopes, or in their collision with new fissile isotopes, inducing new fissions and releasing more thermal energy and neutrons. Thus, not all neutrons produced by fission will result in new fissions.

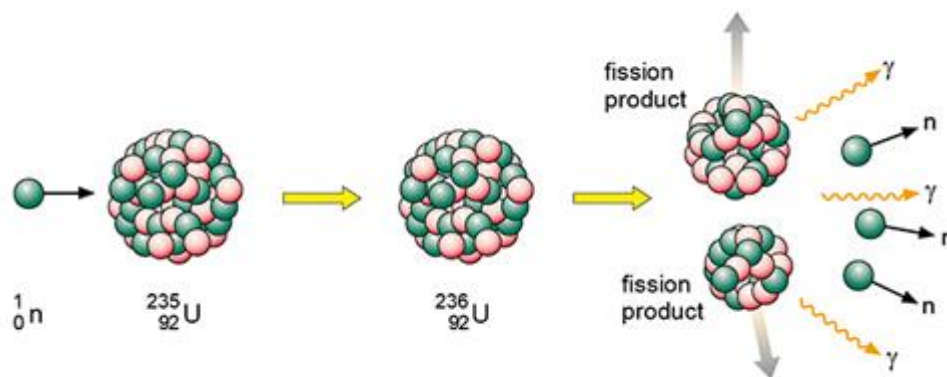


Figure 2. 1 : Nuclear Fission reaction U235

(<https://www.open.edu/openlearn/mod/oucontent/view.php?id=26801§ion=3.3>)

To maintain the chain reaction, it is essential that, for each fission, one of the emitted neutrons splits another nucleus. The number of fission reactions induced by emitted neutrons is called the neutron multiplication factor. The chain reaction decreases and stops if the neutron multiplication factor is less than one. If the multiplication factor is greater than one, the number of fission reactions increases. The objective of nuclear operators is to maintain to one the fission multiplication factor to control the chain reaction. In the case of U-235, as it averagely emits 2.4 neutrons when undergoing fission, an emitted neutron must cause new fission reactions with a 0.42 probability to maintain the chain reaction [2].

2.2. Main components of Pressurized Water Reactor

Pressurized water reactor plants are composed of several components: the core, the primary circuit, the steam generators, the secondary circuit, the turbines, and the cooling circuit [3]. The interlocking of these components is presented in Figure 2. 2.

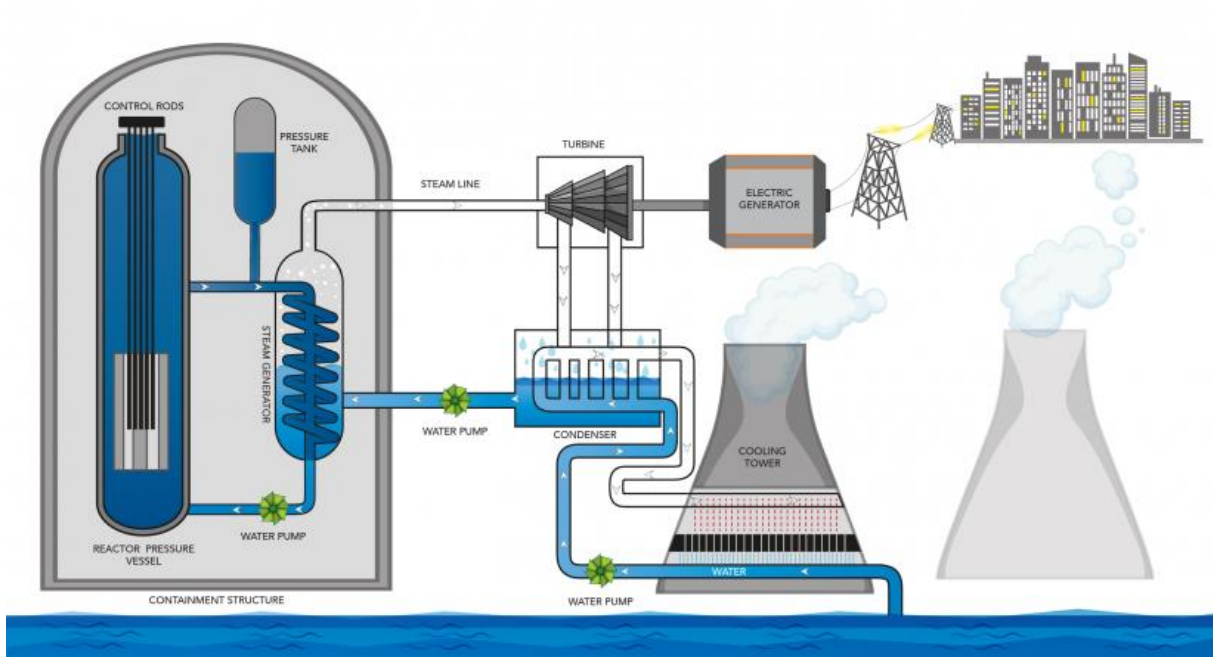


Figure 2. 2 : Pressurized Water Reactor (PWR) diagram - S. Harman Departement Of Energy

2.2.1. The reactor core

The reactor core is located in the vessel in the reactor building. It is where fission reactions occur and the heat is generated.

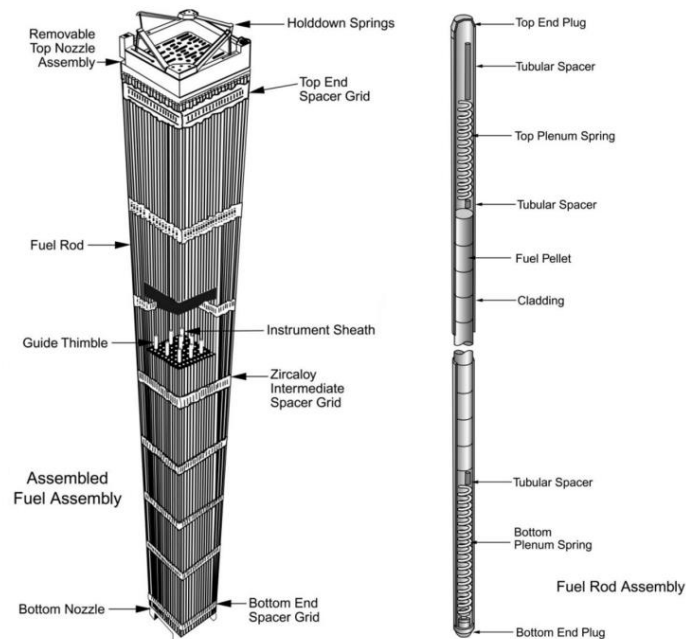


Figure 2. 3: Schematic view of a PWR fuel assembly and a PWR fuel pin [4] (Adapted from [5])

In a PWR, the core is composed of multiple meters-long fuel rods that are grouped to form fuel assemblies (see Figure 2. 3). Inside each fuel rod are stacked fuel pellets, most commonly composed of Uranium OXide (UOX or UO_2) or Mixed OXide (Uranium and Plutonium Oxide

– MOX, originating partially from fuel reprocessing). This fuel contains fissile material (U-235 or Pu-239, which allows the fission reaction to generate thermal energy). Fuel rod claddings are made with Zirconium alloy, a material chosen for its resistance to corrosion and its permeability to neutrons. Hence, the fuel rods' claddings constitute the first safety barrier containing the radioactive products. In total, each assembly contains 264 fuel rods in a French PWR¹⁰.

The total number of assemblies in the core varies between 157 and 205, depending on the reactor's design and nominal power. Typically, reactor operators replace about a quarter to a third of those assemblies with each reactor outage every 12 to 24 months for refueling [6]. Hence, after several years in the core, each assembly is replaced once its fuel is depleted.

Inside the core are also control rods composed of neutron-absorbent materials. The depth at which these control rods are inserted regulates the chain reaction. Through the core, the water of the reactor's primary circuit cools the fuel rods while transferring the heat generated from the fission reactions to the steam generators (see Figure 2. 4).

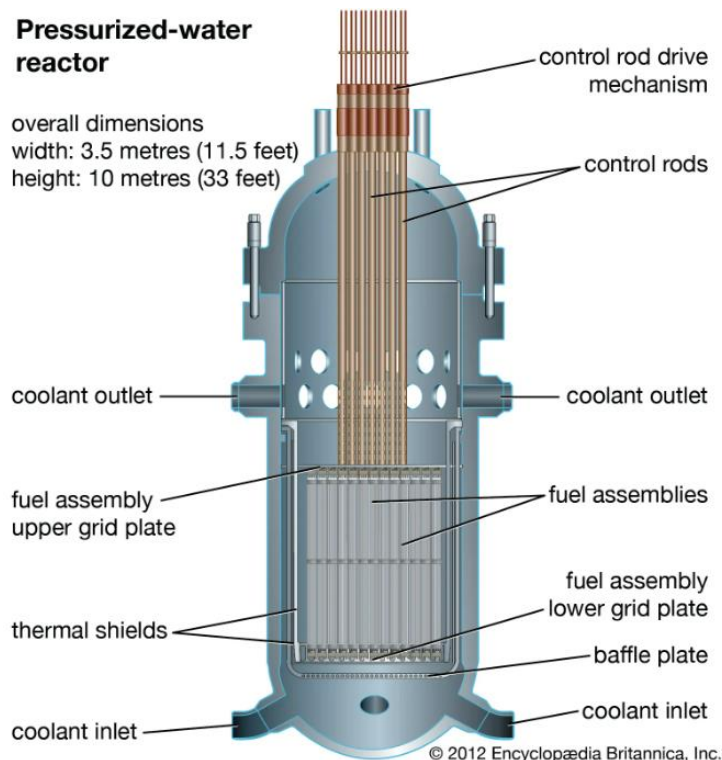


Figure 2. 4: Section of a pressurized-water reactor (© Encyclopædia Britannica, Inc.¹¹)

2.2.2. The primary circuit

The primary circuit of a PWR plant constitutes the second safety barrier preventing the dispersion of radioactive products. It is a closed circuit of pressurized liquid water (155 bar).

¹⁰[https://www.asn.fr/1-asn-informe/actualites/centrales-nucleaires-edf-combustible#:~:text=1%20%2D%20L'%C3%A9tanch%C3%A9it%C3%A9%20du%20combustible,voir%20sch%C3%A9ma%20en%20annexe%201\).](https://www.asn.fr/1-asn-informe/actualites/centrales-nucleaires-edf-combustible#:~:text=1%20%2D%20L'%C3%A9tanch%C3%A9it%C3%A9%20du%20combustible,voir%20sch%C3%A9ma%20en%20annexe%201).)

¹¹ <https://www.britannica.com/technology/nuclear-reactor/Types-of-reactors>

Water has a dual role as a moderator and a coolant. As a moderator, it slows down the neutrons by diffusion, thus favoring fission reactions of fissile material such as U-235. As a coolant, it transports the heat produced by fuel pellets to the steam generators while cooling the core.

The heat of the primary circuit is transferred to the secondary circuit through the steam generators (see Figure 2. 2). The number of primary circuit loops is specific to the design of the reactors and their power (in France, their number varies from 3 for the 900 MW and 4 for the more powerful reactors).

The primary circuit's water also contains diluted boric acid (H_3BO_3), a neutron poison that moderates the chain reaction. By adjusting its concentration in the primary circuit, operators can therefore modulate the thermal energy produced in the core.

2.2.3. The secondary, tertiary, and auxiliary circuits

The secondary circuit is a closed water circuit under lower pressure than the primary circuits (about 70 bar). The thermal energy recovered in gaseous form from the steam generators is sent to the power plant's turbine, which is coupled to an alternator and produces electricity. After going through the turbines, the steam is condensed due to the tertiary circuit. It then returns to the steam generators. The tertiary circuit is, contrary to the other circuits, open to the environment (a river, the sea, or air coolers).

In addition to the primary, secondary, and tertiary circuits that transmit the thermal energy to the turbine and cool the core, other circuits ensure several safety functions. The description of these circuits is not helpful for the presentation of this work.

3. FLEXIBILITY LIMITS OF NUCLEAR POWER PLANT

This section summarizes the potential flexibility constraints that apply to PWRs. This sub-chapter determines the underlying phenomena framing essential flexibility constraints, i.e. pellet-cladding interaction, xenon transients, and outage constraints. The objective is to determine the relevance of modeling these constraints and guide practice to reflect nuclear flexibility in power systems simulations.

3.1. Pellet-cladding interaction and ramping constraints

PWRs can modify their output level by changing their primary circuit's boric acid concentration, a neutron absorber, or by changing neutron-absorbing control rod insertion levels. The underlying principle is to manage the fuel's chain reaction and the thermal energy level it produces by modulating the fission reaction rate in the core¹². Typically, increasing boron concentration in the primary circuit or increasing the insertion level of control rods in the fuel assemblies will decrease the fission reaction rate, thus lowering the thermal power

¹² The core is the place in a nuclear reactor where fission reactions take place and the heat is generated. In a PWR, this core is composed of multiple meters-long fuel rods that are grouped together to form fuel assemblies. Fuel-rod claddings are made with zirconium alloy, which is used for its resistance to corrosion and its permeability to neutrons. Inside each fuel rod are stacked fuel pellets, most commonly composed of Uranium Oxide (UO_2). The heat generated from the fission reactions originating from the fuel pellets is transferred to the water of the reactor's primary circuit that flows through the core. Inside the core are also control rods, which are composed of neutron-absorbent materials, and the depth that these control rods are inserted regulates the chain reaction.

produced, the steam production rate, and the electrical output of the power plant. [7]–[10] note that as control rod movement allows for faster and more precise power management, plant managers favor it over boric acid regulation¹³ to operate flexibly. However, such power variations do not come without thermal and mechanical consequences.

The movement of control rods in the core creates thermal variations that influence the volume of fuel pellets and their surrounding claddings. When control rods are inserted, the temperature drops locally in the core, and part of the fuel's pellets and claddings contract. Conversely, when control rods are withdrawn, the temperature rises locally, and part of the fuel's pellets and claddings dilate. Because the fuel pellets have a higher temperature (especially in the center) and a higher thermal expansion coefficient than their claddings¹⁴, their volume evolves more consequently to power variations [13], [14]. These power variations may bring pellets into contact with the claddings [15], [16], creating mechanical stress that endangers the integrity of the claddings, which is a breach of the first containment barrier of PWRs. This Pellet-Cladding Interaction (PCI) phenomenon does not bring production to a standstill, but it is common practice not to carry out flexible maneuvers following breaches in the cladding [7]. Other corrosion effects due to corrosive fission products may increase the occurrence of such breaches.

The overall effect of PCI on the flexibility capabilities of PWRs is that the maximum power ramping rate has to be limited to avoid creating excessive mechanic stress and keep the number of breaches within the design tolerance of the fuel assemblies. This ramp level is highly dependent on the type of reactor, its irradiation cycle advancement, its operating mode, and the amplitude of the power variation [8], [17], [18]. Although most power variations historically do not exceed 0.5% of the plant's nominal power (P_{nom}) per minute [19], the theoretical ramping rate limits of PWRs range from 2% P_{nom} per minute to 5% P_{nom} per minute, and even 10% P_{nom} per minute for German PWRs [20].

It is important to note that 3rd generation reactors (EPR, AP1000...) should be capable of ramping up/down rates ranging from 3% to 5% P_{nom} per min [19], [21].

3.2. Xenon transients and boron concentration

During the fuel fission reaction that produces heat, two fission fragments are emitted and later considered fission products (see Chapter 2.2.1). These are often unstable atoms that will give birth to other radioactive decay fission products. Some fission products are neutron poisons, meaning that they are undesired neutron absorbers that decrease the fuel's fission reaction rate. Three different neutron poisons significantly impact core reactivity: xenon-135, samarium-149, and gadolinium-157. As xenon-135 has the biggest impact, notably due to its large cross-

¹³ The main advantage of using boric acid concentration over control-rod movements is that boron is uniformly distributed in the nuclear core and does not affect its power distribution [7], [8], [10]. However, the long delay (roughly 15 minutes) between injection into the system and the effect in the core, the generation of effluent due to injection/dilution of the primary coolant, and the slow reactivity modification achievable with boron concentration variation (it takes around 5 hours to half the boron concentration at the end of the fuel cycle) make it less effective for fast power variations [7].

¹⁴ At a temperature of 293 K, the mean thermal coefficient of the fuel pellets (UO_2) is $9.99 \times 10^{-6} \text{ K}^{-1}$ (relative volume change per K variation), and $5.660 \times 10^{-6} \text{ K}^{-1}$ for their surrounding Zircaloy claddings [11], [12].

section¹⁵, and affects the reactor's short-term flexibility, we chose not to consider samarium-149 (poisoning effect that takes approximately three weeks [22]) or gadolinium-157 (which has a significantly smaller cross-section than xenon-135¹⁶).

As seen in Figure 2. 5, xenon is a fission product that mainly originates from the decay of iodine-135, a fission product with a 6.53h half-life whose production rate is proportional to the fission reaction rate. Xenon-135 production in the core thus evolves accordingly with the iodine concentration in the core and then 'disappears', either by neutron capture or decay, giving a 9.17h half-life.

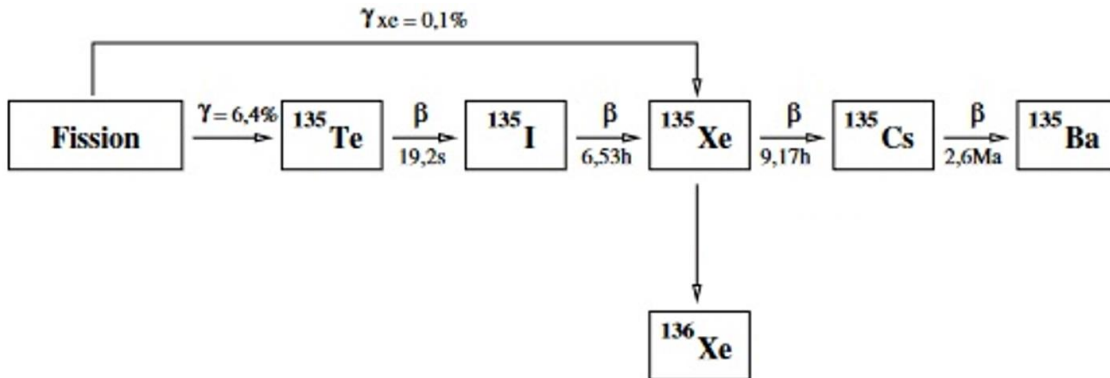


Figure 2. 5: Xenon-135 evolution chain, yields, and half-lives reproduced from [2]

The fact that xenon-135 originates mainly from iodine-135 decay creates a temporal lag between the fission reaction rate variations and xenon-135 concentration, resulting in a flexibility challenge that has to be managed [23]. As reactor power increases, iodine-135 concentration also rises until the reactor's new equilibrium state is reached. Xenon-135 concentration decreases due to increased neutron flux, reaching a minimum a few hours after the start of maneuvers, then returns to an equilibrium state due to the iodine-135 accumulated in the core. Conversely, as reactor power decreases, iodine-135 production rate decreases but xenon-135 concentration rises as it is still generated from the accumulated iodine-135. As xenon-135 is a strong neutron absorber, managing such transients is a big challenge to maneuverability, especially after large power variations. The reactivity variations induced by the xenon transients can nonetheless be overcome during most of the fuel's irradiation cycle, according to [24]. With a sufficient reactivity margin after refueling, it is possible to compensate for the xenon reactivity defects through boric acid concentration adjustments or control rod position changes. [8] notes that plant managers who stabilize their plant's output after maneuvering for several hours[19] do it to simplify operations, not to address technical limitations. However, at the end of the irradiation cycle, the core's reactivity decreases, and the reactivity margin becomes insufficient to compensate for xenon transient effects [10], [24]. Indeed, the boric acid concentration in the primary circuit changes following the reactivity

¹⁵ A nuclear cross section of a nucleus, measured in barns ($1b = 10^{-28} \text{ m}^2$), is used to describe the probability that a specific nuclear reaction will occur. A larger cross-section results in a larger probability of interaction.

¹⁶ Xenon 135, Samarium 149, and Gadolinium 157 have respectively cross-sections for thermal neutrons of 2.6×10^6 barns, 4.1×10^4 barns, and 2.5×10^5 barns [22]. Thus, xenon 135 is the strongest neutron absorber in a thermal reactor.

decrease due to progressive fuel ‘burn-up’, resulting in a decreasing margin for boric acid adjustments in the plant’s primary circuit to control the fission reaction rate. Plants would then need to stabilize their output for multiple hours after maneuvering before ramping back to their initial level. According to [24], xenon transients start to limit flexibility during the last part of the plant’s irradiation cycle. Xenon transient reactivity defects also explain why reactors need to remain closed for several hours after shutting down while in their irradiation cycle.

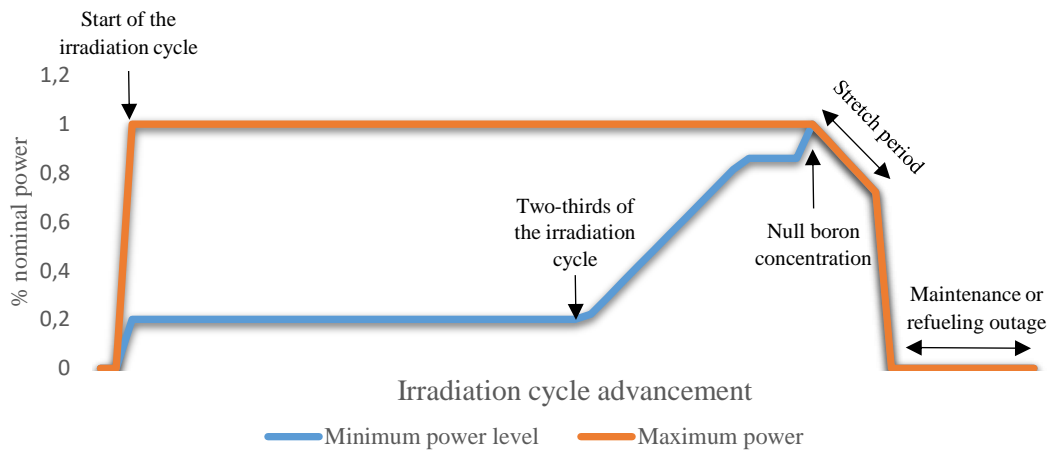


Figure 2. 6: Evolution of minimum power through the pressurized water reactor (PWR) irradiation cycle

The achievable minimal stable power of PWRs thus evolves according to the plants’ advancement in their irradiation cycle [25], [26]. During the first two-thirds of the irradiation cycle, plants can operate flexibly up to 20% of their nominal power, as the boric acid margins are sufficient to compensate for the negative reactivity effects driven by xenon transients. The potential of PWRs to meet flexibility requirements is then maximal, and they can handle load-following services as well as frequency regulation. Then, due to the decreasing boric acid concentration, the achievable scope for ‘load-following’ scope diminishes, and the plant’s minimal power starts to increase linearly until the boric acid concentration reaches zero at the end of the fuel’s irradiation cycle (as illustrated in Figure 2. 6). The reactor can then only ensure primary and secondary frequency regulation. Afterward, the PWR enters a ‘stretch-out’ phase where flexible maneuvers are no longer possible, and the achievable maximal production capacity slowly decreases once the fuel has depleted.

Other components of the reactor's design do influence medium-term flexibility. More information is present in [24]. For example, steam generators' designs may create thermal perturbation that affects the core reactivity, prohibiting fast ramps and forcing the reactor output to remain stable at least one hour before ramping back up. A PWR's flexibility also depends on the operator's operating mode (e.g., Mode A, G, and T for French PWRs).

3.3. Refueling strategies and NPP availability

Each NPP alternates between successive phases of generation and planned outage. Planned outages have to be scheduled to 1) recharge fuel assemblies once the fuel has depleted, 2) run

maintenance on components, and 3) conduct safety inspections. These three elements are crucial factors that govern plant-level available flexibility capacity throughout the year.

The duration of the generation phase depends on reactor type, fuel cycle, and utilities strategy. The irradiation cycle length that frames the duration of the generation phase is defined as the Effective Full Power Day (EFPD), which specifies how long reactors can operate at full power before their fuel gets depleted. EFPD depends on fuel enrichment, and ranges from 280 EFPD for older reactor designs such as CP0 reactors in France [27] to 500 EFPD (as in the case of the EPR [21]) and even 640 EFPD (AP1000 [28] in the case of long operational cycles). These irradiation cycle lengths correspond to generation phase durations ranging from 12 months to 24 months, depending on the NPP’s load factor. Similar to irradiation cycles, the lengths of outage phases also depend on reactor type, fuel cycle, and utilities strategy, but can broadly be classified into two categories: shorter refueling outages, or longer refueling and maintenance outages. Additional regulatory outages may be needed to check that the NPP meets safety requirements (i.e. decennial audit in France). Based on operational feedback, the outage phases represent approximately one-fifth of the irradiation cycle length [29]. This alternation between availability and unavailability is optimized beforehand to maximize the available nuclear generation through peak demand and the plants' load factor. By maximizing their availability to produce electricity during peak demand periods, plant managers profit from higher prices as electric load increases [30], [31]. Thus, outages are typically scheduled during low-demand periods in order to maximize nuclear output and the system’s security of supply. The resulting schedule influences flexibility at two levels: the plant, and the overall nuclear fleet. At plant level, there are some periods where generation and participation in flexibility requirements are impossible due to outages or fuel burn-up. At the fleet level, the addition of each reactor’s availability and flexibility capacities define the fleet’s overall generation capacity and maneuverability. Nuclear generation and flexibility availability vary throughout the year, as illustrated in Figure 2. 7 below for nuclear availability.

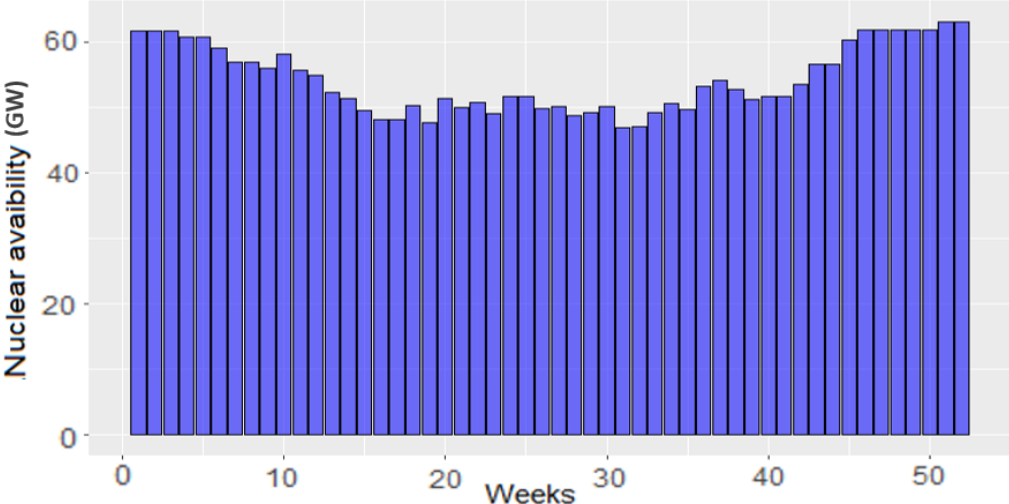


Figure 2. 7 : Average weekly nuclear availability, Years 2015-2019, France

Second, plant managers typically do not shut down every reactor simultaneously, as they have to accommodate human-resource and utility requirements constraints and because simultaneous shutdown could endanger the power system’s security of supply in countries with a high share

of nuclear capacity. Consequently, optimizing human resources for refueling and maintenance tasks while maintaining the electric-system's generation margins is a crucial factor when planning the fleet's outage schedule [32]. For example, in the US, a maximum of 22.5 GWe¹⁷ of its 97.2 GWe¹⁸ fleet went offline simultaneously over the 2016–2020 period. In France, which has a large nuclear fleet, a maximum number of 27 of its 58 reactors fleet went offline simultaneously over the 2010–2019 period¹⁹. Even though there are no physical constraints preventing reactors from shutting down simultaneously, it is crucial to ensure that a minimum fleet share is online to ensure that the optimized schedule is realistic.

3.4. Impact of flexible operations on reactors components

Aside from previously-mentioned constraints, flexible operations result in physical phenomena that impact other reactor components. Indeed, load-following operations are more demanding for the reactor components than baseload operations. Additionally to Pellet-Cladding Interaction mentioned in Chapter 2.3.1, components may be subject to fatigue- a process in which metallic materials lose mechanical strength under cyclic loadings that exceed certain limits - erosion, corrosion, or wear and tear [25]. Such phenomena aggravate the ageism of reactors components like fuel rods and assemblies, control rods and their drive systems, neutron detectors, the core vessel, pressurizers, and steam generators. Conjointly valves and pipes, as well as their turbine components mechanical, electrical, and instrumentation systems, may suffer from increased ageism due to flexible operations. It is crucial to evaluate whether such physical constraints impact operation and safety standards.

As mentioned by [7], it is difficult to separately evaluate reactor components' additional wear and tear induced by flexible operations from the usual wear and tear deriving from baseload operations. Nonetheless, the French and German operational experiences conclude that, if correctly managed, load-following operations have a limited impact on reactors' reliability, costs and safety margins. Regarding reliability, the French experience shows that flexible operations have low impacts on the primary circuit, as no additional safety-risk events were reported when operating flexibly [33]. Conjointly, no additional Pellet-Cladding Interactions events were observed as output variations remain within the pellets' available stress margin [19]. The most significant impact concerns control rod drive mechanisms (CDRMs), whose wear increases due to power variation frequency and amplitude. Due to load-following operations, those mechanisms must be replaced before fatigue occurs, increasing maintenance's direct and indirect costs [33]. The consequences of temperature gradients due to output variations are mainly felt in the secondary circuit (leakage at welded joints, erosion of pipes, and aging of heat exchangers), leading to a higher rate of unplanned shutdowns. Overall, repeated load-following operations decrease the nuclear availability factor by 0.5% to 2% [27].

¹⁷ STATUS OF U.S. NUCLEAR OUTAGES, EIA 2021, "<https://www.eia.gov/nuclear/outages/>"

¹⁸ World Nuclear Performance Report 2020. Produced by: World Nuclear Association. Published: August 2020. Report No. 2020/008

¹⁹ Based on ASN data, <https://www.asn.fr/Controler/Actualites-du-controle/Arret-de-reacteurs-de-centrales-nucleaires>

Regarding costs, the increasing need for maintenance operations on CDRMs and the secondary circuit augments maintenance costs and opportunity costs when reactors suffer from an availability decrease.

Nonetheless, those costs are minimal, according to [25], [33], [34], with no substantial differences from the baseload operation mode. The last aspect that has to be evaluated is environmental impacts. Several parameters must be considered, such as the amount of liquid effluents, solid wastes, and thermal discharge to the environment. The use of boric acid concentrations changes to perform frequency control or load-following operations does increase liquid effluents, as the amount of water in the primary circuit must remain constant. It leads to an increasing volume of liquid that has to be stored and treated, especially when performing consequent output variations (up to 45% of the nominal power) at the end of the irradiation cycle. Thus, it is beneficial to perform load-following operations at the beginning of a reactor's irradiation cycle to limit effluents' volume, as seen in Chapter 2.3.2. Flexible operation mode has no impact on solid waste levels deriving from the fuel's burn-up but increases the consumption of ion-exchange resins (+5.6% compared to average annual consumption) and wastewater filters (+3.4%) [33]. The thermal discharge to the cooling source decreases thanks to load-following operations; hence, nuclear power plants do not face additional constraints regarding this aspect.

4. MODELING POWER SYSTEMS WITH CONSEQUENT SHARES OF VARIABLE RENEWABLES AND NUCLEAR

4.1. Different approaches to the power systems modeling

The current evolution of power systems toward VRE calls for prospective work that has led to the constitution of a rich modeling literature around integrating a higher share of variable renewable sources. Indeed, evaluating future power systems requires modeling tools to simulate their feasibility, implications, and main challenges. Power systems modeling has become increasingly popular in the scientific community starting from early work in the 1970s (e.g. [35]–[37]) until recent years' work by policymakers, researchers, or industrials (e.g. [38]–[40]).

Nonetheless, the literature is not homogenous as objectives may differ, and modeling is computationally demanding. As noted by [41], “depending on the intention and need, a problem can be modeled with different levels of complexity [...], if the objective is to compare two technical solutions quickly, a low-detailed model should be enough. In contrast, when it comes to designing a system that will be implemented on a large scale, accurate modeling and analysis is required”. It is possible to classify power systems models in different ways. [42] differentiate between simulation models based on technical and engineering equations (e.g. EnergyPLAN²⁰ model), larger-scale equilibrium models based on a macroeconomic model (Integrated Assessment Models such as TIMES [43], TIAM [44], [45], PRIMES [46], IMACLIM [47]), and optimization models with a microeconomic approach maximizing social welfare under a perfect market assumption (ANTARES [48], GenX [49], EMMA [50], EOLES [51], DIETER [52], PyPSA [53]). One could add screening-curves models based on a static method aiming to

²⁰ <https://www.energyplan.eu/>

determine fast rules of thumbs of an optimal power system, as used in [27], [37]. Other classifications may be of relevance. For example, [54] notes that modeling approaches in electric systems “can be divided into static (dispatch only) and dynamic (dispatch and investment analyses)”. The difference between those two approaches revolves around whether they rely on capacity mix scenarios to study specific situations or capacity optimization based on investment cost minimization criteria. [55] further notes that dynamic models may use different solving methods, either two-stage optimization (first investment, second dispatch) or simultaneous investment and dispatch. The former solving method allows quicker computation at the expense of results’ accuracy as it may over-estimate investment in technologies with low fixed costs and high variable costs. The latter allows for optimal designs of electric capacities but with greater computational burdens. It is also possible to classify models on their underlying algorithm solving the optimization problem. Besides heuristic methods that do not ensure optimality, mathematical programming uses a selection method to determine the best solution based on specific criteria, specifically the maximization or minimization of an objective function of variables subject to constraints. In this thesis’ case, the best solution is an optimal dispatch, capacity mix, or least-cost equilibrium of power demand and supply. Based on the optimization problem’s formulation and complexity, one can classify the selection method as Linear Programming (LP), Mixed-Integer Linear Program (MILP), or, more broadly, Non-Linear Programming (NLP). Linear Programming relates to mathematical problems with linear objective function and constraints, resulting in a convex set of feasible solutions. Mixed-Integer Linear Programming introduces discrete variables such as binaries, while the objective function remains linear. Discrete variables are specifically useful to integrate generating assets’ unit-commitment constraints into the power system optimization problem. More complex optimization problems may be solved using Non-Linear Programming that allows non-linear objective functions, although the computational burden increases. Overall, the choice of a selection method is an arbitrage between the accuracy of the optimization problem’s formulation and its consequential computational complexity.

Since this thesis aims to include nuclear flexibility constraints in a techno-economic evaluation of future power systems with renewable energy, the chosen approach must include a detailed representation of technical constraints and economic discrimination criteria to dispatch production between technologies. Consequently, rule-of-thumb approaches are not adequate as they do not represent renewable production variability or generators’ production constraints. As it is necessary to adopt economic discrimination criteria to dispatch production, simulation models purely based on technical and engineering equations may not be entirely adequate. Macroeconomic and microeconomic models both allow for detailed representations of constraints mentioned in Chapter 2.3. Nonetheless, as macroeconomic models necessitate greater description of economy sectors and their interactions with climate evolutions while having greater computational complexity, optimization models relying on microeconomic dispatch discrimination criteria are ideal for this thesis’ work.

Considering electricity-focused studies only, nuclear power’s role in future power systems is a research question that has already been addressed, mainly in Western economies cases. Consequently, modeling methods are not homogenous like the modeling literature focusing on power systems. For instance, [27] uses the screening-curves method to evaluate how an

increasing share of variable renewables influences the French nuclear fleet load factor without including detailed technical constraints. [8], [38], [40], [56]–[61] rely on Linear Programming and Mixed-Integer Linear Programming, allowing the inclusion of minimum power levels or even unit-commitment constraints. Studies such as [43], [62]–[64] using Integrated Assessment Modelling aim to represent broader energy systems with sectorial division and to reach their equilibrium, such as TIMES/Markal²¹, or interactions with climate evolutions such as TIAM [44], [45]. Consequently, their representation of nuclear flexibility is less detailed as it increases computational complexity. Hence, all models can not represent nuclear flexibility with the same granularity level and are not all adequate to represent the previously mentioned flexibility limits of PWRs. As this thesis focuses on nuclear flexibility, it is essential to accurately determine an appropriate modeling method to assess the interaction between variable renewables and nuclear reactors.

4.2. Modeling pre-requisites and computational method

4.2.1. Electric systems key characteristics and market structure

In current Western liberalized power systems, the dispatch optimization between technologies is determined by the “merit order” principle on short-term exchange platforms such as the intraday or day-ahead markets. The thesis’ following chapters aim to represent the electric system's key characteristics, meaning that they try to replicate the current liberalized market conditions. Those conditions also include technical constraints like the prominent place of fossil generation (variable renewables, run-of-the-river hydro) and the need to equalize supply and demand always. Broadly, this means that the discrimination rule relies on the “merit order” market design that currently shapes the dispatch between producers.

In the literature, to simplify the representation, electricity markets are supposed to be perfect even if, in practice, abuse of dominant position or the oligopolistic structure of the supply side could be a determinant for system operations. Other aspects may depend on system specificities, for example, hydraulic resources management. As hydraulic generation has negligible variable costs and high maneuverability, it can either be used as baseload generation or marginal generation, providing balancing services to the system. Although maximizing hydraulic generation benefits the system's costs and carbon footprint, the hydroelectricity balancing services ensure supply security. Stakes surrounding aspects of the electric system such as storage facilities use, ancillary services rules, sector-coupling potential (electric vehicle fleet, H2 generation through electrolysis....), and other critical parameters of the studied system also need to be addressed.

4.2.2. Model’s optimality

The goal of operations and capacity expansion models is to determine both environmental and economical optimal dispatch of generation. Following the perfect market assumption (see Chapter 2.4.2.1), the objective function minimizes the system's global costs during a specified period. It includes fixed costs of installed capacity and resulting variable costs from each generating unit, allowing an optimal dispatch for each timestep of the simulation. For capacity

²¹ <https://iea-etsap.org/index.php/documentation>

expansion models, the inclusion of investment optimization in the minimization function adds the objective of determining an optimal capacity mix. Thus, the installed capacity mix approaches economic optimality in capacity expansion models such as [40], whereas operations models' mix relies on predetermined scenarios that may not be optimal like [56].

Environmental aspects can be implemented directly into the objective function, notably through a carbon tax or price that affects each technology's variable cost depending on its carbon footprint [65]. Otherwise, the modelers can also implement a carbon constraint limiting the carbon level the electric system can emit, as in [59].

4.2.3. Capturing renewables and demand variability

VRE generation is highly volatile due to its dependency on weather, so its output can vary significantly and quickly. On the other hand, the electricity load is usually highly volatile, as daily, weekly and seasonal meteorological variations observed in many countries define electric demands. Combining these two variabilities is fundamental to the residual demand profile of the other generation units and storage facilities. The residual demand variability should increase as the share of variable renewables grows, exacerbating the need to consider those fluctuations. It is then crucial to transcribe those fluctuations correctly into the model by adopting a detailed temporal resolution, and the literature is evolving in this direction, with an hourly temporal resolution being mostly adopted as in [8], [24], [38], [40], [56], [60], [66]–[69]. Although [70] notes that analyzing some aspects of renewables integration needs sub-hourly temporal resolutions, 30 or even 15 minutes timesteps, such detailed temporal resolutions increase the model's complexity and may not be desirable.

4.2.4. Dynamic constraints and unit-commitment models

On the supply side, as thermal generating units and storage facilities ensure most of the residual demand, they are the ones that change their output to keep the equilibrium between supply and demand. Technical constraints affect those units' operation, restraining their ability to start up/shut down, modify their output levels, and the time required to complete those maneuvers. The behavior of each generating or storage unit at a specific time step influences its near-future behavior. One of the most prominent examples is the time necessary to start a thermal generating unit after being shut down. The time to « heat » the plant before electricity generation is exploitable creates a potential cost to the plant and the electric system. The decision to shut down a plant must be optimized beforehand, considering the potential inter-temporal effects. The set of inter-temporal constraints, which comprehend ramping constraints, minimum up/downtimes, and transients, is referred to in [71] as dynamic constraints. Dynamic constraints are key determinants of plants' short-term flexibility. It is important to note that each technology possesses different dynamic constraints, resulting in less flexible baseload technology (such as coal and nuclear), whereas peak technology (gas, oil, hydro, batteries) can rapidly maneuver their output.

Representing accurately dynamic constraints permits differentiation of technologies' operation in the model and discriminates them based on their technical capacities. This enhancement also permits economic technology discrimination by including additional costs, such as start-up

costs. As intertemporal constraints condition operational flexibility, it calls for multi-temporal optimization modeling practices and a detailed temporal resolution.

Some of the literature has reviewed the potential impacts of neglecting the detail of both temporal resolution and technological constraints on the models' results. [72] and [73] have assessed that low temporal resolution may overestimate VRE uptake in dispatch systems. On the other hand, investment optimization also needs a detailed temporal resolution, as noted by [74], [75], and [76]. A low temporal resolution in the model favors investment in baseload and VRE technologies while underestimating flexible technologies' needed capacity. A sufficiently detailed temporal resolution is crucial in modeling variable renewables in the electric system.

Regarding the implementation of technical constraints, [77] shows that neglecting unit-commitment constraints in capacity expansion models results in a sub-optimal capacity mix that heightens operational costs and carbon emissions. [78] also notes, in an Irish case study, that the omission of flexibility constraints significantly impacts the optimal generation portfolio. If [79] highlights that some technical constraints may be omitted to shorten computational length and model complexity, it also underlines that this does not apply to models focused on high-share renewables integration and flexibility. [80] reviews more literature about the impact of temporal resolution and technical constraints on models' results.

The literature has been evolving towards a more-comprehensive approach of dynamic constraints through the adoption of Mixed-Integer Programming (MIP) methods. As noted by [59], the previous literature has traditionally used Merit Order/Screening Curve models. Although these allow a more straightforward computational problem, they cannot comprehensively represent all dynamic constraints. Screening curves models usually prohibit inter-temporal considerations. Unit commitment models became more frequent in the literature as they overcome most of the limitations of the former modeling approach, formulated as linear programming (LP) [56] or including non-linearity through Mix-Integer Linear Programming (MILP) or dynamic programming. Using LP, the relaxed integer nature of power plants dramatically reduces the number of variables considered, easing the model resolution. However, this deteriorates the accuracy of the results. For example, using LP makes it impossible to include unit-commitment variables such as start-up/shut-down decision variables.

In conclusion, MILP models bring many advantages to represent market conditions, demand and renewable production variability, and the technical constraints associated with nuclear energy while leading to an optimal solution with a limited computational burden. Hence, the following chapters' models are MILPs to evaluate the future role of nuclear energy in decarbonized mixes.

4.3. Modeling of nuclear flexibility: review and potential effects

In order to review the modeling of nuclear flexibility in the literature, the analysis is classified into three broad categories according to [20]; short-term (sub-hour, hour...), medium-term (hours to days), and long-term flexibility (weeks to months).

4.3.1. Short-term flexibility: modeling and implications

Regarding short-term concerns for modeling, the principal limit relates to ramping constraints that frame the speed at which each plant may modify its output while functioning. Although the underlying phenomena defining the rate PWRs can change their outputs are specific to nuclear, as explained in Chapter 2.3.1, it is possible to synthesize those constraints like any other « dispatchable » generation technology. Limiting short-term flexibility to ramping constraints consists of a fair compromise between model accuracy and simplicity. It is safe to assume that even though short-term constraints differ significantly between nuclear and other generation means, the integration of those constraints in models should be similar.

The impact of the short-term constraints on reactors' flexibility is highly dependent on the time step chosen by modelers. The shorter the time step, the more impactful ramping constraints are on nuclear operations in models. It may then be necessary to adopt a sub-hour time step to assess the impact of those constraints, as one hour allows reactors to ramp up/down from nominal to minimal power even with a conservative ramping assumption of 2% Pnom per minute. Consequently, an insufficiently detailed time step may undermine the impact of short-term constraints, even though the model includes short-term constraints.

Ramping constraints limiting nuclear operations are usual in the power system modeling literature. Hence, as in [56] or [8], the literature clusters short-term flexibility requirements into a unique ramping constraint that frames the plants' overall flexibility. Some models such as [68] resolve the issue of insufficient temporal resolution by implementing hourly ramping constraints – 25% Pnom per hour in this case. It refers to more conservative assumptions on ramping rates of reactors, originating from the fact that nuclear reactors historically operate as baseload, and future PWRs design specification documents foresee ramping rates ranging from 17% to 30% Pnom per hour [10].

The lack of short-term flexibility can be economically detrimental for nuclear power plants, with irreducible generation during low market price periods (i.e., residual demand decreases) and limited generation as market price increases (i.e., residual demand augments). The depleting effect of a lack of flexibility on reactors' profitability would then deepen as the installed capacity of VRE evolves, as seen in [81]. The optimal installed capacity of nuclear reactors would then reduce compared to a model ignoring ramping constraints. From the overall model perspective, short-term nuclear operations constraints may benefit more flexible technologies such as batteries and gas-fired power plants with Carbon Capture and Storage (CCS) to ensure the electric system's flexibility requirements. Omitting short-term constraints or over-estimating nuclear technology's ramping capacity may then underestimate the need for flexible means of generation and storage. Consequently, it can underestimate the technical and economic challenges linked to integrating high shares of VRE capacity in the future electricity mix. Hence, it is crucial to account for ramping constraints if the model's timestep is adequate. As nuclear ramping constraints range from 2% to 5% Pnom/min, short-term flexibility limitations moderately affect maneuvering capacity at an hourly or larger resolution.

4.3.2. Medium-term flexibility: modeling and implications

As noted in Chapter 2.3.2, the evolution of a plant's minimum stable power through its cycle is primordial to its capacity to maneuver. In the context of VRE–nuclear coexistence and high volatility of residual demand, each plant's ability to perform deep load cycling is crucial to the electric system's stability.

The representation of medium-term flexibility constraints (related to xenon transients) varies across the literature. [24] introduces « physics-induced operational constraints » for nuclear operations, allowing representation of both power stabilization after output changes and minimal operating power evolution in the model. Its companion paper, [8], also integrates those constraints to nuclear operations in order to determine the potential benefits of nuclear flexibility in renewables-driven power systems. Those two papers do simplify medium-terms technical constraints as they implement them in their case study. For example, the Xe-135 reactivity defects following a power output drop are all of the same magnitudes as long as this power drop is higher than 10% of the reactor's nominal power. Aside from these two papers, most literature over-simplifies medium-term constraints on nuclear flexibility. About minimal power evolution through the irradiation cycle, the conventional approach is to fix the minimal power output that reactors can operate under, as seen in [7], [56], [59]. Although the level of this achievable minima power output may vary – 50% in [59], 40% in [56] -, it primarily refers to current requirements for newly built reactors, as seen in [21], that recommend an available 50% minimal power. An essential consequence of this modeling choice is that the minimal stable level remains stable through the irradiation cycle, a misrepresentation of minimal power dynamics.

As for necessary power stabilization following output maneuvers due to the previously mentioned xenon transients, there is no representation of the related constraints that would limit consecutive power variations while functioning in most of the literature – the only exception being [24] and [8]. Minimum up/downtimes constraints induced by xenon transients after starting up/shutting down are exclusive to MILP models, as in [8], [24], [59], [60], [68].

Medium-term flexibility assumptions may have an impact on model results. Like ramping constraints, reactors' need to maintain a stable output following a flexible maneuver limits their ability to adapt to the residual demand's fast-level changes. This constraint, if implemented, forbids reactors from performing several maneuvers successively. The omission of this constraint may over-estimate PWR's maneuverability in models, as reactors may consecutively ramp down (inv. up) then ramp up (inv. down) -even though physics-induced models would prohibit it. Nonetheless, as noted in Chapter 2.3.2, the reactivity variations induced by the xenon transients can be overcome during most of the fuel's irradiation cycle. Hence, output stabilization constraints only occur when performing consequent load-following cycles during the last 20% of the irradiation cycle.

Regarding minimal power evolution through the irradiation cycle, it frames the potential maneuvers achievable by reactors. The effect on the estimation of achievable flexibility varies throughout the irradiation cycle of each PWR. At the beginning of the irradiation cycle, a 50 % minimal stable power assumption would under-estimate the reactor's maneuverability potential as minimal achievable power is around 20% of nominal power. Inversely, as minimal

achievable power rises at the end of the irradiation cycle, a 50% minimal stable power assumption would be an over-estimation of a PWR maneuverability potential.

Consequently, the modeling assumption of a constant minimum stable power throughout the irradiation cycle is bound to both over and underestimate achievable maneuverability of PWRs depending on the period. In the context of high renewable penetration in future electric systems, the variability of residual demand and seasonality makes it crucial to estimate the achievable maneuverability of nuclear technology accurately. A fixed and constant minimal power assumption may be a hurdle to the accuracy of such models.

4.3.3. Long-term flexibility: modeling and implications

Although fundamental to available nuclear power capacity and flexibility in the electric system, long-term flexibility components are not implemented in the models. [7] thoroughly describes the stakes surrounding the operational schedule of reactors and its optimization (to either maximize plant profits or minimize load-shedding/black-outs) but does not implement it in its model. The underlying hypothesis is that reactors are available continuously throughout the considered years.

Both [24] and [8] partially raise this issue. In their respective case studies, the authors consider only one 18-month irradiation cycle for their hypothetical plant. [8] focuses on one simulation year following the start of the reactor, meaning that it remains within the first two-thirds of its cycle, and depleting boric acid concentration does not affect its operation. Additionally, [24] focuses on the end of its irradiation cycle, highlighting the effects of physics-induced constraints on the model results. These two papers then evoke the influence of a reactor's schedule on its flexibility capacity but do not consider a fleet perspective.

Hence, the nuclear fleet's availability is generally modeled as constant (as in [56], [60], [59], [40], [82]), even though such an assumption overlooks outage schedule optimization. When neglecting the nuclear fleet schedule, models do not consider factors such as nuclear availability seasonality. It may misestimate available nuclear generation and flexibility throughout the year and thus impact the models' results regarding the security of supply, costs of dispatch, and the system's carbon footprint. Nonetheless, a constant nuclear availability assumption may be valid if the system's residual demand remains relatively constant throughout a year; however, this is a rare situation empirically.

The reactors' operational schedule also impacts the nuclear fleet's total minimum power. As reactors do not start their irradiation cycle at the same time of the year, their minimal stable power evolution is heterogeneous. Indeed, the fleet's overall minimal power is the sum of each reactor's minimal power, meaning that its value depends on each reactor's progress into their respective irradiation cycles, which are strongly linked to their operational schedule. To illustrate, Figure 2. 8 presents the French nuclear fleet's operational schedule in 2016²² and its minimal power evolution based on each reactor's irradiation cycle length (green line). The two other curves show two constant minimal power assumptions based on the same 2016 nuclear

²² Based on data from the Transparency platform of the European Network of Transmission System Operators for Electricity (ENTSO-E) and the French Nuclear Safety Authority (Autorité de Sureté Nucléaire)

schedule – 50% constant minimal power (low-flexibility case) and 20% constant minimal power (high-flexibility case).

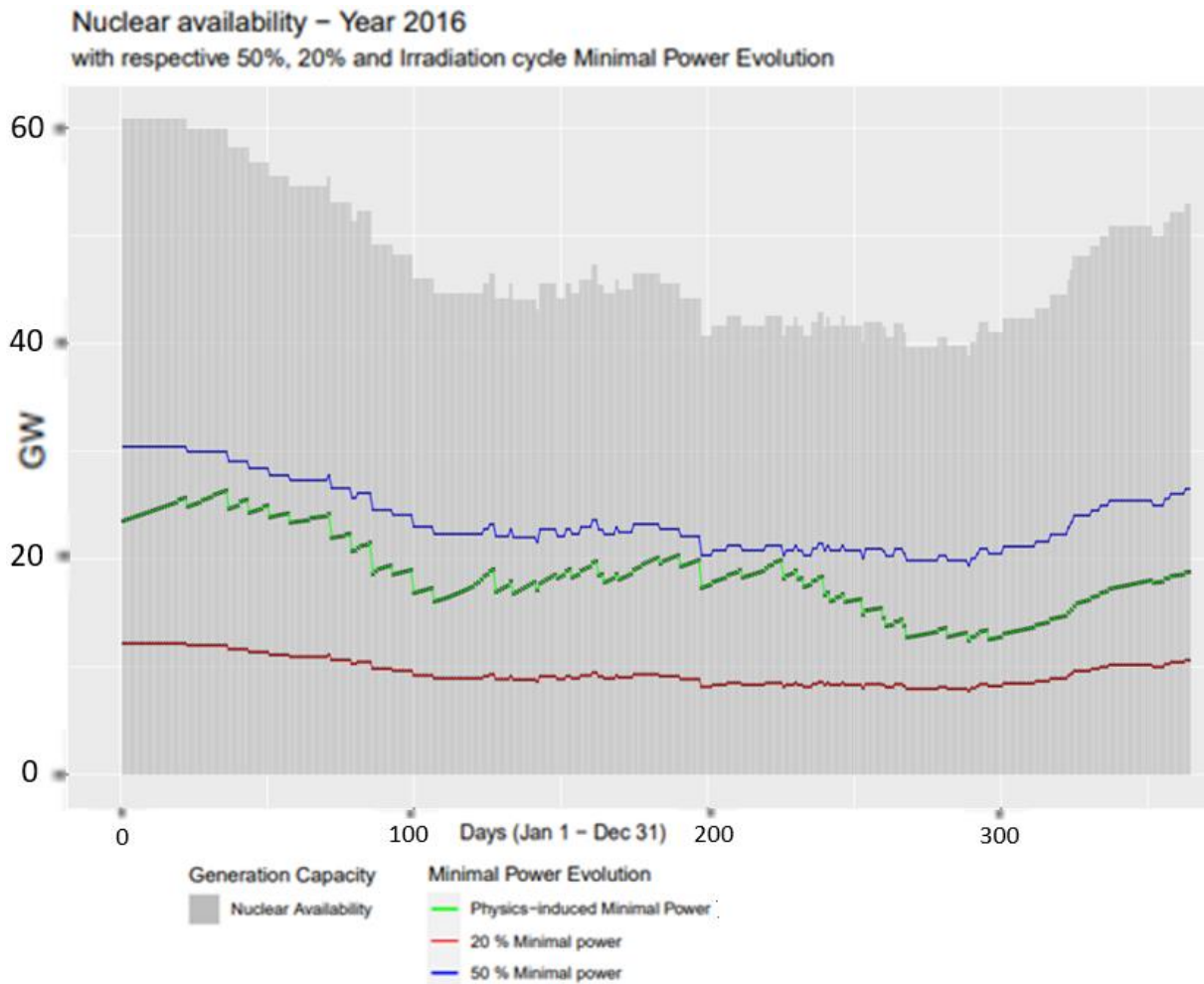


Figure 2. 8: French nuclear fleet generation capacity (2016) and minimal power (constant vs. « physic-induced »)

Each reactor's schedule was computed from ENTSO-E and ASN's data, allowing the computation of each reactor's minimum power evolution following [26]. The central hypothesis is that fuel burnup was proportional to each reactor's advancement in their respective irradiation cycle.

Figure 2. 8 highlights that both constant minimal power assumptions do not accurately represent the fleet's actual minimal power based on the reactor's irradiation cycle, as « physics-induced » minimal power evolutions differ from constant minimal power evolutions. Then, models assuming a constant nuclear minimal power may misestimate its realistic flexibility potential. As the fleet's seasonality is not implemented in models, nuclear flexibility in models could differ significantly from a « realistic » physics-induced nuclear flexibility. Such considerations are crucial when assessing nuclear technology's role in responding to flexibility requirements induced by introducing a large VRE share into the capacity mix.

5. DISCUSSION AND CONCLUSIONS

This chapter reviewed the main principles underlying electricity production using PWRs, the main flexibility constraints PWRs face, and the existing modeling approach to this flexibility.

Current nuclear modeling in the literature does not fundamentally differ from conventional thermal generation modeling. This thesis argues that this is a valid assumption only in a low variable renewable environment, where the need for flexibility from thermal generation remains negligible. However, in the context of the capacity development of variable renewables throughout the electricity mix, flexibility will be crucial in determining the future environmentally and economically optimal capacity mix. Although considered baseload, nuclear has a real flexibility potential that needs to be accounted for and has already been partially implemented in some current models. The mechanisms underlying this flexibility potential are specific to this generating technology and depend on the reactors' type (BWR, PWR, SMR...), operation mode, and regulatory regulations. Regarding PWRs that constitute most of the installed nuclear capacity, xenon transients and the operational schedule of power plants seem to be a blind spot in the literature. Models that, for example, do not implement xenon transients may overestimate nuclear flexibility, as reactors can successively perform maneuvers, which would be prohibited in « physics-induced » models.

Those assumptions influence nuclear flexibility in models and should be better implemented in future works to increase accuracy. Such omissions may misestimate available nuclear generation and flexibility in the model results. Eventually, those misestimations potentially influence electric systems' key aspects, such as operational costs, the security of supply, and carbon footprint. As nuclear technology with low variable costs holds a primary place in the economic merit order, misestimating nuclear flexibility could affect the expected optimal peak-generation capacity, storage facilities, demand-side response, and especially the optimal share of variable renewable capacity in electric systems. Those elements combined are crucial to the economic and environmental competitiveness of nuclear technology in renewable-driven electric systems. Only by correctly assessing the optimal nuclear ratio in the capacity mix and its corresponding load factor can we conclude nuclear technology's viability in the future renewables-driven mix. Deriving from this chapter's conclusions, the rest of this thesis focuses on assessing the impact of nuclear flexibility misrepresentation and proposes novel methods to incorporate nuclear flexibility characteristics in power systems modeling. Using those methods, we build a capacity expansion model with nuclear flexibility considerations aiming to determine the future role of flexible nuclear reactors in a decarbonized European power system.

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CHAPTER 3. NUCLEAR FLEET FLEXIBILITY: MODELING AND IMPACTS ON POWER SYSTEMS WITH RENEWABLE ENERGY

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1. INTRODUCTION

As noted by the previous chapter and [1], most of the electric power systems modeling literature (e.g., [2]) represents nuclear power as an inflexible technology. Studies that partially encompass nuclear flexibility typically represent nuclear generation using assumptions such as ramping constraints or minimal stable power levels similar to other thermal technologies [3]–[8]. Such modeling practices do not accurately represent the specificities of NPP flexibility driven by neutronic constraints, primary circuit dynamics, or refueling strategies. Nonetheless, simplifications are usual in models, as implementing detailed technical constraints increases computational complexity. In a context where reactors operate as baseload, misrepresenting nuclear flexibility constraints is a good trade-off between the models' accuracy and its implementation and computation costs. As mentioned in previous chapters, the “baseload” paradigm is not likely to hold true. Hence, this chapter's objective is to determine the relevance of nuclear flexibility modeling in the new context of future decarbonized power systems with renewable energy.

This chapter is in line with recent works ([1], [9]) that highlight the impact of physics-induced plant flexibility modeling on the evaluation of future electric systems with renewable energy. The chapter focuses on the impact of two nuclear flexibility characteristics on modeling results: fleet schedule optimization and minimal power variations. As ramping constraints do not limit nuclear flexibility at an hourly level, they are not included in this thesis' analysis.

The chapter first highlights the benefits of nuclear schedule optimization to integrate VRE production in simplified electric systems. Another finding is the importance of representing minimal power variations to evaluate nuclear–renewable energy interactions. The main methodological contribution is to propose a novel Mixed-Integer Linear Programming model based on realistic refueling constraints of PWRs to simulate fleet schedule optimization, which enables the computation of each plant's minimum power variations. Another contribution is the case studies based on representative French electric-system data, where the chapter evaluates the benefits of using nuclear flexibility characteristics to integrate renewable energy in a nuclear-based capacity mix.

The findings nevertheless come with limits. The numerical results are case-specific, and so caution is warranted when comparing against real-life power systems, as assumptions such as gas prices heavily influence this chapter's numerical results. The represented power systems are simplistic, with only one country represented, and thus they do not consider the physical network constraints that may influence energy curtailments levels. Most of the levers of flexibility are also excluded, i.e., interconnections with neighboring electric systems, storage facilities, hydroelectricity, and demand-side response, all of which would likely decrease the value of nuclear flexibility. Results reported in this chapter should therefore be extrapolated with care. Nonetheless, the chapter argues that nuclear flexibility should yield similar benefits in power systems with significant nuclear and VRE capacity, where the seasonality of nuclear availability would participate in VRE integration, reducing costs, environmental impacts, and energy curtailment. Chapter 4 will complement this work by focusing on measuring the impact of nuclear flexibility in broader power systems with larger balancing areas, a larger number of generating technologies, and more advanced modeling of flexibility levers.

The objective is not to have precise calculations for a specific country but to demonstrate, through an academic approach, that a precise calculation taking into account nuclear flexibility needs to include aspects related to nuclear fleet fuel management and its effects on the available power range of the fleet.

The chapter is structured as follows. Chapter 3.2 presents a novel mathematical model to represent the nuclear fleet's schedule optimization, the resulting minimum power variations of the plants, and the unit commitment and economic dispatch model used in this chapter, based on the ANTARES Simulator model by the French TSO RTE. Chapter 3.3 resumes the different case studies and the model's results related to fleet schedule optimization and minimum power variations. Chapter 3.4 concludes with the main findings and discusses future work.

2. METHODS

2.1. Mixed-Integer Linear Programming (MILP) schedule optimization model and representation of minimum power evolution

The first model used in this chapter is based on the PWR flexibility constraints presented in Chapter 2.3. Hence, this sub-section focuses on two key parameters: nuclear schedule optimization and minimum power level permitted by xenon transients management and boron concentration. The objective is to replicate nuclear schedule optimization and the advancement of each simulated reactor in its respective irradiation cycle to evaluate a nuclear fleet's flexibility potential. As ramping constraints do not limit nuclear flexibility at an hourly level, they are excluded from this analysis. The following sub-section details the modeling practices and assumptions used to represent nuclear flexibility constraints.

As a plant's irradiation cycle typically lasts several months, it is necessary to adopt an inter-annual approach to simulate the nuclear schedule optimization. Using a benevolent system manager approach for simplicity, a MILP model that maximizes nuclear availability when it benefits the electric system over several years is built. The underlying hypothesis is that this benefit is equivalent to maximizing nuclear availability during peak electric demand periods. A higher nuclear availability during peak electric demand decreases peaking-plant use and tends to drive prices down. The following model aims to represent the dynamics of the nuclear schedule:

Equation 3. 1 : Objective function – Nuclear availability maximization problem

$$\text{Maximize } \sum_{t=1}^T \sum_{i=1}^N D_t * Q_i * U_{it}$$

With constraints: $\forall i, t$:

Equation 3. 2 : Minimum irradiation cycle lengths

$$\forall x \in [0: \underline{C}_j] : U_{i,t+x} \geq U_{i,t} - U_{i,t-1}$$

Equation 3. 3 : Maximum irradiation cycle lengths

$$\sum_{y=0}^{Y_i=\bar{C}_i} U_{i,t+y} \leq \bar{C}_i$$

Equation 3. 4 : Minimum outage duration

$$\forall z \in [0: \underline{S}_i] : U_{i,t+z} \leq 1 + U_{i,t} - U_{i,t-1}$$

Equation 3. 5 : Number of simultaneous outage limitations

$$\sum_{i=1}^N U_{i,t} \geq \underline{\delta} * N$$

Equation 3. 6 : Peaking availability constraints

$$\sum_{i=1}^N U_{i,\bar{t}} = N$$

Equation 3. 7 : Simultaneous outages start constraint

$$\sum_{i=1}^N U_{i,t-1} - U_{i,t} \leq \delta_{outages} * N$$

Equation 3. 1 is the model's objective function that maximizes the sum of the N reactors i times their nominal power Q_i over a determined period T . U_{it} is a binary variable equal to 1 if reactor i is available at time t , else 0. D_t captures the demand variability across the studied period. Equation 3. 2 and Equation 3. 3 frame the length of each plant's irradiation cycle, ensuring that each reactor is available during the entirety of its minimum irradiation cycle length \underline{C}_i and preventing potential overrun of its maximal cycle length \bar{C}_i . Equation 3. 4 frames the length of outages. It ensures that each reactor is unavailable for \underline{S}_i timesteps after shutting down for refueling or maintenance. Equation 3. 5 limits the share $\underline{\delta}$ of nuclear units that can operate maintenance and refueling outages simultaneously, and Equation 3. 6 ensures that all reactors are online during the peak demand of the year \bar{t} . Finally, Equation 3. 7 limits the share of nuclear units $\delta_{outages}$ that can start their outage phases at the same time in order to prevent all reactors from stopping simultaneously.

Unit	Nominal power (MW) - Q_i	Equivalent Full Power Days	Average availability factor	Minimum outage duration (weeks) - S_j	Minimum irradiation cycle duration (weeks) - C_i	Maximum irradiation cycle duration (weeks) - \bar{C}_i	Minimum share of online reactors - δ	Maximum share of simultaneous outage-phase starts - $\delta_{outages}$
Value	1000	280	79.1%	6	38	48	50% ²³	10% ²⁴

Table 3. 1: Hypotheses used for irradiation-cycle and outage lengths

This chapter considers simplified reactors, all similar, with a 1000 MW nominal power, 12-month irradiation cycle length, and 79.1% availability factor, which is equal to the availability factor of French PWRs since they were commissioned to industrial service [10] (see Table 3. 1). The model is built at a weekly timestep to limit computational time. The hypothesis is that each reactor shuts down or starts its irradiation cycle at the beginning of a week. The schedule optimization timeframe chosen throughout the paper is 18 years, spanning the 2001–2019 period. Note that the proposed nuclear schedule optimization model is a simplified formulation of a complex process to determine when NPPs begin their irradiation cycle or outage phase (standardized reactors, foreseeable future across 19 years, and so on). The durations of maintenance and refueling operations are considered deterministic, which is a simplification of real-life outages whose duration may randomly increase as operational difficulties arise. The inclusion of stochastic elements into the nuclear schedule model would increase the model’s soundness, but such considerations are not included here. Each schedule optimization MILP problem is solved using the CPLEX® solver with a 5% relative optimality gap. The problem resolution ran on a computer with a 20-core Intel® Xeon® Gold 6230 CPU clocked at 2.30 GHz using 125 GB of RAM, running CentOS Linux version 7.

Using this MILP model, it is possible to determine the start and end of each reactor’s irradiation cycle as well as its advancement at each point in time. Following [11], [12], each reactor’s minimum power level is computed based on this advancement, which is linked to the decreases in reactivity margin and boron concentration and the burn-up of the fuel, as represented in Figure 2. 6.

Each reactor’s minimum power variation follows a curve where the first phase consists of significant capability to maneuver reactor production level until 20% of nominal power during the first two-thirds of the irradiation cycle. Minimum power level then rises linearly until the boron concentration becomes null, which is the period where PWR flexibility is the lowest. The reactor then enters a ‘stretch’ phase, where its maximum power and minimum power are equal and do not allow any production level changes apart from starting up/shutting down. The fleet’s

²³ Computation derived from ASN data, <https://www.asn.fr/Contrôler/Actualites-du-controle/Arret-de-reacteurs-de-centrales-nucleaires>

²⁴ Operational feedback on the French nuclear fleet, <https://www.asn.fr/Contrôler/Actualites-du-controle/Arret-de-reacteurs-de-centrales-nucleaires>

overall minimum power level equals the sum of each reactor's minimum power level variations, computed from the optimized schedule resulting from our MILP model. Given that start and end date of each reactor's irradiation cycle need to be known in order to evaluate the potential benefit of this aspect of nuclear flexibility, this further justifies the need to adopt a MILP approach to simulate nuclear schedule optimization.

2.2. MILP/UC electric system model

2.2.1. ANTARES Simulator

The economic dispatch model is the open-source ANTARES²⁵ power system simulator developed by RTE, the French Transmission Systems Operator, that simulates the electric demand-supply equilibrium. A broad summary of the model can be found in [13]. The model consists of a unit-commitment (UC) program that determines the optimal economic dispatch of all the generating units in the system at an hourly timestep over one calendar year. The objective function minimizes the operational costs (variable, fixed, start-up, and unsupplied energy costs) to meet the exogenous hourly demand. Thus, the underlying discriminatory criterion between generators is the merit-order approach that ranks generators based on ascending order of short-term marginal costs. Apart from VRE sources, for which generation is considered exogenous to the model, each generating unit's behavior is subject to UC constraints related to its maximum/minimum production capacity and maximum/minimum up/downtime. The ANTARES simulator includes each unit's availability schedule, allowing modelers to adjust for seasonal plant outages. A custom ANTARES solver solves the MILP problem, finding the optimal generation profile for each unit given its constraints, and computes the resulting market prices, CO₂ emissions, spilled energy, and unsupplied energy of the modeled electric system.

The model represents frequency regulation management by integrating spinning reserves for thermal power plant technologies. Aside from coal, gas, and fuel oil technologies, NPP react to automatic generation control signals sent by system operators to ensure frequency regulations and contribute to operating reserves²⁶. As existing reactors reserve 5%–10% of their nominal capacity to ensure primary and secondary frequency adjustments and spinning reserves, we consider that thermal plants reserve 10% of their nominal capacity.

This chapter uses version 7.0.1 in Accurate-Economy mode, for which the mathematical formulation can be found in [14]. Contrary to version 8.0, version 7.0.1 does not optimize the system's capacity mix, meaning that this chapter will focus on specific case studies for which installed capacities were determined exogenously. We consider a deterministic environment with no uncertainties on future VRE production, demand level, thermal plant availabilities, and reserve requirements. The installed capacities' optimality considerations are left for this thesis's next chapter (see Chapter 4).

²⁵ RTE, <https://antares-simulator.org/>

²⁶ Especially spinning reserves, which are extra generating capacity made available by increasing the power output of generators that are already connected to the power system. Generators already connected to the power system do not generally produce at full nominal power, as a strategy to cover spinning reserves.

The following equations do not correspond to the entirety of the ANTARES model but are only the equations used in this chapter for brevity. A more detailed description of the model will be presented in Chapter 4.2.2 as the simulated power system is more complex.

Equation 3. 8 : Objective function – Economic dispatch model

Minimize $COSTS_{operation}$

$$COSTS_{operation} = \sum_{w=1}^{52} (COSTS_{generation,w} + COSTS_{vre,w} + COSTS_{unsupplied,w})$$

Where $COSTS_{operation}$ represents the overall operational costs of the electric system, w represents each week of the simulated year and $COSTS_{generation,w}$, $COSTS_{vre,w}$, $COSTS_{unsupplied,w}$ respectively represent the costs of generation units, costs of renewables units and costs of unsupplied energy.

Equation 3. 9 : Thermal generation’s operational costs

$$COSTS_{generation, w} = \sum_{t=1}^{168} \sum_{\theta=1}^{\theta} (\sigma_{\theta}^{+} * M_{\theta,t}^{+} + \tau_{\theta} * M_{\theta} + \chi_{\theta} * \sum_i^{M_{\theta}} P_{\theta,i,t})$$

Where $P_{\theta,i,t}$ is the production of the generation unit i of technology θ at time t , χ_{θ} is the variable cost of the technology θ . σ_{θ}^{+} represents the potential costs associated with the startup of technology θ and $M_{\theta,t}^{+}$ is the number of units that startup at time t . τ_{θ} represents the hourly fixed costs linked to technology θ and M_{θ} is the number of generation units of technology θ installed in the power system.

Equation 3. 10 : Variable renewable energy’s operational costs

$$COSTS_{vre,w} = \sum_{t=1}^{168} \sum_{vre=1}^{vre} (\chi_{vre} * P_{vre,t} + \tau_{vre} * M_{vre})$$

Where $P_{vre,t}$ is the production of the renewable unit vre , χ_{vre} is the variable cost of the generation unit vre . τ_{vre} represents the hourly fixed costs linked to renewable unit vre and M_{vre} is the number of renewable units vre installed in the power system.

Equation 3. 11 : Unsupplied energy

$$COSTS_{unsupplied,w} = \sum_{t=1}^{168} \delta^{+} * G_t^{+}$$

Where δ^{+} is the value of lost load (VOLL) and G_t^{+} is the unsupplied electricity quantity.

The following equation ensures a constant demand-supply equilibrium in the considered power system while accounting for unsupplied energy and spillages.

Equation 3. 12 : Demand-Supply equilibrium constraint

$$\forall t \in T$$

$$D_t = \sum_{\theta=1}^{\theta} P_{\theta,t} + (G_t^+ - G_t^-)$$

With G_t^- representing spilled power at time t , $\sum_{\theta=1}^{\theta} P_{\theta,t}$ represents the sum of all generating units' production at time t , and $(G_t^+ - G_t^-)$ encompasses the total unsupplied and spilled energy of the zone.

For each thermal generating unit, the production level is bounded by maximal capacity and minimum stable power when running :

Equation 3. 13 : Minimum and maximum power constraint

$$\forall \theta \in \theta_n, \forall i \in M_{\theta} \forall t \in T$$

$$U_{\theta,i,t} * \underline{P_{\theta,i}} \leq P_{\theta,i,t} \leq U_{\theta,i,t} * \overline{P_{\theta,i,t}}$$

With $\underline{P_{\theta,i}}$ and $\overline{P_{\theta,i,t}}$ respectively representing the minimal stable power and maximal power of unit i of technology θ . It is possible to note that $\overline{P_{\theta,i,t}}$ is time dependent, but not $\underline{P_{\theta,i}}$. Such an aspect is discussed in the following sub-section (Chapter 3.2.2.2). $U_{\theta,i,t}$ is a binary variable equals 1 if unit i of technology θ is online at time t , and 0 if not. As mentioned previously, the original ANTARES Simulator

The number of online units of technology θ at time t is constrained by the availability of this technology θ at time t .

Equation 3. 14 : Thermal plants' availability constraint

$$\forall \theta \in \theta_n, \forall t \in T$$

$$\sum_i^{M_{\theta}} U_{\theta,i,t} = M_{\theta,t} \leq \overline{M_{\theta,t}}$$

With $M_{\theta,t}$ representing the number of online units of technology θ , and $\overline{M_{\theta,t}}$ the number of units that are available to produce electricity at time t .

Each generating unit state is constrained by its minimum on time Δ_{θ}^+ and their minimum off time Δ_{θ}^- , ensuring that all thermal units respect their commitment constraints, as transcribed in Equation 3. 15 and Equation 3. 16.

Equation 3. 15 : Minimum uptime constraint

$$\forall n \in N, \forall \theta \in \theta_n, \forall t \in T, \forall k \in [0: \Delta_{\theta}^+]$$

$$U_{\theta,i,t+k} \geq U_{\theta,i,t} - U_{\theta,i,t-1}$$

Equation 3. 16 : Minimum downtime constraint

$$\forall n \in N, \forall \theta \in \Theta_n, \forall t \in T, \forall z \in [0: \Delta_\theta^-]$$

$$U_{\theta,i,t+z} \leq 1 + U_{\theta,i,t} - U_{\theta,i,t-1}$$

For all thermal generation, we do not account for potential ramping constraints, as no technologies considered in the model are constrained at an hourly timestep.

The production level is considered exogenous for renewable generating units, as climate conditions determine their hourly capacity factor. Thus, generation from renewable generating units is determined by :

Equation 3. 17 : VRE production

$$\forall vre \in VRE, \forall t \in T$$

$$P_{vre,t} = \overline{P_{vre,t}} * cf_{vre,t}$$

$P_{n,vre,t}$ is the electricity produced by each VRE resource at hour t, $\overline{P_{n,vre,t}}$ is the installed capacity of each VRE source, and $cf_{vre,t}$ is the hourly capacity factor of each VRE source in the considered power system.

2.2.2. Customization of the model

As written in Equation 3. 13, the original ANTARES Simulator does not allow for minimum stable power level variations for thermal generation. Such model characteristic does not allow the representation of nuclear reactors' minimum power evolution at the end of their irradiation cycle. Hence, consequent programming work has been conducted in collaboration with the SERMA/DM2S department at CEA-Saclay to build a custom ANTARES model that bypasses this limitation. This custom ANTARES version modifies Equation 3. 13 into Equation 3. 18, where each thermal plant's minimum power $\underline{P_{\theta,i,t}}$ is time dependent contrary to the original ANTARES model.

Equation 3. 18 : Customized minimum and maximum power constraint

$$\forall \theta \in \Theta_n, \forall i \in M_\theta \quad \forall t \in T$$

$$U_{\theta,i,t} * \underline{P_{\theta,i,t}} \leq P_{\theta,i,t} \leq U_{\theta,i,t} * \overline{P_{\theta,i,t}}$$

The customization of the ANTARES model is the central piece of the consideration of reactors' minimum power evolution. Although briefly presented, such work represents consequent joint efforts from the SERMA/DM2S department at CEA and the author of the thesis, as the open-source ANTARES model is complex. Hence, the thesis author would like to thank Mr. Karim Ammar and Mr. Thibault Moulignier for their technical support regarding this customization. During this thesis' following chapters, the customized version of the model will be used exclusively.

2.3. Assumptions and case studies

2.3.1. Assumptions

The case studies in this chapter are based on a simplified French electric system. The French system is chosen due to its high share of installed nuclear power, meaningful feedback on nuclear fuel-cycle management, and available data on renewables and electric demand. The electric demand data used to optimize the nuclear schedule range (2001– 2019) is historical French demand from RTE. The primary hypothesis that NPP managers optimize their schedule based on their electricity demand expectations (Equation 3. 1). The demand profile used to compute the optimized schedule is thus the average profile across those years. 2020 is excluded due to the decrease in demand due to the economic slowdown caused by the Covid-19 pandemic. The paper builds VRE production profiles using actual capacity factor data from the renewables.ninja website, which is widely used in the electric simulation literature. Using capacity factors instead of actual generation profiles allows us to test out multiple case studies at different VRE integration levels.

Although the schedule optimization model creates an inter-annual schedule for a specified fleet, the electric system simulation is limited to only a representative year. As noted by [15], the choice of a representative year can be made under several criteria. Here the chosen year is the one with the renewable capacity factor closest to the French capacity factor profiles over the 2000–2019 period. The year 2006 was determined to be the most representative for France, with a sum of absolute error values of 1.5% for onshore wind, offshore wind, and solar photovoltaic capacity factors compared to the capacity factors of the whole period. It is important to note that other factors that impact our simulations' numerical results, such as electric demand variations, could have been included in the representative year selection process. Selecting a different year would indeed impact numerical results, notably energy curtailment levels, market prices, and technology revenues, but the author argues that the effect of additional fleet flexibility would yield similar results with different selected years. Moreover, [15] thoroughly confirmed that selecting 2006 as a representative year did not impact the operational adequacy of the simulated power system, notably when testing years with different VRE capacity factors. Thus, electric demand, VRE capacity factors, and the reactors' operation and outage phases resulting from the nuclear schedule model, which the ANTARES Simulator uses to simulate electric system operations, are all year-2006 data.

Furthermore, this chapter focuses only on the isolated electric system of one country, meaning that the following case studies do not account for potential levers of flexibility such as interconnections or sector-coupling mechanisms (EV charging, hydrogen production, and so on). Only a limited set of installed technologies are considered, i.e. onshore wind, offshore wind, solar photovoltaic, nuclear, and natural gas. Installed capacities of nuclear and VRE are case-specific and fixed exogenously, whereas natural gas capacity is an output of each simulation, where gas capacity is scaled to cover peak residual demand and no load loss. Gas capacity is thus oversized in the presented cases, but because the chapter focuses solely on variable costs, the over-capacity of natural gas does not impact the model's economic results aside from gas being the last marginal unit that fixes the marginal prices. The natural gas technology considered here is open-cycle gas turbine (OCGT) plants with 38% electrical

efficiency due to their high flexibility. Variable costs such as fuel are fixed over one year, and sourced from [3].

Technology	Nominal capacity (M)	Variable costs ²⁷ (\$ ²⁸ /MWh)	Minimum stable power (%)	Minimum uptime (hours)	Minimum downtime (hours)	Start-up costs (\$/MW/start)	Reserve requirements (%)	Environmental impacts (gCO ₂ eq/kWh) – IPCC (2014)
Wind	-	0	-	-	-	-	-	11
Solar PV	-	0	-	-	-	-	-	41
Nuclear	1000	11.5	50%	8	24	500	10%	12
Natural Gas	300	96.11	25%	1	1	50	10%	490

Table 3. 2: Overview of costs, flexibility and environmental impacts of electric utility technologies [3]

The chapter constrains the flexible behavior of each thermal technology modeled. As mentioned beforehand, ramping constraints are not accounted for as they do not limit nuclear or OCGT flexibility at an hourly timestep. Thus, apart from the PWR characteristics discussed earlier, flexibility constraints are limited to minimum uptime and downtime constraints only. The chapter assumes a simplified representation of the minimal power evolution in the constant schedule case and the optimized schedule case with constant minimum power variations. Given that part of the nuclear fleet is at the beginning of its irradiation cycle—i.e. with high load-following capabilities—while other reactors are at the end of their irradiation cycle—i.e. with limited load-following capabilities—, the chapter considers in these two cases that each reactor’s minimum power is 50% of its capacity, and so all-fleet minimum power is at 50% of its availability, in line with [3]. This assumption allows the isolation of the respective impacts of nuclear schedule optimization and physics-induced minimum power variations. The other flexibility characteristics in Table 3. 2 correspond to plants commissioned in 2020 [3].

2.3.2. Cases

Three main nuclear flexibility assumptions are considered. Table 3. 3 recaps the underlying hypotheses.

Name	Schedule assumption	Minimum power assumption
A	Constant	50% ²⁹
B	Optimized	50%

²⁷ Over the long-term, marginal cost, i.e. cost linked to the production of one additional MWh, equalizes the first derivative of the linear cost function of generating technologies, and therefore variable cost per unit of production. Consequently, the variable costs presented here are used to compute the ‘merit order’ in the following simulations.

²⁸ USD₂₀₁₈: this assumption, derived from [3], is used throughout the entire study

²⁹ Refers to minimum power assumption found in the literature: 40% in [9], 50% in [12], [23], [36], 55% in [8]

C	Optimized	Variable throughout each reactor's irradiation cycle
---	-----------	--

Table 3. 3: Nuclear flexibility assumptions of the cases

Assumption *A* assumes that nuclear availability and the fleet’s minimum power are constant throughout the simulated year. This constant availability is equal to the average availability of the nuclear fleet in *B* and *C* that use the schedule optimization model described in 3.1. The first objective is to compare simulation results between *A* and *B* to evaluate the impact of nuclear schedule optimization on modeled results. The second objective is to analyze the potential additional impact of *C* to determine the stakes surrounding minimum power variations.

Several sensitivity cases for all assumptions are presented, depending on the number of reactors installed and VRE penetration, which are key factors for NPP flexibility requirements. Each reactor-fleet sensitivity case represents various reactor scenarios, ranging from 20 to 60 reactors, and each VRE penetration case represents various VRE scenarios, ranging from 0 to 80% of total load (no curtailment).

The chapter hypothesizes that the production ratio of onshore and offshore wind to solar capacities remains constant for each test case. This production ratio is assumed equal to its current value for the currently-installed French VRE capacities [18]. Table 3. 4 details the corresponding installed capacities for each VRE penetration scenario and nuclear capacity case.

VRE penetration scenario	Solar (GW)	PV	Wind – onshore and offshore - (GW)	Nuclear capacity (GW)		
				20 reactors scenario	40 reactors scenario	60 reactors scenario
0% VRE	0		0	20	40	60
20% VRE	19.96		33.86			
40% VRE	39.93		67.72			
60% VRE	59.89		101.58			
80% VRE	79.85		135.44			

Table 3. 4 : Installed VRE and nuclear capacities for each simulated case

The five VRE penetration scenarios, three fleet sizes, and three nuclear flexibility constraint assumptions result in a simulated total of 45 different cases.

3. RESULTS

This section presents the key results for each of the nuclear flexibility assumptions. The chapter’s first findings are linked to the impact of nuclear schedule optimization on nuclear availability profile. The chapter goes on to discuss the effect of a physics-induced minimum power variations approach on available nuclear flexibility. Finally, analysis of the simulation results and sensitivity cases highlights the stakes surrounding flexibility modeling practices as

the share of VRE penetration and nuclear capacity increases, i.e. when the flexibility required for NPP increases.

3.1. Schedule optimization and resulting minimum power variations

The reactor operating schedule is computed for each nuclear fleet scenario case, i.e. 20 reactors, 40 reactors, and 60 reactors (see Figure 3. 1). The schedule allows for greater nuclear availability during peak-demand periods and lower availability during low-demand periods in each nuclear fleet scenario. Indeed, each schedule scenario is positively correlated to the electric demand profile. The model thus replicates usual nuclear availability dynamics seen in Figure 2. 7. Compared to the constant availability assumption, each schedule is better correlated to the demand profile. Second, the impact of the schedule optimization varies according to size of the fleet. The profile gap between the constant availability assumption and the optimized schedule gets more significant as nuclear installed capacity increases.

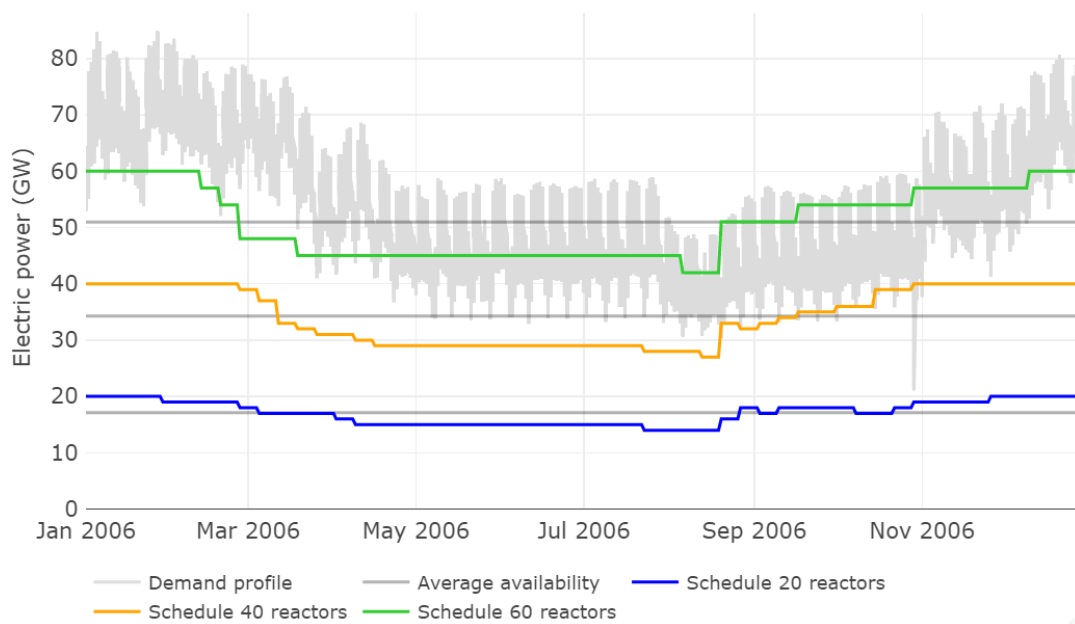


Figure 3. 1 : Nuclear availability for each nuclear fleet size scenario, resulting from the schedule optimization model

The computed nuclear schedules result in a minimum nuclear availability during the period of lowest electric demand (i.e. in August) for all reactor fleet scenario cases. As the number of reactors that can stop simultaneously is constrained, not all reactors can stop during the minimal demand period, even though stopping may be economically optimal for the plant managers. Thus, a share of the reactors effectuate their outages before August, during the second-lowest electric demand period. As all outages occur during low-demand periods, the reactors are potentially available during high-demand periods (i.e. from November to April), thus minimizing the level of unsupplied energy of the electric system.

Based on these schedules, the fleet’s minimum power and load-following potential for each nuclear fleet scenario was computed. The first finding is that a physics-induced minimum power level results in an overall greater flexibility potential than the assumptions widely used

in the electric simulation literature. Indeed, as seen in Figure 3. 2 in the 40 reactors case, the physics-induced minimum power level is lower than the 50% minimum power assumption for all nuclear fleet scenarios based on constant nuclear availability. This highlights that using a physics-induced approach results in higher flexibility capability, which could be a lever for VRE integration. By comparing the physics-induced approach to the 50% minimum power assumption based on the optimized nuclear schedule, the author finds that the physics-induced approach broadly results in greater nuclear flexibility potential. However, these results do not hold for some months (around April–June), as nuclear flexibility may be higher in cases *A* and *B* than in case *C* (see Figure 3. 3). This period is when most reactors are in the last phase in the irradiation cycle and so have minimal ability to maneuver. The conclusion is that a constant minimum power assumption tends to underestimate the overall nuclear flexibility potential and may overestimate it in some cases. The misestimation is greater as a constant nuclear schedule is considered. The difference between the physics-induced nuclear flexibility approach and the other assumptions underlines how the assessment of nuclear capability to accommodate renewable energy variability may differ depending on the chosen minimum power hypothesis.

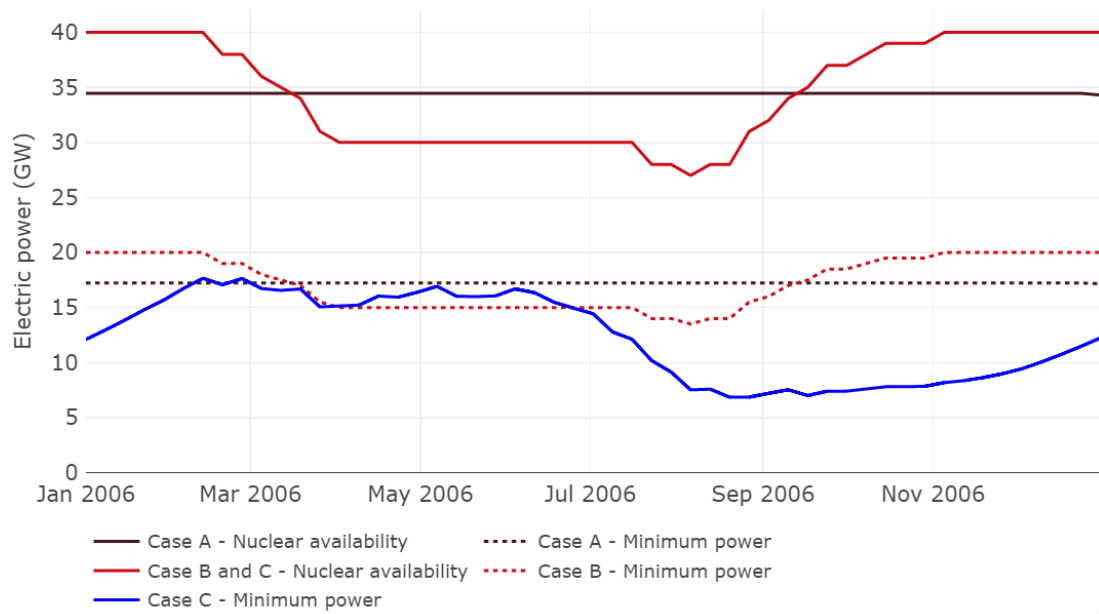


Figure 3. 2: Comparison of nuclear availability and minimum power assumptions in the 40-reactors case.

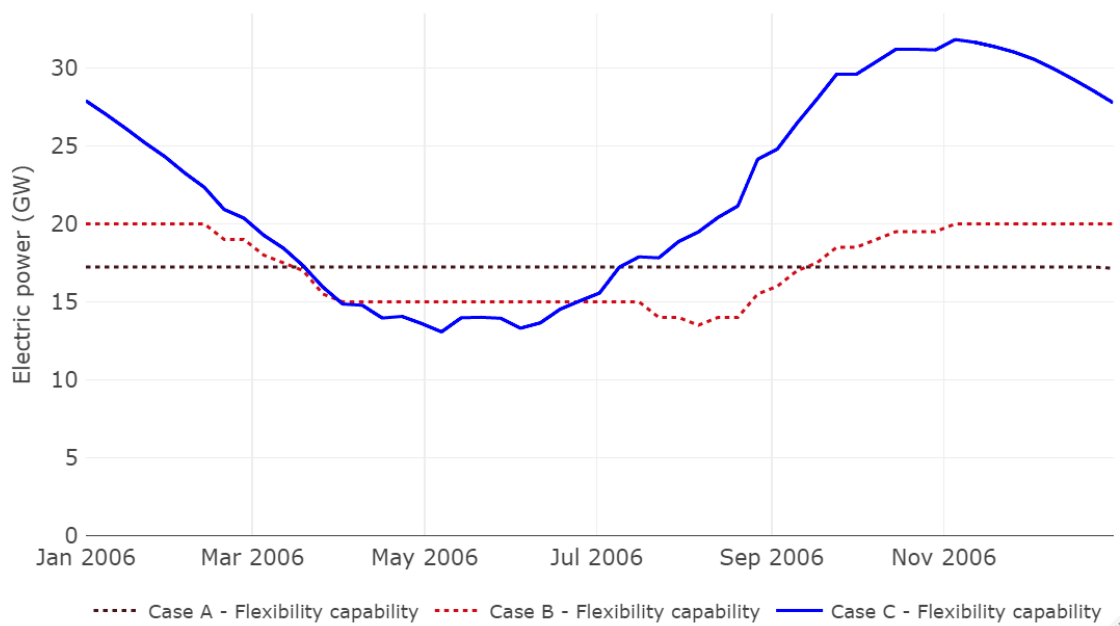


Figure 3. 3: Load-following potential in the 40-reactors case.

3.2. Simulation results

Using the three flexibility assumptions (*A*, *B*, and *C*), the author simulated power system operation with several VRE penetration levels (0%, 20%, 40%, 60%, 80%) and nuclear capacity levels (20, 40, 60 reactors). Then, the simulation results were compared to evaluate the impact of nuclear flexibility on electric system operation with renewable energy. Six metrics were used to evaluate the impact of nuclear flexibility: thermal commitment dispatch, energy curtailment level, operational costs, direct CO₂ emissions, markets prices, and revenues per technology.

The aim was to use these metrics to evaluate the technical, economic, and environmental aspects of a nuclear–renewable-based electric system.

3.2.1. Thermal commitment dispatch

As gross VRE production level is weather-dependent, its level is not sensitive to nuclear schedule optimization. For the sake of brevity, gross VRE production level is not detailed in this sub-chapter, and the focus is instead on the thermal commitment dispatch. Thermal commitment dispatch evolves with each case’s installed capacities, with nuclear production increasing with an increasing number of reactors in the mix (see Table 3. 5). Conjointly, gas production level decreases, as it is the marginal technology of the ‘merit order’.

	0% VRE	20% VRE	40% VRE	60% VRE	80% VRE
20 reactors					
40 reactors					
60 reactors					

Table 3. 5 : Annual thermal energy dispatch: illustration in B cases. See Appendix 1 – Table A1

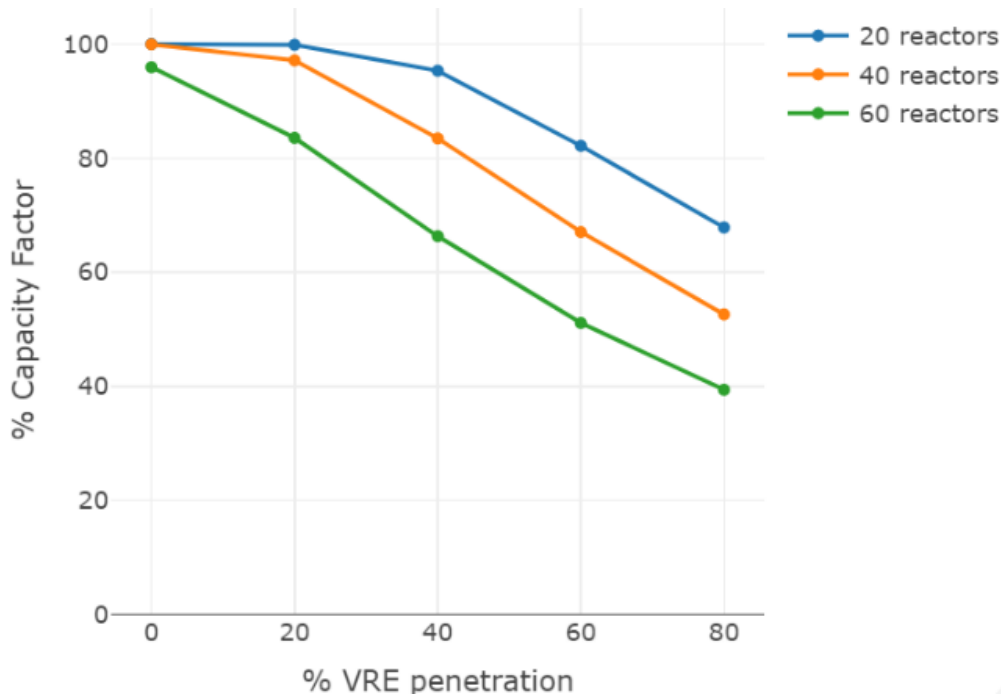


Figure 3. 4: Annual nuclear capacity factor in B

The impact of nuclear flexibility assumptions on optimal thermal commitment dispatch—measured by comparing the results of simulations for *A*, *B*, and *C*—varies depending on VRE penetration level and nuclear fleet size. In capacity cases with low VRE penetration and limited nuclear capacity, the optimal thermal dispatch does not diverge significantly between the nuclear flexibility assumptions. This may indicate that nuclear flexibility modeling is not a crucial concern when considering electric systems where NPPs profit from a load factor near 100% (reported in Figure 3. 4).

In cases with higher VRE penetration and fleet capacity, NPP are expected to maneuver more due to the decreasing level of residual demand. The resulting nuclear capacity factor then evolves negatively to VRE penetration and fleet size (Figure 3. 4). In such capacity mixes, schedule optimization, i.e. *B*, increases nuclear production and decreases gas production compared to *A* (Table 3. 6). The changes in nuclear and gas output become more significant as nuclear fleet size increases. Regarding the impact of minimum power variation, the comparison between *B* and *C* (Table 3. 7) shows that it only marginally increases nuclear production—by up to 0.04%—with increasing share of VRE and nuclear reactors installed in the capacity mix. The effect becomes more substantial when we consider gas production, with up to a 10.61% decrease in the high VRE and nuclear capacity mixes in *C* compared to *B*.

Thus, nuclear flexibility increases nuclear production and decreases the use of gas in capacity mixes that require nuclear to be flexible. The impact is more substantial in *C* that better represents nuclear flexibility potential. These results underline that enhanced nuclear flexibility decreases the need for peaking plants to meet the demand–supply equilibrium of the electric system while increasing nuclear availability for production during peak-demand periods.

	0% VRE		20% VRE		40% VRE		60% VRE		80% VRE	
Technology	Nuclear	Gas	Nuclear	Gas	Nuclear	Gas	Nuclear	Gas	Nuclear	Gas
20 reactors	-0.03%	0.01%	0.00%	0.00%	0.76%	-0.71%	1.49%	-1.75%	2.31%	-3.18%
40 reactors	-0.04%	0.07%	1.07%	-3.27%	2.25%	-10.95%	2.86%	-18.92%	2.64%	-22.38%
60 reactors	1.84%	-12.69%	2.96%	-46.09%	2.19%	-65.90%	1.56%	-73.25%	1.23%	-75.52%

Table 3. 6: Annual thermal energy dispatch change in Assumption B vs. A

	0% VRE		20% VRE		40% VRE		60% VRE		80% VRE	
Technology	Nuclear	Gas	Nuclear	Gas	Nuclear	Gas	Nuclear	Gas	Nuclear	Gas
20 reactors	0.00%	0.00%	0.00%	0.00%	-0.01%	0.01%	0.02%	-0.02%	0.02%	-0.04%
40 reactors	0.00%	0.00%	0.00%	0.01%	0.00%	-0.02%	0.03%	-0.23%	0.03%	-0.29%
60 reactors	0.00%	-0.01%	0.00%	-0.07%	0.01%	-0.62%	0.02%	-3.07%	0.04%	-10.61%

Table 3. 7: Annual thermal energy dispatch change in Assumption C vs. B

3.2.2. Energy curtailment

The curtailed energy level of the simulated cases ranged from 0% of total electricity production (e.g. 0% VRE penetration – 20 reactors – all Assumptions) to 18.41% (i.e. 80% VRE penetration – 60 reactors – Assumption A). Curtailment occurs when electric output exceeds the corresponding electric load due to excess VRE production or a lack of flexibility in thermal plants that, at some point, cannot adjust their output. Whatever the nuclear flexibility assumptions, curtailed energy level positively correlates with VRE penetration levels, which increase the need for balancing to ensure supply–demand equilibrium. Another finding is that the curtailed energy level of each case positively correlates to its installed nuclear fleet capacity, with share of curtailed energy increasing with increasing number of reactors in the simulated mixes. This negative effect of fleet size on energy curtailment level is due to the replacement of flexible gas production by limited-flexibility nuclear technology.

Comparing *B* to *A* first finds that nuclear schedule optimization decreases the share of wasted energy due to curtailment for all capacity mixes. This decreasing trend is more pronounced in *C*. Curtailment levels are the lowest in *C* compared to other nuclear flexibility assumptions, with a maximum curtailment share level of 11.93% (80% VRE penetration – 60 reactors). Like for thermal commitment dispatch, these impacts are less significant in low VRE and nuclear capacity cases, as the substantial gas production meets most of the flexibility requirements, resulting in marginal energy curtailment levels, and near-null benefits of additional nuclear

flexibility. These benefits become substantial as soon as VRE covers a 40% share of electric demand (Figure 3. 5).

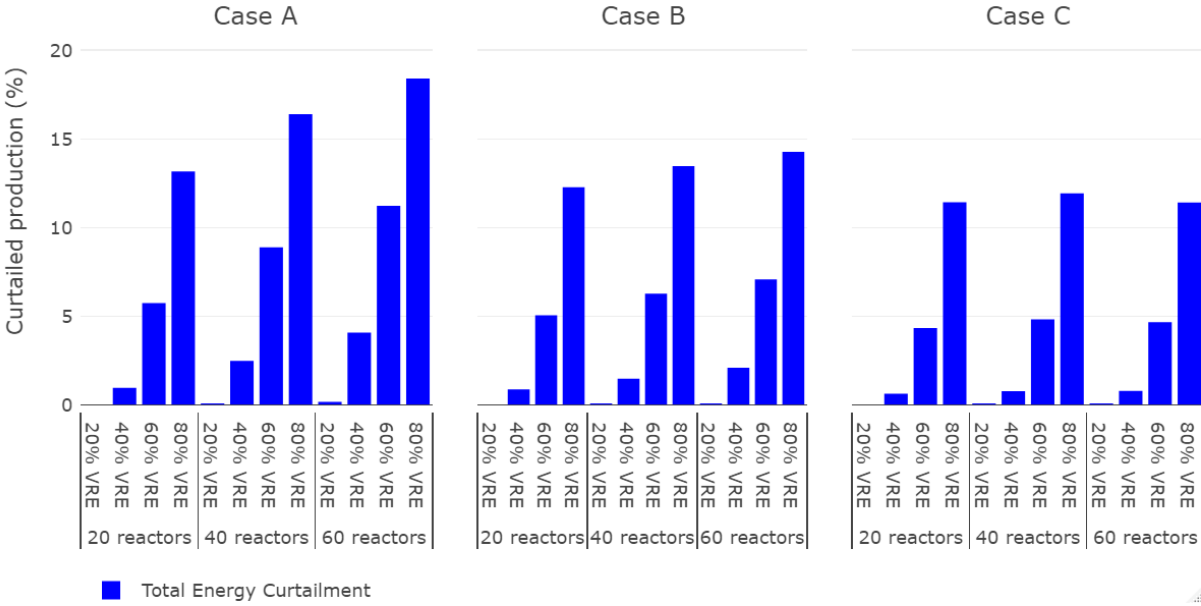


Figure 3. 5 : Curtailed energy share for each VRE, nuclear, and nuclear flexibility assumption case (see Appendix 2 – Table A2.3).

3.2.3. System costs and direct CO₂ emissions

In all simulated capacity cases except scenarios with 0% VRE penetration and 20 or 40 reactors, the power system costs decrease in cases B and C compared to case A, as seen in Figure 3. 6 and Figure 3. 7. The cost decrease gets greater as the share of variable renewables and nuclear in the capacity mix increases. Thus, the overall effect of nuclear flexibility is that it decreases the operational costs of the electricity system in cases with a significant share of VRE penetration and high nuclear capacity. The first driver is the increasing share of the demand covered by VRE technologies—whose have zero variable costs—due to lower curtailment levels. Replacing gas production by nuclear production further reduces these system costs. The additional cost decrease of case C compared to case B (Figure 3. 7) as soon as VRE penetration reaches 40% underlines the impact of modeling the minimum power variations of the reactors in cases where nuclear operates flexibly. Indeed, the cost benefits derived from C compared to A can reach a 27.19% cost decrease (see Figure 3. 7 and Appendix. 2 – Table A2.1) for the case with 80% VRE penetration and 60 GW nuclear capacity (vs. 18.84% in B). Conversely, as the impact is null in low-VRE-penetration cases (Figure 3. 7), the conclusion is that minimum power variation of the reactors is not an essential factor for evaluating operational costs in such power systems. Overall, the cost comparison between fleet flexibility cases highlights the economic benefits of nuclear flexibility, as electric systems with substantial shares of renewables and nuclear are considered.

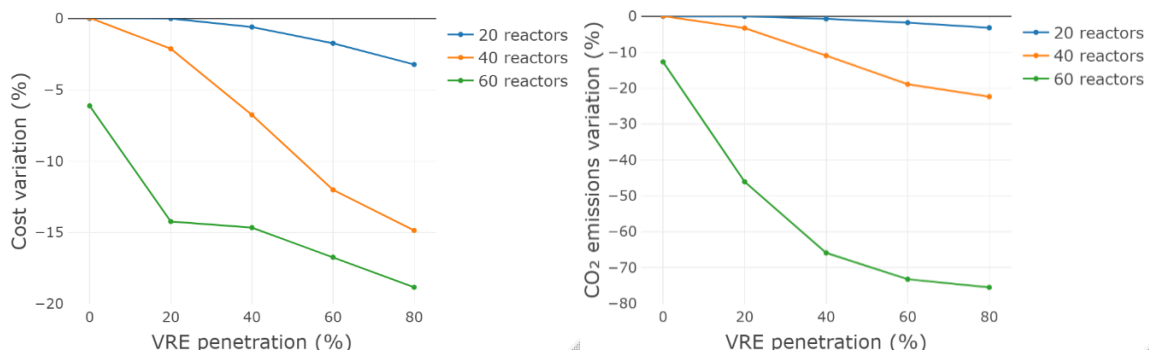


Figure 3. 6: Changes in costs (left) and direct CO₂ emissions (right) with optimized schedule cases (B) versus constant schedule cases (A)

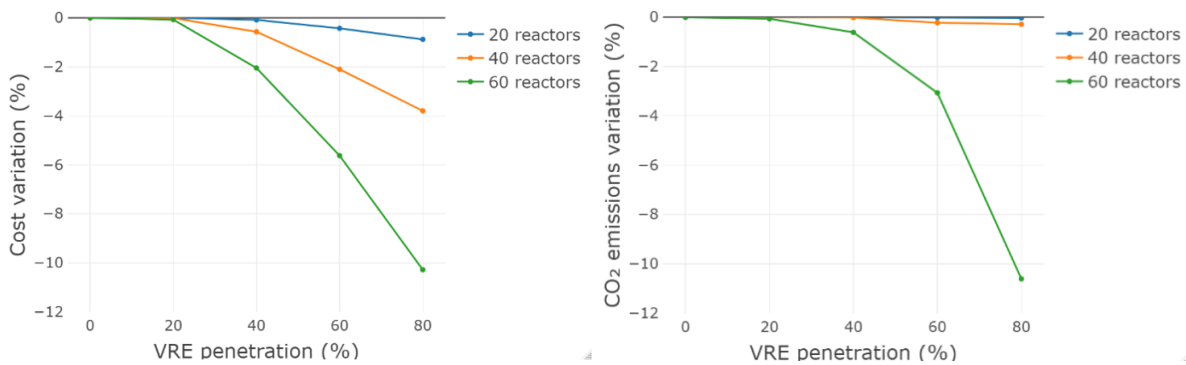


Figure 3. 7: Changes in costs (left) and direct CO₂ emissions (right) with physics-induced minimum power cases (C) versus optimized schedule cases (B)

Like system costs, nuclear schedule optimization decreases the direct CO₂ emissions of generating electricity (measured in CO₂ g/kWh generated). The relative decrease can reach up to 75.52% in the 80% VRE penetration – 60 GW nuclear capacity case in case B vs. case A (see Figure 3. 6 and Appendix. 2 –Table A2.2). Nonetheless, direct CO₂ emissions evolve only marginally (less than 3% decreases) in cases with 20 or 40 reactors and less than 40% VRE penetration. Assumption C also marginally reduces the system’s environmental footprint compared to case B, except in cases with 60 reactors only (Figure 3. 7). Thus, nuclear fleet flexibility does not strongly influence the electric system’s environmental footprint if fleet capacity is low.

The conjoint evaluation of the considered electric system’s costs and CO₂ emissions highlights that nuclear flexibility gains potential benefit with increasing NPP flexibility requirements. In cases where nuclear plants operate in ‘baseload’ generation mode with low nuclear capacity and load factors close to 100%, the consideration of schedule optimization and minimum power variations does not appear a crucial factor for evaluating both system costs and environmental impacts.

3.2.4. Market prices

The market price level formed by the merit order evolves as a function of the economic dispatch of each case, with higher market prices in cases with higher gas production (which links to Table 3. 4 and Table 3. 5). Thus, market prices decrease in cases with a higher nuclear and VRE capacity, as seen in Table 3. 8. Although the cost assumptions described in Table 3. 2 influence

the numerical results for prices, the author argues that they would not change the merit order ranking of the technologies, with gas plants still the marginal technology.

Case A	0% VRE	20% VRE	40% VRE	60% VRE	80% VRE
20 reactors	96.11	95.62	84.07	64.29	48.00
40 reactors	95.49	80.63	52.88	35.99	23.35
60 reactors	68.89	40.51	24.07	13.69	8.83

Table 3. 8 : Average market price (\$/MWh) for all capacity cases – Case A

The impact of nuclear flexibility on market prices varies with VRE penetration level and nuclear capacity installed. Cases *B* and *C* increase the total market price level in cases with low VRE penetration and nuclear capacity (see Appendix 3 – Table A.3). However, as relative VRE and nuclear capacity in the electric mix increases, this impact becomes negative, with decreasing market prices (e.g. cases with 60% and 80% VRE penetration – 40 reactors, and 20%, 40%, 60% and 80% VRE penetration – 60 reactors). This makes it hard to confidently rule on the impact of nuclear flexibility based on market price alone. To further evaluate this impact, this sub-chapter focuses on negative and peaking price occurrences, which gives better insight into the relationship between nuclear flexibility and prices.

In all capacity mix cases except low VRE penetration scenarios, cases *B* and *C* both decrease the occurrence of negative and null price hours (Table 3. 9). In periods of high VRE production and when thermal production cannot adjust production level to the residual demand variations, negative prices can occur, reflecting the willingness of thermal plant managers to avoid shutting down. Enhanced nuclear flexibility leads to lower energy curtailment levels in *B* and *C*, thus reducing the number of hours where price is negative or null, as noted in Table 9. Thus, the conclusion is that the primary impact on market prices is a decrease in number of negative or null price hours for all capacity mix cases.

	Case comparison	0% VRE	20% VRE	40% VRE	60% VRE	80% VRE
20 reactors	$\frac{B - A}{A}$	0.00%	0.00%	-10.31%	-8.20%	-6.57%
	$\frac{C - A}{A}$	0.00%	0.00%	-33.70%	-22.48%	-17.32%
40 reactors	$\frac{B - A}{A}$	0.00%	-28.36%	-30.07%	-22.21%	-16.11%
	$\frac{C - A}{A}$	0.00%	-85.07%	-59.26%	-41.76%	-31.00%
60 reactors	$\frac{B - A}{A}$	0.00%	-60.28%	-37.78%	-27.17%	-18.83%
	$\frac{C - A}{A}$	-100.00%	-96.26%	-74.34%	-56.25%	-42.08%

Table 3. 9: Variations in occurrences of negative prices for all VRE penetration, nuclear capacity, and nuclear flexibility scenario cases

Conjointly to a decreasing number of hours with negative or null prices, nuclear flexibility also affects the occurrence of peaking prices in simulation results, as seen in Table 3. 10. In cases with high VRE penetration and nuclear capacity, the number of hours with peaking prices decreases (i.e. cases with 80% VRE penetration and 40 reactors, or 40%, 60% and 80% VRE penetration and 60 reactors in Table 3. 10). This evolution is linked to the decreasing gas output needed to balance electric demand and supply. As gas production is the primary driver of high market prices, the decrease in gas production directly impacts the occurrence of peaking prices. The average market price of the electric system therefore decreases, even though the number of negative price hours also decreases (Table 3. 9).

Nuclear scenario	VRE penetration	0%	20%	40%	60%	80%
20 reactors	$\frac{B - A}{A}$	0.00%	0.13%	1.10%	2.10%	2.26%
	$\frac{C - A}{A}$	0.00%	0.13%	1.07%	1.74%	1.88%
40 reactors	$\frac{B - A}{A}$	0.51%	5.54%	9.34%	0.79%	-3.06%
	$\frac{C - A}{A}$	0.51%	5.54%	9.16%	-0.04%	-4.40%
60 reactors	$\frac{B - A}{A}$	12.83%	1.92%	-34.66%	-42.95%	-49.73%
	$\frac{C - A}{A}$	12.83%	1.92%	-36.06%	-48.03%	-64.29%

Table 3. 10: Variations in occurrences of peaking prices for all VRE penetration, nuclear capacity, and nuclear flexibility scenario cases

In cases with lower VRE penetration (e.g. the 20% VRE penetration – 60 reactors case, Table 3. 11), there is an opposite impact, with an increasing number of hours with peak prices even though overall gas production also decreased. This is directly linked to the schedule optimization process, as it reduces nuclear availability during low-demand periods. In cases with low VRE and nuclear capacity where gas is necessary to re-balance electric demand and supply, lower nuclear availability in low-demand periods results in a growing number of hours where gas is marginal, and thus where prices are peaking.

As peaking prices are more likely to occur during low-demand periods, the weighted average market prices per MWh produced may still decrease. Figure 3. 8 and Table 3. 11 illustrate this situation in the 20% VRE penetration – 60 reactors case, where *B* increases the number of peak price hours relative to *A* by 1.92%, but the weighted average market price decreases. The author argues that this is due to the simplicity of the simulated electric system, as gas production is the adjustment variable in cases where VRE and nuclear capacities may be undersized for the electric demand.

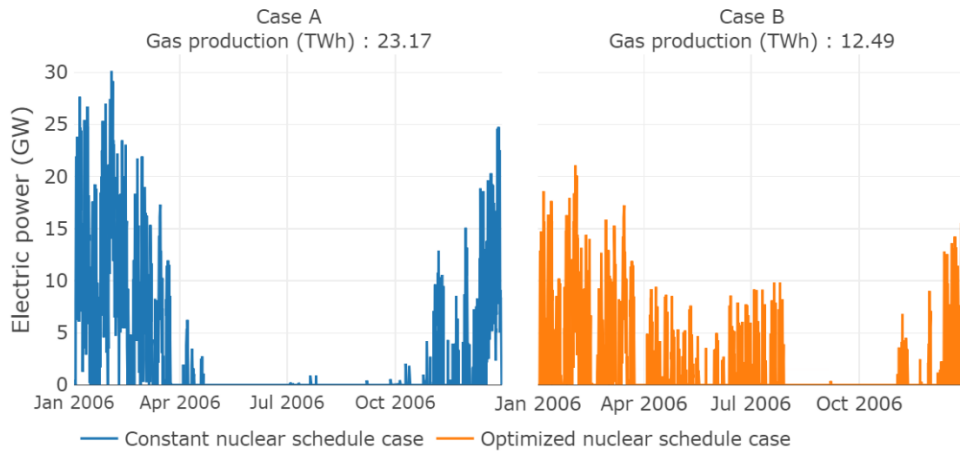


Figure 3. 8: Comparison of gas production between the constant schedule (A) and optimized schedule (B) assumptions – 20% VRE penetration and 60 reactors scenario

Nuclear flexibility assumption	Weighted average market price, \$/MWh	Number of hours <0 \$/MWh	Load share <0	Number of hours >50 \$/MWh	Load share >50
A	40.51	214	1.88%	2390	34.56%
B	39.43	85	0.74%	2436	33.12%
$\frac{B - A}{A}$	-2.65%	-60.28%	-60.62%	1.92%	-4.16%

Table 3. 11: Market price data: ‘20% VRE penetration – 60 GW nuclear capacity’ case

Overall, *B* and *C* have similar impacts on market prices, although *C* further reduces negative price hours, resulting in higher market prices.

3.2.5. Revenues per technologies

To further the analysis, the composition of each technology revenue is investigated. The underlying argument is that, in the simplified case studies used in this chapter, there are two main drivers of revenues: first, the share of each technology output sold at low prices, which drives revenues down, and second, the share sold at peaking prices, which drives revenues up. If these two shares conjointly increase or decrease, their effects on revenues may balance out.

Overall, as seen in Table 3. 12, nuclear is the low-carbon technology that first benefits from higher prices due to its ability to adjust production in response to the market price signal. This holds true for all the simulated capacity cases. On the other hand, solar is the lowest-remunerated technology as its production is concentrated during sunny hours, which is when most negative prices periods occur (as illustrated in Figure 3. 9). Indeed, the high solar irradiance around midday decreases market price, especially in cases with high VRE penetration. Wind technology benefits from higher revenues than solar technology, as its production is spreads out across the day, thus benefiting more frequently from peaking prices (Figure 3. 9). In all VRE penetration and nuclear capacity scenarios, nuclear flexibility decreases the output share of all simulated technologies sold at low market prices due to the in

negative price occurrences described in Table 3. 8, especially in case C compared to case B (illustrated in Figure 3. 9). Detailed numerical results can be found in Appendix 4.

Case A	Nuclear				Wind				Solar			
	20% VRE	40% VRE	60% VRE	80% VRE	20% VRE	40% VRE	60% VRE	80% VRE	20% VRE	40% VRE	60% VRE	80% VRE
20 reactors	95.58	86.60	73.45	63.94	94.517	71.927	45.51	30.12	94.40	67.72	37.70	18.09
40 reactors	79.08	56.11	43.81	33.89	70.569	36.642	21.50	12.01	67.69	28.31	12.62	5.85
60 reactors	39.83	27.07	18.22	14.21	30.835	14.824	7.15	4.36	25.27	11.18	4.16	1.73

Table 3. 12 : Technology revenues (\$/MWh) for all capacity cases – Case A

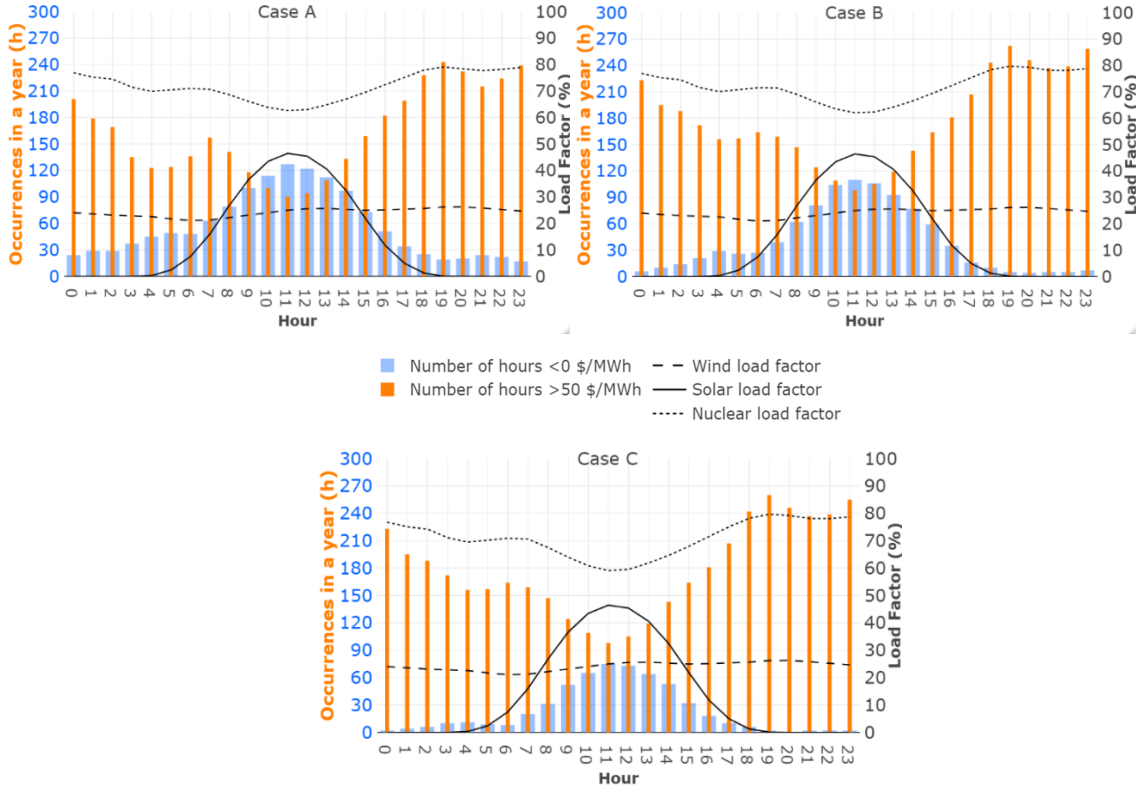


Figure 3. 9 : Average load factor for each technology and frequency of occurrences of negative and peaking prices, by hours: the ‘40% VRE penetration – 40 reactors’ case

Nuclear benefits more from flexibility, as it is the most dispatchable low-carbon technology in the electric system considered in this chapter. Schedule optimization and physics-induced minimum power enhance the ability of nuclear to adjust production to market price signals. In most capacity cases (i.e. with 20 and 40 reactors; see Appendix 4.3), nuclear revenues per MWh increase thanks to a diminishing share of production sold at negative price hours and an increasing share sold at peak prices, as illustrated in Table 3. 13 for the 40% VRE penetration – 40 reactors case. Note that case C further reduces the share of production sold at negative

prices, resulting in even higher revenues for nuclear. This highlights the benefits of nuclear flexibility for nuclear revenues. In cases with high nuclear capacity (i.e. 20%, 40%, 60%, 80% VRE penetration and 60 reactors; see Appendix 4.3), nuclear revenues decrease as gas production firmly declines with additional nuclear flexibility, thus reducing the share of nuclear production sold at peak prices. Note, however, that C reduces this effect and results in higher nuclear revenues than B (e.g. Table 3. 13).

	Solar			Wind			Nuclear		
Nuclear flexibility assumption	Average revenues \$/MWh	Output share sold <0 \$/MWh	Output share sold >50 \$/MWh	Average revenues \$/MWh	Output share sold <0 \$/MWh	Output share sold >50 \$/MWh	Average revenues \$/MWh	Output share sold <0 \$/MWh	Output share sold >50 \$/MWh
A	28.31	31.70%	24.17%	36.64	27.20%	33.41%	56.11	9.25%	53.99%
B	34.39	26.50%	30.66%	37.60	19.63%	33.52%	61.74	4.86%	60.04%
C	35.40	17.75%	30.66%	38.32	12.31%	33.38%	62.75	1.76%	60.81%
$\frac{B-A}{A}$	21.48%	-16.41%	26.81%	2.61%	-27.85%	0.31%	10.03%	-47.46%	11.22%
$\frac{C-A}{A}$	25.04%	-44.00%	26.81%	4.59%	-54.73%	-0.11%	11.83%	-80.93%	12.65%

Table 3. 13 : Average revenues level (\$/MWh) and profile: 40% VRE penetration – 40 GW nuclear capacity case

Solar technology also benefits from higher revenues due to enhanced nuclear flexibility (Table 3. 14). Enhanced ability of nuclear to accommodate renewable production variability means that the share of solar production sold at negative prices decreases, especially in C (illustrated for the 40% VRE penetration – 40 reactors case in Table 3. 13). The decreased energy curtailment drives up the average revenues per MWh of solar, which also benefits from an increased share of production sold at peak prices, as seen in Table 3. 13. In some cases with higher VRE penetration and nuclear capacity (i.e. 80% VRE penetration and 40 reactors, or 40% VRE penetration and 60 reactors), this trend towards increasing revenues may be offset by a diminished number of peak price hours, thus decreasing solar revenues in B. However, the additional nuclear flexibility in C increases solar revenues for all VRE penetration and nuclear capacity scenarios (Table 3. 14).

Solar	Case	20% VRE	40% VRE	60% VRE	80% VRE
20 reactors	A	94.40	67.72	37.70	18.09
	C	94.84	70.23	40.63	19.39
	$\frac{C-A}{A}$	0.46%	3.71%	7.79%	7.17%
40 reactors	A	67.69	28.31	12.62	5.85

	<i>C</i>	74.49	35.40	13.88	6.37
	$\frac{C - A}{A}$	10.04%	25.04%	9.97%	9.01%
60 reactors	<i>A</i>	25.27	11.18	4.16	1.73
	<i>C</i>	32.66	11.59	6.65	3.72
	$\frac{C - A}{A}$	29.26%	3.74%	59.72%	114.99%

Table 3. 14 : Average revenues from solar (\$/MWh) in all capacity cases – Comparison of A vs. C.

The overall impact of nuclear flexibility on wind revenues remains undetermined, as wind revenues slightly increase in cases with low VRE penetration and nuclear capacity and vary in cases with higher VRE penetration and nuclear capacity, with no definite trend emerging. Like for nuclear and solar technology, nuclear flexibility decreases the share of wind production sold at negative prices in all capacity mix cases. On the other hand, as VRE and nuclear are higher than the 40% penetration and 40 GW (see Appendix 4.), the share of wind production sold at peaking prices decreases, thus having varying influence on the overall revenues level. Comparing simulation results for *B* and *C*'s, it shows that the average wind revenues per MWh increase with increasing nuclear flexibility.

Wind	Case	20% VRE	40% VRE	60% VRE	80% VRE
20 reactors	<i>A</i>	94.517	71.927	45.51	30.12
	<i>C</i>	94.726	72.521	46.36	30.93
	$\frac{C - A}{A}$	0.22%	0.83%	1.88%	2.69%
40 reactors	<i>A</i>	70.569	36.642	21.50	12.01
	<i>C</i>	72.006	38.324	21.95	12.52
	$\frac{C - A}{A}$	2.04%	4.59%	2.11%	4.24%
60 reactors	<i>A</i>	30.835	14.824	7.15	4.36
	<i>C</i>	27.335	13.752	8.61	5.83
	$\frac{C - A}{A}$	-11.35%	-7.24%	20.47%	33.59%

Table 3. 15 : Average revenues from wind (\$/MWh) in all capacity cases – Comparison of A vs. C.

Even though the impact of nuclear flexibility on revenues is ambiguous and differs depending on the technology and capacity mix case (see Table 3. 13, Table 3. 14, Table 3. 15 and Appendix 4), schedule optimization and minimum power variations have a strong influence on their revenue compositions. Indeed, nuclear flexibility limits the extreme negative price events that drive average revenue per MWh down. It is then essential to consider nuclear flexibility parameters when evaluating the economic viability of an electric system's technologies.

4. DISCUSSION AND CONCLUSION

This chapter explores the stakes surrounding nuclear flexibility modeling to evaluate decarbonized electric system operations with renewable energy. It presents a novel formulation of the nuclear refueling and maintenance schedule that frames nuclear operations, including irradiation-cycle and outage lengths. Using the resulting schedule, a physics-induced minimum power variation was computed to accurately evaluate a fleet's flexibility potential. This work highlights that current schedule modeling assumptions rarely represent the seasonality factor of nuclear availability, which results in higher nuclear availability during peak-demand periods and schedules maintenance and refueling outages during low-demand periods. Nuclear schedule optimization reduces operational costs, energy curtailments, peaking-plant use, and environmental impacts linked to electricity generation. Another key finding is that nuclear schedule optimization becomes increasingly relevant with increasing relative share of VRE and nuclear capacity in the capacity mix: it shows little influence on simulation results in cases with few reactors and limited VRE penetration, but significant impacts in other cases. The overall impact of schedule optimization on market prices and revenues per technology remains undetermined, as the revenue benefits linked to the decrease of negative price occurrences may be offset by a decreasing number of peak prices. Nonetheless, as nuclear is the low-carbon generating technology modeled in this paper that is the most responsive to price signals, its revenues per MWh benefit the most from additional flexibility.

The chapter also points out that a constant minimum power assumption misestimates the nuclear fleet's flexibility potential. A physics-induced minimum power approach based on an optimized nuclear schedule leads to higher flexibility margins, resulting in more efficient electric system operations with nuclear and renewable energy. Indeed, a physics-induced approach enhances the benefits of the optimization schedule in terms of electric-system operational costs, VRE integration, peaking-plant use, and environmental impacts. Minimum power variations are therefore essential to assessing the operation of electric systems with high shares of nuclear and renewable energy.

Finally, the joint analysis of the stakes surrounding schedule optimization in tandem with minimum power variations modeling practices highlights the need to accurately represent flexibility constraints in order to evaluate electric system operations with renewables and nuclear. Although historically used as a 'baseload' technology, the use of nuclear as a flexible low-carbon technology to further integrate VRE capacities while ensuring security of supply could be favored if it proves cost-optimal. This work shows that enhanced nuclear flexibility modeling practices are essential to validly assess this potential cost-optimality. In this thesis' context, representing nuclear flexibility constraints in simulation models seems to be of importance to determine the role of nuclear energy in power systems with renewable energy. Chapter 4 relies on those results and incorporates this chapter's modeling framework in a broader investment and simulation model to evaluate the relevance of flexible nuclear reactors in future decarbonized power systems.

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6. APPENDICES

APPENDIX 1: Economic dispatch for all VRE–Nuclear scenarios :

TWh	0% VRE		20% VRE		40% VRE		60% VRE		80% VRE	
	Nuclear	Gas	Nuclear	Gas	Nuclear	Gas	Nuclear	Gas	Nuclear	Gas
20 reactors	149.69	330.36	149.51	234.53	140.13	149.57	114.62	94.62	89.50	61.62
40 reactors	300.94	179.11	292.29	91.76	245.76	43.94	186.96	22.28	138.75	12.38
60 reactors	426.99	53.06	371.55	12.49	286.52	3.17	208.07	1.17	150.53	0.59

Table A1. Economic dispatch for all VRE–Nuclear cases – Optimized nuclear schedule assumption (B)

APPENDIX 2: Cost and CO₂ evolutions

		0% VRE	20% VRE	40% VRE	60% VRE	80% VRE
$\frac{B - A}{A}$	20 reactors	0.01%	0.00%	-0.59%	-1.73%	-3.22%
	40 reactors	0.05%	-2.12%	-6.75%	-12.01%	-14.86%
	60 reactors	-6.12%	-14.23%	-14.66%	-16.74%	-18.84%
$\frac{C - A}{A}$	20 reactors	0.01%	0.00%	-0.67%	-2.15%	-4.07%
	40 reactors	0.06%	-2.12%	-7.28%	-13.86%	-18.09%
	60 reactors	-6.12%	-14.29%	-16.40%	-21.42%	-27.19%

Table A2.1 Relative change in operational costs of the electric system for all VRE penetration, nuclear capacity, and nuclear flexibility assumptions cases

		0% VRE	20% VRE	40% VRE	60% VRE	80% VRE
$\frac{B - A}{A}$	20 reactors	0.01%	0.00%	-0.71%	-1.75%	-3.18%
	40 reactors	0.07%	-3.27%	-10.95%	-18.92%	-22.38%
	60 reactors	-12.69%	-46.09%	-65.90%	-73.25%	-75.52%
$\frac{C - A}{A}$	20 reactors	0.01%	0.00%	-0.70%	-1.77%	-3.22%
	40 reactors	0.08%	-3.26%	-10.96%	-19.11%	-22.60%
	60 reactors	-12.70%	-46.12%	-66.11%	-74.07%	-78.12%

Table A2.2 Relative change in direct CO₂ emissions of the electric system for all VRE penetration, nuclear capacity, and nuclear flexibility assumptions cases

		0% VRE	20% VRE	40% VRE	60% VRE	80% VRE
A	20 reactors	0.00%	0.00%	0.96%	5.74%	13.16%
	40 reactors	0.00%	0.05%	2.48%	8.89%	16.40%
	60 reactors	0.00%	0.15%	4.07%	11.22%	18.41%
B	20 reactors	0.00%	0.00%	0.87%	5.06%	12.27%
	40 reactors	0.00%	0.03%	1.47%	6.27%	13.47%
	60 reactors	0.00%	0.06%	2.09%	7.08%	14.27%
C	20 reactors	0.00%	0.00%	0.63%	4.34%	11.42%
	40 reactors	0.00%	0.00%	0.77%	4.82%	11.93%
	60 reactors	0.00%	0.00%	0.79%	4.66%	11.41%

Table A2.3 Share of curtailed electricity of the electric system for all VRE penetration, nuclear capacity, and nuclear flexibility assumptions cases

APPENDIX 3: Market prices for all simulation and nuclear flexibility cases

		0% VRE			20% VRE			40% VRE			60% VRE			80% VRE			
Case	A	Av	Hours	Hours	Av	Hours	Hours	Av	Hours	Hours	Av	Hours	Hours	Av	Hours	Hours	
		σ market price	< 0\$/MWh	> 50\$/MWh	σ market price	< 0\$/MWh	> 50\$/MWh	σ market price	< 0\$/MWh	> 50\$/MWh	σ market price	< 0\$/MWh	> 50\$/MWh	σ market price	< 0\$/MWh	> 50\$/MWh	σ market price
20 reactors																	
	A	96.11	0	8736	95.62	0	8669	84.07	543	7394	64.29	2086	5464	48.00	3563	3980	
	B	96.11	0	8736	95.70	0	8680	84.60	487	7475	65.26	1915	5579	48.66	3329	4070	
	C	96.11	0	8736	95.70	0	8680	84.74	360	7473	65.44	1617	5559	49.04	2946	4055	
	B-A	0.00%	0.00%	0.00%	0.09%	0.00%	0.13%	0.62%	-	1.10%	1.51%	-8.20%	2.10%	1.38%	-6.57%	2.26%	
	C-A	0.00%	0.00%	0.00%	0.09%	0.00%	0.13%	0.79%	-	1.07%	1.79%	-	1.74%	2.18%	-	1.88%	
40 reactors																	
	A	95.49	0	8630	80.63	67	6709	52.88	1360	3930	35.99	3233	2537	23.35	4619	1568	
	B	95.72	0	8674	82.94	48	7081	55.73	951	4297	35.90	2515	2557	22.84	3875	1520	
	C	95.72	0	8674	82.98	10	7081	56.17	554	4290	36.54	1883	2536	23.59	3187	1499	
	B-A	0.24%	0.00%	0.51%	2.87%	-	5.54%	5.40%	-	9.34%	-0.24%	-	0.79%	-2.17%	-	-3.06%	
	C-A	0.24%	0.00%	0.51%	2.92%	85.07	5.54%	6.22%	59.26	9.16%	1.53%	41.76	-0.04%	1.03%	31.00	-4.40%	
60 reactors																	
	A	68.89	1	5199	40.51	214	2390	24.07	2136	1209	13.69	4210	610	8.83	5401	364	
	B	73.30	1	5866	39.43	85	2436	19.18	1329	790	11.55	3066	348	7.60	4384	183	
	C	73.30	0	5866	39.52	8	2436	20.02	548	773	12.90	1842	317	8.82	3128	130	
	B-A	6.40%	0.00%	12.83%	-2.65%	-	1.92%	-	-	-	-	-	-	-	-	-	
	C-A	6.40%	0.00%	12.83%	-2.44%	60.28	1.92%	16.82	37.78	34.66	15.57	27.17	42.95	13.88	18.83	49.73	
	B-A	-	100.00	12.83%	-	96.26	1.92%	-	74.34	36.06	-5.77%	56.25	48.03	-0.06%	42.08	64.29	
	C-A	-	100.00	12.83%	-	96.26	1.92%	-	74.34	36.06	-5.77%	56.25	48.03	-0.06%	42.08	64.29	

Table A3. Market price variations for all VRE penetration, nuclear capacity, and nuclear flexibility assumptions cases

APPENDIX 4: Revenues for each low-carbon technology

	20% VRE penetration			40% VRE penetration			60% VRE penetration			80% VRE penetration						
	Avg \$/MWh	%Hours < 0\$/MWh	%Hours > 50\$/MWh	Avg \$/MWh	%Hours < 0\$/MWh	%Hours > 50\$/MWh	Avg \$/MWh	%Hours < 0\$/MWh	%Hours > 50\$/MWh	Avg \$/MWh	%Hours < 0\$/MWh	%Hours > 50\$/MWh				
20 reactors	A	94.40	0.00%	97.98	67.72	15.85%	68.60	37.70	46.48%	37.28	18.09	70.11%	17.32	17.32%		
	B	94.84	0.00%	98.50	69.87	13.98%	70.88	40.05	45.20%	39.88	18.82	68.63%	17.98	17.98%		
	C	94.84	0.00%	98.50	70.23	10.79%	70.88	40.63	40.02%	39.87	19.39	63.51%	17.96	17.96%		
	$\frac{B-A}{A}$	0.46%	0.00%	0.53%	3.17%	-11.78%	3.33%	6.23%	-2.76%	6.98%	4.02%	-2.11%	3.80%	3.80%		
	$\frac{C-A}{A}$	0.46%	0.00%	0.53%	3.71%	-31.92%	3.33%	7.79%	-13.90%	6.95%	7.17%	-9.42%	3.67%	3.67%		
	40 reactors	A	67.69	2.02%	66.69	28.31	31.70%	24.17	12.62	62.68%	9.84	5.85	82.39%	4.52	4.52%	
		B	74.37	1.31%	74.48	34.39	26.50%	30.66	12.70	57.48%	9.23	5.38	79.10%	3.51	3.51%	
		C	74.49	0.28%	74.48	35.40	17.75%	30.66	13.88	47.12%	9.21	6.37	70.33%	3.50	3.50%	
		$\frac{B-A}{A}$	9.86%	-35.02%	11.69%	21.48%	-16.41%	26.81%	0.65%	-8.31%	-6.21%	-8.05%	-3.99%	-22.23%	-22.23%	
		$\frac{C-A}{A}$	10.04%	-86.12%	11.69%	25.04%	-44.00%	26.81%	9.97%	-24.84%	6.39%	9.01%	-14.64%	-22.50%	-22.50%	
		60 reactors	A	25.27	5.77%	17.05	11.18	45.23%	5.77	4.16	76.39%	1.71	1.73	88.76%	0.52	0.52%
			B	32.42	2.27%	25.03	9.76	33.57%	2.51	4.32	66.32%	0.53	2.03	83.78%	0.19	0.19%
C			32.66	0.20%	25.03	11.59	17.61%	2.51	6.65	45.99%	0.51	3.72	68.67%	0.14	0.14%	
$\frac{B-A}{A}$			28.32%	-60.66%	46.80%	-12.68%	-25.79%	-56.54%	3.81%	-13.18%	-69.14%	16.94%	-5.61%	-63.54%	-63.54%	
$\frac{C-A}{A}$			29.26%	-96.56%	46.80%	3.74%	-61.06%	-56.54%	59.72%	-39.79%	-69.95%	114.99%	-22.64%	-72.69%	-72.69%	

Table A4.1 Solar revenues for all VRE penetration, nuclear capacity, and nuclear flexibility assumptions cases

60 reactors						40 reactors						20 reactors						e Cas
$\frac{C-A}{A}$	$\frac{B-A}{A}$	C	B	A		$\frac{C-A}{A}$	$\frac{B-A}{A}$	C	B	A		$\frac{C-A}{A}$	$\frac{B-A}{A}$	C	B	A		
-	-	27.335	27.100	30.835		2.04%	1.86%	72.006	71.881	70.569		0.22%	0.22%	94.726	94.726	94.517		
11.35	12.11																	
93.76	51.85	0.30%	2.34%	4.87%		81.15	23.42	0.35%	1.44%	1.88%		0.00%	0.00%	0.00%	0.00%	0.00%		
-	-	18.76	18.76	23.51		2.13%	2.13%	71.56	71.56	70.07		0.25%	0.25%	98.36	98.36	98.12		
20.23	20.23																	
7.24%	16.77	13.752	12.338	14.824		4.59%	2.61%	38.324	37.600	36.642		0.83%	0.47%	72.521	72.264	71.927		
-	-	11.90	25.51	37.64		54.73	27.85	12.31	19.63	27.20		-	5.93%	9.06%	11.63	12.36		
68.40	32.24											26.68						
52.71	50.72	4.28%	4.46%	9.05%		0.11%	0.31%	33.38	33.52	33.41		0.35%	0.41%	73.35	73.40	73.10		
20.47	0.04%	8.61	7.15	7.15		2.11%	1.06%	21.95	21.27	21.50		1.88%	1.61%	46.36	46.24	45.51		
-	-	34.96	49.49	62.72		33.75	18.34	35.62	43.90	53.76		-	7.28%	32.40	36.81	39.70		
44.26	21.09											18.38						
-	-	1.34%	1.58%	3.38%		10.10	8.41%	17.19	17.51	19.12		0.04%	1.04%	45.61	46.06	45.59		
60.42	53.26																	
33.59	6.63%	5.83	4.65	4.36		4.24%	1.18%	12.52	11.87	12.01		2.69%	1.59%	30.93	30.60	30.12		
-	-	52.17	64.79	74.64		22.80	11.82	52.51	59.98	68.02		-	4.86%	50.79	55.24	58.06		
30.10	13.19											12.52						
-	-	0.39%	0.71%	1.71%		15.28	12.78	8.35%	8.59%	9.85%		-	0.61%	29.87	30.08	29.90		
77.41	58.35											0.10%						

Table A4.2 Wind revenues for all VRE penetration, nuclear capacity, and nuclear flexibility assumptions cases

	60 reactors						40 reactors						20 reactors												
	$\frac{C-A}{A}$	$\frac{B-A}{A}$	C	B	A	$\frac{C-A}{A}$	$\frac{B-A}{A}$	C	B	A	$\frac{C-A}{A}$	$\frac{B-A}{A}$	C	B	A	$\frac{C-A}{A}$	$\frac{B-A}{A}$	C	B	A	Case	Avg \$/MWh	%Hours < 0\$/MWh	%Hours > 50\$/MWh	
20% VRE penetration	1.46%	1.28%	40.41	40.34	39.83	4.02%	3.94%	82.26	82.20	79.08	0.40%	0.40%	0.04%	0.26%	0.40%	0.10%	0.10%	95.68	95.68	95.58		95.58	0.00%	99.38%	
40% VRE penetration	-	-	0.03%	0.43%	1.35%	-	-	0.04%	0.26%	0.40%	-	-	0.04%	0.26%	0.40%	#0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%	99.49%
60% VRE penetration	1.51%	1.43%	34.17%	34.15%	33.67%	4.63%	4.59%	83.63%	83.59%	79.93%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%	99.49%	99.49%	99.38%		99.49%	0.00%	99.38%	
80% VRE penetration	-	-	23.55%	22.78%	27.07%	11.83%	10.03%	62.75%	61.74%	56.11%	1.76%	1.76%	1.76%	1.76%	1.76%	2.08%	1.16%	88.40%	87.60%	86.60%		88.40%	1.25%	89.20%	
	13.00%	15.84%	1.53%	7.32%	16.11%	-	-	1.76%	4.86%	9.25%	-	-	1.76%	4.86%	9.25%	-	-	1.25%	2.67%	3.28%		1.25%	1.25%	3.28%	
	90.48%	54.60%	14.45%	14.32%	20.59%	12.65%	11.22%	60.81%	60.04%	53.99%	80.93%	47.46%	60.81%	60.04%	53.99%	2.08%	1.24%	91.06%	90.31%	89.20%		91.06%	1.24%	89.20%	
	29.82%	30.43%	17.91%	16.45%	18.22%	14.92%	9.99%	50.35%	48.19%	43.81%	14.92%	9.99%	50.35%	48.19%	43.81%	8.18%	4.82%	79.46%	76.99%	73.45%		79.46%	4.82%	73.45%	
	-	-	4.24%	16.50%	33.59%	-	-	5.31%	12.10%	22.97%	-	-	5.31%	12.10%	22.97%	-	-	4.60%	8.92%	12.54%		4.60%	4.60%	12.54%	
	87.37%	50.87%	8.16%	8.09%	12.51%	12.89%	8.95%	46.64%	45.01%	41.31%	76.89%	47.30%	46.64%	45.01%	41.31%	8.04%	4.93%	80.94%	78.62%	74.92%		80.94%	4.93%	74.92%	
	34.77%	35.30%	14.73%	13.08%	14.21%	20.99%	12.83%	41.01%	38.24%	33.89%	20.99%	12.83%	41.01%	38.24%	33.89%	14.16%	8.04%	73.00%	69.09%	63.94%		73.00%	8.04%	63.94%	
	3.66%	7.94%	5.85%	23.55%	43.70%	-	-	8.68%	18.06%	32.73%	-	-	8.68%	18.06%	32.73%	-	-	8.01%	14.85%	21.00%		8.01%	8.01%	21.00%	
	86.61%	46.12%	4.61%	5.07%	9.14%	16.62%	10.17%	36.05%	34.06%	30.91%	73.46%	44.83%	36.05%	34.06%	30.91%	61.84%	29.28%	73.78%	70.08%	64.84%		73.78%	29.28%	64.84%	
	49.54%	44.56%	4.61%	5.07%	9.14%	16.62%	10.17%	36.05%	34.06%	30.91%	16.62%	10.17%	36.05%	34.06%	30.91%	13.79%	8.08%	73.78%	70.08%	64.84%		73.78%	8.08%	64.84%	

Table A4.3 Nuclear revenues for all VRE penetration, nuclear capacity, and nuclear flexibility assumptions cases

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1. INTRODUCTION

The objective of the present chapter is to explore the new operational paradigm for nuclear energy and determine how reactors adapt to future decarbonized power systems. In order to explore this new paradigm, the chapter follows up on previous work surrounding nuclear flexibility modeling in power systems with renewable energy in [1], corresponding to Chapter 3. In this previous work, the relevance of nuclear flexibility constraint modeling in systems with high shares of renewable energy has been highlighted, and modeling frameworks to represent those constraints have been proposed. The present chapter extends this previous work through nuclear flexibility modeling in broader power systems simulation, with more market zones and generating technologies.

The chapter focuses on a decarbonized European power system in 2050, as most countries have committed to decarbonizing their energy sector altogether [2], [3]. The objective is to determine a cost-optimal capacity mix and determine whether nuclear capacity remains valuable for the power system using a capacity expansion and simulation model. Capacity expansion models applied to power systems are mathematical models aiming to determine the cost-optimal capacity mix to meet future electric demand. The underlying principle is to allow investments in generating units, transmission capacities, and flexibility services (e.g., storage units), resulting in a cost-optimal capacity mix that secures the security of supply while meeting decarbonization goals. The results of capacity expansion models lay the foundations for potential debate regarding climate change mitigation policies, technology developments, or the need for investments in new capacities. Hence, the implication of capacity expansion models' results may influence power systems' evolution toward their decarbonized future.

The first contribution of the chapter is the European dimension of the model, allowing the inclusion of the VRE potential diversity among Europe, strategic choices toward decarbonization for each country, and electricity exchanges between balancing zones that allow for better VRE integration. Hence, the chapter extends previous analyses focusing on one country, as in [4] that focuses solely on a French decarbonized power system. Investments are possible in new generations, storage, and transmission capacities to ensure an increasing electric demand while minimizing operational costs. Electric generation is then allocated between technologies based on ascending order of marginal costs and each plant's technical constraints, aiming to replicate the dynamics of short-term power markets in Europe. The chapter's second contribution is the detailed nuclear flexibility constraints modeling in a broad capacity expansion program. Such modeling accurately evaluates reactors' technical and economic viability with a high share of variable renewable capacities. By combining the representation of numerous generating technologies in several countries and the flexibility potential of nuclear power plants, the chapter is able to determine whether flexible nuclear is of relevance in future decarbonized power systems.

The chapter is structured as follows. Chapter 4.2 describes the capacity expansion model, 'ANTARES-Xpansion RTE' Simulator, its main assumptions, the parameters used in this chapter, and the nuclear flexibility constraints included. Chapter 4.3 presents the optimal capacity derived from the input parameters and extensively focuses on nuclear production. Chapter 4.4 discusses simulation results, the main assumptions, and the technical and economic

consequences for the nuclear fleet. Chapter 4.5 concludes with the main findings and discusses future work.

2. METHODS

2.1. Overview of the simulated system

The simulated electric system is the European power system centered around France, with aggregated neighboring areas. The chapter considers all countries of the European continent while focusing on Western Europe for detailed results. The main regions aggregated are Eastern Europe and Northern Europe, which decrease the computational complexity of the model. We argue that such aggregations have a limited impact on simulation results of the Western Europe region of our model. Appendix 1 and Figure 4. 1 present all simulated countries and related aggregations.

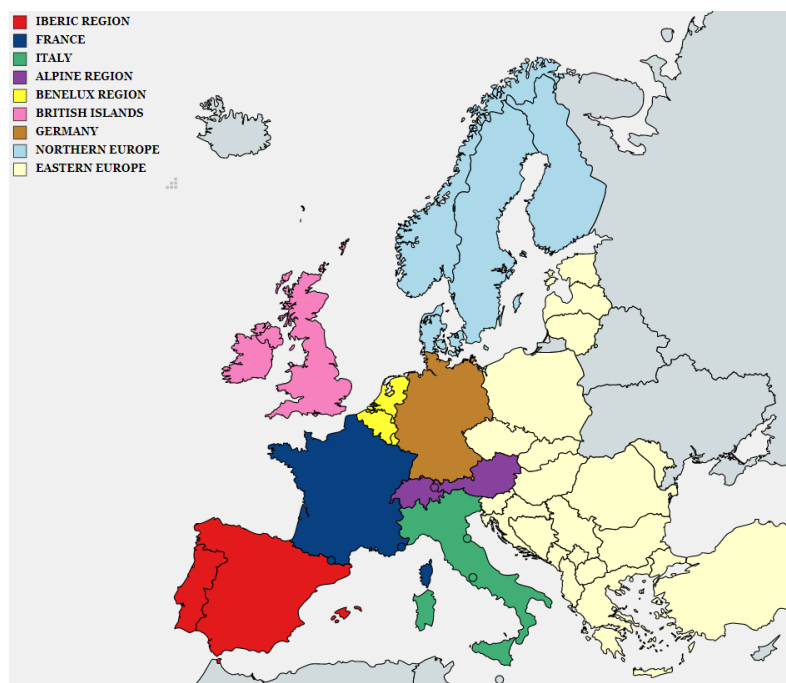


Figure 4. 1: Map of the simulated European power system

2.2. Capacity expansion and simulation model formulation

The capacity expansion model used in this chapter is the R package *AntaresXpansion*³⁰ that works along with the open-source *ANTARES*³¹ power system simulator (v8.1) developed by RTE, the French Transmission Systems Operator, that simulates the electric demand-supply equilibrium at an hourly timestep. The principle of the *ANTARES* Simulator has already been presented in Chapter 3.2.2 and can be found in [5]. A more detailed version of the model will be presented in this chapter, accounting for additional zones, generating, and storage technologies. Hence, the following equations encompass more modeling parameters, although their underlying principle is similar to the equations in Chapter 3.2.2.1. As in Chapter 3.2.2.2,

³⁰ <https://github.com/AntaresSimulatorTeam/antares-xpansion>

³¹ RTE, <https://antares-simulator.org/>

a custom version of the power simulation model has been created alongside this thesis to account for the reactor's minimum power evolution during their irradiation cycle.

Additionally, the AntaresXpansion package optimizes the investments in new capacities and transmission lines for an existing brownfield system. It thus allows the determination of a cost-optimal generation mix and network development that meet the electric demand requirements. Given a brownfield power system, it is possible to define investment candidates in which the model will potentially invest to decrease the overall costs of the system. Each investment is deemed valuable only if it decreases the total cost of the system while accounting for the related additional annualized investments, fixed, and O&M costs. The following section describes the equation of the AntaresXpansion package and ANTARES Simulator model used in this chapter.

2.2.1. Objective function decomposition

The objective function, shown in 2.2, is the sum of the investment costs and the operational costs of the electric system, encompassing the annuities, fixed and variable costs of the transmission system, storage facilities, and generation units, as well as the costs linked to unsupplied and spilled energy. Equation 4. 2, Equation 4. 3, Equation 4. 4, Equation 4. 5, Equation 4. 6, and Equation 4. 7 further detail 2.2.

The model is run at an hourly timestep with a one-year optimization range. The yearly optimization range is separated into 52 weeks, with operational costs of the system minimized using Mixed-Integer Linear Programming for each week successively. This main simplification is a trade-off between the model's accuracy and computational performance. Solving the economic dispatch in one yearly optimization range at an hourly timestep with several demand nodes would burden the model's efficiency.

2.2 : Objective function

Equation 4. 1 : Objective function

$$\text{Minimize } (COSTS_{investment} + COSTS_{operation})$$

Equation 4. 2: Investment costs

$$\begin{aligned} COSTS_{investment} &= \sum_{n=1}^N \left(\sum_{\theta=1}^{\theta_n} annuity_{\theta} * (P_{n,\theta}^* - P_{n,\theta}^{ante}) \right) + \sum_{vre=1}^{VRE} annuity_{vre} \\ &\quad * (P_{n,vre}^* - P_{n,vre}^{ante}) + \sum_{l=1}^L annuity_l * (C_l^* - C_l^{ante}) \end{aligned}$$

Where $P_{n,\theta}^*$ represents the optimal capacity of technology θ in market zone n needed to ensure demand-supply equilibrium while minimizing costs found by the capacity expansion model. Similarly, $P_{n,vre}^*$ is the optimal capacity of variable renewable technology vre in market zone n found by the capacity expansion model. C_l^* represents the optimal transmission capacity of link l between two market nodes. $P_{n,\theta}^{ante}$, $P_{n,vre}^{ante}$ and C_l^{ante} represent the pre-existing capacities in each zone of the simulated electric system. $annuity_{\theta}$, $annuity_{vre}$ and $annuity_l$

respectively represent the annualized investment costs of technology θ , variable renewable energy vre and link l .

Equation 4. 3 : Operational costs

$$\begin{aligned} COSTS_{operation} &= \sum_{w=1}^{52} (COSTS_{storage,w} + COSTS_{generation,w} + COSTS_{vre,w} \\ &+ COSTS_{unsupplied,w}) \end{aligned}$$

Where $COSTS_{operation}$ represents the overall operational costs of the electric system, w represents each week of the simulated year and $COSTS_{storage,w}$, $COSTS_{generation,w}$, $COSTS_{vre,w}$, $COSTS_{unsupplied,w}$ respectively represent the operational costs of storage units, costs of generation units, costs of renewables units and costs of unsupplied energy.

Equation 4. 4 : Storage costs

$$COSTS_{storage,w} = \sum_{t=1}^{168} \left(\sum_{n=1}^N \sum_{\lambda}^{\Lambda} \varepsilon_{n,\lambda,t} * (H_{n,\lambda,t} - \rho_{\lambda} \Pi_{n,\lambda,t} + O_{n,\lambda,t}) \right)$$

Where $\varepsilon_{n,\lambda,t}$ represents the cost associated with the storage unit λ in market node n at time t , $H_{n,\lambda,t}$ is the electricity leaving the storage unit λ in market node n at time t , $\Pi_{n,\lambda,t}$ is the electricity entering the storage unit λ in market node n at time t . ρ_{λ} is the efficiency of the storage unit λ . $O_{n,\lambda,t}$ is the overflow of the storage unit, especially for hydroelectricity storage.

Equation 4. 5 : Thermal generation costs

$$COSTS_{generation, w} = \sum_{t=1}^{168} \sum_{n=1}^N \sum_{\theta=1}^{\theta_n} (\sigma_{\theta}^{+} * M_{n,\theta,t}^{+} + \tau_{\theta} * M_{n,\theta} + \chi_{\theta} * \sum_i^{M_{\theta,n}} P_{\theta,i,n,t})$$

Where $P_{\theta,i,n,t}$ is the production of the generation unit i of technology θ in zone n at time t , χ_{θ} is the variable cost of the technology θ . σ_{θ}^{+} represents the potential costs associated with the startup of technology θ and $M_{n,\theta,t}^{+}$ is the number of units that startup at time t in zone n . τ_{θ} represents the fixed costs linked to technology θ and $M_{\theta,n}$ is the number of generation units of technology θ installed in zone n .

Equation 4. 6 : Renewables costs

$$COSTS_{vre,w} = \sum_{n=1}^N \sum_{vre=1}^{VRE} (\chi_{vre} * P_{n,vre,t} + \tau_{vre} * M_{n,vre})$$

Where $P_{n,vre,t}$ is the production of the renewable unit vre in zone n at time t , χ_{vre} is the variable cost of the generation unit vre . τ_{vre} represents the fixed costs linked to renewable unit vre and $M_{n,vre}$ is the number of renewable units vre installed in zone n .

Equation 4.7 : Unsupplied energy costs

$$COSTS_{unsupplied, w} = \sum_{n=1}^N \delta_n^+ * G_{n,t}^+$$

Where δ_n^+ is the value of lost load (VOLL) and $G_{n,t}^+$ is the unsupplied electricity quantity.

Due to the computational complexity of the investment phase, the model uses an iterative Benders decomposition algorithm to reduce the optimization problem complexity. The main principle is separating the original problem into multiple parts, one master problem and several sub-problems. Broadly, the model's objective function can be assimilated as a two-stage problem, with investments as first-stage and optimal dispatch as second-stage decisions. The Benders decomposition process used in this paper is detailed in Chapter 4.2.2.7.

2.2.2. Demand-Supply adequacy equation

Derived from Kirchhoff's law, there must be a constant equilibrium between electricity demand for each hour in each zone n and the generating units' production, exchanges with neighboring zones, storage units balance, and unsupplied or spilled energy.

Equation 4.8 : Demand-Supply adequacy

$$\begin{aligned} \forall n \in N, \forall t \in T \\ D_{n,t} = \sum_{\theta=1}^{\theta_n} \sum_i^{M_{n,\theta}} P_{n,\theta,i,t} + \sum_{vre=1}^{VRE} P_{n,vre,t} + \sum_{\lambda}^{\Lambda} (H_{n,\lambda,t} - \Pi_{n,\lambda,t}) + (G_{n,t}^+ - G_{n,t}^-) \\ - \left(\sum_l^{L_n^+} F_{l,t} - \sum_l^{L_n^-} F_{l,t} \right) \end{aligned}$$

With $G_{n,t}^-$ representing spilled power in node n , $\sum_l^{L_n^+} F_{l,t}$ the sum of upstream flows through interconnections, $\sum_l^{L_n^-} F_{l,t}$ the sum of downstream flows through interconnections. $\sum_{\theta=1}^{\theta_n} \sum_i^{M_{n,\theta}} P_{n,\theta,i,t}$ and $\sum_{vre=1}^{VRE} P_{n,vre,t}$ represents the sum of all generating units' production at time t , $\sum_{\lambda}^{\Lambda} (H_{n,\lambda,t} - \Pi_{n,\lambda,t})$ represents the storage balance at time t , $(G_{n,t}^+ - G_{n,t}^-)$ encompasses the total unsupplied and spilled energy of the zone, and $(\sum_l^{L_n^+} F_{l,t} - \sum_l^{L_n^-} F_{l,t})$ represents the balance between import and export exchanges.

2.2.3. Generating units production constraints

Each generating unit's production level is constrained by its technical characteristics. For thermal generating units, the primary constraint relates to their maximum and minimum production levels. As in Chapter 3.2.2.2, thermal plants' minimum power level is time-dependent thanks to the customization of the original ANTARES model, allowing the representation of minimum power evolution for nuclear power plants.

Equation 4. 9 : Maximum and minimum production levels

$$\forall n \in N, \forall \theta \in \Theta_n, \forall i \in M_{n,\theta} \quad \forall t \in T$$

$$U_{n,\theta,i,t} * \underline{P_{n,\theta,i,t}} \leq P_{n,\theta,i,t} \leq U_{n,\theta,i,t} * P_{n,\theta}^*$$

Equation 4. 10: Maximum online units per technology

$$\forall n \in N, \forall \theta \in \Theta_n, \forall t \in T$$

$$\sum_i^{M_{n,\theta}} U_{n,\theta,i,t} = M_{n,\theta,t} \leq M_{n,\theta}$$

The model encompasses minimum running and not-running durations that contribute to the unit-commitment plan.

Equation 4. 11 : Running units per technology

$$\forall n \in N, \forall \theta \in \Theta_n, \forall t \in T$$

$$\sum_{i=1}^{M_{n,\theta}} U_{n,\theta,i,t} = M_{n,\theta,t} = M_{n,\theta,t-1} + M_{n,\theta,t}^+ - M_{n,\theta,t}^-$$

The number of running units $M_{n,\theta,t}$ at time t in zone n is equal to the sum of the number $M_{n,\theta,t-1}$ of running units in $t - 1$ and the number of units that startup $M_{n,\theta,t}^+$ minus the number of units that shutdown $M_{n,\theta,t}^-$.

Equation 4. 12 : Minimum uptime durations

$$\forall n \in N, \forall \theta \in \Theta_n, \forall t \in T, \forall k \in [0: \Delta_\theta^+]$$

$$U_{n,\theta,i,t+k} \geq U_{n,\theta,i,t} - U_{n,\theta,i,t-1}$$

Equation 4. 13 : Minimum offline durations

$$\forall n \in N, \forall \theta \in \Theta_n, \forall t \in T, \forall z \in [0: \Delta_\theta^-]$$

$$U_{n,\theta,i,t+z} \leq 1 + U_{n,\theta,i,t} - U_{n,\theta,i,t-1}$$

Each generating unit state is constrained by its minimum on time Δ_θ^+ and their minimum off time Δ_θ^- , ensuring that all thermal units respect their commitment constraints.

Similarly to Chapter 3.2.2, potential ramping constraints are not accounted for, as no technologies considered are constrained at an hourly timestep. The production level is once again considered exogenous for renewable generating units, as climate conditions determine their hourly capacity factor.

Equation 4. 14 : Renewables production

$$\forall n \in N, \forall vre \in VRE_n, \forall t \in T$$

$$P_{n,vre,t} = P_{n,vre,t}^* * cf_{n,vre,t}$$

$P_{n,vre,t}$ is the electricity produced by each VRE resource at hour t , $P_{n,vre,t}^*$ is the installed capacity of each VRE source in each zone n , and $cf_{n,vre,t}$ is the hourly capacity factor of each VRE source in each zone n .

2.2.4. Electricity storage

Electricity stored at t is equal to the electricity stored at $t - 1$ plus the difference between the electricity charged and the electricity unloaded from the storage unit at time $t - 1$, while accounting for the storage' efficiency ρ_λ .

Equation 4. 15: Stored electricity level

$$\forall n \in N, \forall \lambda \in \Lambda_n, \forall t \in T$$

$$R_{n,\lambda,t} = R_{n,\lambda,t-1} + \rho_\lambda \Pi_{n,\lambda,t} - H_{n,\lambda,t}$$

Equation 4. 16: Maximum stored electricity capacity

$$\forall n \in N, \forall \lambda \in \Lambda_n, \forall t \in T$$

$$R_{n,\lambda,t} \leq \overline{\overline{R_{n,\lambda,t}}}$$

Equation 4. 17: Discharging capacity limitation

$$\forall n \in N, \forall \lambda \in \Lambda_n, \forall t \in T$$

$$0 \leq H_{n,\lambda,t} \leq \overline{H_{n,\lambda}}$$

Equation 4. 18 : Charging capacity limitation

$$\forall n \in N, \forall \lambda \in \Lambda_n, \forall t \in T$$

$$0 \leq \Pi_{n,\lambda,t} \leq \overline{\Pi_{n,\lambda}}$$

$R_{n,\lambda,t}$ is the storage level of storage unit λ , $I_{n,\lambda,t}$ and $O_{n,\lambda,t}$ respectively representing the natural inflows and overflows that may affect the unit storage level in the case of hydroelectricity. The filling rate $R_{n,\lambda,t}$ of the storage units is bounded by the maximal storage capacity $\overline{\overline{R_{n,\lambda,t}}}$. The instantaneous unloading $H_{n,\lambda}$ and charging $\Pi_{n,\lambda}$ power are also bounded for each storage units of zone n .

To avoid an unrealistic behavior of short-term storage units, we add a cyclicity constraint that force the storage filling rate to ensure the replacement of the electricity each week.

Equation 4. 19 : Storage cyclicity constraint

$$\forall n \in N, \forall \lambda \in \Lambda_n, \forall t \in T$$

$$\sum_{t=1}^{T=168} \rho_\lambda \Pi_{n,\lambda,t} = \sum_{t=1}^{T=168} H_{n,\lambda,t}$$

2.2.5. Hydroelectricity storage

There are three different types of hydraulic storage modeled; hydraulic reservoirs, open Pumped-Storage Plants (Pumped-Storage Open Cycle), and closed Pumped-Storage Plants. Hydraulic reservoirs represent storage facilities whose stored electricity only derives from natural hydraulic inflows, thus without charging capacities. Pumped-Storage Open Cycles do receive natural inflows but can also pump water from another hydraulic reservoir for later use. Pumped-Storage Closed Cycles do not receive natural inflows but can pump water for later use, behaving similarly to batteries. Thus, the model only adds constraints related to the storage filling rate of Pumped-Storage Open Cycle and hydraulic reservoirs

Equation 4. 20 : Hydraulic storage level

$$\forall n \in N, \forall \lambda \in \Lambda_n, \forall t \in T$$

$$R_{n,\lambda,t} = R_{n,\lambda,t-1} + \rho_\lambda \Pi_{n,\lambda,t} - H_{n,\lambda,t} + I_{n,\lambda,t}$$

$I_{n,\lambda,t}$ representing the natural inflows that may affect the unit storage level in the case of hydroelectricity

Equation 4. 21 : Hydraulic storage level bounding constraint

$$\forall n \in N, \forall \lambda \in \Lambda_n$$

$$\underline{R}_{n,\lambda,t} \leq R_{n,\lambda,t} \leq \overline{R}_{\lambda,n,t}$$

The reservoir level of Pumped-Storage Open Cycle and hydraulic reservoirs is constrained by lower \underline{R}_λ and upper \overline{R}_λ bounds based on the historical filling rate the considered zone n . As Pumped-Storage Open Cycle and hydraulic reservoirs are considered long-term storage technologies, the cyclicity constraint is yearly, enabling long-term storage behaviors.

Equation 4. 22 : Hydraulic cyclicity constraint

$$\forall n \in N, \forall \lambda \in \Lambda_n, \forall t \in T$$

$$\sum_{t=1}^{T=8760} \rho_\lambda \Pi_{n,\lambda,t} + \sum_{t=1}^{T=8760} I_{n,\lambda,t} = \sum_{t=1}^{T=8760} H_{n,\lambda,t}$$

2.2.6. Investment constraints

The total installed capacity should be equal to the sum of each technology's invested and pre-existing capacity. The same condition applied to interconnections between zones.

Equation 4. 23 : Total thermal technology capacity

$$P_{n,\theta}^* = P_{n,\theta}^{ante} + P_{n,\theta}^{invest}$$

Equation 4. 24: Total variable renewable technology capacity

$$P_{n,vre}^* = P_{n,vre}^{ante} + P_{n,vre}^{invest}$$

Equation 4. 25 : Total interconnections capacity

$$C_l^* = C_l^{ante} + C_l^{invest}$$

Moreover, total installed capacities are not infinite due to land-use-related constraints, social acceptance, maximum available natural resources, or other technical constraints. Thus, a technological constraint on maximum installed capacity is defined :

Equation 4. 26 : Maximum installable capacity for each thermal technology

$$P_{n,\theta}^* \leq \overline{P_{\theta,n}}$$

Equation 4. 27: Maximum installable capacity for each variable renewable technology

$$P_{vre,\theta}^* \leq \overline{P_{vre,n}}$$

Equation 4. 28 : Maximum installable capacity for each interconnection

$$C_l^* \leq \overline{C_l}$$

Where $\overline{P_{\theta,n}}$, $\overline{P_{vre,n}}$ and $\overline{C_l}$ respectively represent the maximum installed capacity for thermal technology θ , variable renewable technology vre , and link l .

2.2.7. Investment algorithm

The investment program is iterative and relies on the Benders decomposition algorithm. At the first iteration of the investment problem, the model computes the total investments and operation costs with the maximum installed capacity that can be invested for each investment candidate. The model's optimization problem is separated into weeks to reduce computational complexity.

The first step of the Benders decomposition is rewriting the investment program. Assuming that all 52 weeks of a year are independent, it is possible to rewrite Equation 4. 3 using z , a tuple defined as $z = (P_{1,1}^* \dots P_{n,\theta}^* \dots P_{N,\theta}^*, P_{1,1}^* \dots P_{n,vre}^* \dots P_{N,VRE}^*, C_1^* \dots C_l^* \dots C_L^*)$, with $P_{n,\theta}^*$ and $P_{n,vre}^*$ the optimal capacities for technology θ and variable renewable technology vre in zone n , and C_l^* the optimal capacity for link l . Hence, operational costs can be written as Equation 4. 29 and Equation 4. 30.

Equation 4. 29 : Operational costs decomposition

$$COSTS_{operation} = \sum_{w=1}^{52} COSTS_{operation,w}(z)$$

Equation 4. 30 : Operational costs reformulation

$$COSTS_{operation,w}(z) = \text{Min}_{y_w \in Y} g_w^T y_w$$

$$s. t. W_w y_w = d_w - Q_w z$$

Where $COSTS_{operation,w}(z)$ is the operational cost of week w , y_w represents all variables of the weekly model problem, Y is the admissible set of the variables, $g = (g_1 \dots g_w \dots g_{52})$ is the cost vector, $W = \text{diag}(W_1 \dots W_{52})$ is a block diagonal, and $d_w = (d_1 \dots d_{52})$ represents the weekly electric demand and availability of generating plants. $Q_w = \begin{pmatrix} Q_1 \\ \vdots \\ Q_{52} \end{pmatrix}$ are the constraints of the power system.

Following the reformulation of operational costs, it is possible to write the overall objective function. With Z as the admissible set of tuples z such as $Z = \prod_{z_i} [0: \bar{z}]$, 2.2 can be written as Equation 4. 31 and Equation 4. 32. \bar{z} is the maximal investment tuple for all technologies and interconnection links. Additionally, investment in capacities may be bounded by linear constraints $Az = b$, where $A \in R^{n,(L*\theta)}$ and $A \in R^n$, n being the number of constraints.

Equation 4. 31 : Investment problem formulation

$$\text{Min}_{z \in \prod_{z_i} [0: \bar{z}]} \text{annuity}_z^T z + COSTS_{operation}(z)$$

$$s. t. Az = b$$

Equation 4. 32 : Investment problem decomposition

$$\begin{aligned} \text{Min}_{z \in Z} \text{annuity}_z^T z + \sum_{w=1}^{52} \text{COSTS}_{\text{operation},w}(z) \\ \text{s. t. } Az = b \end{aligned}$$

For each weekly problem, there is a dual whose solution provides a lower bound to the original. The dual problem is written as in Equation 4. 33.

Equation 4. 33 : Weekly dual problem

$$\begin{aligned} \text{COSTS}_{\text{operation},w}(z) = \text{Max}_{\pi_w \in \Pi_w} \pi_w^T (d_w - Q_w z) \\ \text{s. t. } W_w \pi_w \geq g_w \end{aligned}$$

Π_w being the admissible set of variables of week w . The feasible set of each weekly dual problem $S = \{\pi_w, W_w \pi_w \geq g_w\} \cap \Pi_w$ is a non-empty, bounded polyhedron that does not depend on investment levels z , and always has a solution that is one of the extreme points of S . Hence, the weekly dual problem can be written as in Equation 4. 34.

Equation 4. 34 : Weekly dual problem – extreme point solutions

$$\text{COSTS}_{\text{operation},w}(z) = \text{Max}_{\pi_w \in \text{extr}(S)} \pi_w^T (d_w - Q_w z)$$

Equation 4. 32 can therefore be written as a min-max problem:

Equation 4. 35 : Min-max investment problem formulation

$$\begin{aligned} \text{Min}_{z \in Z} \text{annuity}_z^T z + \sum_{w=1}^{52} \text{Max}_{\pi_w \in \text{extr}(S)} \pi_w^T (d_w - Q_w z) \\ \text{s. t. } Az = b \end{aligned}$$

The last reformulation step is linearization by introducing Ψ_w defined as $\Psi_w \geq \pi_w^T (d_w - Q_w z)$. The final reformulation of the investment equation is the Benders master problem (Equation 4. 36). Each weekly problem is considered a satellite of this master problem.

Equation 4. 36 : Min-max problem with Benders cuts

$$\begin{aligned} \text{Min}_{z \in Z} \text{annuity}_z^T z + \sum_{w=1}^{52} \text{Max}_{\pi_w \in \text{extr}(S)} \Psi_w \\ \text{s. t. } \Psi_w \geq \pi_w^T (d_w - Q_w z), \forall w, \forall \pi_w \in \text{extr}(S) \\ Az = b \end{aligned}$$

Constraints $\Psi_w \geq \pi_w^T (d_w - Q_w z)$ are Benders' cuts, which are used to reduce the problem's complexity gradually. As solving the master problem is complex, the model proceeds iteratively. The first iteration considers that all Benders cuts are removed; thus, $z = \bar{\bar{z}}$. The master problem is solved with $z = \bar{\bar{z}}$ then the 52 satellite problems as in Equation 4. 37.

Equation 4. 37 : Satellite problem formulation – first iteration

$$\begin{aligned} COSTS_{operation,w}(\bar{z}) &= \text{Max}_{\pi_w \in \Pi_w} \pi_w^T (d_w - Q_w \bar{z}) \\ s. t. W_w \pi_w &\geq g_w \end{aligned}$$

Suppose that $\bar{\pi}_w$ is the optimal solution to this problem for week w with an optimal value $\bar{\pi}_w^T (d_w - Q_w \bar{z})$, benders cuts are added to the master problem with $\Psi_w \geq \bar{\pi}_w^T (d_w - Q_w \bar{z})$. Hence, 52 new benders' cuts are added for each iteration. It is then possible to solve the master problem as presented in Equation 4. 38.

Equation 4. 38 : Master problem – first iteration

$$\begin{aligned} \text{Min}_{z \in Z} \text{annuity}_z^T \bar{z} &+ \sum_{w=1}^{52} \text{Max}_{\pi_w \in \text{extr}(S)} \Psi_w \\ s. t. \Psi_w &\geq \pi_w^T (d_w - Q_w \bar{z}), \forall w \\ Az &= b \end{aligned}$$

The optimal solution z is used as the new assumption for the next iteration, removing all previous benders cuts. New benders cuts are added to the master problem when re-solving the 52 satellites problem. At each iteration, the total investment with optimal solution z of the iteration is computed $\text{annuity}_z^T z + \sum_{w=1}^{52} \pi_w^T (d_w - Q_w z)$, which represents the upper bound of the investment problem. Once the optimality gap between the upper and lower bound (optimal solution of the master problem) falls under a threshold defined beforehand, the iteration stops, and the last computed z is the optimal tuple of capacities.

More information on the Benders decomposition algorithm can be found at <https://github.com/AntaresSimulatorTeam/antares-xpansion/blob/develop/docs/user-guide/optimization-principles/problem-formalization.md>.

2.3. Inputs parameters

2.3.1. Hourly electricity demand

Most of this chapter's hourly electricity demand time series derive from ERAA2021-2030 [6] for each European country. ERAA2021-2030 considers foreseeable changes in the demand profile up to 2030, including reduced demand for lighting and heating and increased demand for the industry, air conditioning, and electric vehicles. In total, ERAA2021-2030 makes available 35 climate scenarios, with demand profiles based on meteorological conditions from 1982 to 2016. As the chapter focus on Western Europe, the chapter considers that for France and its neighboring countries, the electric demand levels and profiles will further change by 2050. Thus, France and its neighboring countries' hourly electricity demand time series derive from the Optimal System-Mix Of flexibility Solutions for European electricity (OSMOSE) WP1³² project, an international research project funded by the European Union as part of the

³² <https://www.osmose-h2020.eu/project-overview/wp1/>

Horizon 2020 program and coordinated by RTE. In order to model the future of the European electric system with consequent needs for flexibility, ten hourly electricity demand time profiles were built. The OSMOSE European project chose to base their demand profiles based on meteorological data from the period 1982-1991 for brevity. Furthermore, the profiles encompass future demand profile changes due to electric vehicle charging and discharging, consumption of heat pumps, and demand-side management. The chapter uses those hourly electricity demand time series to run the simulation, thus limiting the analysis to 10 different meteorological scenarios. For simplicity, the chapter considers that the electric demand of countries in Eastern Europe and Northern Europe will not evolve more than forecasted in ERAA2021-2030.

Due to the latest ambitious electrification plans announced in Western European countries to further decarbonize their energetic systems, the electric demand levels are increased compared to the OSMOSE project. The demand increases are based on the latest RTE report, « Futurs énergétiques en 2050 » [7], e.g., 645 TWh for the French electric demand in 2050 (see Table 4.1). I hypothesize that most of the increased demand spawns from increased industry demand, so it is a base supplementary electric consumption. Thus, the additional electric consumption does not modify the demand profile but only its overall level.

TWh	France	Germany	Italy	Spain	United Kingdom
Forecasted demand (2050)	645	990	610	500	705

Table 4.1: Forecasted 2050 demand scenarios

2.3.2. VRE profiles

To the best of current knowledge, there is no publicly available capacity factors time series for 2050 VRE profiles considering climate change, technological progress, and VRE plants' location changes. Thus, this chapter's VRE profiles derive from ERAA-2021-2030, based on the "renewables.ninja" website³³, whose use is widespread among the modeling literature [4], [8]–[12]. ERAA2021-2030 considers that technological progress linked to improvement in solar panels and taller wind turbines will be partially offset by VRE capacity factor erosion linked to plants' location, as new VRE units will be in less solar irradiated and wind-exposed locations. There are 36 hourly capacity factors time series for each simulated country but only data from 1982 to 1991 are used following OSMOSE's demand data.

2.3.3. Pre-existing capacities and investments limits

As the investment algorithm adds capacities to a « brownfield » European power system, there are pre-existing generating and storage assets. The chapter chose to focus on investments in renewables, thermal technologies, and interconnections. Thus, assumptions surrounding flexible technologies, such as hydroelectricity and batteries, are especially dimensioning. In order to not under-estimate the potential role of those technologies, the chapter assumes

³³ <https://www.renewables.ninja/>

consequent pre-existing flexibility technologies capacities, following the OSMOSE project results. For hydroelectricity, the chapter considers that additional capacity until 2050 is marginal, as most potential in Western Europe is maximized and the building of new capacities may not be socially acceptable. For batteries, the OSMOSE estimates for 2050 are consistent with European plans for 2050 [13], [14], reports from storage industries [15], [16], and existing scientific literature on future storage needs in Europe [17]–[22]. Hence, the chapter is not likely to overestimate the role of flexible thermal technologies in future decarbonized power systems as they compete with consequent storage capacities to ensure flexibility services. The pre-existing capacities in each country before the investment phase are displayed in Table 4. 2. As a decarbonized Western European power system is considered, no fossil plants remain in France and its neighboring countries. It is important to note that the displayed capacities derived from the OSMOSE project may not correspond to the current European decarbonization strategy, especially for aggregated zones and in times of geopolitical uncertainties, as current goals were recently heightened.

Resource Capacities (GW)	Alpine region	Benelux	Germany	Iberic region	France	Italy	British Islands	Western Europe
Biofuel	0.75	0.16	6.45	0.00	2.00	0.91	1.24	11.51
Hydro - Run of River & Pondage (Turbine)	10.34	0.23	4.73	4.43	13.60	6.25	2.31	41.89
Hydro - Reservoir (Turbine)	2.49	0.00	1.30	14.74	9.85	9.65	0.01	38.03
Hydro - Pumped Storage Open Loop (Turbine)	16.78	0.00	1.64	6.52	1.85	3.33	0.00	30.12
Hydro - Pumped Storage Closed Loop (Turbine)	2.47	1.22	7.38	6.87	1.95	8.75	3.04	31.68
Hydro - Pumped Storage Open Loop (Pumping)	-7.26	0.00	-1.36	-6.00	-1.85	-2.10	0.00	-18.57
Hydro - Pumped Storage Closed Loop (Pumping)	-2.47	-1.15	-7.42	-6.68	-1.95	-8.82	-2.98	-31.46
Storage Capacity - Reservoir (GWh)	757.03	0.00	258.58	12938.10	10000.00	5649.10	0.00	29602.81
Storage Capacity - Reservoir Open (GWh)	10532.60	0.00	416.67	7979.76	100.00	309.38	0.00	19338.41
Storage Capacity - Pump Storage Closed (GWh)	71.80	5.30	242.17	99.04	0.00	70.40	28.10	516.81

Batteries (Injection)	2.20	4.60	35.02	20.39	13.10	12.13	0.00	87.44
Batteries (Offtake)	2.20	4.60	35.02	20.39	13.10	12.13	0.00	87.44
Storage Capacity - Batteries (GWh)	8.79	18.41	140.08	81.58	52.38	48.53	0.00	349.77

Table 4. 2: Brownfield capacities in Western Europe

2.3.4. Economic parameters

Table 4. 3 summarizes technologies' economic parameters and assumptions. As the objective function of the model dispatches generating technologies based on cost minimization, these economic parameters are determining factors to conclude on a cost-optimal decarbonized European system.

Technology	Overnight costs (€ ³⁴ /kW)	Fixed O&M (€/kW/year)	Variable O&M (€/MWh)	Fixed start-up costs – warm start (€/MW)	Start-up fuel consumption - warm start (GJ/MW.start)	Construction time (years)	Lifetime (years)	Efficiency (%)
Wind Onshore	900	34.5	-	-	-	1	25	-
Wind Offshore	1300	47	-	-	-	1	30	-
Wind Offshore – float	1900	47	-	-	-	1	30	-
Solar PV - farms	500	9.2	-	-	-	1	25	-
Solar PV – commercial roof	700	9.2	-	-	-	1	25	-
Solar PV – residential roof	1500	9.2	-	-	-	1	25	-
Hydroelectricity – lake and reservoir	2275	11.4	-	-	-	5	80	-
Hydroelectricity – run-of-river	2970	14.9	-	-	-	5	80	-
Hydroelectricity – Pumped storage	500	7.5	-	-	-	1	55	75%

³⁴ €₂₀₂₀: this assumption is used throughout the entire paper.

Battery Li-ion	140	1.96	-	-	-	0.5	12.5	92%
Biogas (Anaerobic digestion)	2510	83.9	3.1	20	0.2	3	30	-
Hydrogen	800	16.5	240	20	0.2	3	30	34%
Nuclear power	4500/5400/7900	97.5	14.5	21	14	10	60	33%
Interconnections	1400	0	0	-	-	4	80	-

Table 4. 3: Economic parameters hypotheses based on [23]–[26], [4], [6], [7]

The central hypothesis is that generating technologies' costs are homogeneous across Europe. This is a simplification due to the availability lack of data regarding cost differentiation in 2050. Thus, there is no consideration of countries' comparative advantages regarding workforce or installation costs for brevity. The model considers operating costs (variable, fixed, startup, and investments costs -annuity per MW). Start-up cost considerations are limited to decarbonized gas and nuclear technology and computed for each reactor, following techno-economics from ERAA2021 [6] that consider fuel consumption and cost of each startup. Because the model can invest in VRE, nuclear, decarbonized gas technologies, and interconnections, it does not integrate into the capacity expansion phase the investment costs of other technologies whose capacities are considered constant in the objective function (see Chapter 4.2.2). This model limitation results in enhanced computational performance at the expense of the results' accuracy. Indeed, investments in new VRE capacities may be discouraging as the costs of existing capacities are only fixed, operation and maintenance, and variable, with no investments or financial costs considered.

Following ERAA2021-2030, the unsupplied electricity cost per MWh is 15 000€. The cost of interconnections is differentiated for each additional grid reinforcement between modeled zones, derived from the latest « System Needs » TYNDP-ENTSO-E study [27]. The discount rate used to compute technologies' investment is 4%, following [7]. For batteries and pumped-storage hydroelectricity facilities, the storage capacity CAPEX per kWh are respectively 5 €/kWh and 100 €/kWh deriving from [4], [26].

2.3.5. Technical parameters

In order to account for the technical limitations of each thermal technology, the model includes the following technical parameters (see Table 4. 4).

Technology	Minimum uptime (h)	Minimum down time (h)	Minimum stable power (%)
Biogas (Anaerobic digestion)	1	1	25%

Hydrogen	1	1	25%
Nuclear power	8	24	See Chapter 4.2.5

Table 4. 4: Technical parameters of generating technologies [1], [6], [28]

As ramping constraints do not limit thermal technologies' flexibility at an hourly level, they are not included in the model.

2.3.6. Limiting investment for VRE

Derived from [29], investment in new VRE capacities are capped based on national technical potentials. Capacity limitations prevent the model from producing non-realistic capacity mixes, notably through over-investment in low-cost technologies. For each country, the installable wind and solar capacity potential is determined by a combination of the size of each country, land share where renewables plants can be installed, and the capacity that can be installed in the installable area. [29] considers that onshore wind turbines can be installed in 5% of forests and 30% of the agricultural land, with a 4 MW/km² maximum capacity density. Offshore turbines lie within less than 55km to the shores with a 6 MW/km² maximum capacity density and must belong to their country's exclusive economic zone. Solar PV installable capacity varies depending on the system considered. For large land-based systems, only a small share (2% with 30 MW/km² maximum capacity density) of a country surface may be eligible to install PV plants, as few other uses of the land dedicated to solar power are possible. Regarding commercial and residential rooftop panels, the available rooftop and facade area is approximated based on each country's population, with an installation potential of 50% of the total roof area. Table 4. 5 resumes each country's renewable capacity potential.

Country	Wind Onshore (GW)	Wind Offshore (GW)	PV (GW)
Austria	45.8	0.0	29.2
Belgium	17.7	9.1	21.4
Bulgaria	68.5	11.6	39.6
Czech Republic	56.1	0.0	38.3
Germany	222.6	83.6	200.4
Danemark	32.6	149.0	22.5
Estonia	15.8	55.9	7.3
Spain	366.9	55.0	221.6
Finland	71.8	130.5	20.3
France	381.7	133.7	251.8
Greece	105.6	27.6	62.8
Croatia	19.8	47.1	13.4
Hungary	68.2	0.0	44.3
Ireland	56.3	52.2	32.9

Italy	190.2	77.7	159.9
Lithuania	37.6	9.2	20.7
Luxembourg	1.7	0.0	1.4
Latvia	28.4	43.1	13.6
Netherlands	23.6	57.1	31.8
Poland	193.9	40.7	134.4
Portugal	51.0	16.7	35.1
Romania	183.0	24.3	111.2
Sweden	93.4	167.7	30.0
Slovenia	8.3	0.3	5.4
Slovak Republic	27.2	0.0	18.3
Balkan Region	134.7	5.3	83.7
Switzerland	20.8	0.0	18.7
Norway	32.2	122.2	12.0
United Kingdom	212.5	312.4	179.3

Table 4. 5: VRE potential across countries

As recent concerns regarding onshore wind development have appeared, as populations may not favor onshore turbine installations near inhabited areas, limiting the model to the maximum technical installation capacity may result in overestimated onshore capacities that do not integrate the sociologic aspects of onshore wind turbine installation. [30] note that few studies have assessed the onshore wind potential for each country in Europe ([31]–[34]), with most computed potentials being technical ([34] referring to a « socio-technical » potential) and recommends that « *potential assessments must explicitly include social and political factors [...] Ignoring them may lead to misleading, typically overestimated, results* » [35]. To my knowledge, no comprehensive European data regarding wind onshore installable capacity encompasses sociologic aspects. [36] computed a 121 GW socio-technical onshore wind potential for France, taking political and sociological barriers into account. In order to approximate the socio-technical wind onshore potential for all countries, the hypothesis is that the ratio between socio-technical potential and technical potential remains the same as in France. Such an assumption may overestimate the total potential as France has a lower population density than other European countries.

2.3.7. Limiting investment in nuclear power plants

Contrary to VRE, there are almost no land limitations for thermal technologies potentials in Western Europe. However, installation rates must limit future thermal capacities depending on supply chain constraints and construction time. Such concerns are especially valid for nuclear power plants, whose construction times have steadily increased in Western Europe as 3rd generation reactors are being built. Thus, there is a limit on the maximum nuclear capacity the model may invest in by 2050, based on a best-case scenario for existing plants' lifetime

extensions and new capacity building. For hydrogen-ready gas plants, the assumption is that such considerations do not apply.

The possibility of investing in new reactors is reserved only to countries with pre-existing experience in reactor operations, as developing a national nuclear sector requires support from populations and continued political, industrial, and technical actions. Thus, the hypothesis is that no new countries will adopt this technology. Several countries with an existing fleet also exclude nuclear power from their plans for decarbonization, namely Belgium, Germany, Spain, and Switzerland. No new reactor can be built in those countries. Hence, the countries that may invest in new reactors are France, the Netherlands, and the United Kingdom. The maximum nuclear capacity for each country is determined thanks to prospective work from national TSOs, nuclear operators, or governments' energy plans (see Table 4. 6).

Region	Benelux	France	British Islands
Maximum Nuclear capacity (GW)	3.0	50.9	24

Table 4. 6: Nuclear potential across Western Europe

Hence, the maximum French nuclear capacity in 2050 is capped at 50.9 GW following [7], representing a mix of new EPR builds, Small Modular Reactors developments, and lifetime extension past 60 years of operation for some 2nd generation reactors. According to French nuclear industry stakeholders and the national TSO RTE [7], the number of EPR2 that can be built until 2050 is limited to 14 due to supply chain constraints. Moreover, to reduce building costs, the new reactors would be built in pairs to benefit from savings linked to the « pair effect », with the first pair starting commercial operation in 2035 at best. Thus, investments in new EPR2 must be in pairs, and their total capacity can not exceed 23.1 GW in France. Since in recent years, the interest in small modular reactors has been growing with many international projects such as the NuScale (PWR, 60 MW, USA), Natrium (Molten Salts Reactors, 500 MW, USA), HTR-PM (High-Temperature Gas Cooled Reactor, 210 MW, China), Brest-Od-300 (Fast-Breeding Reactor, 300 MW, Russia) or Nuward (PWR, 170 MW, France), investment in SMR capacities is possible. For simplicity, the chapter chose to focus on the Nuward design only. Although SMRs projects advancements are non-homogeneous, with some already operational, some in construction, or some at the design stage, the hypothesis is that Nuward can be built before 2050, with construction starting as soon as 2030 [37]. According to [7], which considers an optimistic hypothesis, it would be possible to install up to 4 GW of SMR in France in 2050.

Under the 51 GW French nuclear capacity cap hypothesis, all 2nd generation reactors have to operate until 60 years of operation if deemed appropriate by the French Nuclear Safety Authority. Some reactors will also have to remain operational after 60 years of operation in order to maintain the capacity of historical reactors at around 24 GW. It is a strong assumption about the ability of reactors to operate safely over time and is subject to uncertainties. In order to determine which reactors would still be operational, we assume that the oldest reactors will be closed first. Thus, the list of existing reactors that the optimization model can consider is described in Table 4. 7.

Reactor name	Construction start (Year)	Commercial commissioning (Year)	Nominal power (MW)
Belleville 2	1980	1989*	1 310
Cattenom 2	1979	1988*	1 300
Cattenom 3	1980	1991	1 300
Cattenom 4	1982	1992	1 300
Chinon B3	1980	1987*	905
Chinon B4	1981	1988*	905
Chooz B1	1984	1996	1 500
Chooz B2	1985	1997	1 500
Civaux 1	1988	2002	1 495
Civaux 2	1991	2002	1 495
Golfech 1	1982	1991	1 310
Golfech 2	1984	1994	1 310
Flamanville 3	2007	2023**	1 650
Nogent_1	1981	1988*	1 310
Nogent_2	1982	1989*	1 310
Penly_1	1982	1990	1 330
Penly_2	1984	1992	1 330
StAlban_2	1979	1987*	1 335
Total		-	23 895
*reactors that may operate past 60 years		**planned commercial commissioning	

Table 4. 7: Historical reactors still in operation

The British cap is fixed at 24 GW as the current British Energy Strategy objective aims to triple the 2022 nuclear capacity [38]. The assumption is that no historical reactors will remain in the UK power system in 2050, apart from nuclear reactors currently under construction. Regarding the Netherlands, although no plans to build any new nuclear plants exist, there are currently no laws fixing a potential nuclear phase-out. As the Netherlands has limited nuclear, its capability to build new reactors is limited to only two 1.5 GW 3rd generation reactors following recent propositions from EPZ, the country's sole nuclear operator.

2.3.8. Limiting capacities in interconnections investment

As most European decarbonization plans expect an increasing exchange capacity between countries to increase the overall security of supply of the power system, it is necessary to account for the development of new and existing interconnections networks. Thus, interconnections capacity between countries can be increased, with maximum potential derived from the latest « System Needs » ENTSO-E study for each line [27] (see Table 4. 8). The

underlying hypothesis is that all new lines are High-Voltage Direct Current (HVDC) for simplicity, with costs differentiated for each line.

First zone	Second zone	Maximum investment potential
Alpine region	Germany	10500
	France	4500
	Italy	2900
Benelux region	Germany	16500
	France	7000
	British Islands	9400
Germany	Benelux region	9500
	France	7800
	British Islands	3500
Iberic region	France	9000
France	Italy	3000
	British Islands	7600

Table 4. 8: Interconnections investments potentials [27]

2.4. Studied Scenarios

Previous academic works have discussed capacity expansion models' assumptions and their impact on modeling results [39]–[41], [8], [12], [42], [10], highlighting that potential misrepresentation of some power systems components may result in biased results. In particular, climate data assumptions may strongly impact the cost-optimal mix's shape, as noted by [9], with a volatile share of renewables capacity due to meteorological variability across years. To control this effect, the capacity expansion model is run for ten climatic scenarios derived from the meteorological data based on the 1982-1991 period mentioned in Chapter 4.2.3.1 and Chapter 4.2.3.2. Thus, the cost-optimal capacity mix resulting from the investment phase is insensitive to inter-annual climate variability.

As a central nuclear cost assumption, new nuclear capacities are EPR2 (1650 MW) or SMR based on the Nuward design (170MW), with a 4500 €/kW overnight cost following EDF's future EPR2 and SMR series cost prediction [7]. Thus, nuclear reactors benefit from the serial effect caused by building several reactors with similar designs and components. In order to adopt a conservative hypothesis regarding the costs of existing reactors' lifetime extensions, their investment cost is considered equal to new program costs.

As recent nuclear projects in Europe have been subject to construction delays and cost overruns, there are two alternative nuclear cost scenarios to capture the current new build cost uncertainties. The first alternative scenario considers new builds' costs increasing to 5400 €/kW. This overnight cost level is announced for the first EPR2 that may be built in France in its new nuclear program currently being considered [7]. The second alternative scenario considers a pessimist cost evolution for new builds, with overnight costs remaining similar to the first EPR

built in France, Flamanville 3, 7900 €/kW, according to [7]. This cost is also in the cost range of the Hinkley Point C reactors, whose overnight costs are evaluated between 7800 and 8100 €/kW. Such a hypothesis represents a worst-case scenario for the nuclear sector, assuming that the nuclear sector has not been able to increase the economic competitiveness of 3rd generation reactors. The objective is to determine whether the cost-optimal investment in new nuclear capacity is sensitive to cost overruns.

For each overnight cost scenario, interlayer interest costs during construction are accounted, with a 4% weighted average cost of capital and a ten years construction time hypothesis. As the chapter's focus is on the effect of nuclear costs on its role in a future decarbonized European power system, nuclear costs are the only parameters that vary across scenarios, all things being equal.

2.5. Nuclear flexibility modeling

Similarly to [1], nuclear schedule optimization and minimum power evolution are accounted to model nuclear flexibility potential in a decarbonized Western Europe power system. The formulation of the nuclear flexibility model is the same as presented in Chapter 3.2.1 and thus will not be detailed here. The model accounts for each reactor's nominal power, irradiation cycle lengths, and outage durations to determine an optimal operating schedule for the nuclear fleet.

The irradiation cycle length of older 2nd generation reactors (Chinon B3 and Chinon B4) is 12 months, corresponding to 280 Equivalent Full Power Days (EFPD - Chapter 2.3.3). Other 2nd generation reactors have longer cycles, up to 15 months (380 to 395 EFPD). The chapter hypothesizes that 3rd generation reactors (EPR2, SMRs) have 18 months irradiation cycle lengths following the example of Flamanville 3 (see Table 4. 9). Regarding SMRs, the underlying hypothesis is that their flexibility characteristics are similar to EPR2's as there is currently a lack of available data regarding those operational aspects. Such a hypothesis may misestimate SMRs' flexibility potential. For example, Nuward reactors would not contain boric acid; thus, their minimum power would not increase at the end of their irradiation cycle, as explained in Chapter 2.3.2. Regardless, the chapter adopts this conservative assumption to not over-estimate the available flexibility from the nuclear fleet.

Unit	Nominal power (MW) -	Equivalent Full Power Days	Average availability factor	Minimum outage duration (weeks) -	Minimum irradiation cycle duration (weeks) -	Maximum irradiation cycle duration (weeks) -	Minimum share of online reactors -	Maximum share of simultaneous outage-phase starts -
	Q_i			S_i	C_i	\bar{C}_i	$\underline{\delta}$	$\delta_{outages}$
Chinon B3/ Chinon B4	905	280	79.1% ([43])	6	38	48		

2 nd generation reactors	1300 – 1500	380-395		8	54	69	50% ³⁵	10% ³⁶
EPR2/Nuward	1650/170	470		10	65	80		

Table 4. 9: Nuclear flexibility inputs parameters

Based on the computed optimal planning, each reactor’s minimum power is computed following [44] and [45], allowing a detailed representation of the load-following capabilities of reactors. During the first two-thirds of each reactor’s irradiation cycle, a reactor can ramp down up to 20% of its nominal capacity. Then, minimal power increases simultaneously with the fuel’s burnup and decreasing boron concentration. At the end of the irradiation cycle, the reactor can no longer operate load-following maneuvers as boron concentration is null, and xenon transients significantly affect the reactor’s ability to modify its output rapidly.

Nuclear flexibility modeling is strongly linked to the nuclear fleet considered, as it is highly dependent on the number of reactors, their respective nominal power, and irradiation cycle and outage durations. Hence, in the iterative investment process that relies on Benders decomposition described in Chapter 4.2.2.7, the optimal nuclear fleet schedule and minimum power evolutions are computed for each iteration that modifies nuclear capacity.

3. RESULTS

This section presents the main results of our capacity expansion and simulation model. The first result discussed relates to the cost-optimal capacity mix reached in the central nuclear cost configuration and nuclear capacity’s sensitivity to overnight costs. Then, the nuclear operational schedule and minimum power resulting from the nuclear flexibility model mentioned in Chapter 4.2.5 is presented for each nuclear cost assumption. Afterward, the chapter discusses the economic dispatch resulting from the cost-optimal capacity mix and focuses on nuclear production, plants’ load factor, and flexibility maneuvers. Lastly, the chapter comments on market prices and each technology’s revenues. It highlights that as nuclear does not operate as a baseload mean of generation, its ability to recover its costs highly depends on the average market price, hence on the capacities of the power mix. At each step, there is a primary focus on the central cost scenario, i.e., 4500 €/kW, as there is a low sensitivity of new nuclear reactors’ capacity to cost uncertainties linked to delays and supply chain

³⁵ Computation derived from ASN data, <https://www.asn.fr/Contrôler/Actualites-du-controle/Arret-de-reacteurs-de-centrales-nucleaires>

³⁶ Operational feedback on the French nuclear fleet, <https://www.asn.fr/Contrôler/Actualites-du-controle/Arret-de-reacteurs-de-centrales-nucleaires>

mismanagement. Hence, the alternative scenarios, 5400 €/kW and 7900 €/kW, are presented solely if the results differ significantly.

3.1. Cost-optimal capacity in investment technologies

Several technologies can be invested in to minimize the future cost of the decarbonized European power systems, and other technologies' capacity is determined exogenously following the OSMOSE project and ERAA2021-2030. For brevity, this section presents the cost-optimal capacities only in investment technologies. Other technologies' capacities are displayed in Table 4. 10.

The cost-optimal future capacity mix in Western Europe is predominated by renewables capacities, with 949.01 GW wind capacity and 495.65 GW solar capacity. Due to the high electric demand in most European countries to decarbonize their energy sector, it is optimal for all considered countries to invest in new renewable capacity despite unfavorable meteorological conditions for some (e.g., low solar irradiance in Germany).

Cost-optimal capacity (GW)	Alpine region	Benelux	Germany	Iberic region	France	Italy	British Islands	Western Europe
Nuclear	0	3	0	0	50.90	0	24	77.90
Wind	21.11	64.48	158.97	178.99	142.04	137.99	245.43	949.01
Solar PV	34.17	38.27	117.51	89.09	84.86	102.68	29.07	495.65
Hydrogen-compatible gas plants	10.00	22.12	96.45	20	8.00	40.91	54.23	251.71

Table 4. 10: Cost-optimal capacity - Central cost scenario

Regarding renewables saturation, the wind capacity cap is reached in three zones, the Alpine Region, Germany, and Italy, highlighting the economic competitiveness of wind energy (onshore and offshore). Inversely, optimal solar investments are not limited by capacity caps in any zones; thus, countries do not maximize their solar potential, with saturation rates ranging from 13% (British Islands) to 71% (Alpine Region).

Most new solar capacity is in southern countries due to higher load factors linked to better irradiance. Inversely, countries with lower solar irradiance, such as the Benelux region, and the British Islands, do not massively invest in this technology. Indeed, lower high factors for solar panels depreciate their economic competitiveness compared to other technologies. The same phenomena occur with wind investment, as countries with higher load factors invest more in new wind turbines, as those turbines are then competitive. Due to interconnections limitations, low solar load factors, and nuclear construction time, solar capacity in Germany and wind capacity in the British Islands rise significantly to meet the future electric demand. In an unconstrained capacity expansion model, without capacity potentials and network constraints, most renewable new capacities would be concentrated in the areas with the best load factors, as no transmission limitations or capacity saturation would occur. Consequently, such models would likely result in non-existent solar investment in the British Islands or wind in the Alpine

Region, highlighting the stakes surrounding model parametrization regarding capacity potentials.

Hence, the investment results show that the renewable investment scale is sensitive to several factors. The first parameter is meteorological conditions, favoring investment in countries with high capacity factors. Indeed, the countries with the most significant solar capacity increases have high irradiances, such as the Iberic region and Italy. On the other hand, Germany, whose solar capacity in 2021 is the more consequent, only reaches 158.97 GW. By comparing the cost-optimal renewables capacity found by the capacity expansion model and the initial 2021 installed capacity, it is possible to evaluate the capacity increase scale and installation speed per year until 2050 (see Table 4. 11), which confirms that the countries with the most consequent solar capacity increases are the Iberic region and Italy. The same effect applies to wind technology, with a more substantial increase in countries with high wind capacity factors. The second parameter that conditions investment is capacity potential. Indeed, wind onshore capacity potential is maximized in several considered countries, namely the Alpine region, the Benelux region, Germany, and the United Kingdom. Thus, wind onshore's capacity resulting from the investment model is not economically optimal but constrained by its socio-technical limitations. Hence, a high wind onshore social acceptance among populations or changes in environmental regulations should increase the total wind capacity resulting from the model. Another finding relates to installation speed rates. Reaching such renewable capacity is feasible for solar but may be challenging for wind capacities in the Iberic region, France, Italy, and the British Islands compared to their historical maximal installation speed rates (see Table 4. 12 and Table 4. 13). Enhanced installation speed rates will be necessary for such countries to attain the computed cost-optimal wind capacity. This does not invalidate the feasibility of the cost-optimal capacity mix, as recent European plans aim to install more consequent renewables capacities.

2021 capacity (GW)	Alpine region	Benelux	Germany	Iberic region	France	Italy	British Islands	Western Europe
Solar – 2021 capacity (GW)	6.13	21.04	58.46	17.63	14.51	22.70	13.70	154.15
Multiplication factor	457%	82%	101%	405%	485%	352%	112%	222%
Installation speed (GW/year)	1.00	0.62	2.11	2.55	2.51	2.86	0.55	12.20
Solar – Cost-optimal capacity (GW)	34.17	38.27	117.51	89.09	84.86	102.68	29.07	495.66
Wind – 2021 capacity (GW)	3.61	12.94	63.76	32.75	18.68	11.28	31.46	174.46
Multiplication factor	485%	398%	149%	447%	661%	1124%	680%	444%
Installation speed (GW/year)	0.63	1.84	3.40	5.22	4.41	4.53	7.64	27.66
Wind – Cost-optimal capacity (GW)	21.11	64.49	158.97	178.99	142.04	137.99	245.43	949.02

Table 4. 11: Installed renewables capacity compared to 2021 [3]

Country	Alpine region	Benelux	Germany	Iberic region	France	Italy	British Islands
Year maximum	2021	2020	2012	2019	2021	2011	2015
Maximum (GW)	1.12439	4.66192	8.161	4.309603	2.687	9.539	4.073942

Table 4. 12: Maximum historical installation rate – Solar energy – computation by authors based on IRENA data

Country	Alpine region	Benelux	Germany	Iberic region	France	Italy	British Islands
Year maximum	2014	2020	2017	2007	2017	2009	2017
Maximum (GW)	0.435737	2.952092	6.145	3.618	1.932793	1.354	3.976563

Table 4. 13: Maximum historical installation rate – Wind energy – computation by authors based on IRENA data

Countries' willingness to invest in a novel nuclear program and maximum installable capacity linked to construction times and supply chain constraints limit investment in new nuclear capacity. Thus, nuclear programs represent a minor share of the total investment toward a decarbonized Western European power system, especially compared to renewables investment levels. Indeed, the total nuclear capacity represents 77.905 GW for Western Europe. Nonetheless, all countries that can invest in new capacities build new reactors. Additionally, the nuclear capacity potential is maximized for all countries in the central nuclear cost scenario, highlighting the economic competitiveness of new nuclear builds and long-term operations of existing reactors. Hence, supply-chain constraints and construction time constrain nuclear capacity rather than costs. This result holds when considering higher overnight nuclear costs with unchanged nuclear capacity in the first alternative cost scenario (i.e., 5400 €/kW overnight costs – see Table 4. 14). In the highest nuclear cost scenario (i.e., 7900 €/kW overnight costs, similar to Flamanville 3's cost overruns), the cost-optimal nuclear capacity slightly decreases only in France from 50.905 GW to 43.895 GW. We conclude that nuclear costs do not strongly influence the future share of nuclear power in decarbonized European power systems, but the industrial capacity to develop a nuclear fleet does. Nuclear remains valuable to renewables-dominated power systems even at high costs as it provides firm generation in periods with low VRE production. In France, the decreased nuclear capacity corresponds to reduced investment in SMRs (340 MW Nuward capacity vs. 4 GW in the low-cost scenario) and less EPR2 built (12 EPR2 instead of 14). Nonetheless, the decreased capacity in the worst-case scenario does not undermine the economic competitiveness of fleet renewable with consequent renewables investment. Such results highlight the stakes surrounding construction delays for nuclear energy, with a 2050 capacity that will consequently depend on the ability to develop new nuclear programs.

Nuclear overnight costs scenario	Alpine region	Benelux	Germany	Iberic region	France	Italy	British Islands
4500 €/kW	0	3	0	0	50.905	0	24
5400 €/kW	0	3	0	0	50.905	0	24
7900 €/kW	0	3	0	0	43.865	0	24

Table 4. 14: Nuclear capacity under different overnight costs scenarios

Apart from nuclear capacity, there are few changes to the cost-optimal capacities in the alternative nuclear cost scenarios. In the first alternative scenario, there is no evolution in installed capacities. Such a result highlights that a 900 €/kW increase in nuclear’s overnight costs does not impact the cost-optimal Western European power system. In the higher nuclear costs scenario, apart from the French nuclear capacity decrease, there is an increase in wind and hydrogen capacity and a decrease in solar capacity, as seen in Figure 4. 2. The capacity variations are considered marginal in the face of the total renewable and hydrogen capacities.

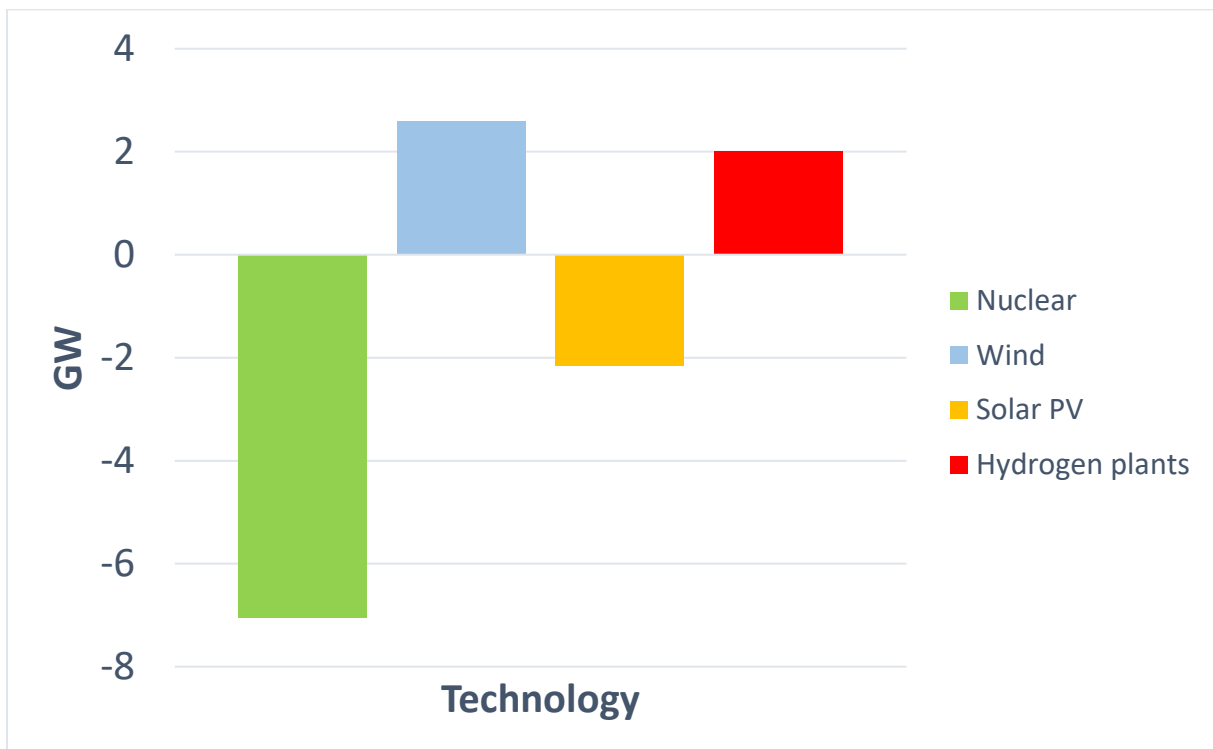


Figure 4. 2: Capacity evolution in France under the 7900 €/kW overnight cost scenario compared to the 4500 €/kW overnight nuclear cost scenario

Total investment in decarbonized gas plants is 251.7 GW, mainly in countries with no nuclear development plants. The development of decarbonized gas plants reflects a need for robust generation in periods with low renewables production and maximized use of production levers such as hydroelectricity, biomass, batteries, and interconnections. In order to compensate for such periods, it is cost-optimal to invest in new firm capacity instead of covering the unsupplied energy cost. Thus, even though the future European power system needs new firm capacities to

meet increased electric demands, such plants do not benefit from high load factors as they mainly produce electricity during peak-demand periods.

The last component of future power systems with consequent development is the exchange capacity between countries. The capacity expansion model strongly increases the total interconnection capacity up to its maximum potential for each line. The models' optimal interconnections capacity is mainly determined by their maximum investment levels, like new nuclear plants. This result highlights the economic advantage of an increased exchange capacity between European countries, enabling new non-domestic outputs for renewables production and firm generation.

First zone	Second zone	Maximum investment potential	Cost-optimal investment
Alpine region	Germany	10500	10500
	France	4500	4500
	Italy	2900	2900
Benelux region	Germany	16500	16500
	France	7000	7000
	British Islands	9400	9400
Germany	Benelux region	9500	9500
	France	7800	7800
	British Islands	3500	3500
Iberic region	France	9000	9000
France	Italy	3000	3000
	British Islands	7600	7600

Table 4. 15: Interconnections potential and additional investment for all cases

3.2. Overview of nuclear flexibility

As noted in Chapter 4.2.5, the nuclear outage schedule and minimum power are modeled for each iteration of the investment algorithm and each nuclear cost scenario, allowing the representation of nuclear flexibility. Similarly to [1], Figure 4. 3 represents the last iteration for the French fleet, with the fleet’s available nuclear capacity and overall minimal power used to compute the economic dispatch presented in the following sections.

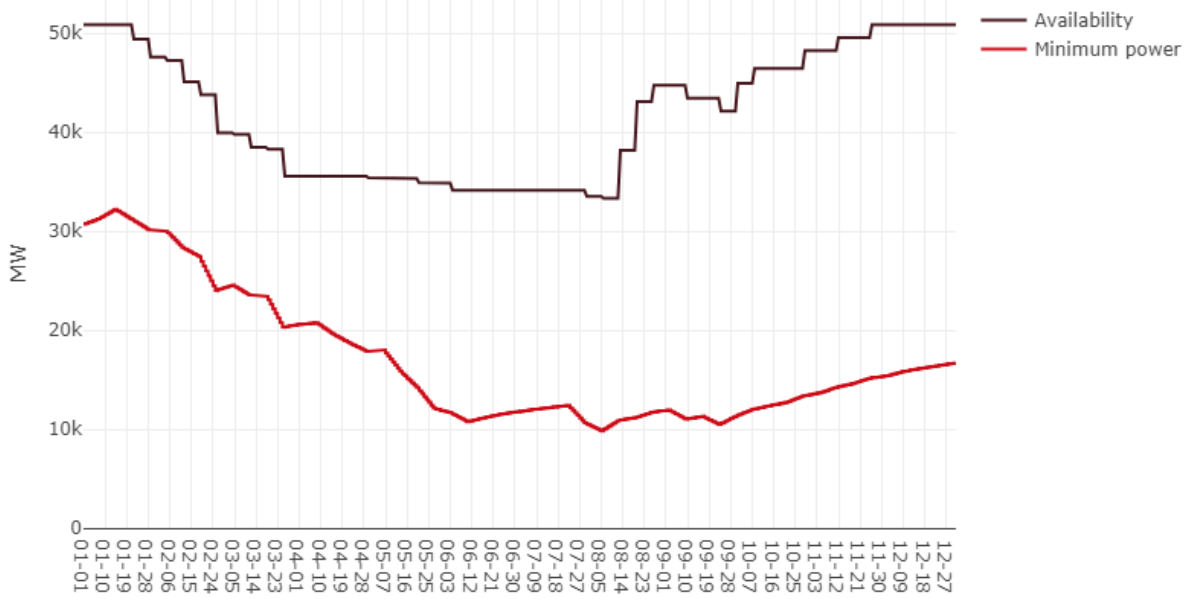


Figure 4. 3: French nuclear availability and minimum power - 50.905 GW capacity

Nuclear availability is more significant during winter as electric demand is higher due to climate conditions. Inversely, most outages occur during the summer as electric demand is lower. Hence, following Chapter 2.3.2 and [1], [44]–[46], reactors’ minimum power tends to increase around the end of winter prior to most outages for refueling and maintenance operations.

As the cost-optimal capacity does not change between the 4500 €/kW and 5400 €/kW overnight cost scenarios, the nuclear operational schedule is the same for both cases. The nuclear operational schedule for the 7900/kW case is presented in Figure 4. 4. Its dynamics are the same as the operational schedule of the two other cases.

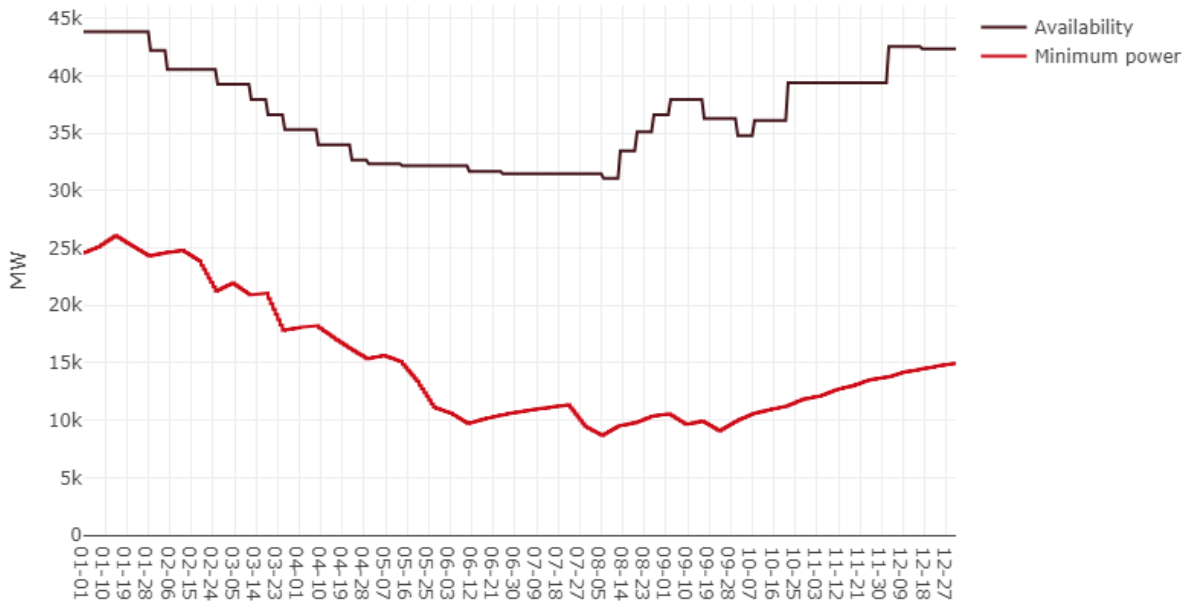


Figure 4. 4: French nuclear availability and minimum power - 43.865 GW capacity

3.3. Economic dispatch between technologies

Table 4. 16 and Figure 4. 5 resume the average annual economic dispatch for each considered country and all simulated years (see Chapter 4.2.3).

TWh	Alpine region	Benelux	Germany	Iberic region	France	Italy	British Islands	Western Europe
Hydroelectricity (Run-Of-River and Storage)	49.91	0.72	18.77	35.49	57.37	41.61	5.20	209.07
Nuclear	0.00	13.06	0.00	0.00	208.08	0.00	73.68	294.82
Decarbonized Gas (Biomass and hydrogen)	5.03	12.78	102.39	11.16	3.11	66.85	12.73	214.06
Wind	54.73	251.86	547.20	486.47	402.14	340.03	954.53	3036.95
Solar	41.17	38.96	101.53	158.16	108.60	141.43	29.27	0.00
Pumped-Storage Open Cycle (Net position)	22.20	0.00	-0.28	-1.61	-0.26	2.03	0.00	22.08
Pumped-Storage Closed Cycle (Net position)	-0.52	16.16	-1.91	-19.05	-0.20	-2.51	0.00	-8.03
Batteries (Net Position)	-0.14	-0.23	-1.77	-1.20	-0.63	-1.10	0.00	-5.06
Import from neighboring countries	-7.37	-7.14	230.70	-10.79	-108.48	52.72	-147.45	2.19
Total	165.02	326.17	996.63	658.65	669.73	641.05	927.94	4385.20

Table 4. 16: Average economic dispatch – All years – Central nuclear cost scenario

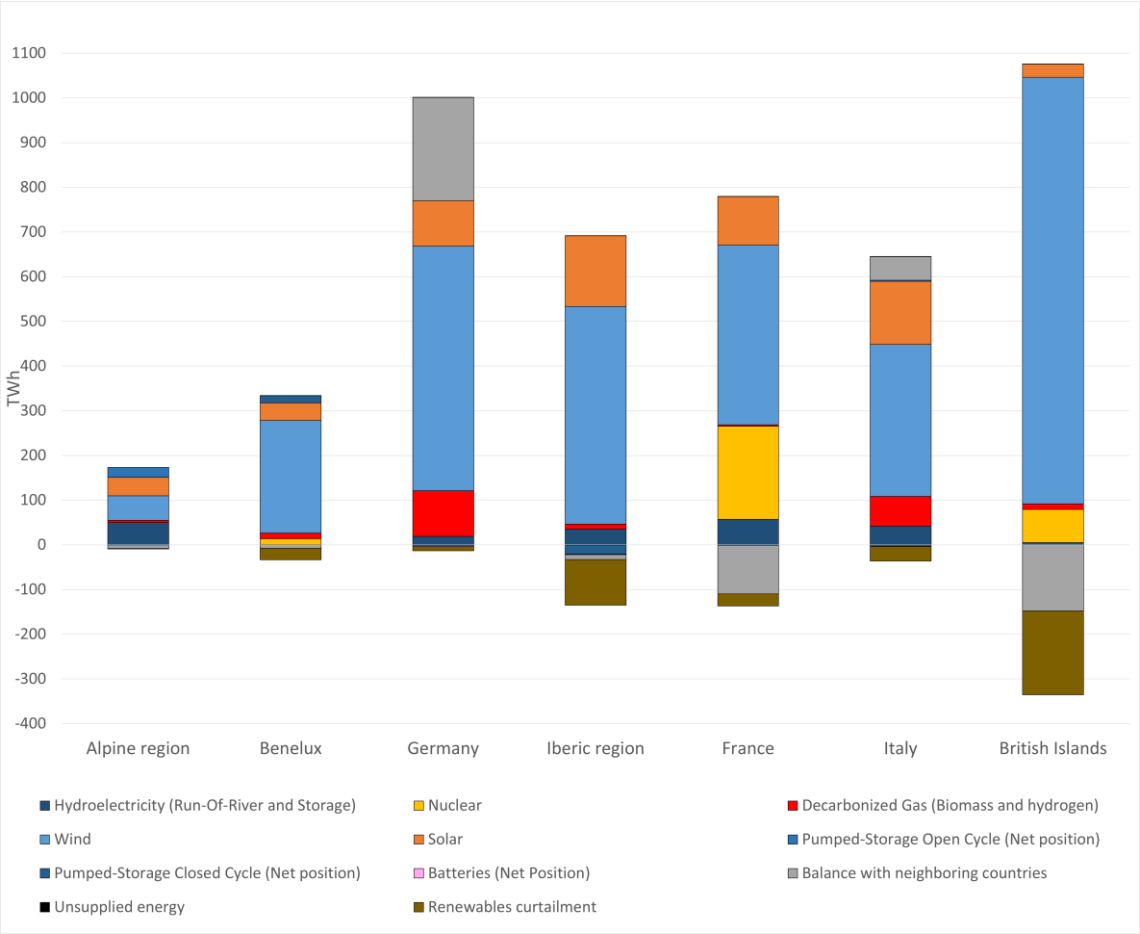


Figure 4. 5: Average economic dispatch histogram - All years - Central nuclear cost scenario

Variable renewables represent the dominant technology in the economic dispatch of decarbonized power systems in all Western European countries. Wind generation is the technology with the most significant output, representing approximately two-thirds of the overall electricity production (Figure 4. 5 and Table 4. 16). This result corresponds to the investment phase output, where most new renewable capacities were wind turbines. Similarly to renewables investments, most production originates from the British Islands. It results in consequent renewables curtailment, up to 19.20% and 17.19% of wind and solar output, respectively (Table 4. 17). Such curtailment levels undermine the economic rentability of British wind capacities and highlight the transmission bottlenecks that limit variable renewables output. Solar is the second dominant generating technology, with a higher production share in southern countries with high irradiance or the Alpine region, with limited wind capacity. Like wind capacity, high solar capacity may result in high curtailment levels, especially in the Iberic region.

% spilled	Alpine region	Benelux	Germany	Iberic region	France	Italy	British Islands	Western Europe
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Wind	0,85%	8,66%	1,33%	14,43%	4,80%	5,89%	19,20%	10,62%
Solar PV	2,55%	11,19%	2,17%	20,47%	7,11%	9,07%	17,19%	10,59%

Table 4. 17: Average renewables curtailment - All years

Nuclear production represents a minor share of the total electric mix in the considered capacity mixes. At most, nuclear reactors cover 31.07% of the electric demand in France, as it is the country with the largest nuclear fleet. The low nuclear share in the economic dispatch is due to its limited capacity compared to renewables and reactors' low production levels compared to their installed capacity. Indeed, nuclear reactors do not operate in baseload mode in a cost-optimal power system dominated by renewable capacities. Nuclear has to ramp down frequently to adapt to renewable production variability, as detailed in Section 3.4. The same phenomenon occurs with decarbonized gas, whose production level is mainly concentrated in countries without nuclear capacity. In such countries, hydrogen and biomass capacities are used more frequently to ensure the electric demand and supply equilibrium in periods with low renewables output and insufficient storage availability. Decarbonized gas production remains low for Western Europe compared to its installed capacity, highlighting that decarbonized gas' uses are concentrated during peak residual demand periods.

Loss of load durations (LOLD) are lower than 7.2 hours for all zones and all years (Table 4. 18). Hence, several zones (Benelux, Germany, the Iberic region, and Italy) do not meet the current security of supply criteria (3h per year). It is mostly due to the meteorological conditions of a single year – corresponding to 1987- characterized by low VRE production levels, notably wind. Thus, this year's loss of load duration is 61 hours for Benelux, 38 hours for Germany, 21 hours for the Iberic region, and 12 hours for Italy. In other years, the security of supply is met. In the case of Italy, three meteorological years do not respect the security of supply criteria, 1985 and 1987 with 12 hours each, and 1989 with 34 hours. The chapter argues that increasing the number of meteorological years simulated would provide a robust analysis of the security of supply. Indeed, among the present ten years simulation, 1987 is an outlier. Such considerations are left for future work, as building additional prospective demand profiles is costly. Eventually, the loss of load durations presented here highlight the decreased supply security linked to supply-side variability. In volume, the unsupplied energy share does not exceed 0.0327% of a zone's electricity demand (Benelux), highlighting the adequacy of the installed capacities to meet the electric demand overall.

Exchanges between zones play an important role in the security of supply between zones. Some zones import electricity massively (Germany, Italy) while others are consequent exporters (France, the British Islands), as seen in Figure 4. 5. Although countries with nuclear energy have a positive trade balance with neighboring countries, such correlation may be due to other systems components such as the share of renewables (e.g., wind capacities in the British Islands), the geographic location of each zone (e.g., France as a central zone in Western Europe), or interconnections capacities. Western Europe's balance with the rest of the simulated system (Northern Europe and Eastern Europe) is -2.19 TWh. Hence, the cost-optimal Western European power system is slightly in deficit.

Country	Alpine region	Benelux	Germany	Iberic region	France	Italy	British Islands
Loss of load duration (hours)	0	7	4.1	3.5	3.0	7.2	1.4
% of the electric demand that is unsupplied	0,0000%	0,0327%	0,0093%	0,0075%	0,0093%	0,0079%	0,0023%

Table 4. 18: Loss of load duration and share of unsupplied electricity - All years

3.4. Nuclear production and flexibility

The first metric of interest is the annual load factor of the nuclear fleet. Contrary to the traditionally used baseload mode, where reactors maximize their output, the nuclear fleet has a low load factor, ranging from 44.31% to 62.80%, depending on the considered countries (see Table 4. 19). The region with higher nuclear load factors is Benelux. This is due to Benelux’s capped wind offshore and onshore potentials, increasing the average nuclear production to ensure the constant demand-supply equilibrium. In countries with higher renewable potential, such as France and the British Islands, nuclear reactors need to decrease their production more frequently to accommodate renewables production increases.

TWh	Benelux	France	British Islands	Western Europe
Nuclear capacity (GW)	3.0	50.905	24.0	77.905
Nuclear production (TWh)	13.06	208.08	73.68	294.82
Load Factor (%)	62.80	58.99	44.31	54.61

Table 4. 19: Nuclear capacity, generation, and load factor

Nuclear production duration curves highlight that, in France, Benelux, and the British Islands, the nuclear load factor is inferior to half of the nuclear-installed capacity during at least 50% of an average year (see Figure 4. 6 below). Such load factors confirm that nuclear would mainly operate in partial load to accommodate for renewables production. A comparison is made with two historical years in France, 2015 representing a high nuclear production year (415 TWh annual production) and 2021, an historically low production year (315 TWh annual production). In both cases, nuclear load factors in future decarbonized European power systems will be inferior to historical load factors (Figure 4. 6 and [43]). Such results highlight that, even though nuclear capacity is of interest to the power system, it will operate differently than the baseload mode, which questions the level of nuclear revenues in such capacities settings.

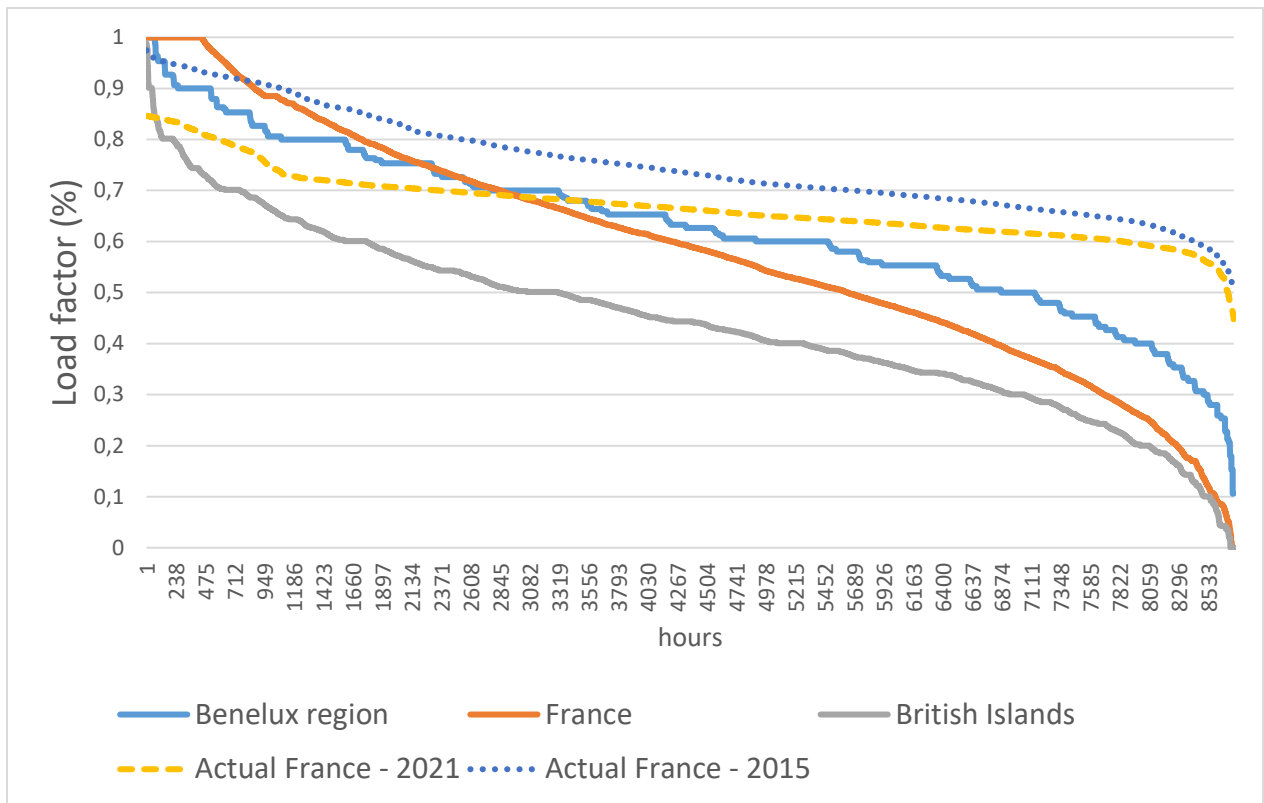


Figure 4. 6: Average nuclear load factor duration curves for all countries and French historical data

In order to illustrate the flexibility required from nuclear power plants to balance the electric supply and demand, two extreme weeks are presented in the French zone, one with low renewables production and the other with favorable meteorological conditions for wind turbines and solar plants.

In the first week, as seen in Figure 4. 7, nuclear reactors operate in baseload mode. In such situations, nuclear capacity is the primary generating technology, although it does not ensure the entirety of the domestic electricity demand (49.9% of the weekly domestic demand). Indeed, imports from neighboring countries are high throughout the week like decarbonized gas during peak residual demand periods. Regarding storage technologies, batteries and hydraulic pumped storage, when used, fill their reservoirs during mid-day when solar production is high to generate electricity during the night. Following the average load factor across the ten years simulated (illustrated in Figure 4. 6), such weeks are rare as nuclear usually functions at lower output levels.

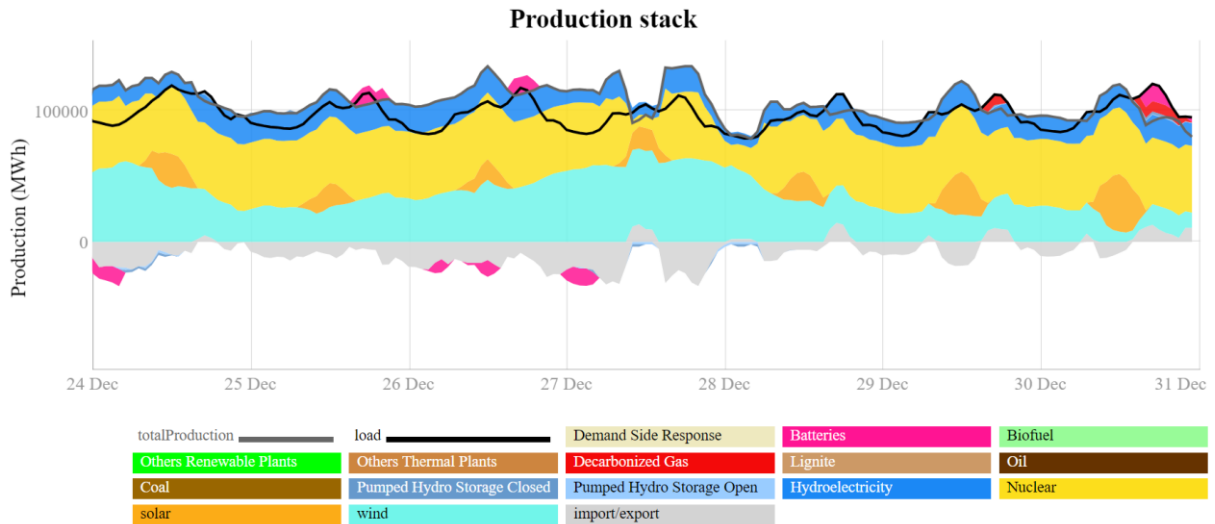


Figure 4. 7: French economic dispatch between technologies - December 24th to December 31st - 1982 meteorological data

The second week illustrates an opposite situation, with favorable conditions for renewable production, especially wind turbines (see Figure 4. 8). During such weeks, wind and solar capacities are sufficient to meet the domestic supply-demand equilibrium, with renewables production that exceeds interconnections exchanges and needs to be curtailed. Thus, nuclear reactors do not generate electricity during the illustrated week, shutting themselves off as wind turbine output rises at the start of the week. This constitutes a new paradigm for nuclear energy that may remain offline for prolonged periods in future decarbonized European power systems. High renewables production also evicts other generating technologies, with non-existent decarbonized needs and marginal storage facilities use.

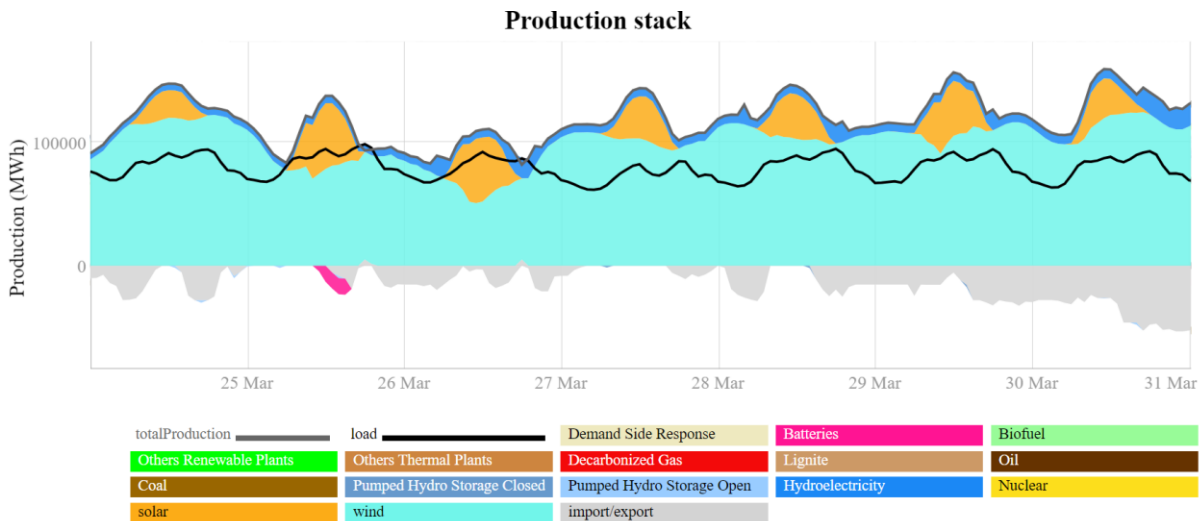


Figure 4. 8: Economic dispatch between technologies - March 24th to March 31st - 1986 meteorological data

The average hourly nuclear output change equals 3.94% of the total installed capacity. Although such output changes remain within PWRs' flexibility capabilities [47]–[49], [44], [46], [45], [50], [28], [1], historical average hourly output changes are inferior (e.g., 0.71% in 2015 and 0.44% in 2021). If the periods where nuclear reactors' output remains stable are excluded, 136

upwards and downwards output changes are more consequent, representing respectively 17.23% and 15.14% of the total installed capacity, respectively.

Magnitude range	Average number of hours with upward ramping for all simulated years	Average number of hours with downward ramping for all simulated years
0 - 5%	228.6	266.9
5% - 10%	183.7	281
10% - 20%	237.3	237.3
20% - 30%	137.3	137.3
30% - 40%	89.2	89.2
40% - 50%	47	47
50% - 60%	31.5	31.5
60% - 70%	15.7	15.7
70% - 80%	3.2	3.2
80% - 90%	2.5	2.5
90% - 100%	0.7	0.7
100%	0	0
Average hourly change (%)	3.94%	

Table 4. 20: Upward and downward ramping magnitude frequencies- French fleet

Ramping maneuvers are consequent though most remain below 50% of the available nuclear capacity (Table 4. 20). In some extreme hours, nuclear reactors may need to activate more than 90% of their capacity in less than one hour to accommodate decreasing renewables production and increasing demand. Such ramping maneuvers correspond to the startup of all offline reactors, which may be operationally challenging, although in line with nuclear flexibility constraints.

Apart from output maneuvers’ magnitude, Figure 4. 9 highlights that nuclear reactors tend to modulate their power in the middle of the day, as solar energy benefits from higher capacity factors. The second period with low nuclear output corresponds to night hours when electricity demand is low and wind output is higher. Higher nuclear output occurs during peak-demand periods such as the start of the evening, corresponding to a spike in domestic electric demand to heat and cook and decreasing solar production. Hence, nuclear reactors tend to adapt their production level according to demand and renewables variations.

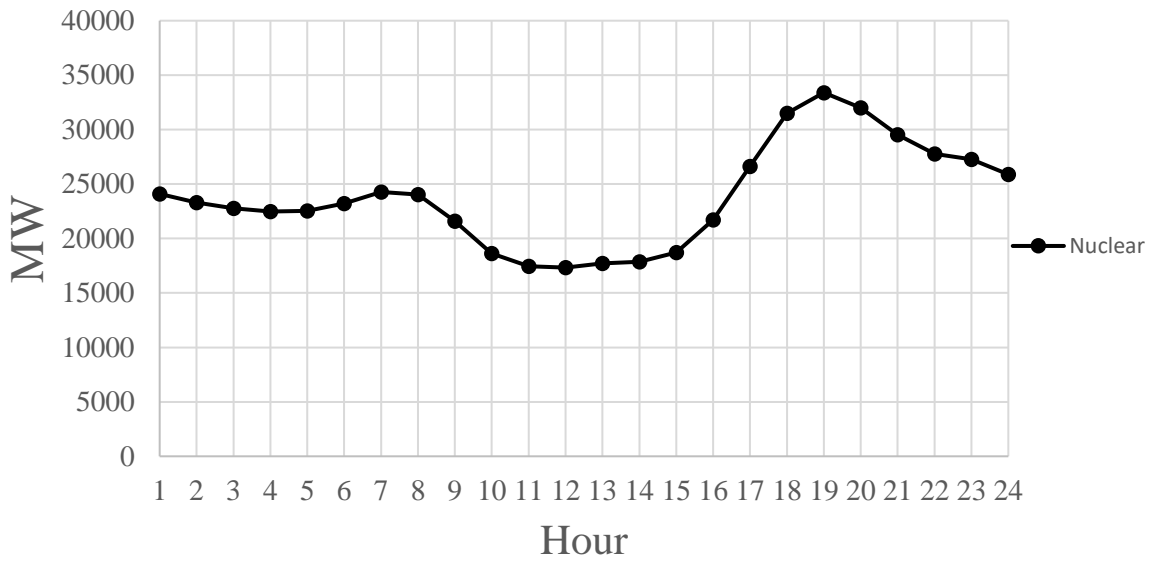


Figure 4. 9: Average nuclear hourly production - French fleet

Figure 4. 10 illustrates the magnitude of upward and downward output maneuvers depending on the hour of the day. It further confirms that greater downward maneuvers occur mid-day and night as electric demand decreases and solar production increases. Inversely, greater upward maneuvers occurs at the start of the evening, as solar production decreases and power demand increases.

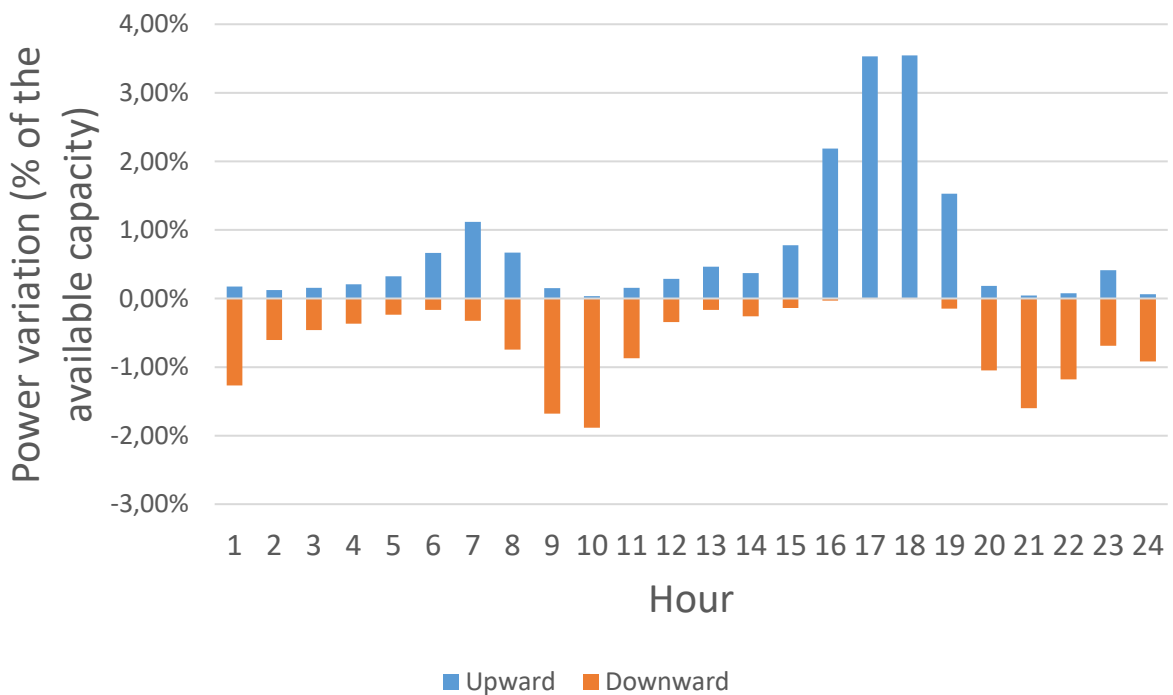


Figure 4. 10: Average upward and downward output maneuvers - French fleet

3.5. Overview of market prices and technologies' revenues

In order to reflect the current short-term market design, the chapter computes price levels per hour according to the “merit order” approach [51], hypothesizing that markets are perfect. Then, future contracts between producers and suppliers are not accounted for in the price formation scheme. Additionally, transmission, distribution and commercial costs are ignored for simplicity. Thus, comparing the computed market prices below and real-life price levels should be made with care, as the computed prices do not aim to represent the final price of electricity that final consumers would pay. For example, computed prices are higher than the historical long-term and short-term prices for all considered zones (typically around 50 €/MWh³⁷, 2021 and 2022 excluded). Such a result is due to costs assumptions surrounding the marginal cost of decarbonized plants that were computed following [7]. Hence, as numerical results surrounding market prices and technologies' revenues are sensitive to marginal cost assumptions, this part focuses on comparing price levels and revenues between zones and technologies.

Average market prices vary significantly across countries in the cost-optimal capacity mix, with electricity prices around 150 €/MWh in Italy, Germany, and the Alpine region. Inversely, France, the British Islands, the Benelux region, and the Iberic region benefit from lower market prices, between 64.71 and 110.39 €/MWh. Conjointly, countries with higher prices tend to import electricity from neighboring countries, as illustrated by negative commercial balances in Germany, Italy, and Spain. Countries with higher nuclear capacity (see Table 4. 14) tend to benefit from lower market prices and positive commercial balances (see Table 4. 21). Such results are likely due to the low marginal costs of nuclear energy, although the effect is limited due to the relatively small size of the Western European nuclear fleet. Thanks to the “merit order” approach, nuclear decreases the average market price when it is the marginal technology instead of storage technologies or decarbonized gas. Hence, market prices tend to be lower in countries with nuclear capacities. The same logic applies when considering electricity exchanges between zones, nuclear imports being competitive for countries without nuclear compared to domestic decarbonized gas production.

Country	Alpine region	Benelux	Germany	Iberic region	France	Italy	British Islands
Average market price (€/MWh)	142.36	110.39	146.82	100.52	103.9	188.45	64.71
Balance (TWh)	7.37	7.14	-230.70	10.79	108.48	-52.72	147.45

Table 4. 21: Average market prices and net balance for each zone

Figure 4. 11 highlights the price level differences between zones and hours. In all zones, market prices drop around mid-day, corresponding to the solar production increase, and tend to remain low during the night as wind production is high and demand is low. The highest market prices for all zones occur at the start of the evening, as solar production decreases and power demand

³⁷ <https://www.epexspot.com/en/market-data>

increases. Apart from Italy and the British Islands, all countries have similar hourly prices evolution dynamics. Italy benefits less from price decreases during the night as the share of wind production in its mix is lower than in other countries. On the opposite, British Islands benefit from lower prices during the night due to their consequent wind capacity.

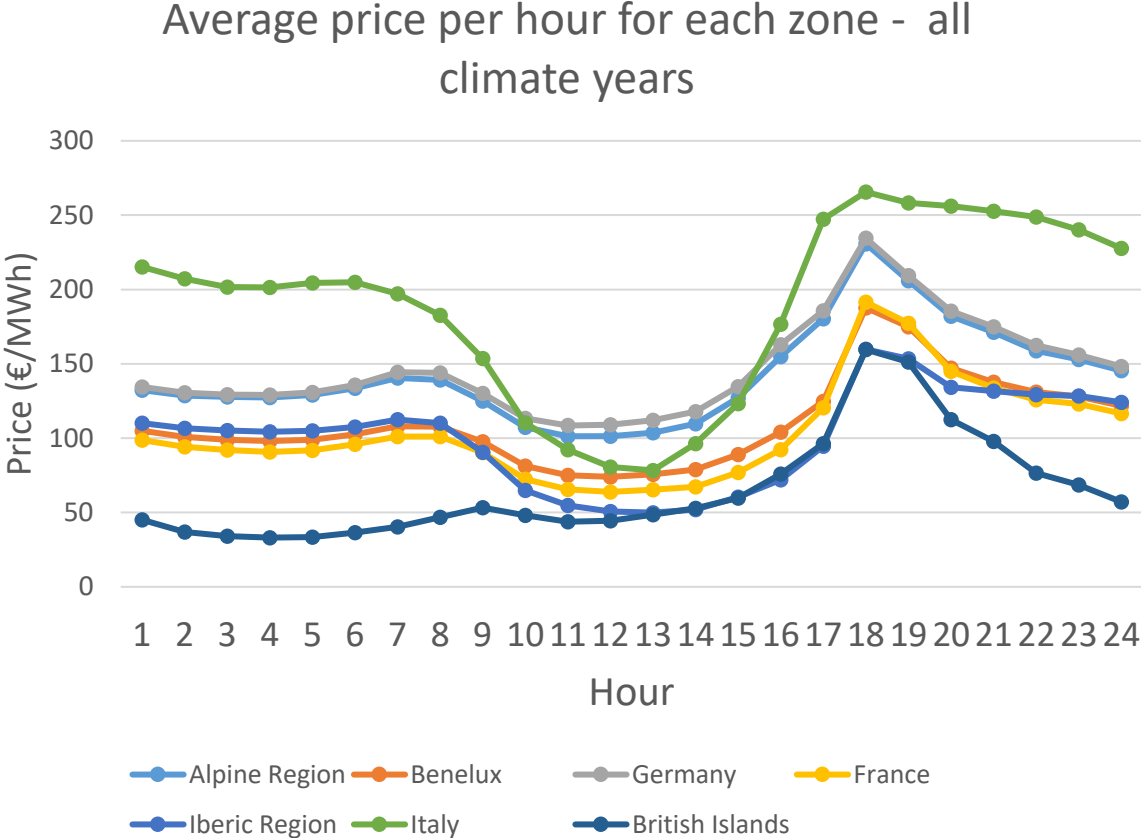


Figure 4. 11: Average price per hour for each zone - all climate years

Revenues for each technology thus vary to market prices in their respective zone, with higher revenues in Italy and lower in the British Islands (Table 4. 22). Nonetheless, there is a constant order between technologies, with nuclear capturing higher revenues and solar being the lowest. Such a result is due to nuclear’s ability to modulate its output according to the price signal, thus increasing its average revenue per MWh produced. Indeed, as seen in Figure 4. 9 and Figure 4. 11, nuclear production variations are similar to market price variations. On the other hand, as solar production is concentrated around mid-day, which corresponds to the lower prices hours (Figure 4. 11), its average revenues per MWh are the lowest out of all considered technologies (see Table 4. 22). Wind technology, while being non-dispatchable like solar technology, benefits from higher revenues as its production is more spread across the day.

Revenues per MWh	Alpine region	Benelux	Germany	Iberic region	France	Italy	British Islands
Nuclear	0	126,66	0	0	139,08	0	81,35
Wind	148,57	115,90	154,60	100,28	108,80	184,26	66,09
Solar PV	98,11	61,15	93,70	47,04	57,80	94,67	46,73

Table 4. 22: Weighted Average revenues per MWh

Discussions have emerged on generators' profitability in renewables-dominated power systems due to the "self-cannibalization effect" of renewable energy [52]–[59]. Indeed, with near-zero or null marginal costs, renewable energy tends to drive market prices down as it produces electricity, diminishing their and other generators' overall profits. [54] shows that prices in decarbonized power systems with renewable energy will likely be more volatile with most hours with low market prices and few with high prices that capture the scarcity of electricity and allow generators to recover their costs. Although in perfect market conditions, generators should recover their costs in the long term, such conditions are not met here as producers can not entirely determine their production level as their capacity potential limits constrain it. Then, it is difficult to evaluate whether an "energy-only" market design based on merit order price determination, where generators' sole revenues derive from revenue from short-term power markets, will suffice to ensure that decarbonized technologies are profitable. In this chapter's case, although technologies benefit from relatively high prices per MWh, several concerns may emerge regarding their profitability due to their low load factors or high curtailment levels in specific zones. To illustrate, nuclear traditionally recovers its high investment and fixed costs thanks to its high load factor. In a context where nuclear plants' load factor is depleted in future decarbonized power systems with renewable energy, such a paradigm does not hold, and their lack of profitability would result in reactors' shutdown or non-investment in new capacities. In the case that reactors are not profitable, although economically competitive in future decarbonized power systems, it advocates for support mechanisms or hybrid markets schemes [59] to ensure their profitability. The same concerns apply to renewable energy, as market prices may not be sufficient to ensure cost recovery without support mechanisms. Hence, Table 4. 23 computes technologies' profit per MWh for all zones by subtracting investment annuities, fixed costs, startup costs, and variable costs to technologies revenues.

Profit per MWh	Alpine region	Benelux	Germany	Iberic region	France	Italy	British Islands
Nuclear	-	34,18	-	-	42,22	-	-44,34
Wind	116,01	82,93	121,58	63,91	76,07	137,30	35,06
Solar PV	28,91	-20,75	-2,78	0,08	-7,34	34,14	-36,09

Table 4. 23: Profit for each technology (€/MWh)

The first result is that wind technology is the most profitable technology among renewable and nuclear energy for all zones, as its overall costs are sufficiently low compared to the revenue it captures in power markets. In this chapter's simulations, wind technology would not necessitate additional support mechanisms or hybrid market reform to be invested in. This result does not hold when considering solar energy. Indeed, in Benelux, Germany, France, and the British Islands, solar generators make a loss for each MWh produced on average, endangering their economic viability and investors' willingness to invest in this technology. Solar profitability does not seem to be linked to curtailment levels, as German solar generators' profits are negative even though curtailment levels are low (2.17%). Inversely, Italian solar generators' profits are positive even with 9.07% of their production curtailed on average (see Table 4. 17).

For nuclear plants, profits are positive for two zones, Benelux and France, and negative for one, the British Islands. Such a result is coherent with market price levels across zones and each fleet’s load factor. Indeed, British reactors are characterized by low load factors (44.31% on average – see Table 4. 19) and low market prices (see Table 4. 21), resulting in negative profit for the plant. The other result is that, in other zones, nuclear reactors may be profitable even though their load factor is depleted. As illustrated in Figure 4. 9, their ability to ramp up/down according to price signals allows them to increase their overall revenues, thus their profitability. Hence, it is possible for reactors operating flexibly to be profitable if, during some hours, market prices are sufficiently high to allow them to ramp up production and recover their costs. The profitability differences between British reactors and other zones’ reactors mainly derive from their power mix structure. In the British Islands, even though nuclear reactors are cost-optimal in decarbonized power system, the scarcity value of electricity is not sufficiently high to recover nuclear’s investment and fixed costs. Consequently, support mechanisms or hybrid market reforms are of interest to support British reactors’ profitability but are not necessary for nuclear technology in other zones.

The relevance of support mechanisms varies depending on the considered technology and zones. In order to illustrate this phenomenon, Table 4.24 computes the break-even price for all technologies and all zones. Such computation shows that break-even prices are not homogenous across zones and technologies, although wind technology is characterized by lower break-even prices contrary to nuclear power plants. Table 4.24 highlights that support mechanisms or hybrid-market reforms that would enhance technologies’ profitability, such as capacity payments, would need to be carefully designed depending on the considered zone and technology. Indeed, a uniform mechanism across Europe may result in insufficient support (e.g., nuclear reactors in British Islands) or excessive payments for already profitable plants (e.g., nuclear reactors in France). In the wake of market design reforms, such considerations must be carefully assessed.

Break-even	Alpine region	Benelux	Germany	Iberic region	France	Italy	British Islands
Nuclear	-	91,85	-	-	96,84	-	124,31
Wind	32,57	32,97	33,02	36,38	32,73	46,96	31,03
Solar PV	69,19	81,89	96,48	46,96	65,14	60,53	82,82

Table 4.24: Break-even level for all technologies (€/MWh)

4. DISCUSSION

This section discusses potential hurdles for nuclear energy in a cost-optimal decarbonized European power system. Indeed, several questions arise for the nuclear fleet in light of the investment and economic dispatch results, especially regarding nuclear reactors' technical and economic viability in such production schemes.

In Chapter 2, the main physical limitations to nuclear flexibility were summarized, notably ramping constraints, minimum power evolutions linked to boric acid concentration in the primary circuit, and reactors’ maintenance or refueling outages schedule. Hourly output

variations presented in Chapter 4.3.2 remain below PWRs' ramping constraints capabilities, up to 5% of a reactor's nominal power per minute [1], [45], [60], [61]. Thus, nuclear reactors can operate the output variations required in a power system dominated by VRE. Regarding minimum power, [1] notes that capacity expansion models assuming a constant minimum power underestimate nuclear flexibility potential. This is not the case in this chapter's simulation results as nuclear flexibility is more detailed, thus preventing the misestimation of reactors' ability to adapt to VRE production. Eventually, the most uncertain technical factor relates to the schedule of reactors' maintenance and refueling outages. As mentioned in Chapter 2, the irradiation cycle duration ranges from 12 to 24 months, depending on the fuel's enrichment and reactors' type [60]–[62]. Additionally, the fuel's depletion rate is one of the main parameters that condition the duration of the irradiation cycle, this rate being proportional to the reactor's output. In a decarbonized European power system dominated by VRE production, reactors' fuel depletion rate will then decrease, increasing the theoretical irradiation cycle lengths. Thus, the schedule of nuclear plant outages would need to adapt to this new paradigm. Such potential changes are not accounted in this work.

Another uncertainty relates to the economic aspect of nuclear energy. As mentioned previously, nuclear reactors are traditionally used as “baseload” generating means in order to maximize their load factor, thus their overall revenues. In this chapter's simulation results, the share of hours with negative or null market prices is consequent, e.g., 42.19% hours of the year in France. During such periods, nuclear revenues are negative if in operation. Hence, nuclear revenues are concentrated in a reduced number of hours whose prices must compensate for the overall decreasing load factor. Although the French simulation results show that the average nuclear revenue per MWh produced is sufficient to recover investments and fixed costs, such a result is dependent on the reactors' load factor and the capacities mix of the rest of the system. Additionally, as peaking prices are concentrated in a limited number of hours, nuclear market revenues are more volatile, which increases the inherent risk of reactors' revenue schemes. Such phenomena would likely increase investors' risk and thus the financing costs of new nuclear builds, undermining their economic competitiveness. In the context of high nuclear investments and fixed costs that increased significantly first 3rd generation reactors costs [63], market design reforms, support mechanisms, or public financing schemes would decrease the risk associated, increasing nuclear profitability.

5. CONCLUSIONS

This chapter concludes the thesis manuscript by exploring the role of flexible nuclear energy in a 2050 decarbonized Western European power system. The presented capacity expansion model focuses on the European continent and allows investment in renewables, nuclear, hydrogen facilities, and interconnections while including hydraulic, batteries, and biomass generation. Most investments occur in renewables capacities thanks to their decreasing costs and high potential across Europe. Overall, new investment levels are high as ensuring an increasing electric demand is crucial to the energy sector's decarbonization. In countries that do not exclude nuclear from their strategy toward net-zero emissions levels, potential nuclear investments are maximized, with construction time and supply-chain constraints limiting their installable nuclear capacity and nuclear capacity being poorly sensitive to nuclear costs. Hence,

the chapter highlights that new nuclear programs are cost-optimal even in worst-case nuclear cost scenarios as they diminish the overall power system costs. Consequently, countries that invest in new nuclear reactors benefit from lower prices and better commercial balance with neighboring countries. The impact of interconnections capacities limitations is then crucial, as enhanced transmission capacities would result in higher nuclear exports, reducing the market price gap between countries while optimizing renewables and nuclear production.

The second finding of the chapter focuses on the economic dispatch of the cost-optimal capacity mix. Similarly to invested capacities, renewables are the dominant technologies ensuring 80.5% of the total Western European electric demand. Due to VRE production's inherent variability, nuclear must operate as a flexible technology to ensure the supply-demand equilibrium at times with low renewable output and insufficient storage disponibility. Hence, the resulting nuclear load factor decreases, especially in countries with high nuclear capacity, like France and the British Islands. Nuclear reactors may remain offline for prolonged periods when renewable production is sufficient to meet the electric demand. The reactors' ability to ramp up their production level is also crucial in the case of renewable production decreases.

Finally, the chapter underlines potential technical and economic hurdles induced by a reduced nuclear load factor and increased flexibility requirements. Regarding technical constraints, increasing nuclear flexibility may modify the dynamics of irradiation cycles and outage phases, resulting in novel nuclear availability schedules. Further investigations are needed to determine the impact of high VRE penetration on the fleet's operational schedule. Reactors' economic viability is also uncertain, with an increasing number of hours with negative or null hours undermining revenues and eventually increasing investment risks in this technology. Hence, the present paper calls for future research focusing on a joint approach between capacity expansion models and novel market designs (hybrid market designs, power purchase agreements schemes...), allowing modelers to better address the stakes surrounding nuclear in decarbonized power systems.

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7. APPENDICES

APPENDIX 1 : Aggregation hypotheses

Node ID	ENTSOE	Country ID	Country	Country modeled
BE00		BE	Belgium	Benelux
LUG1		LU	Luxembourg	
NL00		NL	Netherlands	
IE00		IE	Ireland	British Islands
UK00		UK	United Kingdom	
UKNI				
AL00		AL	Albania	Eastern Europe
BA00		BA	Bosnia and Herzegovina	
BG00		BG	Bulgaria	
CY00		CY	Cyprus	
CZ00		CZ	Czech Republic	
EE00		EE	Estonia	

GR00	GR	Greece	
GR03			
HR00	HR	Croatia	
HU00	HU	Hungary	
LT00	LT	Lithuania	
LV00	LV	Latvia	
ME00	ME	Montenegro	
MK00	MK	Republic of North Macedonia	
MT00	MT	Malta	
PL00	PL	Poland	
RO00	RO	Romania	
RS00	RS	Serbia	
SI00	SI	Slovenia	
SK00	SK	Slovak Republic	
TR00	TR	Turkey	
UA01	UA	Ukraine	
FR00	FR	France	France
DE00	DE	Germany	
DEKF			
ES00	ES	Spain	Iberic
PT00	PT	Portugal	
ITCA	IT	Italy	Italy
ITCN			
ITCS			
ITN1			
ITS1			
ITSA			
ITSI			
DKE1	DK	Denmark	Northern Europe
DKKF			
DKW1			
FI00	FI	Finland	
NOM1	NO	Norway	
NON1			
NOS0			

SE01	SE	Sweden	
SE02			
SE03			
SE04			
AT00	AT	Austria	Alpine region

Table 1 : List of simulated countries and aggregated zones

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CHAPTER 5. GENERAL CONCLUSION

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The conclusive chapter is composed of two parts. First, the main contributions and findings are summarized. The second part discusses some limitations and resumes the main research extensions emerging from the presented work.

1. SUMMARY OF CONTRIBUTIONS

This thesis' overall context relates to the increasing share of renewable energy in power systems, their impact on the residual demand, and the main challenges nuclear energy faces in such future.

Chapter 2 resumes the main physics principles of electricity production using Pressurized Water Reactors, and presents the main components of those reactors. The flexible operation of PWRs units is constrained by technical parameters such as Pellet-Cladding Interaction, xenon transients, and refueling and maintenance of reactors. These flexibility constraints are highly specific to nuclear energy, especially as plants' available flexibility is dependent on their operational schedule and their advancement in their irradiation cycle. Hence, operational schedule optimization and fuel burnup influence the degree to which nuclear and renewable energy integration may coexist in power systems; thus, considering those flexibility specificities may be important. The chapter then discusses various modeling approaches and determines that a MILP method is the best compromise between the results' accuracy and the models' computational complexity in the thesis' context.

The chapter's central contribution to the literature is the analysis of modeling practices regarding nuclear operations in power system simulations. It highlights that most works model nuclear power as any other thermal technology, thus neglecting the specificities of this technology's flexibility limitations. The chapter then discusses the potential effects of such modeling choices, notably the overestimations and underestimations induced by the absence of operational schedules and minimum power evolutions.

Chapter 3 aims to evaluate the effects of neglecting nuclear flexibility constraints in power system simulations. Eventually, this chapter's objective is to determine the pertinence of implementing two particular nuclear flexibility characteristics, plants' operational schedule, and minimum power evolutions throughout the reactor's irradiation cycle. The chapter highlights that the pertinence of ramping constraints modeling is limited in hourly power system models, as PWRs' flexibility is not constrained on this time scale. The first contribution to the literature is a novel MILP formulation of nuclear operational schedule optimization based on PWR's irradiation cycle and outage durations. The underlying principle is the maximization of nuclear availability in peak demand periods, similar to real-life schedule optimization. The second contribution is the computation of each reactor's minimum power evolutions based on the computed schedule. Hence, the chapter evaluates the fleet's overall flexibility capabilities.

The chapter compares three nuclear flexibility modeling assumptions applied to a simplified power system. The first assumption corresponds to current nuclear flexibility modeling, neglecting the specific constraints limiting the technology's flexible operations. Another encompasses operational schedule optimization, hence representing nuclear availability seasonality. Finally, the last modeling assumption represents both operational schedule and

minimum power evolutions. Several VRE integration levels are simulated, from 0% to 80% penetration levels. The chapter finds that the representation of nuclear schedule optimization reduces the estimated operational costs, energy curtailments, peaking-plant use, and environmental impacts linked to electricity generation. Regarding market prices and revenues, the number of negative prices hours is reduced, and technologies' profits increase. Additionally, implementing reactors' minimum power evolutions results in increased flexibility margins, enhancing better VRE integration, decreasing peaking-plant use, and reducing environmental impacts.

By comparing the different VRE cases, the chapter primarily highlights that the relevance of nuclear flexibility constraints in power systems is highly dependent on renewables penetration in the capacity mix. Indeed, the modeling results show low sensitivity to nuclear flexibility modeling assumptions in cases with low VRE penetration. In such cases, the additional computational burden justifies that modeling practices do not account for nuclear flexibility constraints. In cases with high shares of VRE production, those constraints strongly impact modeling results, highlighting their relevance in modeling practices focusing on the nuclear-renewables interaction.

Chapter 4 incorporates detailed nuclear flexibility constraints in a capacity expansion and simulation model. The objective is to expand previous modeling cases in a broader European power system while determining a cost-optimal decarbonized power system in 2050 and the role of flexible nuclear reactors in such a context. The capacity expansion model allows investment in renewables, nuclear, hydrogen facilities, and interconnections in a brownfield European system, with hydraulic, batteries, and biomass capacities calibrated to current projections for 2050. The chapter foresees substantial electric demand level increases in the face of consequent electrification to decarbonize the energy sector and encompasses maximum development potential for all technologies. Regarding nuclear reactors, countries' willingness, construction speed, and supply-chain constraints limit the installable capacity in future decarbonized power systems. Several nuclear cost scenarios are considered to assess its optimal capacity's sensitivity to potential cost overruns and building delay uncertainties.

The chapter's first contribution relates to renewables' central role in future Western European power systems, as wind and solar are the most invested technologies and broadly cover 80% of power generation. The second contribution is flexible nuclear capacity's low sensitivity to costs increases, with a moderate capacity decrease only in the worst-case scenario corresponding to Flamanville 3's cost overruns. In the other cost scenarios, nuclear development potential is maximized in all zones allowing investment in new builds and highlighting their cost-optimality. Thus, supply-chain constraints and construction lengths constrain the future nuclear capacity in Western European decarbonized power systems rather than costs or limited flexibility.

Finally, the chapter addresses how nuclear reactors would operate in the cost-optimal renewables-driven decarbonized power system. As PWRs cycle more frequently to adapt to renewables production variability, their load factor decrease substantially with prolonged shutdown periods when meteorological conditions favor wind and solar output. Consequently,

the number and magnitude of reactors' flexibility maneuvers increase, with upward maneuvers occurring around the early morning and the start of the night and downward maneuvers centered around mid-day and midnight as solar and wind production increase. The last contribution relates to the power system's market prices and solar, wind, and nuclear revenues. The chapter raises uncertainties regarding technologies' economic viability, especially solar, as its production has a decreasing impact on prices, and nuclear, in zones where price levels are insufficient to recover reactors' consequent investments and fixed costs, as illustrated in the British Islands zone.

2. LIMITATIONS AND FUTURE WORK

The main limitations of the work presented in this thesis relate to the modeling simplifications used to evaluate the role of flexible nuclear in the French and Western European electric transitions. Indeed, the models used here do not accurately represent key elements that would likely impact future power systems' demand and supply. Then, there is a distinction to be made between simplifications deriving from the necessity to focus on a specific research field, limit models' computational complexity or linked to data unavailability, and simplifications that lay the foundations for further research into the future role of flexible nuclear power. The objective of this last part is to address those simplifications.

Among the first category of simplifications, the thesis groups together the failure to consider many of the challenges related to nuclear development presented briefly in the manuscript's introduction. In particular, this includes considerations of the societal acceptability of nuclear energy, risk perception in the face of potential accidents, and waste management. While these considerations are essential to determine a comprehensive assessment of the prospects for nuclear energy, they are part of a broader effort to combine many fields of research to inform public decision-making on the future of this technology. Hence, this thesis limits its contributions to techno-economics considerations.

In the same way, the refinement of the models used, for example, by reducing the time step used for determining the economic dispatch between production and flexibility capacities or the investment in an optimal mix, is difficult to implement without significantly increasing the calculation complexity. This also applies to modeling the flexibility of pressurized water reactors, some constraints not being considered in this thesis because their representation would require smaller (e.g., ramping constraints) or larger time scales (wear and tear effect of flexible maneuvers on PWRs components). Such details also require more data, which can be challenging when the modeling approach considers several meteorological years across many zones.

Among the category of simplifications that introduces further research, the thesis considers the blind spots of the modeling approach. First, although partially implemented in the demand data, it would be beneficial to explicitly represent in the model the new flexibility levers that will develop in the near future. The thesis refers in particular to the charging of electric vehicles and its optimization, as well as the emergence of demand response during periods of grid tension or high prices. Explicit modeling of these elements would allow a better estimation of their

contribution to flexibility requirements rather than hypothesizing them a priori by including them in the demand. Improvements related to modeling the hydrogen P2G2P loop avoid potential misestimations induced by the assumption retained in the thesis, namely that hydrogen supply is exogenous.

Moreover, integrating sectoral coupling elements, especially regarding the demand for heat or decarbonized gas, would allow a better evaluation of potential outlets for surplus renewable electricity. Similarly, nuclear reactors could benefit from these new outlets, which would theoretically increase their load factor, thus, their economic viability.

Regarding the determination of cost-optimal capacities, the capacity expansion model's extension to storage capacities is the primary integration improvement to be made. Indeed, although the presented work includes storage capacities calibrated to 2050, their inclusion in the investment algorithm would better depict the competition reactors face to meet flexibility requirements.

Eventually, by integrating detailed PWRs' technical constraints into broader power system simulation models, potential future work could better assess flexible nuclear's interaction with renewable energy and storage capacities. Such future researches are a direct extension of the thesis work presented here.

Other research questions emerge from the work presented here. Among them, including a local dimension of electrical systems would add a new aspect of the flexibility requirements by allowing congestion to be represented on the network, which could influence reactor flexibility. Again, determining the right level of detail is crucial.

The economic aspect of flexible nuclear operation could also be further explored, although the question of the economic viability of reactors was partially addressed in the last chapter. However, the thesis only considered the price formation mechanism resulting from the merit order without considering long-term Forward and Future contracts that represent most of the current reactors' revenues. Thus, a modeling framework allowing the inclusion of these contracts and their price formation would make it possible to estimate the reactors' economic viability better. Similarly, modeling approaches that implement novel market designs, such as hybrid markets, would help inform decision-making related to structural reforms of electricity markets. Additionally, future market designs' ability to orient the actions of the European actors, private or public, toward long-term decarbonization goals could be a substantial contribution.

The interpretation of models' results must always be contextualized due to, among others, data unavailability or necessary simplifications, and the thesis highlights that the modeling approach presented here underlines crucial stakes surrounding the future of decarbonized power systems and their evaluation. Overall, the manuscript advocates for increased use of the approaches presented in this text for decision-making. In addition, the assessment of the future of nuclear power in electrical systems will have to be based on interdisciplinary analyses, making it possible to include most of the challenges toward decarbonization. This holds especially true in current uncertain times when structural decisions about the energy future must be made. In this context, this thesis hopes to participate as much as possible in this effort.