

École polytechnique de Louvain

How to formulate robust guidelines for the Belgian energy transition under commissioning time uncertainty?

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Abstract

Energy system models are increasingly used to guide decarbonisation policy, but most treat an investment decision as immediately available capacity. This ignores the time needed for planning, permitting, and construction, producing overly optimistic deployment schedules and overestimating system flexibility. This study extends EnergyScope Pathway—a linear whole-energy-system optimisation model applied to Belgium’s transition to 2050—by adding a commissioning time from investment decision to operation for seven power-sector technologies. The extension gives the model an explicit notion of decision timing: it identifies not only what to build, but also when the decision must be taken for the capacity to be available on time. Three analyses quantify the effect of commissioning time.

A comparison against the standard model shows that commissioning times increase total operational costs. The main drivers are higher gas reliance through gas cogeneration of heat and power and Combined Cycle Gas Turbine before nuclear power comes online, and higher renewable-methanol imports after 2040.

Since commissioning time varies widely, each technology’s uncertainty is characterised by an illustrative log-normal distribution and propagated using Polynomial Chaos Expansion. As a result, nuclear and onshore wind commissioning times are the main drivers of the transition cost uncertainty. When these technologies face delays, the model offsets higher gas consumption and reduces coal use in high-temperature industrial heat, keeping overall emissions within the carbon budget. Moreover, the result confirms that delays cost more than accelerations saves.

Benchmarked against four economic uncertainties, contribution of commissioning time uncertainty to the transition cost is marginal compared to that of the fossil-fuel prices.

These findings translate into clear robust guidelines related to the Belgian energy transition such as urgent decisions required, preserving existing assets and preparing future decision

Abbreviations

Acronyms

CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CHP	Cogeneration of heat and power
Coal US	Coal Ultra-Supercritical
Coal IGCC	Coal Integrated Gasification Combined Cycle
DET	Deterministic scenario
e-fuels	electrofuels
FC	Fuel Cells
GW	Gigawatt
GWP	Global Warming Potential
H ₂	Hydrogen
LFO	Light fuel oil
NCT	No Commissioning Time
OPEX	Operational and maintenance cost
PCE	Polynomial Chaos Expansion
PDF	Probability Density Function
PV	Photovoltaic
SMR	Small Modular Reactor
TWh	Terawatt-hour

1 Introduction

Energy system models are essential tools for guiding the transition towards climate-neutral economies. They help policymakers evaluate decarbonisation strategies, assess technology deployment pathways, and estimate costs and emissions [1]. These systems integrate multiple technologies across production, conversion, storage, and mobility—all subject to technical and economic constraints. To capture these complex dynamics, models vary in scope, detail, and temporal resolution. This study is based on a bottom-up approach, which represents technologies and energy flows in detail to allow for precise infrastructure planning [2]. Furthermore, rather than only using a snapshot model that only optimises a single reference year, this analysis uses a pathway model. Tracking the energy system continuously over consecutive years is essential to understand the timing of investments. To produce meaningful analysis, pathway models must also capture final energy uses—heat, electricity, mobility, and industrial feedstocks—alongside investment and operational costs.

EnergyScope Pathway [3] meets these requirements. It is a linear whole-energy-system optimisation tool developed at UCLouvain, building on the EnergyScope Typical Day snapshot model [4], [5]. EnergyScope Pathway captures system evolution through annual phases with monthly resolution and uses a perfect foresight formulation—assuming complete knowledge of future conditions when optimising [3].

Yet a critical gap remains. EnergyScope Pathway assumes that investment decisions translate immediately into operational capacity. This ignores the years required for planning, permitting, construction, and commissioning of energy infrastructure. Delaying the availability of key technologies forces reliance on more expensive alternatives and imposes limits on how fast the energy system can be transformed.

This study aims at closing that gap by introducing a commissioning time into EnergyScope Pathway for a selection of seven power sector technologies: nuclear power plants, onshore and offshore wind, small modular reactor (SMR), geothermal, field photovoltaic¹(PV) and Combined Cycle Gas Turbine (CCGT). The selection considers the significant commissioning time and the central role of electricity production in decarbonising heat, mobility, and industry.

Commissioning time is inherently uncertain. It varies widely depending on regulatory processes, construction complexity, supply chain conditions, and social acceptance. A single deterministic scenario does not capture this variability. Each technology’s commissioning time is therefore characterised by a log-normal distribution calibrated on Belgian and European data.

EnergyScope Pathway is applied to Belgium—a challenging case study given its limited renewable potential, high population density, heavy energy import reliance, and ongoing nuclear phase-out debate. That context makes initial energy-mix replacement particularly sensitive to commissioning times. Uncertainties are propagated in EnergyScope Pathway using third-order Polynomial Chaos Expansion, a modelling technique that quantifies how these uncertainties translate into variance in total transition costs—at a smaller computational cost than Monte Carlo sampling [1].

The analysis of this study is structured to answer the following questions:

1. How is commissioning time implemented in EnergyScope Pathway?
2. How does commissioning time affect the cost-optimal technology mix and total transition cost of Belgium’s energy pathway to 2050?
3. Which commissioning time contributes most to transition cost uncertainty?
4. What is its relative importance in the context of energy system uncertainties?
5. What are the implications for policy guidelines?

¹PV is divided into utility-scale and residential installations. Large solar farms face longer permitting, grid connection, and construction requirements that are considered negligible for rooftop installations.

2 Methodology

The methodology is articulated in four phases to transform EnergyScope Pathway from a model assuming instant deployment to one that explicitly tracks multi-year commissioning timelines—enabling the quantification of decision timing for each technology deployment.

To start with, EnergyScope Pathway and the relevant Belgian energy system specifications are presented in Section 2.1. Section 2.2 then describes the commissioning pipeline implementation. Section 2.3 characterises commissioning time uncertainty. Finally, Section 2.4 explains how these uncertainties are propagated in the model.

2.1 Whole-energy-system pathway model

EnergyScope Pathway [3] aims at optimising Belgium’s energy transition by minimising the total cost—the sum of annualised investment costs (CAPEX) and operation and maintenance costs (OPEX). The transition runs from 2020 to 2050, consistently with the EU net-zero target [6]. EnergyScope Pathway covers 114 technologies and 28 resource types across electricity, high and low temperature heat, passenger and freight transport, and non-energy sectors. Sectoral demands are specified as end-use demand—passenger-km, ton-km, thermal energy—allowing endogenous technology mix optimisation.

The optimisation operates within a cumulative carbon budget expressed through Global Warming Potential (GWP), following the GWP100a-2013 indicator [7]. GWP accounts for full life-cycle emissions including resource extraction, transport, and combustion. Belgium’s budget is set to 1.5 GtCO₂eq over 2020–2050 [6]. The zero emission target of 2050 is defined at 5.8 MtCO₂eq in EnergyScope Pathway. This reflects the life-cycle scope of GWP: even in a fully decarbonised system, residual emissions persist from, for instance, waste combustion, biomass use, and uranium extraction. Setting the constraint to absolute zero would make the optimisation problem infeasible [3].

Far more constraints are integrated in the model as defined in the work of Limpens et al. [3]. Among those, maximum potential capacity constraints for electricity technologies are particularly relevant in this study and detailed in Section 6.1.

From a planning perspective, EnergyScope Pathway divides the energy transition into representative years—every 5 years defining the phase duration. At each representative year, the snapshot model EnergyScope TD [4] optimises the energy mix to meet sectoral demand. The optimisation provides technology sizing, operation schedules, primary energy requirements, and technology merit order. EnergyScope Pathway then links these years into a pathway optimising the total cost.

The installed capacity (F) is tracked for each technology through an annual balance equation connecting two consecutive years (y_{start} and y_{stop}) and thus ensuring a coherent pathway:

$$F(y_{\text{stop}}, i) = F(y_{\text{start}}, i) + F_{\text{new}}(p, i) - F_{\text{old}}(p, i) - \sum_{p_2 \in \text{PHASE}} F_{\text{decom}}(p, p_2, i). \quad (1)$$

During each phase p , F_{new} represents the newly commissioned capacity decided, F_{old} is the capacity reaching end-of-life, and F_{decom} refers to prematurely decommissioned capacity. In the standard formulation, F_{new} is decided and available within the same phase—capacity is instantaneously operational—revealing the gap this study aims to fill.

Each simulation runs in 25 seconds under monthly resolution. The complete model is documented in Limpens et al. [3] and available as open-source software², with a new dedicated branch based on this study’s extension.

²https://github.com/energyscope/EnergyScope_pathway

2.2 Commissioning time implementation

The commissioning time makes newly commissioned capacity (F_{new}) dependent on decisions made in previous phases. The lag is defined by the commissioning time expressed in years (t_{com}). Technologies with instant deployment have $t_{\text{com}} = 0$. In this study, t_{com} is considered constant during a scenario but the formulation supports time-varying values. The mathematical formulation of the commissioning time is defined in Section 6.2.

The standard phase duration of EnergyScope Pathway is five years, which inherently limits the model’s ability to capture t_{com} of a shorter duration. To capture commissioning times at annual scale, the phase duration is reduced to one year as illustrated in Figure 1. The annual scale means t_{com} is rounded to the upper integer—values of 3.4 and 3.7 years both map to 4 years—making the model insensitive to sub-annual variations. Missing data for new representative years are computed by linear interpolation from the work of Limpens et al. [3].

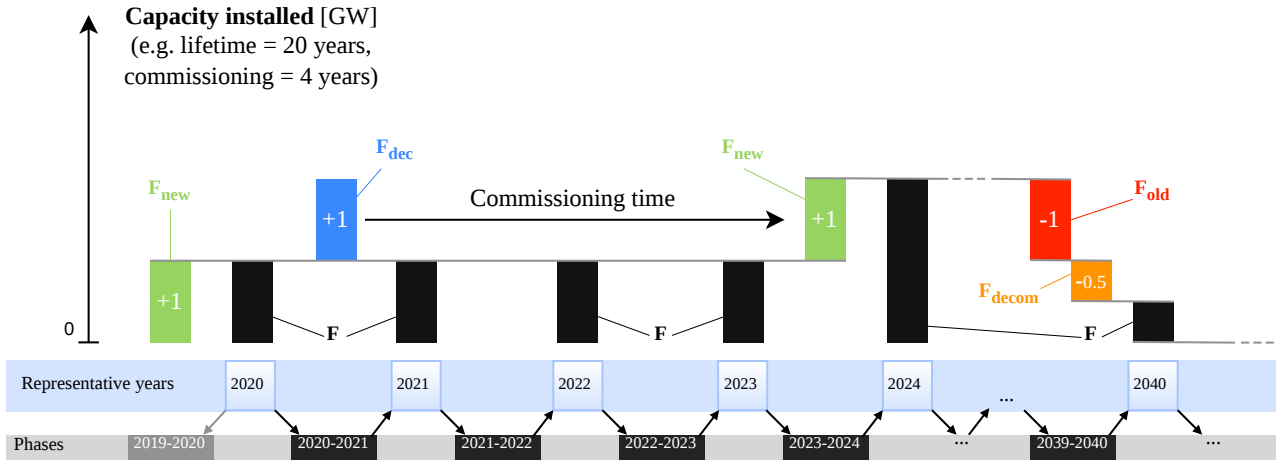


Figure 1: Illustration of the commissioning time for a technology with 20-year lifetime and 4-year commissioning time. In phase 2019–2020, 1 GW is set as EnergyScope Pathway’s initial constraint before the optimisation window begins. During phase 2020–2021, an additional 1 GW is decided, which starts the commissioning times and progresses through 4 annual stages. It becomes operational in phase 2023–2024, contributing to F_{new} and thus injected in Equation 1. The first capacity reaches its 20-year end-of-life in 2039–2040 and retires ($F_{\text{old}} = 1$ GW). Simultaneously, 0.5 GW of the second capacity is decommissioned ($F_{\text{decom}} = 0.5$ GW). Figure adapted from Limpens et al. [3].

Figure 1 illustrates the timing defined by t_{com} between a capacity decided (F_{dec}) and the operational availability (F_{new}) filling the gap with instantaneous deployment. Investment costs are adapted to be distributed across commissioning times rather than charged upfront in the standard model, better reflecting real cash flow patterns. The mathematical adaptation is defined in Section 6.3.

As the commissioning time is now implemented in EnergyScope Pathway, the next section characterises its uncertainty for each of the seven technologies considered.

2.3 Uncertainty of commissioning time

Defining t_{com} is not straightforward. As for other parameters in EnergyScope Pathway like investment cost and resource availability [8], t_{com} is inherently uncertain. The commissioning process involves multiple sequential stages—permitting, engineering studies, construction, and grid connection—and uncertainty compounds at each step. For instance, permitting for solar takes two to four years in several EU countries—double of the legal maximum—due to uncoordinated processes, slow environmental reviews, and staff shortages [9], [10]. Construction delays stem

from supply chain disruptions, labour shortages, and weather stoppages [11]. Offshore wind faces additional constraints from restricted marine work windows [12].

No single distribution perfectly captures this variability. Log-normal distributions are chosen in this study, consistent with project management literature [13], [14]. Three properties justify this choice: they enforce strict positivity ($t_{\text{com}} > 0$), they are right-skewed—one third of electricity projects reported delays in 2024 [15]—and they reflect the multiplicative nature of delays, where a permit delay extends construction, which compounds with supply chain disruptions.

The parameters (μ , σ^2) of the log-normal distribution are computed from two quantiles using the method of Cook et al. [16]. The 10th percentile (x_1) reflects favourable conditions based on recent Belgian projects and European benchmarks. The 90th percentile (x_2) captures moderate delays, deliberately excluding extreme outliers. The resulting distributions are shown in Table 1 and Figure 2. Data sources and quantile selection are discussed in Section 6.4.

Technology	x_1 [yr]	x_2 [yr]	μ [yr]	σ^2 [yr ²]
Field PV	2 [17]	5.2 [18], [19]	3.3	1.8
Onshore wind	4 [20]	9.7 [18], [19]	6.6	5.4
Offshore wind	9.5 [21]	14.5 [18]	11.8	3.8
Nuclear	10 [22]	15 [23]	12.4	3.8
SMR	5 [23], [24]	10 [24]	7.3	4.1
CCGT	4 [25]	6 [26], [27]	4.9	0.6
Geothermal	6 [28]	12 [28]	8.8	5.9

Table 1: Log-normal distributions calibrated on Belgian projects and European benchmarks.

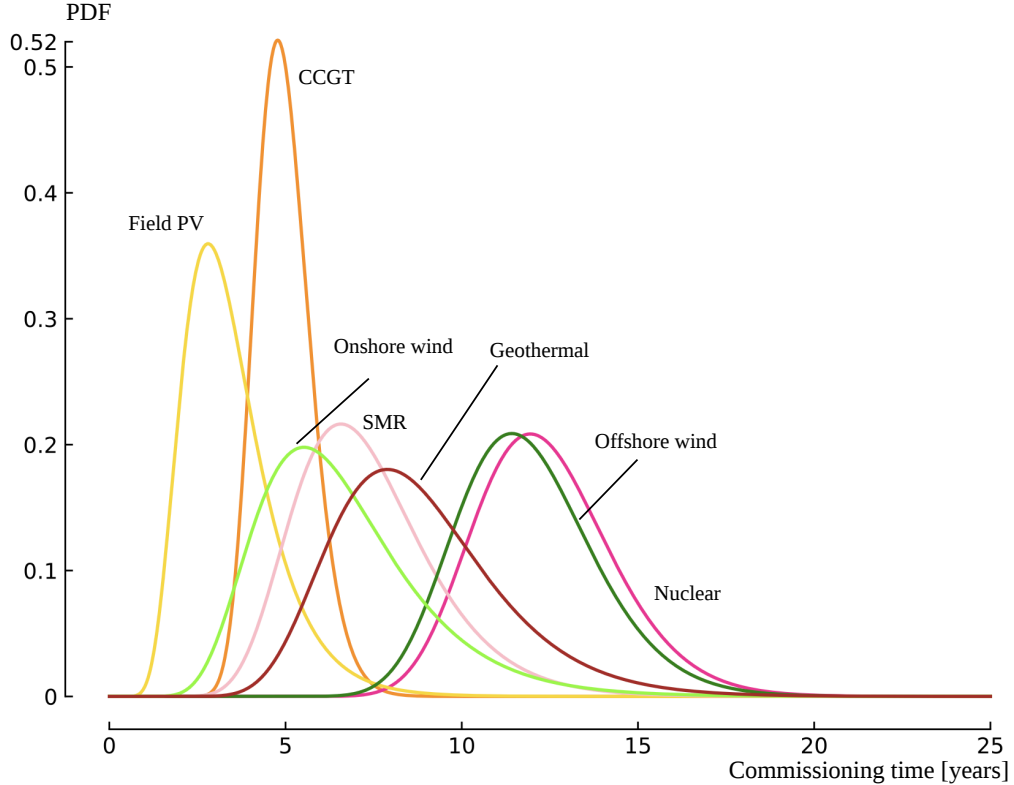


Figure 2: Probability Density Functions (PDF) of the distribution. Field PV and CCGT have the shortest commissioning times. Onshore wind, SMR, and geothermal are intermediate. Nuclear and offshore wind have the longest tails.

These distributions are illustrative—they provide a structured framework to test system robustness across plausible commissioning scenarios.

The uncertainty of commissioning time is now defined for the power sector. The next section focuses on its propagation through EnergyScope Pathway in a computationally efficient way.

2.4 Uncertainty propagation

Commissioning time uncertainties are propagated through EnergyScope Pathway by using a third-order Polynomial Chaos Expansion (PCE), following Rixhon et al. [8]. PCE is a surrogate modelling technique that approximates the input-output relationship of a computationally expensive model using polynomial expansions. A third-order PCE with seven stochastic inputs requires 240 model evaluations. Each evaluation solves the linear programme in approximately 25 seconds, giving a total computation time of 1 hour and 40 minutes. By comparison, Monte Carlo sampling requires around 1000 evaluations to ensure adequate coverage of the stochastic input space—roughly 7 hours. The surrogate achieves a leave-one-out error of 0.08, confirming its accuracy [29].

While propagating the uncertainties, commissioning times are treated as independent random variables. This simplification neglects cross-technology dependencies and autoregressive dynamics—e.g., accelerating deployment through learning or slowing through resource saturation.

PCE enables variance-based sensitivity analysis through Sobol indices, quantifying each technology’s contribution to total transition cost variance [30].

3 Results

The study transformed EnergyScope Pathway into a model that explicitly tracks commissioning timelines. Results are analysed in three steps to quantify the impact of commissioning times on Belgium’s cost-optimal energy transition to 2050.

At first, the comparison of the standard EnergyScope Pathway formulation—assuming instantaneous deployment—against a deterministic scenario using median commissioning times of the distribution—is used to isolate the structural effect of commissioning time in Section 3.1. Section 3.2 then considers commissioning times as uncertain and identifies which technologies drive transition cost uncertainty. Finally, Section 3.3 benchmarks commissioning time uncertainty against four economic parameters, situating it in the broader context of long-term energy planning uncertainties.

3.1 Deterministic scenarios

The analysis starts with a comparison of two scenarios to highlight the impact of commissioning time on the cost-optimal solution.

On one side, the No Commissioning Time scenario (NCT) assumes instantaneous commissioning time ($t_{\text{com}} = 0$) as in the standard EnergyScope Pathway formulation.

On the other side, the deterministic scenario (DET) considers the median commissioning time of the distribution, as defined in Table 2.

	Field PV	CCGT	Wind on.	SMR	Geoth.	Wind off.	Nuclear
Median [yr]	4	5	7	8	9	12	13

Table 2: Median commissioning times used in the DET scenario, rounded up to the nearest integer.

Both scenarios use the same inputs such as carbon budgets, demand projections, and constraints.

Figures 3 show the direct influence of commissioning time on the installed capacity portfolio. An important difference is nuclear: the +6 GW expansion is delayed from 2030 in NCT to 2033 in DET—a direct consequence of the 13-year commissioning from a 2020 decision. This three-year gap, visible in the delayed pink area, forces the system to find alternatives.

Onshore wind cannot fill this gap. It reaches its 20 GW maximum by 2030 in both scenarios, but in DET the first capacity becomes operational only after 7 years—creating an additional supply gap. Offshore wind faces an economic constraint. Its 12-year commissioning makes it uneconomical in DET as no new capacity beyond the initial 2.3 GW of 2020 is installed. Compared to 5.2 GW by 2035 in NCT, offshore wind area is lower.

The model responds through PV reallocation and faster deployment visible in the expanded yellow area. In NCT, the model splits 52 GW equally between field and residential PV. In DET, residential PV saturates at 52 GW while field PV declines to 8 GW—driven by instantaneous commissioning of residential installations. Total PV capacity increases by 8 GW in DET.

From 2040, geothermal is also affected. NCT deploys 3.9 GW while the DET deploys only 0.55 GW. Additionally, the 3 GW of onshore wind reaching end-of-life in 2050 is not replaced in DET.

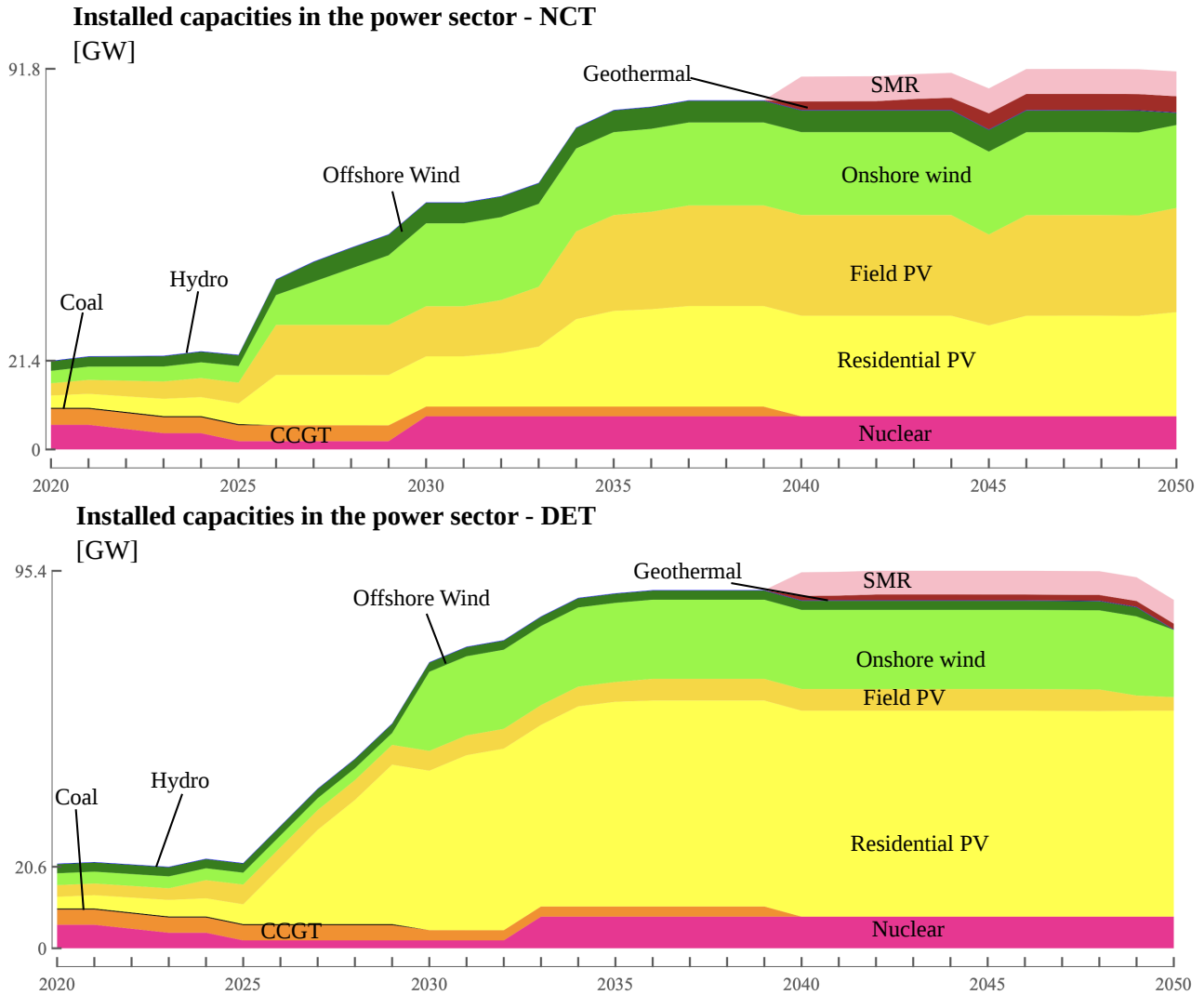


Figure 3: Installed capacities in the power sector for the NCT and DET scenario. Nuclear expansion delayed by 3 year, reallocation towards residential PV, lower geothermal and offshore wind capacity. Linear ramps limit the expansion of wind and PV capacity until 2030, no nuclear deployment before 2030, and no SMR and geothermal until 2040 as defined in Section 6.1.

These capacity differences directly shape electricity production across the transition as shown in Section 6.5. The differences are summarised in Table 3.

Period	Higher production
2020–2039	Equivalent
2030–2033	NCT
2033–2040	DET
2040–2050	NCT

Table 3: Electricity production difference between NCT and DET.

To identify the uncertainty related to the production, Figures 4 and 5 analyse the electricity production mix by resource—uranium refers to nuclear and SMR, wind to onshore and offshore, solar to field and residential, gas to CCGT and cogeneration of heat and power (CHP), and coal to ultra-supercritical plants.

During 2020–2029, the model adapts to maintain equivalent production. Nuclear decommissioning—a loss of around 30 TWh between 2021 and 2025—is offset by gas in both scenarios. Gas is systematically higher in DET, replacing also the wind production—always lower in DET due to later onshore commissioning and absent offshore deployment. From 2027, DET compensates with more PV to replace the missing offshore Wind production.

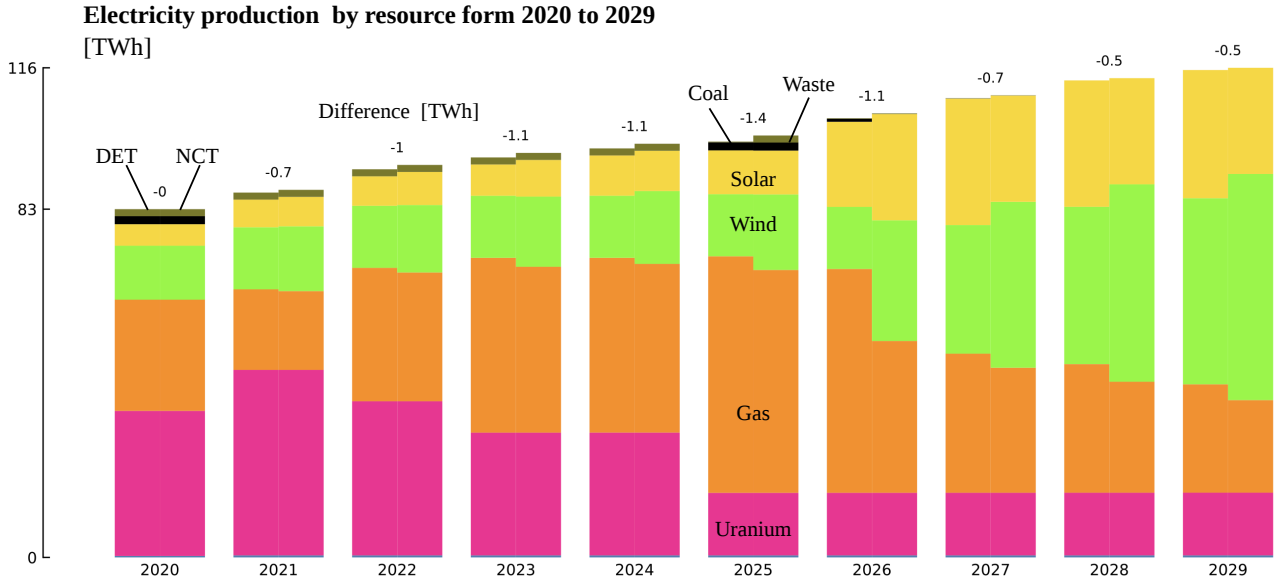


Figure 4: Gas compensates for nuclear decommissioning and late onshore wind deployment as does PV production. Maximum production difference is 1.4 TWh in 2025.

From 2030, the nuclear commissioning gap drives the divergence. NCT produces 23.3 TWh more in 2030 due to immediate nuclear availability. DET compensates partially through accelerated PV deployment and increased gas use. Once nuclear comes online in 2033, the residual PV capacity remains operational—DET produces 13.7 TWh more than NCT until 2039. After 2040, NCT recovers through higher geothermal and offshore wind, while DET continues to rely on PV. Gas maintains flexibility until 2040, more prominently in DET.

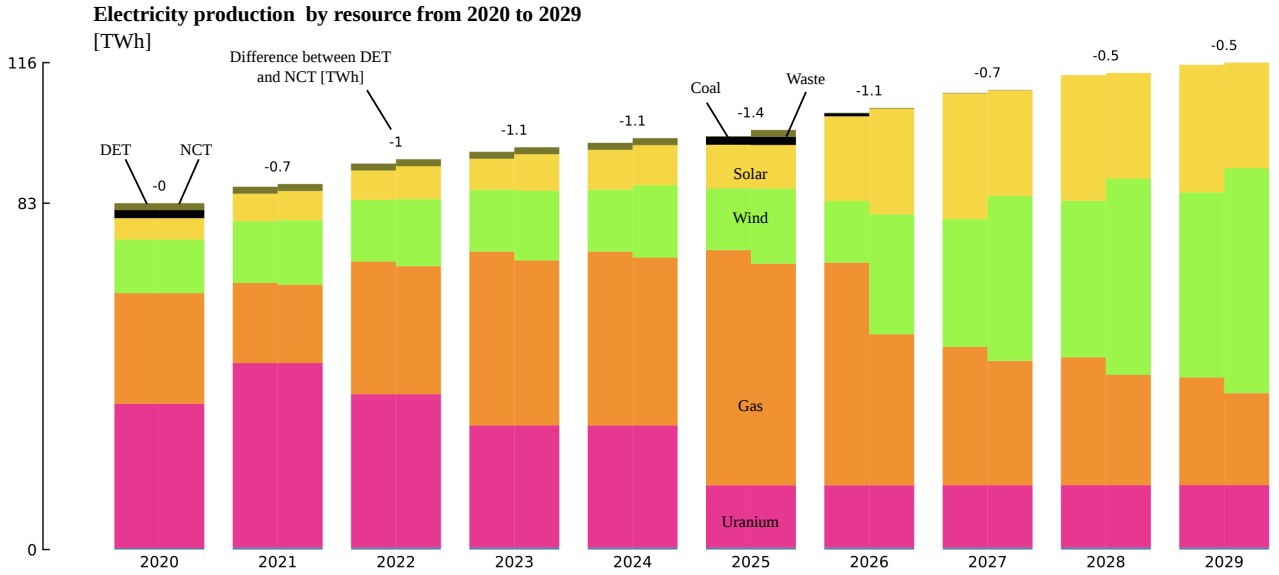


Figure 5: Nuclear commissioning gap drives production divergence from 2030. DET relies on PV and gas as backup. NCT produces more with offshore wind and geothermal after 2040.

The production variation forces the system to adapt on the consumption side. Figure 6 shows the electricity consumption difference between both scenarios.

During the nuclear gap (2030–2033), the DET scenario is forced to curtail high-temperature industrial direct electrification in Figure 6 by up to 21.6 TWh—the sector is unable to transition away from fossil fuels. Once nuclear is operational in 2033, DET accelerates electrification—up to 11.3 TWh above NCT—until 2040. This electricity surplus also triggers a slight increase in hydrogen electrolysis. From 2040, the NCT scenario achieves higher overall electricity production, enabling superior levels of both industrial electrification and hydrogen electrolysis compared to DET. By 2050, NCT consumes up to 34 TWh across these two end-uses. The marginal 0.6 TWh discrepancy between Figures 5 and 6 comes from a reduction in low-temperature heat production within the DET scenario, an effect not detailed in the plot.

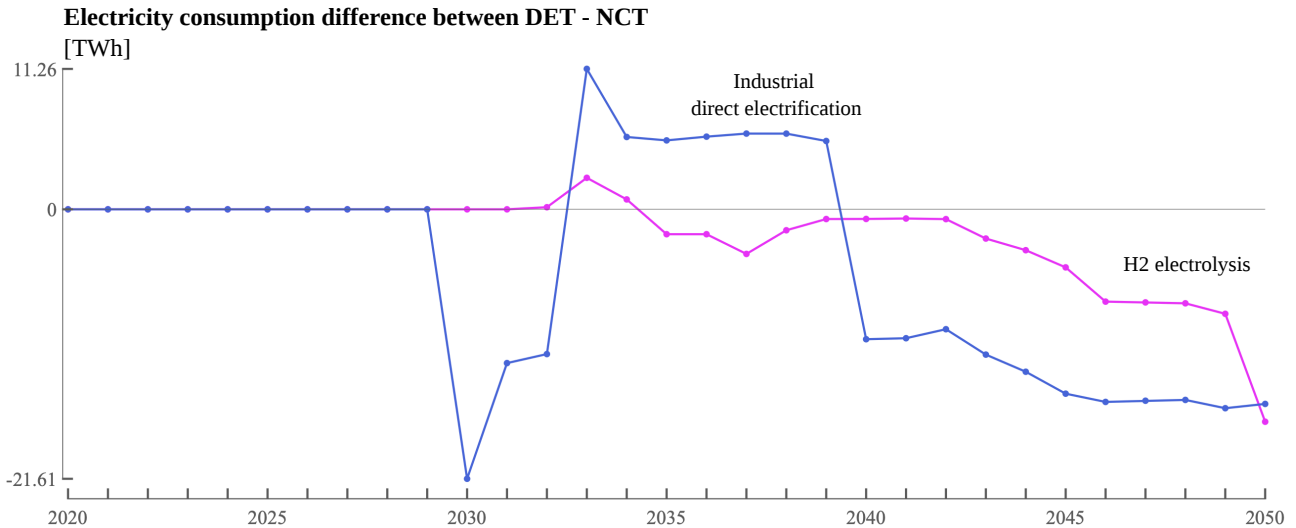


Figure 6: Positive values indicate higher consumption in DET. Negative values indicate higher consumption in NCT. This figure is relevant with the difference of production in Table 3.

The high-temperature heat sector mainly absorbs the electricity production difference as detailed in Section 6.7.

These consumption changes translate directly into costs and adaptation of production—as

the demand is the same in both scenarios. Figure 7 shows the operational cost difference between DET and NCT across the transition.

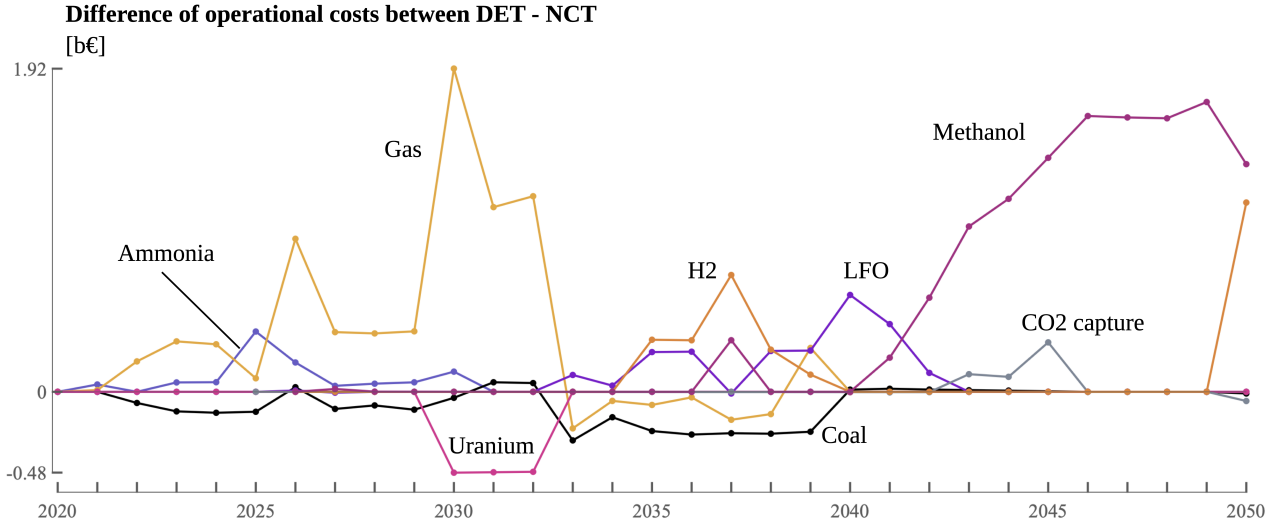


Figure 7: Gas dominates cost increases before 2033. Post-2040 costs are driven by renewable methanol imports.

Before 2033, gas drives the cost increase. CHP and CCGT compensate for delayed nuclear and wind capacity, raising gas demand. Gas emits less than coal—0.27 versus 0.4 MtCO₂/GWh—and higher gas consumption reduces coal usage, explaining the negative coal cost in Figure 7. Coal is attractive during rapid electrification periods due to its lower cost, and used in the high-temperature heat boilers, whose production is replaced by CHP and gas boilers. Once nuclear is commissioned in 2033, gas consumption drops as electrification accelerates, as shown in Figure 6.

The difference of electricity production in DET triggers a cascade of cost increases, summarised in Table 4.

Primary effect	Secondary effect	Import impact
Less Ind direct elec	More bio-gas boilers	Renewable methanol imports from 2040
Less H ₂ electrolysis	Less synthetic methanol	Renewable methanol imports from 2040
More wood for heat	Less wood for HVC	LFO imports until 2043
Less SMR ^a production	Less H ₂ supply	Ammonia until 2030 and H ₂ imports

Table 4: ^aSMR refers here for Steam Methane Reforming. Refer to Limpens et al. [3] for more detailed explanation of the process of non-energy sector.

From a total cost’s perspective, these adaptations explain the 12 b€ increase summarised in Table 5. The total cost is significantly lower than the 954 b€ reported in a previous study by Coppitters et al. [31]. This is due to the more granular decision phase—from 5 years to 1 year—enabling more continuous investments.

	NCT [b€]	DET [b€]	Variation [b€]
CAPEX	360.1	360.2	+0.1
OPEX	466	478	+12
Total transition cost	826.1	838.2	+12.1

Table 5: Total transition cost increases are driven entirely by operational costs.

As a conclusion, commissioning time in the DET scenario induces a 1.4% cost penalty and reshapes the technology mix, primarily in electricity and high-temperature heat production. However, the energy system maintains gas backup capacity throughout the transition. The analysis is based on a deterministic scenario that captures a single sample from the distribution. Since commissioning times vary widely, one scenario does not quantify the uncertainty of transition costs or identify which technologies drive cost uncertainty. Section 3.2 addresses this limitation through stochastic analysis across 240 scenarios.

3.2 Uncertainty analysis

This section identifies which commissioning times drive transition cost uncertainty and how the energy system adapts across 240 scenarios. To do so, the analysis proceeds in three steps. It first evaluates how the commissioning time affects capacity expansion, then links the decisions of expansion to electricity production to highlight model adaptation, and finally identifies the technologies driving total cost uncertainty.

Table 6 presents the range of commissioned capacity for each power sector technology.

Technology	Min [GW]	Median [GW]	Max [GW]
Nuclear	6	8	8
Onshore wind	17	17	20
SMR	6	6	6
Residential PV	53.7	54.1	54.1
Field PV	2	9.9	24.1
Geothermal	0	0.6	2.7
Offshore Wind	0	0	4.6

Table 6: CCGT (gas and ammonia), coal ultra-supercritical, and coal integrated gasification combined cycle are never deployed—systematically excluded from optimal solution.

Three deployment patterns emerge from these results. SMR, residential PV, and nuclear show near-zero uncertainty, being deployed at or near fixed capacities in all scenarios. Conversely, field PV and geothermal exhibit the highest uncertainty, with maximum capacities up to 2.5 times their median. Offshore wind represents a highly conditional case: its median deployment is zero, meaning most scenarios do not deploy more capacity. Figure 8 connects this uncertainty directly to commissioning times.

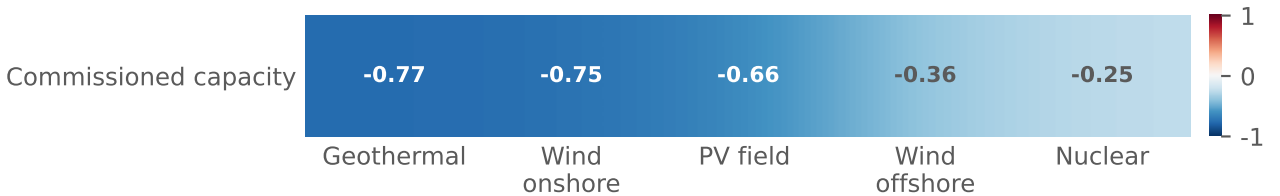


Figure 8: Negative correlation: longer commissioning times reduce commissioned capacity.

For most technologies, a longer commissioning time reduces total commissioned capacity. Geothermal, onshore wind, and field PV show the strongest negative correlations, explaining their wide capacity ranges in Table 6. In contrast, nuclear and offshore wind show lower correlations. Nuclear remains heavily deployed in all scenarios but the model does not systematically replace the initial 2 GW capacity reaching its end-of-life in 2045. Offshore wind shows low correlation because it is only deployed in the most favourable scenarios, resulting in limited capacity overall. Finally, SMR shows no correlation because its deployment is fixed to a specific target year regardless of timing variations. Figure 9 visualises the timing of decisions.

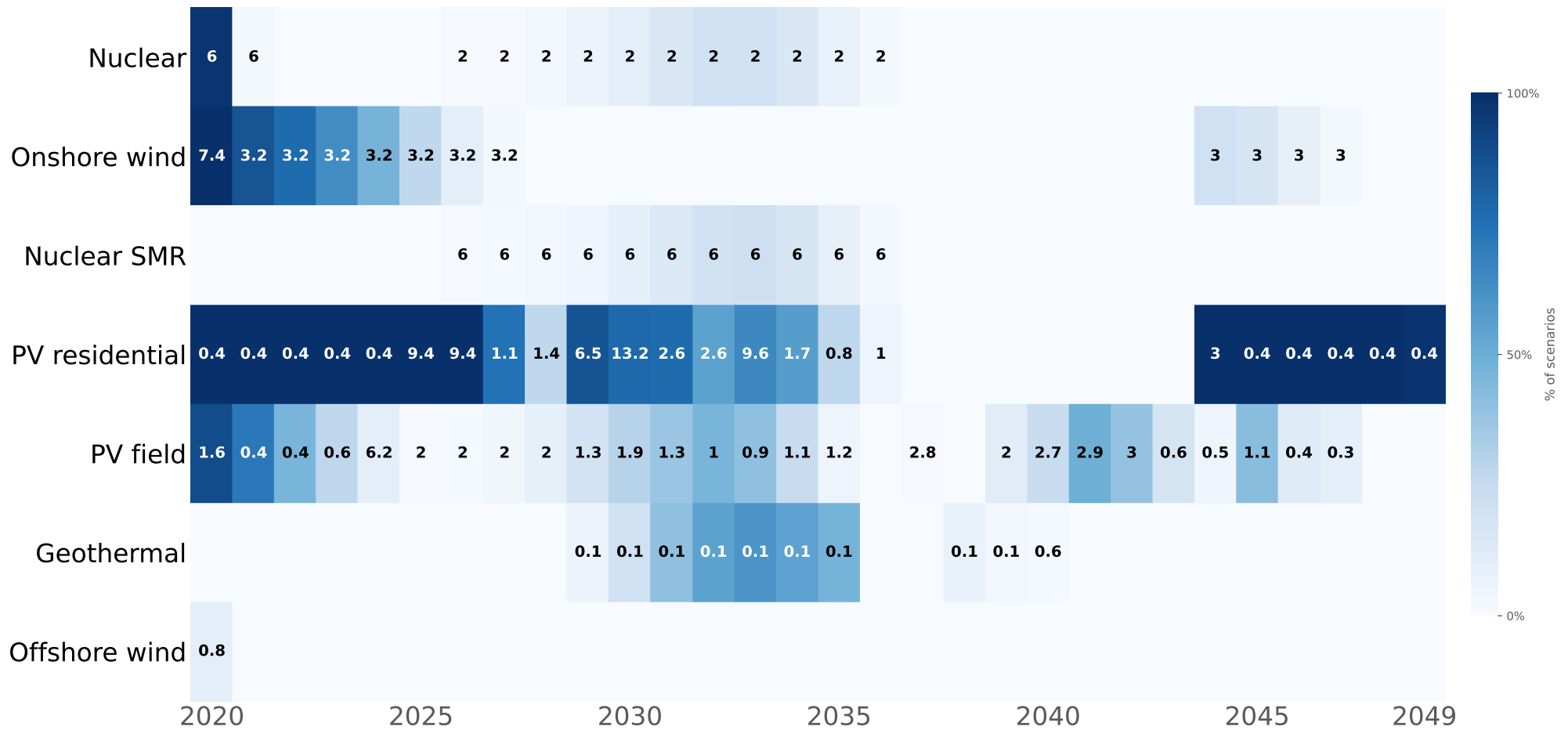


Figure 9: The heat map visualises decisions for electricity production capacity across the seven commissioned technologies from 2020 to 2049. Each row represents a technology, and each column represents a year. The colour intensity indicates the percentage of scenarios in which investments occur in that year, ranging from 0% (lightest) to 100% (darkest blue). The numbers displayed within each cell show the median commissioned capacity expressed in GW, calculated only among scenarios that make a decision in the concerned year.

The decisions timing shown in Figure 9 reveals how commissioning uncertainty dictates different deployment strategies across technologies.

Consistent with Table 6, SMR and residential PV follow deterministic paths. SMR decisions are concentrated in 2026–2036 to ensure 6 GW of operational capacity by 2040, as required by the constraints in Section 6.1. Similarly, residential PV follows a maximum deployment strategy. Decisions begin at 0.4 GW annually before jumping to 9.4 GW by 2026 respecting the linear ramp constraint. From 2027, the deployment rate is uncertain but the final target across scenario is the same: reaching 52 GW. Post-2044 decisions are when end-of-life replacements begin.

In contrast, technologies like field PV and geothermal serve as adaptive solutions. Field PV decisions span the entire transition, with total decision ranging between 2 and 24.1 GW. This uncertainty is directly tied to commissioning time—the -0.66 correlation in Figure 8 confirms that a longer commissioning time systematically penalises its deployment. Beyond 5 years, field PV is excluded from the cost-optimal portfolio. Geothermal follows a similar conditional pattern, with multiple decisions by scenario between 2029 and 2040. Its high negative correlation (-0.77) indicates it is not cost-optimal with commissioning time. Its threshold is about 12 years—in 10% of the samples—where deployment falls to zero.

The most conditional technology is offshore wind, which is only viable under highly optimistic samples. Decisions occur exclusively in 2020, and only in 10% of scenarios—a median of 0.8 GW in Figure 9 and a maximum of 4.6 GW from Table 6—with the remaining 90% receiving no investment.

Nuclear and onshore wind both follow early-phase decision patterns for the same reason. Nuclear deployment follows a two-phase pattern. The first phase is the initial 6 GW expansion, with decisions in 2020 (98% of scenarios) or 2021 (2%) to reach operational capacity by 2030—the earliest allowed by Section 6.1. The 2021 decisions occur when commissioning time is 9 years, allowing capacity to become operational exactly in 2030. Since commissioning exceeds 10 years in 90% of scenarios, commissioning systematically overlaps the 2030 target. The second phase involves replacing the 2 GW decommissioned in 2045. These decisions occur between 2026 and 2036, except when commissioning time exceeds 21 years. In those cases, no replacement occurs, explaining the negative correlation in Figure 8 and the 6 GW minimum in Table 6. Onshore wind requires a 17 GW investment between 2020 and 2026 to reach the 20 GW cap by 2030. The pattern depends strictly on commissioning time: if beyond 10 years, a single 2020 decision deploys all capacity to become available after 2030. Conversely, if shorter than 10 years, multiple decisions throughout 2020–2026 are required to respect the linear ramp constraint. A second investment of 3 GW for end-of-life replacement occurs in 2044–2047 in 40% of scenarios, specifically when commissioning time is shorter than 5 years.

These two technologies drive cost uncertainty confirmed by the Sobol index in Table 7. Any delay forces substitution towards more expensive alternatives. Technologies with lower indices have a negligible impact on cost variance for two reasons: they are either conditional investments—only deployed when commissioning time is favourable making them in competition with other adaptive solution—or fixed-target investments such as SMR.

Technology	Total-order Sobol index
Onshore wind	0.5
Nuclear	0.48

Table 7: Other technologies contribute marginally (<0.01)

To understand what makes onshore wind and nuclear influence the total cost, the analysis traces how commissioning uncertainty propagates into electricity production. Figure 10 illustrates the resulting production uncertainty across the 240 scenarios.

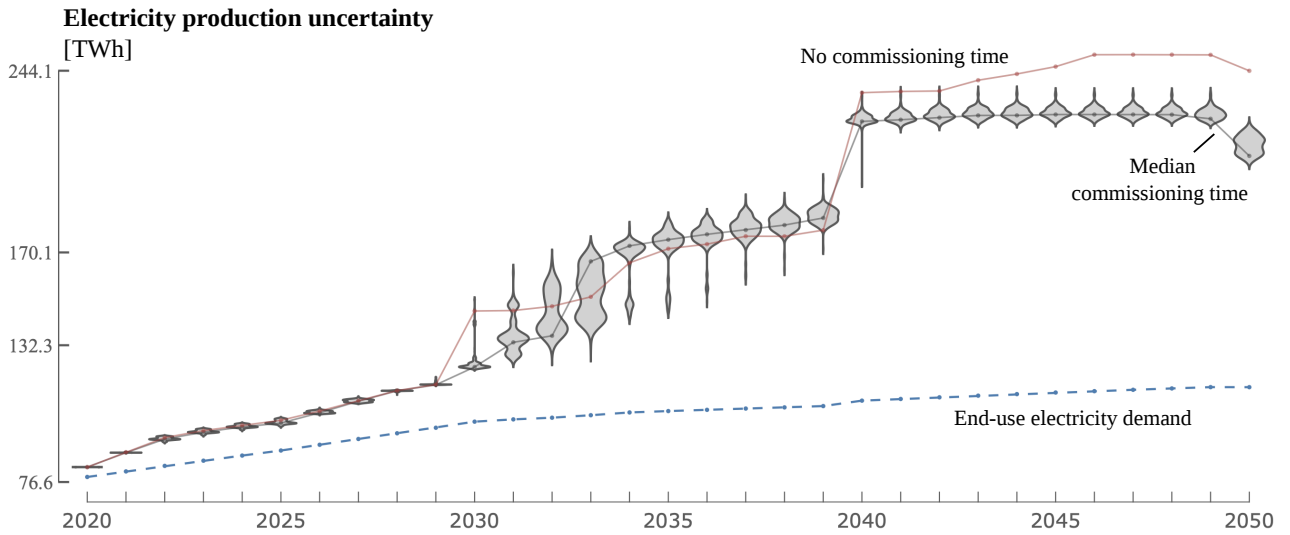


Figure 10: Production remains stable during 2020–2029, with a maximum difference of 37.8 TWh in 2032 and a post-2040 difference of 15.5 TWh.

Production is stable during 2020–2029, consistent with the deterministic analysis. The primary uncertainty window occurs between 2030 and 2040. As discussed in Section 3.1, nuclear deployment creates a production gap. The uncertainty analysis shows this gap can extend until 2040 depending on the commissioning time distribution.

To manage these uncertainties, the model adapts through systematic substitution mechanisms. Correlations detailed in Section 6.8 highlights these mechanisms across the transition for all scenarios.

- **2020–2025 – Early nuclear phase-out.**

CCGT and gas CHP cover the lost nuclear production, which in turn lowers coal and gas boiler heat production. Early onshore wind commissioning reduces the need for CHP.

- **2025–2030 – Late onshore wind.**

Gas CHP, CCGT, and both residential and field PV ramp up to replace the missing wind production. Higher gas use reduces coal consumption and accelerates the switch from digesters to bio-hydrolysis, improving the conversion rate to produce bio-gas.

- **2030–2040 – Nuclear gap.**

Before nuclear is deployed, gas CHP, PV, and CCGT provide partial backup, driving the production uncertainty in Figure 10. High-temperature electrification is scaled back, heat shifts to gas and wood, while thermal heat pumps cover low-temperature heat. Once nuclear is commissioned, the reverse pattern applies.

- **2040–2050 – Heat under constraint.**

Lower electricity availability for heat raises industrial gas-boiler use (bio-gas) with wood boilers as backup when that is not enough. The coal boiler is no longer producing. Reduced renewable methanol and hydrogen production is covered by imports.

This analysis also highlights a strong interplay between field PV and geothermal, characterised by the correlations in Section 6.9. When field PV reduces its commissioning time, the model prioritises its deployment, which subsequently reduces the required geothermal capacity. The deployment of these two technologies is therefore coupled and depends heavily on the nuclear production gap: a large gap combined with fast PV commissioning time accelerates field PV expansion, displacing geothermal, and vice versa. Furthermore, as shown by the mechanisms,

when both nuclear and onshore wind experience severe delays, the massive deployment of field PV provides sufficient electricity to ensure cost-optimality in other sectors, rendering geothermal investments unnecessary.

These mechanisms translate into cost uncertainty. The main reason investment cost increases is the greater expansion of renewable production, e.g. field PV, when onshore wind commissioning is long. Slower nuclear commissioning forces additional investment in bio-hydrolysis and bio-methanation infrastructure as the system relies more heavily on biogas. Onshore wind increases the Steam Methane Reforming investment in the last year, because not replacing the initial end-of-life capacity reduces the electricity production, as seen in 2050 of Figure 10, for the production of hydrogen. Section 6.10 provides the correlation related to the investment costs.

For the operational cost, the mechanisms converge on two replacement resources: gas and coal. Gas consumption uncertainty is directly related to nuclear operational timing, as shown in Figure 11—fast deployment reduces gas dependency earlier, slow deployment sustains it longer. Onshore wind delays amplify this effect. For instance, a commissioning time beyond 10 years creates a 45 TWh gap of lower-cost renewable production, forcing accelerated PV deployment and further coal reductions.

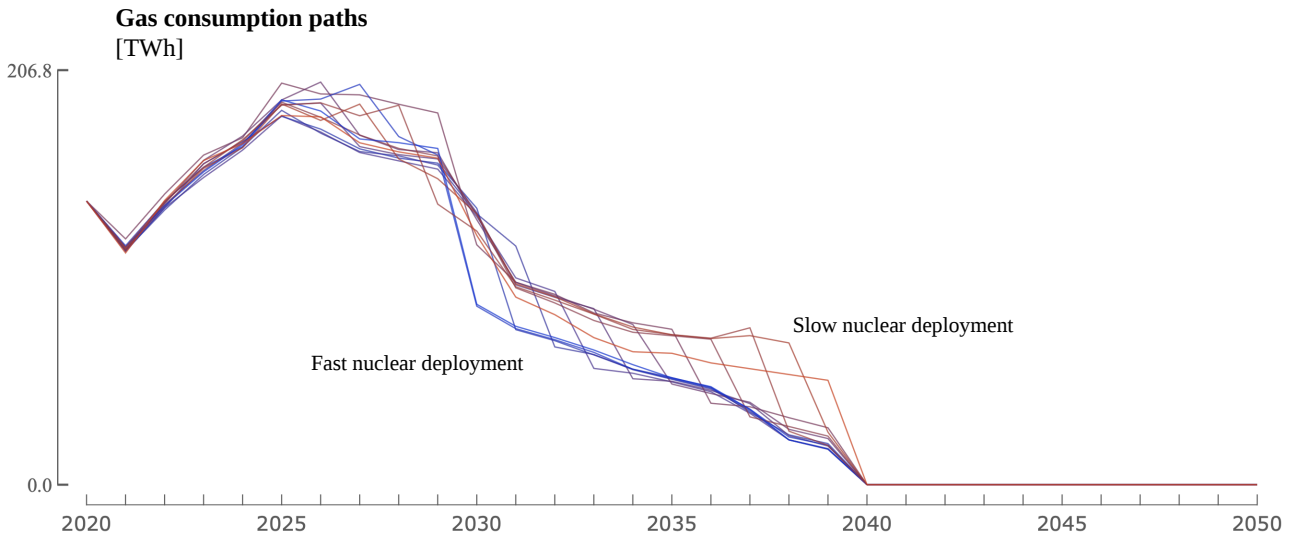


Figure 11: Increase gas consumption until 2025 due to nuclear decommissioning. Fast deployment (blue) reduces gas dependency earlier. Both converge to zero by 2040.

The coal-for-gas trade-off until 2040 is the mechanism keeping every scenario feasible. Once the model needs to increase the electricity production, it uses gas CHP. The cumulative carbon budget is fixed at 1.5 GtCO₂-eq and thus the extra gas consumption is offset by cutting coal use in high-temperature boilers—removing a less expensive high-carbon alternative. This substitution is the main reason operational costs increase alongside nuclear and onshore wind commissioning times.

This substitution translates into consumption uncertainty. Figure 12 quantifies it: gas dominates with 480 TWh, while coal moves inversely as the carbon budget trade-off plays out. The correlation in Section 6.11 confirms the higher consumption of gas, renewable methanol and hydrogen, and LFO import is due to commissioning time.

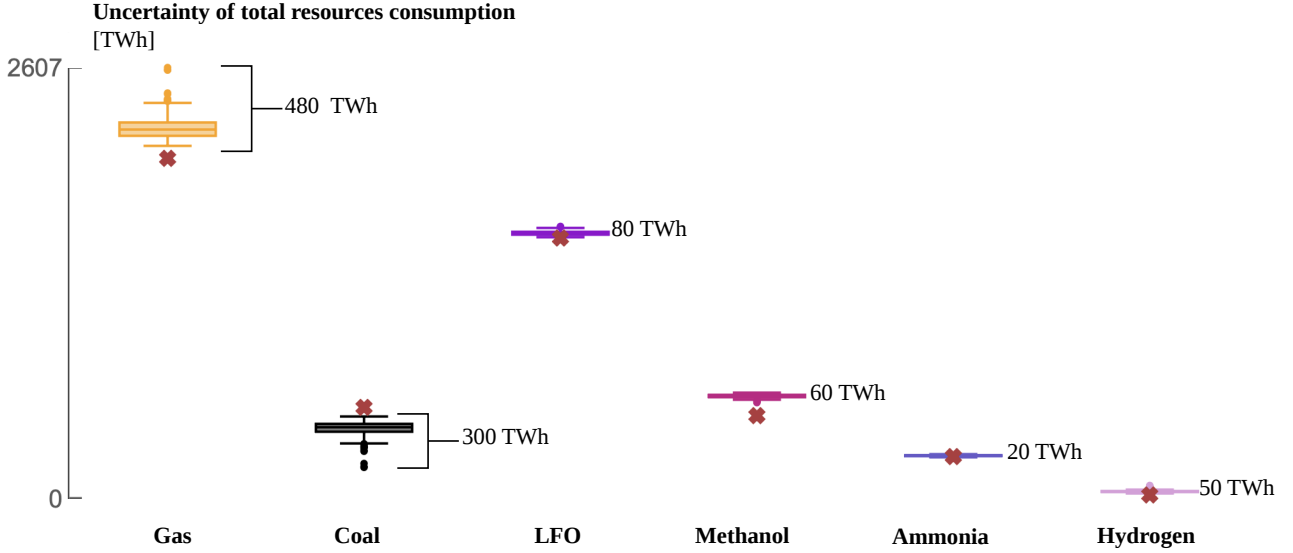


Figure 12: Gas shows the largest absolute uncertainty (480 TWh). Coal uncertainty is 300 TWh in the opposite direction—more gas means less coal. The instantaneous scenario (red cross) value shows lower import overall, with highest coal usage.

The total cost uncertainty is represented in the Table 8.

Scenario	Minimum [b€]	Median [b€]	Maximum [b€]
Total cost	831.2	838.5	856.1

Table 8: Compared to median, upward deviation (+17.6 b€) is larger than downward (-7.3 b€).

The cost uncertainty represents an asymmetric tail. Delay costs more than acceleration saves and the minimum cost scenario exceeds the NCT scenario (826.1 b€).

Nuclear and onshore wind jointly dominate this uncertainty through increased reliance on fossil fuels—mainly gas up to 480 TWh (18.4 b€). However, commissioning time is not the only source of uncertainty in long-term energy planning. Section 3.3 benchmarks its contribution against dominant economic uncertainties to situate their relative importance.

3.3 Comparison with economic uncertainties

Commissioning time is not the only source of uncertainty in EnergyScope Pathway. Its relative weight is analysed by benchmarking it against four economic cost drivers [3]: fossil-fuel (coal, gas, LFO, gasoline, diesel) and electrofuels (hydrogen, renewable methane, electro-liquid) operational costs, and fuel cell and car investment costs. Their distributions are defined in Section 6.12. A second-order PCE with 156 scenarios reaches a leave-one-out error of 0.002 and the Table 9 reports the resulting Sobol indices.

Parameter	Total-order Sobol index
Fossil fuel cost	0.94
Car investment cost	0.04
E-fuel operational cost	0.01

Table 9: Fossil fuel cost dominates cost uncertainty. All commissioning time parameters show negligible influence.

Fossil fuel costs explain 94% of the total cost uncertainty.

Scenario	Minimum [b€]	Median [b€]	Maximum [b€]
Total cost	558	764.5	941.8

Table 10: Uncertainty increases when economic uncertainties are considered as show with Table 8.

Economic uncertainties introduce an investment cost difference in the mobility sector (driven by fossil fuel cost) and a larger investment cost uncertainty in the electricity sector, as compared in Sections 6.13. When fuel becomes expensive, relying on gas is no longer cost-optimal, and the system is forced towards new solutions.

These results bring two key lessons. First, global fuel prices dictate the total cost uncertainty of the transition, not commissioning times. This is explained by the way Belgium’s energy system is built: in the early years, the country remains deeply dependent on fossil fuels. Secondly, these two sources of uncertainty are fundamentally different. Fuel prices are completely outside of Belgium’s control. Commissioning times, on the other hand, can be shortened through better governance. Crucially, the two are linked: the only way to escape the fossil fuel market is to bring clean electricity online as fast as possible. Therefore, even though commissioning delays account for less than 1% of the total cost uncertainty, managing them remains the most powerful tool the government actually controls. The next section translates these analyses into concrete guidelines.

4 Discussions

The results reveal three main technology profiles. The first category—nuclear and onshore wind—is always deployed to maximum capacity, making their commissioning times the dominant cost drivers. The second category—field PV, geothermal, and offshore wind—is conditional, with deployment occurring only under favourable timelines. The last category—SMR and residential PV—is always deployed with different timing of decision. PV’s flexible timing acts as a buffer against uncertainty.

This section translates these deployment patterns into recommendations. For each technology, the analysis connects model findings to Belgium’s current energy landscape, compares them with Elia’s 2024 Belgian Electricity System Blueprint [32], and quantifies the urgency of near-term decisions based on the commissioning time distributions of Figure 2.

4.1 Nuclear

The results confirm that nuclear capacity is economically favourable for Belgium. All 240 scenarios invest in 6 GW of new capacity, with decisions taken at the earliest possible stage to reach operational status by 2030. Any delay forces a shift towards more expensive alternatives, primarily gas.

Both this study and Elia’s 2024 blueprint conclude that nuclear extension reduces total system costs, particularly as electricity demand peaks towards 2040 [32]. However, a key difference remains: while Elia identifies a maximum of 4 GW of new nuclear capacity by 2040, this study deploys 6 GW. The 2 GW gap raises an unresolved question about Belgium’s real nuclear potential.

The model tolerates a maximum commissioning time of 21 years; beyond this threshold, nuclear deployment is no longer cost-optimal. While the latest optimal operational date is 2040 in EnergyScope Pathway, current projections suggest that no new plants will be commissioned before 2039 [33]. Table 11 quantifies the resulting pressure on decision timing based on last deployment—2040.

Decision year	Commissioning time [yr]	Success probability
2026	14	0.8
2028	12	0.5
2030	10	0.1
2032	8	0

Table 11: Probability of commissioning new nuclear by 2040 as a function of decision year, based on the distribution in Figure 2.

As quantified in Table 11, a decision in 2026 offers an 80% probability of commissioning the required capacity by 2040, whereas waiting until 2030 reduces this probability to just 10%. The decision window closes by 2032, beyond which new nuclear capacity cannot reach the cost-optimal operational date. While the 2026 state-backed proposal to purchase shares in existing assets [34] aims to secure the operations of Doel 4 and Tihange 3 until 2045, it does not address the requirement for new deployment. Consequently, the choice to invest in new nuclear installations remains an urgent near-term priority.

In contrast, policy decisions regarding the replacement of Doel 4 and Tihange 3 for the 2045 horizon are less pressing. Table 12 details the timeline for this second deployment phase.

Decision year	Commissioning time [yr]	Success probability
2026	19	1
2028	17	1
2030	15	0.9
2032	13	0.6

Table 12: Probability of commissioning new nuclear by 2045 as a function of decision year, based on the distribution in Figure 2.

For this 2045 replacement phase, the system maintains a 90% success probability even if the decision is deferred until 2030. The pressure on this second decision is therefore significantly lower, allowing policymakers a broader strategic window to evaluate long-term options, only if it is certain that these two GW will be kept until 2045.

4.2 Onshore wind

Wind reaches its 20 GW maximum in all scenarios, with decisions occurring at the earliest possible stage. As the most cost-effective renewable technology in the Belgian context, its importance is echoed by Elia’s blueprint [32]: accelerated deployment systematically reduces total system costs, while delays force a shift towards more expensive alternatives, namely field PV and gas, as highlighted in this study.

However, the gap between the current trajectory and model requirements is severe. By the end of 2025, installed capacity reached only 3.4 GW [35], and current policy targets just 5.6 GW by 2030 [32]. In contrast, this study requires 20 GW by 2030, necessitating a deployment rate of 1.7 GW/year—nearly four times the current pace of 0.44 GW/year proposed by Elia.

Table 13 quantifies the challenge of accelerating onshore wind deployment based on the commissioning time distribution.

Commissioning time [yr]	Probability
4	0.1
6	0.5
8	0.8

Table 13: Probability of achieving a given commissioning time for onshore wind, based on the distribution in Figure 2.

While reaching an 8-year commissioning time is achievable in 80% of scenarios, reducing this period below 6 years requires significant regulatory reform. Three actionable measures could bridge this gap. First, implementing a one-stop-shop permitting system would consolidate applications under a single authority; Germany utilised this approach to reduce permitting times sevenfold [36]. Second, the full digitalisation of permitting processes is essential for real-time tracking and procedural efficiency [37]. Third, limiting legal challenges to a maximum of two appeals and granting renewable projects "overriding public interest" status would drastically reduce judicial delays [38].

It should be noted that EnergyScope Pathway does not account for social resistance, grid connection bottlenecks, or workforce limitations. The required 1.7 GW/year deployment rate assumes these barriers are overcome. Consequently, policy must shift to treat onshore wind acceleration as a structural priority rather than a secondary target.

4.3 Small modular reactors

SMR capacity reaches 6 GW in 100% of scenarios, with flexible decision timing adjusted to ensure operational capacity by 2040. In optimistic scenarios, the decision can be deferred until 2036. Conversely, the earliest decisions occur in 2026, allowing for a 14-year commissioning period—a timeline consistent with the 15-year estimate proposed by Elia [32].

Belgium’s current SMR strategy aligns with these model findings. A 300 MW project is already planned for deployment by 2035 [39], supported by a dedicated regulatory framework for Generation IV technology established in 2025 [40]. Table 14 quantifies the probability of achieving the 2040 operational target based on the year the final investment decision is made.

Decision year	Commissioning time [yr]	Success probability
2026	14	1
2030	9	0.9
2034	6	0.3

Table 14: Probability of commissioning SMR by 2040 as a function of decision year, based on the distribution in Figure 2.

SMR decisions are less time-critical than those for large-scale nuclear: a decision in 2030 still offers a 90% probability of commissioning by 2040. However, the probability distribution reflects only permitting and construction uncertainties, not technology readiness or commercial scalability risks; these figures should therefore be treated as indicative rather than prescriptive—even more as SMR is an innovative technology. Currently, Belgium’s SMR strategy appears on track, provided that technology development and regulatory frameworks progress as projected [41].

4.4 Photovoltaic

Residential PV saturates at 52 GW in every scenario by 2037, regardless of other technology outcomes. It serves as the system’s primary buffer against commissioning uncertainty: when

nuclear or onshore wind face delays, residential PV compensates immediately due to its near-instantaneous commissioning time.

The required deployment rate, however, exceeds current feasibility. In 80% of scenarios, the model necessitates up to 13 GW of investment decisions in 2030 alone based on Figure 9. This target contrasts sharply with the current expansion rate of 1.2 GW/year and Elia’s maximum estimated feasible rate of 4 GW/year [32].

Real-world constraints further compound this gap. Labor shortages currently affect 75% of European energy employers [42], with Belgium specifically lacking skilled installers [43]. Additionally, supply chain disruptions continue to delay key components [44], while grid congestion increasingly limits injection capacity [45]. Finally, social acceptance remains a critical brake; for instance, historical urban landscapes show significantly lower acceptance for rooftop installations than modern structures [46].

Belgium’s recent policy shifts illustrate the risks of reducing solar support. The end of net metering in 2024–2025 and the reduction of subsidies caused residential PV uptake to fall by 60% [47], [48]. This decline directly compromises the system’s primary buffer against commissioning delays in other sectors. To ensure long-term stability, strong policy incentives must be maintained to sustain deployment rates.

Field PV serves as a conditional backup rather than a primary technology. Its total deployed capacity varies significantly, ranging from 2 to 24.1 GW across scenarios, depending strictly on the commissioning timelines of nuclear and onshore wind.

When commissioning times remain below 5 years—80% of probability—field PV serves as a complementary technology. Its main role is to strengthen the deployment of residential PV when nuclear is delayed. Beyond this window, the model actively avoids its deployment. Streamlining permitting and reducing grid connection delays for large-scale installations therefore represent direct policy levers to expand the system’s adaptive capacity.

Both this study and Elia’s blueprint converge on a key finding: total PV capacity never reaches its theoretical 104 GW maximum when nuclear is systematically commissioned [32]. This analysis identifies a requirement of 54–74 GW by 2037, whereas Belgium currently has 13 GW installed [49] and targets only 33.6 GW by 2035 [50]. This substantial gap underscores that PV deployment must be treated as a structural priority rather than a mere renewable target; it is the primary absorber of commissioning uncertainty in the energy transition based on EnergyScope Pathway.

4.5 Offshore wind

Offshore wind is the most constrained technology in this analysis. Investment occurs in only 10% of scenarios, exclusively in 2020, with a maximum capacity of 4.6 GW. Its 12-year median commissioning time makes it uncompetitive against faster alternatives in the majority of scenarios.

Belgium’s current trajectory diverges significantly from these results. The existing 2.3 GW capacity is targeted to reach 5.8 GW by 2030 and 8 GW by 2040 [51]. The model’s restricted deployment reflects a structural constraint: with decisions limited to the post-2020 period, offshore wind’s growth potential is heavily penalised by its long lead times.

The Princess Elisabeth Island project (+3.5 GW [52]) demonstrates Belgium’s commitment to this sector. However, the project is currently facing major cost overruns related to grid connection infrastructure [53], leading to revisions towards a lower-cost design. This mirrors the model’s finding: offshore wind is economically viable only under highly favourable conditions.

Assuming the 5.8 GW target remains achievable by 2030, Table 15 quantifies the urgency of the subsequent decisions required to meet the 2040 target.

Decision year	Available time [yr]	Success probability
2026	14	0.9
2028	12	0.6
2030	10	0.2
2032	8	0

Table 15: Probability of commissioning offshore wind by 2040 as a function of the decision year, based on the distribution in Figure 2.

A decision in 2026 provides a 90% probability of commissioning by 2040. Waiting until 2030 drops this to 20%, suggesting that a four-year delay nearly eliminates project feasibility. Meeting the 8 GW target for 2040 requires three immediate actions: accelerated permitting, secured grid infrastructure, and immediate investment decisions to minimise the delay.

4.6 Geothermal

Geothermal energy is deployed in 85% of scenarios but never reaches its 4 GW maximum capacity. Decisions are staggered between 2029 and 2040, with capacity ranging from 0 to 2.7 GW. Deployment falls to zero if commissioning exceeds 12 years—a 10% probability in the current distribution. Unlike SMR, geothermal is not a primary cost-optimal solution; its staggered investment pattern indicates a secondary, adaptive role. It competes directly with field PV: when PV commissioning times are short, geothermal investment systematically decreases. Table 16 quantifies the decision urgency for this technology.

Decision year	Available time [yr]	Success probability
2026	14	1
2028	12	0.9
2030	10	0.7
2032	8	0.4
2034	6	0.1

Table 16: Probability of commissioning geothermal capacity by 2040 as a function of the decision year, based on the distribution in Figure 2.

A decision in 2026 offers a 100% probability of commissioning by 2040, but waiting until 2034 reduces this to 10%. Currently, Belgium has no commercial geothermal electricity production [54], and national targets prioritise low-temperature geothermal for district heating over power generation [55]. Furthermore, Elia’s blueprint does not include geothermal as a viable electricity generation option. The model’s requirement of up to 2.7 GW by 2050 therefore represents a strategic pathway not currently prioritised in Belgian policy. Its long-term viability remains contingent on the development of Enhanced Geothermal Systems (EGS) and sustained R&D investment [56].

4.7 Combined Cycle Gas Turbines

This study and Elia’s blueprint reach opposite conclusions regarding CCGT. Elia requires 13–15 GW of thermal capacity by 2050, including 8–10 GW of new CCGT installations running on green molecules or equipped with carbon capture [32]. In contrast, this study finds no requirement for new CCGT investment in any scenario. Existing capacity operates until 2040 and is subsequently decommissioned, as the model systematically excludes new thermal gas units from the cost-optimal portfolio.

Elia’s blueprint plan is already visible in current infrastructure: the Flémalle CCGT (875 MW), commissioned by end-2025, was specifically designed to bridge the nuclear phase-out transition and provide grid stability against renewable fluctuations [57], [58].

4.8 High-temperature industrial heat

The high-temperature heat sector serves as the primary absorber of electricity production variability. When electricity is scarce, industrial electrification is scaled back, and gas or wood boilers act as necessary backups. Conversely, when electricity is abundant, direct electric heating dominates the sector.

While Belgium phased out coal for power generation in 2016, the fuel remains present in the industrial sector, representing 4.5% of total primary energy consumption in 2023 [55]. Current industrial processes still rely heavily on fossil fuels for high-temperature applications [59]. The model reflects this reality: boilers provide low-cost backup heat specifically when electricity availability is high. Within the fixed carbon budget, gas and coal act as substitutes; an increase in gas reduces coal use. Commissioning times in power generation perpetuate the gas dependency. Consequently, reducing and ultimately eliminating industrial coal use is a decision that policymakers must make.

Elia’s 2024 blueprint identifies three pathways for high-temperature heat: full electrification, distributed energy with green molecules, and a biomethane-dominated scenario [32]. Elia concludes that electrification is the most cost-effective path but requires significant technology breakthroughs by 2050. This study reaches a similar conclusion: full electrification is only selected when commissioning times are short and carbon-free electricity is abundant. When delays occur, the system compensates with wood and biogas, shifting the industrial profile towards Elia’s "distributed energy" scenario.

Ultimately, high post-2040 gas consumption drives a surge in renewable methane imports. Although Belgium’s domestic biomethane potential is estimated at 21 TWh [32], the model utilises only 1.5 TWh—just 7% of that potential. This results in a structural import dependency on international renewable fuel markets. Reducing this vulnerability requires prioritising more electricity production and accelerating industrial electrification to decouple the sector from international fuel price volatility and supply chain risks.

5 Conclusion

This study extends the EnergyScope Pathway model by adding a commissioning time that links new capacity to past investment decisions. Across seven power-sector technologies, it replaces instantaneous deployment with explicit, multi-year commissioning times. EnergyScope Pathway identifies what to build and when the decision must be taken. Three analyses quantified this effect.

First, the structural cost of commissioning time is isolated by comparing a deterministic scenario—considering median commissioning time—with the standard scenario—instantaneous deployment. The total transition raises by 12.1 b€ (+1.4%). This mainly comes from the operational cost: an increase of gas use before nuclear deployment via industrial CHP and CCGT and higher renewable-methanol imports after 2040. Delaying the 6 GW nuclear expansion from 2030 to 2033 creates a lack of electricity production mainly absorbed by the high-temperature heat sector.

The second analysis studies the effect of commissioning time uncertainty by using 240 scenarios. Nuclear and onshore wind are the two technologies with commissioning time truly impacting the transition cost. Both technologies are deployed to their maximum in every scenario. Therefore, any delay forces a shift towards more expensive alternatives. The resulting cost uncertainty is asymmetric. Delays cost more than acceleration saves. The carbon budget is

still met in every scenario through a systematic trade-off. Higher gas use is offset by lower coal use in high-temperature heat.

In the third analysis, commissioning time is put in context by benchmarking it against four economic uncertainties. Fossil-fuel prices alone account for a sensitivity of 94% on the transition cost uncertainty while commissioning times account for less than 1%. Commissioning times govern feasibility and timing rather than the magnitude of the total cost compared to economic uncertainties. Crucially, fuel prices are an exogenous risk, but commissioning times are directly controllable through permitting and regulation. This is a key policy lever.

The analysis translates into robust guidelines, grouped by type of recommendation.

- **Urgent decisions required (by 2026).**

Increase of nuclear capacity needs a decision in 2026 as it gives an 80% chance of commissioning the deployment by 2040. Waiting until 2028 drops the chance to 50%, and after 2032 it becomes impossible.

Reform of permitting is required to accelerate the onshore wind capacity deployment. Currently, an 8-year commissioning time is reached in 80% of the cases while permitting is the binding factor.

Likewise, faster permitting of field PV allows an additional renewable buffer.

Any offshore wind capacity beyond the planned 5.8 GW needs a decision in 2026 for a 90% chance of deployment by 2040. By 2030 this falls to 20%.

- **Preserve existing assets.**

It is important to keep incentives stable for residential PV. This maintains the energy system's main buffer.

- **Get prepare for future decisions.**

Nuclear replacement of Doel 4 and Tihange 3 for 2045 needs to be decided in 2030 to keep a 90% success chance. Deciding in 2032 reduces this to 60%. This is a decision with an accepted delay but only if both units are kept running until 2045.

The study confirms that more electricity means less exposure to fossil fuels and electrofuels. Accelerating renewable deployment beyond the cost-optimal level is the most effective way to reduce import reliance and thus the cost uncertainty of the Belgian energy transition. With no new nuclear expected before 2039, the electricity sector relies on gas for over a decade, increasing carbon emissions. Removing industrial coal usage becomes a strategic choice to compensate.

5.1 Limitations

Several assumptions bound these results.

EnergyScope Pathway runs under perfect foresight. It optimises with full knowledge of future demands, costs, and constraints, so the reported penalties are a lower bound: real, fragmented decision-making under uncertainty would face larger costs.

The model is solved with a monthly time resolution. This formulation captures seasonal variations in renewable production and demand but cannot represent daily fluctuations in solar and wind output, nor the short-term charge and discharge cycles of storage technologies such as batteries. As a result, the role of short-term storage may be underestimated, and the integration costs of intermittent renewables are likely understated [3].

Commissioning times are characterised by log-normal distributions that are illustrative rather than predictive. The distribution shape, the 10th–90th percentile range, and the exclusion of extreme outliers for nuclear (projects have exceeded 30 years [22]) all shape the stochastic results. The distributions are static: they ignore learning effects that could shorten commissioning

times and saturation effects that could lengthen them. Commissioning times are treated as independent random variables. This neglects correlated delays. The annual resolution also rounds each commissioning time up to the nearest year, masking sub-annual differences.

Only seven power-sector technologies were assigned commissioning time. Grid reinforcement, storage, heat, mobility, and industrial retrofits are still assumed to deploy instantly.

Finally, EnergyScope Pathway does not represent social acceptance, grid-connection bottlenecks, workforce limits, or financing constraints. The deployment rates identified here assume these constraints are overcome.

5.2 Future work

Future work should relax the independence and static assumptions by modelling correlated and time-varying commissioning times, including learning-by-doing. Extending the commissioning time to grid, storage, and demand-side technologies would capture system-wide bottlenecks rather than power-supply timing alone. Coupling the perfect-foresight results with a myopic formulation would test how far the decision windows identified here hold under uncertainty.

Finally, extending the modelling horizon beyond 2050 would reveal whether the portfolio represents a stable long-term endpoint or merely a transitional configuration that could constrain subsequent decades. Such an extension would further quantify the urgency of strategic decisions that must account for the infrastructure requirements beyond 2050.

6 Appendices

6.1 Constraints on electricity generation production expansion

Technology	2020 [GW]	Max [GW]	Year
field PV	2.95	52.05	2030
Residential PV	2.95	52.05	2030
Onshore Wind	3.0	20	2030
Offshore Wind	2.31	8	2030
Nuclear	5.94	8	2030
SMR	0	6	2040
CCGT	3.86	None	-
Geothermal	0	4	2040

Table 17: Technology capacity constraints from Coppitters et al. [31]. Linear ramps constrain wind and PV expansion until 2030.

Wind and PV expansion is limited by a linear ramp until 2030. No ramp applies to geothermal, SMR, or nuclear. Without these constraints, the model could select extreme deployment rates, particularly in early transition years, limiting the analysis of the study. Belgium’s nuclear fleet is partially decommissioned by government decision [60]: capacity declines from 5.95 GW in 2020 to 3.93 GW in 2023, and to 2 GW in 2025, retaining only Doel 4 and Tihange 3. Commissioned in 1985 and assuming a 60-year lifetime, both units reach end-of-life by 2045 in EnergyScope Pathway.

6.2 Commissioning time implementation in EnergyScope Pathway

A new variable $F_{\text{com}}[p, p_{\text{dec}}, i, k]$ is introduced to track new projects through each commissioning stage k . The indices represent: p (current phase), p_{dec} (decision phase), and i (technology).

All notations used in this section are related to the work of Limpens et al. [3].

To represent the commissioning time related to each technology, the input model is t_{com} expressed in years. Since the model operates with annual phases, t_{com} is converted to a number of commissioning phases through a ceiling function:

$$\text{phase}_{\text{com}}[y, i] = \max \left(1, \left\lceil \frac{t_{\text{com}}[y, i] + t_{\text{start}}}{t_{\text{phase}}} \right\rceil \right), \quad \forall y \in \text{YEARS}, i \in \text{TECH}. \quad (2)$$

The parameter t_{start} represents commissioning progress possible within the decision phase of duration t_{phase} . This study assumes $t_{\text{start}} = 0$: projects with $t_{\text{com}} < t_{\text{phase}}$ year become instantaneously operational.

Consider a technology decided in 2020-2021 with a commissioning time of 3.7 years. The model converts this year value into number of phases: $\text{phase}_{\text{com}} = \max(1, \lceil 3.7/1 \rceil) = 4$ phases. The project progresses through these four annual stages and becomes operational in 2024. For technologies with instant deployment ($t_{\text{com}} = 0$), the formula yields one phase, making capacity available the following year.

This discrete representation introduces a limitation. A project requiring 2.3 years and another requiring 2.8 years both round to 3 years. The model treats them identically, even though one is actually five months faster. The one-year phase resolution cannot capture sub-annual timing differences.

Projects flow through F_{com} following progression rules. New capacity invested in decision phase p_{dec} enters at stage 1. Each year, projects advance one stage forward, moving through

stage 2, then 3, continuing until they reach $\text{phase}_{\text{com}}$ and become operational. Projects can be partially or fully cancelled at any stage—perhaps due to funding changes or revised priorities. The progression equation for intermediate stages $k = 2, 3, \dots, \text{phase}_{\text{com}}$ captures this movement and defined as

$$F_{\text{com}}[p, p_{\text{dec}}, i, k] = F_{\text{com}}[\text{prev}(p), p_{\text{dec}}, i, k - 1] - F_{\text{cancel}}[p, p_{\text{dec}}, i, k] \quad (3)$$

where $\text{prev}(p)$ denotes the previous phase and F_{cancel} represents capacity abandoned before completion.

When stage k reaches $\text{phase}_{\text{com}}$, the project becomes operational and contributes to F_{new} . This captures the moment construction ends and production begins. The transition sums all projects reaching their final stage in phase p :

$$F_{\text{new}}[p, i] = \sum_{\substack{p_{\text{initial}} \in \text{PHASE} \\ y_{\text{start}} \in \text{PHASE_START}[p_{\text{initial}}]}} F_{\text{com}}[p, p_{\text{initial}}, i, \text{phase}_{\text{com}}[y_{\text{start}}, i]]. \quad (4)$$

Several boundary constraints ensure F_{com} consistency:

$$F_{\text{com}}[p, p_{\text{dec}}, i, k] = 0, \quad \text{for} \quad \begin{cases} \text{ord}(p) = 1, k \geq 2 & \text{(initial condition)} \\ \text{ord}(p) < \text{ord}(p_{\text{dec}}) & \text{(pre-decision)} \\ \text{ord}(p) > \text{ord}(p_{\text{dec}}) + \text{phase}_{\text{com}} - 1 & \text{(post-completion)} \end{cases} \quad (5)$$

where $\text{ord}(p)$ returns the phase index in the optimisation sequence.

The model starts in 2020 with no project decided. All existing capacity is treated as operational initial state rather than projects mid-construction. This simplification primarily affects early-year results where real projects were already under construction.

Parameter	Unit	Description
$t_{\text{com}}[\text{year}, \text{tech}]$	years	Commissioning time
$\text{phase}_{\text{com}}[\text{year}, \text{tech}]$	phases	Commissioning time in annual stages
t_{start}	years	Commissioning progress within decision phase
Variable	Unit	Description
$F_{\text{com}}[p, p_{\text{dec}}, i, k]$	GW ^a	Capacity at stage k , decided in p_{dec} , currently in p
$F_{\text{cancel}}[p, p_{\text{dec}}, i, k]$	GW	Capacity cancelled at stage k

Table 18: New parameters and variables. ^a[MpkM] for passenger, [MtkM] for freight mobility, [GWh] for storage technologies.

6.3 Adaptation of investment cost with the commissioning time

The fraction $1/\text{phase}_{\text{com}}$ divides total investment cost equally across commissioning stages. A project with $\text{phase}_{\text{com}} = 4$ pays 25% each year over four years. A fast-track project with $\text{phase}_{\text{com}} = 1$ pays everything upfront in the decision year, reverting to standard model behaviour. The cost averaging between $c_{\text{inv}}[y_{\text{start}}]$ and $c_{\text{inv}}[y_{\text{stop}}]$ follows the same logic as the standard model—accounting for cost changes over the phase duration. Refer to Limpens et al. [3] for details on the parameter of the equation:

$$C_{\text{inv,phase}}[p] = \sum_{p_{\text{initial}}, i, k} F_{\text{com}}[p, p_{\text{initial}}, i, k] \times \frac{c_{\text{inv}}[y_{\text{start}}, i] + c_{\text{inv}}[y_{\text{stop}}, i]}{2} \times \frac{1}{\text{phase}_{\text{com}}[y_{\text{initial}}, i]} \times \tau_{\text{phase}}[p]. \quad (6)$$

6.4 Creation of commissioning time distributions

The lower quantile x_1 represents favourable but realistic conditions. Where Belgian data exist, they are used directly. Where they do not, European benchmarks are used instead. $p_1 = 10\%$ is set to avoid infeasibly short durations while still capturing optimistic scenarios.

For field PV, the Kristal Solar Park serves as reference—a 97 MW_p installation and the largest solar field in the Benelux, commissioned within 2 years [17]. For onshore wind, Engie reports 3–4 years from initial planning to operational handover [20]—4 years is selected to avoid an overly optimistic lower bound. For offshore wind, a European benchmark is used: the Netherlands provides the closest benchmark: its streamlined regulatory approach combines construction and exploration permits, achieving 4.5 years permitting and a mandated 5-year construction window [21]. For nuclear, Belgium has not built new capacity in decades, so international data is used, suggesting approximately 10 years under favourable conditions for modern reactor designs [22]. SMR is an emerging technology with limited deployment history; a Nth-of-a-Kind assumption is adopted—3 years construction and 2 years permitting—based on manufacturer projections and regulatory analyses [23], [24]. CCGT benefits from mature technology status; Belgium’s recent Flémalle plant provides a 4-year reference [25]. For geothermal, the Balmatt-site Mol project achieved 4-year construction [28]; assuming regulatory streamlining, permitting is estimated at 2 years, giving $x_1 = 6$ years.

Table 19: Quantiles used to fit log-normal distributions, calculated using the method of Cook et al. [16].

Technology	x_1 [yr]	x_2 [yr]
field PV	2	5.2
Onshore Wind	4	9.7
Offshore Wind	9.5	14.5
Nuclear	10	15
SMR	5	10
CCGT	4	6
Geothermal	6	12

The upper quantile x_2 represents the 90th percentile—moderate delays, deliberately excluding extreme outliers that would distort the distribution. For field PV, Gumber et al. [18] report a 75th percentile construction time of 3.2 years across European projects; combined with the EU directive capping permitting at 2 years [19], this gives $x_2 = 5.2$ years. Onshore wind follows the same approach, combining a 7.9-year construction time [18] with the 2-year permitting directive. Offshore wind extends construction to 10 years based on the C-Power project [61], combined with the 4.5-year Dutch permitting benchmark. Nuclear relies on international benchmarks suggesting 15-year timelines [23]. SMR uses a First-of-a-Kind estimate of 10 years [24]. For CCGT, two Belgian projects are combined: the Seraing plant’s 3-year construction [26] and the Vilvorde project’s 3-year permitting [27]. For geothermal, the Balmatt-site Mol project required 4 years of active construction and 8 years of permitting and delays [28], giving $x_2 = 12$ years.

6.5 Electricity production in DET and NCT scenarios

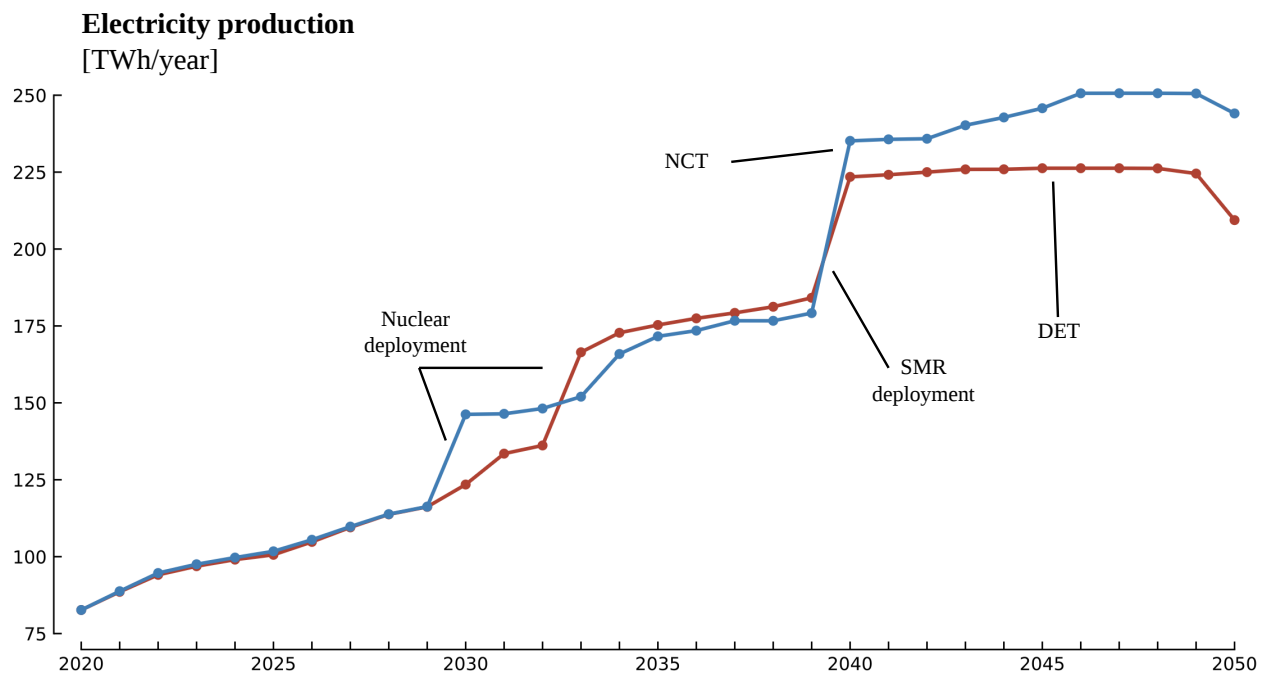


Figure 13: Capacity differences drive distinct electricity production trajectories across three phases. In 2020-2030, both scenarios converge. In 2030-2040, delayed nuclear availability in DET creates a lack of production. DET produces more electricity than NCT once nuclear is commissioned. In 2040-2050, DET produces less electricity.

6.6 Electricity layer balance in DET and NCT scenarios

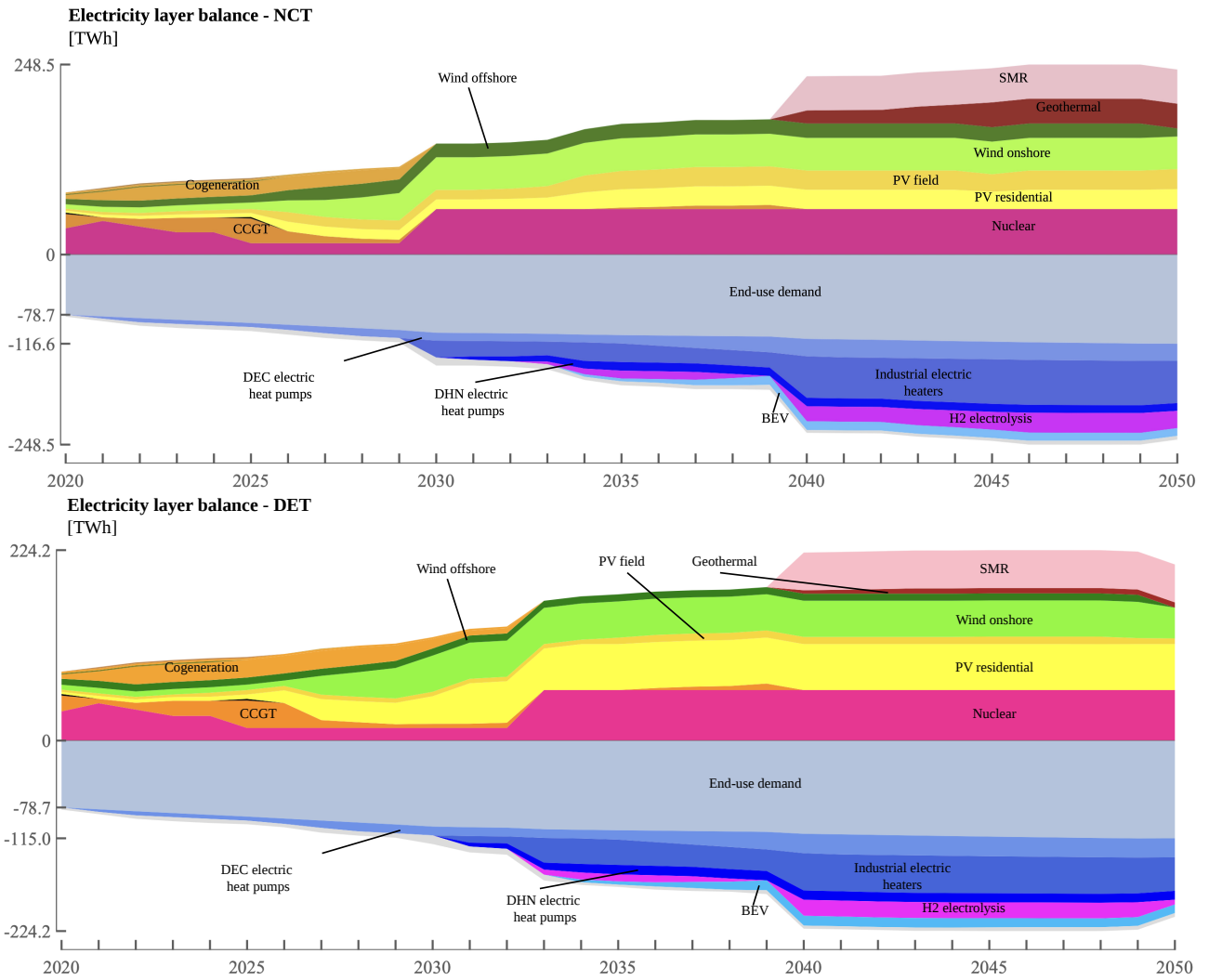


Figure 14: Positive areas show generation, negative areas show consumption by conversion technologies. CHP ends earlier upon nuclear commissioning, accelerating industrial electric boiler deployment. Geothermal and offshore wind contribute more in NCT than in DET.

6.7 High-temperature heat layer in NCT and DET scenarios

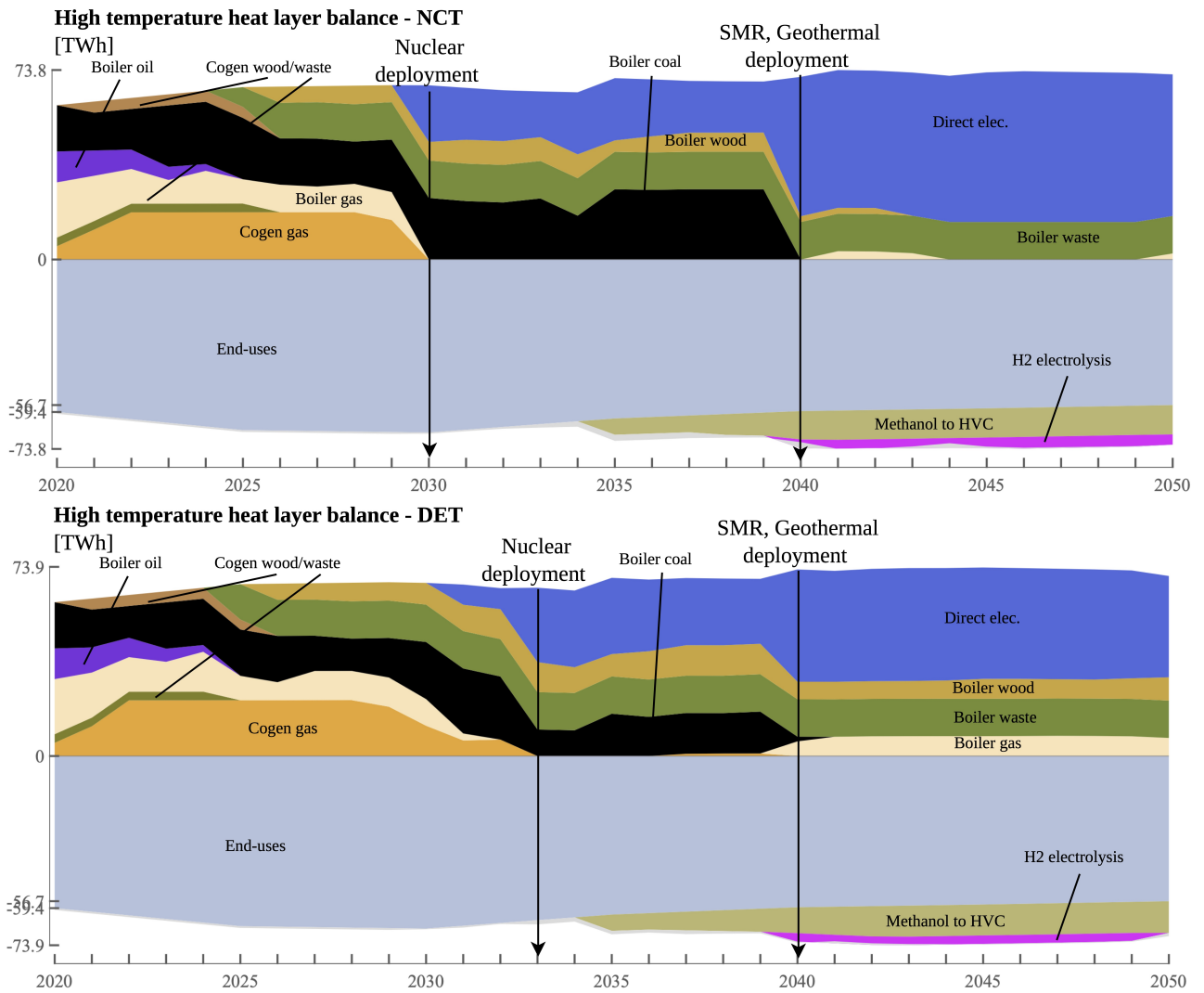


Figure 15: Positive areas show generation, negative areas show consumption by conversion technologies. Both scenarios rely on coal utilisation until 2040, more in NCT. Once nuclear is commissioned, gas usage declines and electrification is accelerated in DET. After 2040, lower electricity in DET forces continued reliance on gas and wood—both almost phased out in NCT.

6.8 Adaptation with commissioning time uncertainty

6.8.1 Electricity production

Figure 16 correlates the total electricity production by scenario to the commissioning time.

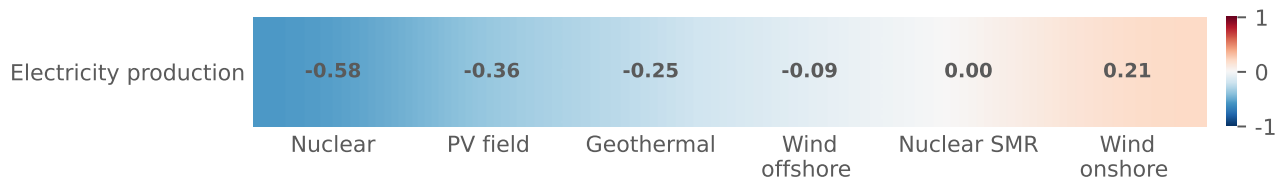


Figure 16: Longer nuclear commissioning reduces total electricity production per scenario. Conversely, longer onshore wind commissioning increases total production.

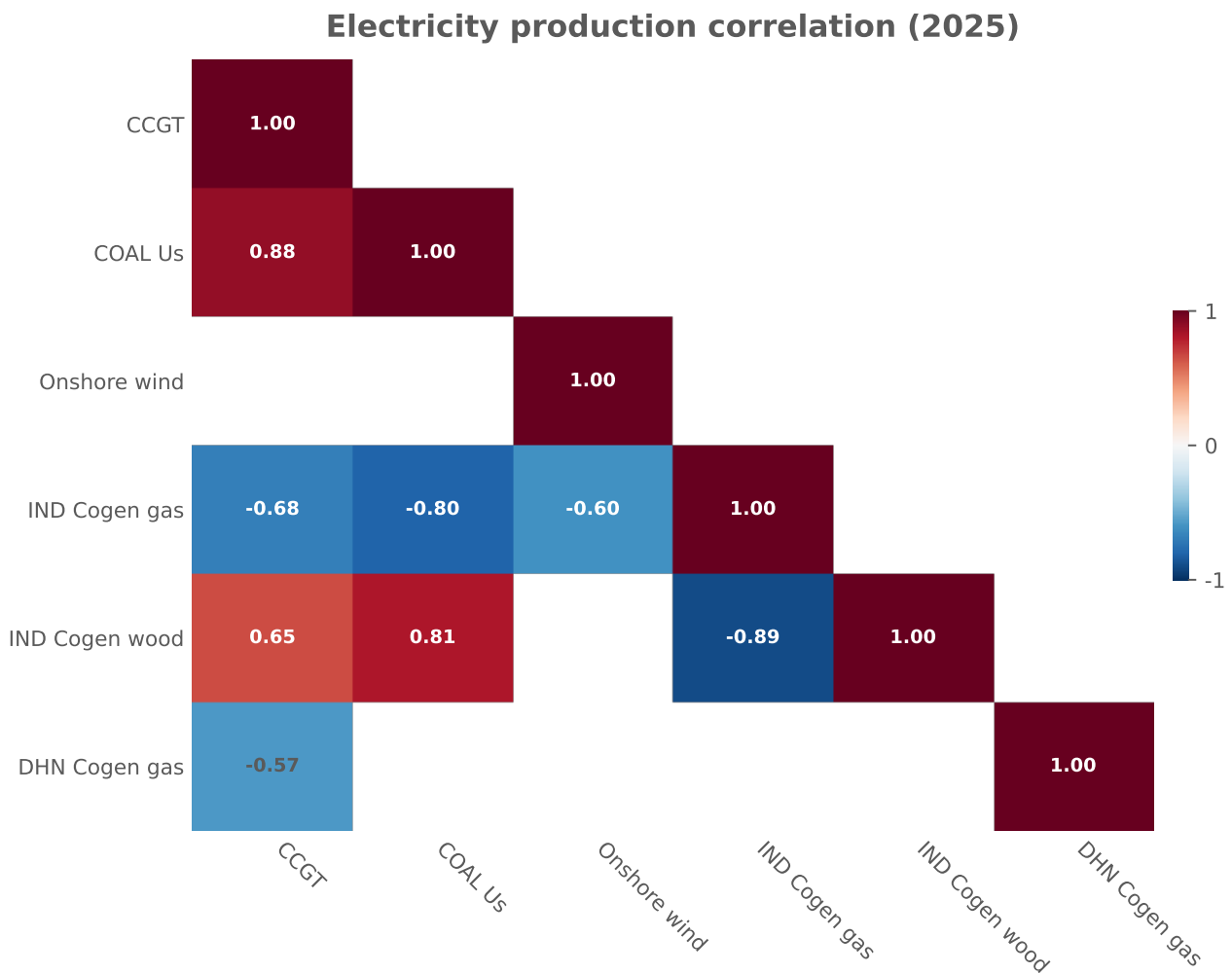


Figure 17: CCGT and coal co-vary strongly and exhibit opposite relationships with CHP: negative with gas and positive with wood. The strongest pattern is the substitution between gas and wood CHP. Onshore wind reduces gas CHP. Correlations below $|0.5|$ are masked.

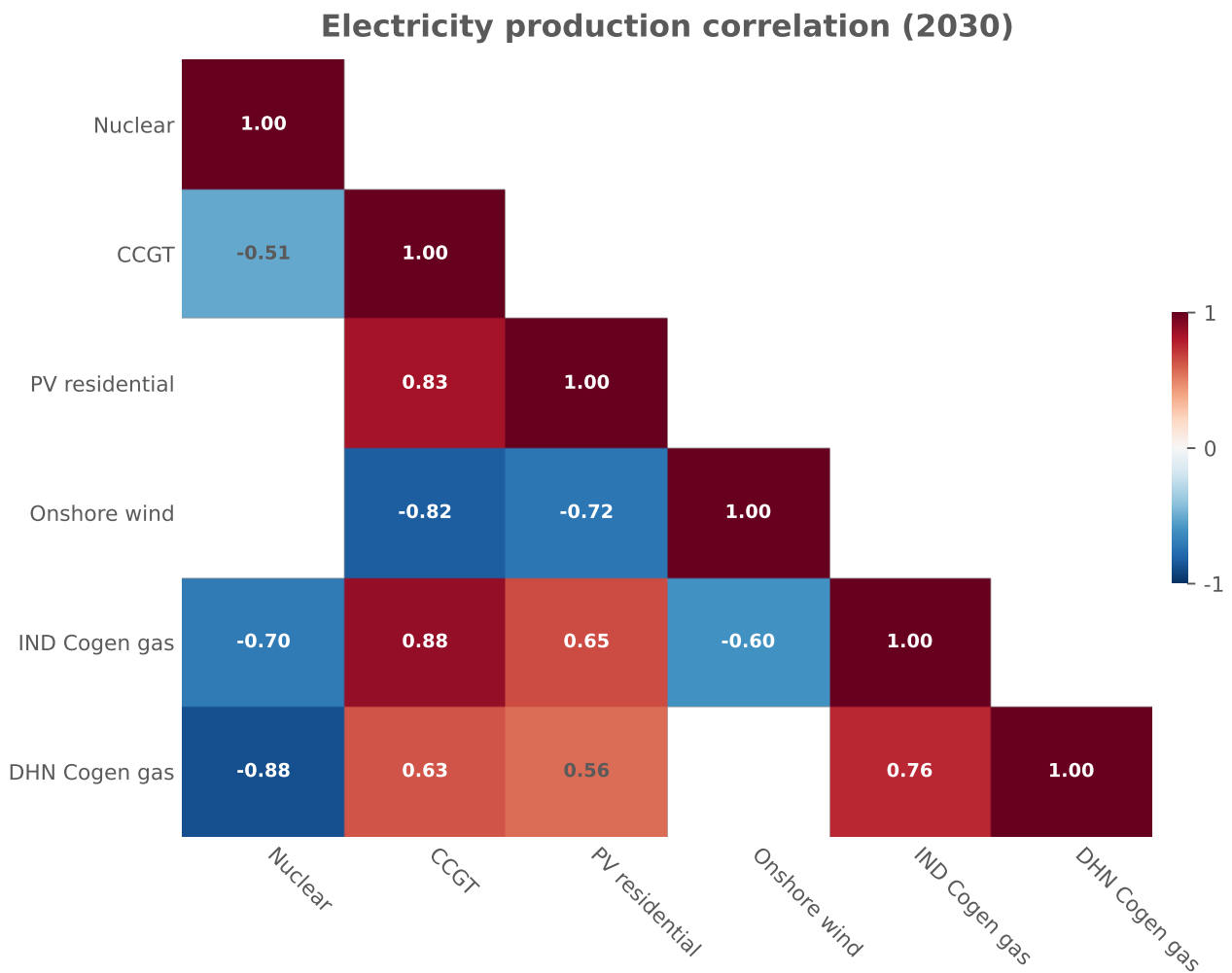


Figure 18: Nuclear production is strongly anti-correlated with CHP, onshore wind. CCGT scales with gas CHP and residential PV. Onshore wind strongly displaces both CCGT and gas CHP and residential PV. Correlations below $|0.5|$ are masked.

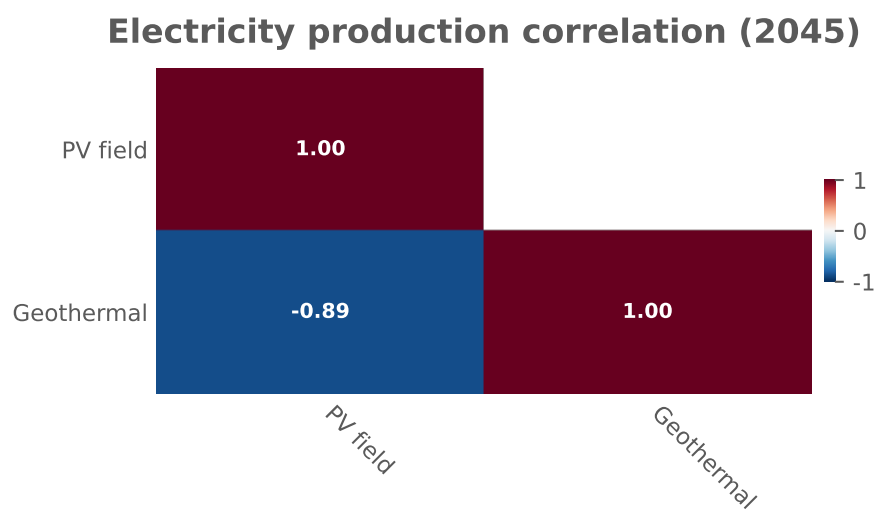


Figure 19: Geothermal production reduced field PV production.

6.8.2 High-temperature heat production

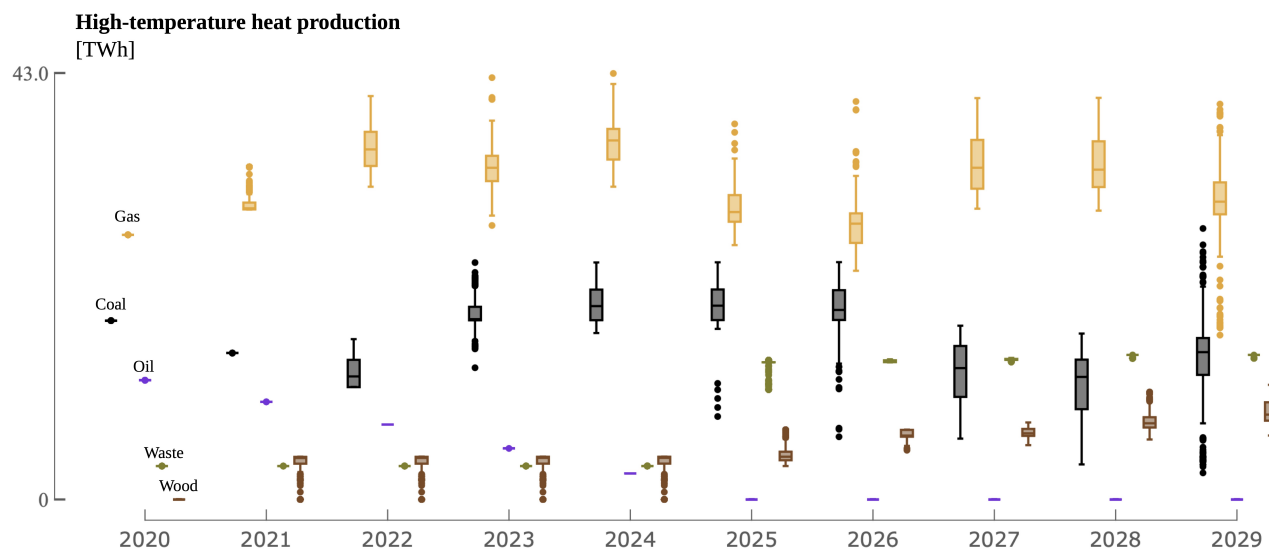


Figure 20: First electrification in 2029 in case of high electricity production.

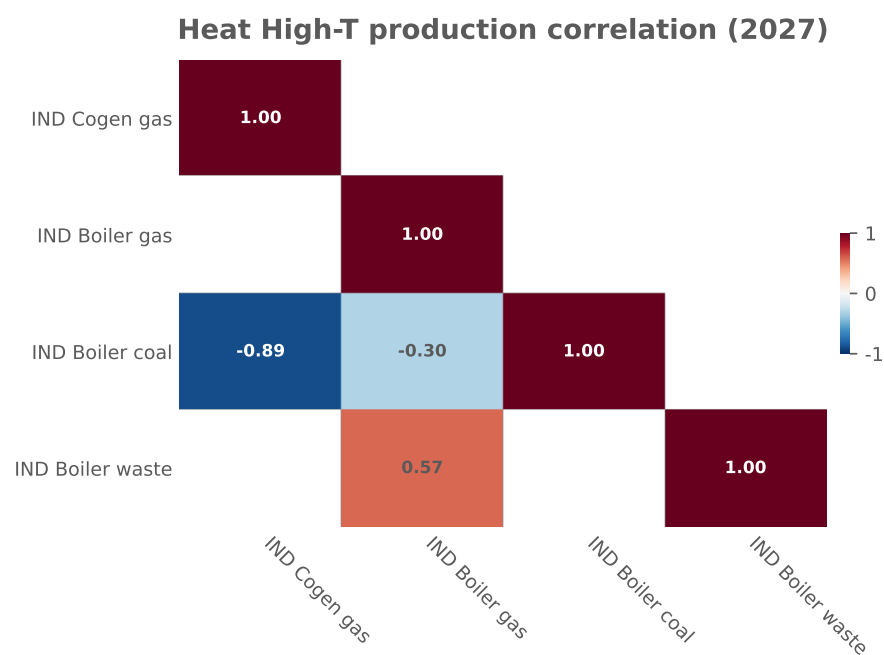


Figure 21: Gas CHP and boiler dominate production with a negative correlation. Gas CHP and gas boiler show negative correlations with coal boilers. Correlations with absolute values below 0.3 are masked in the matrix.

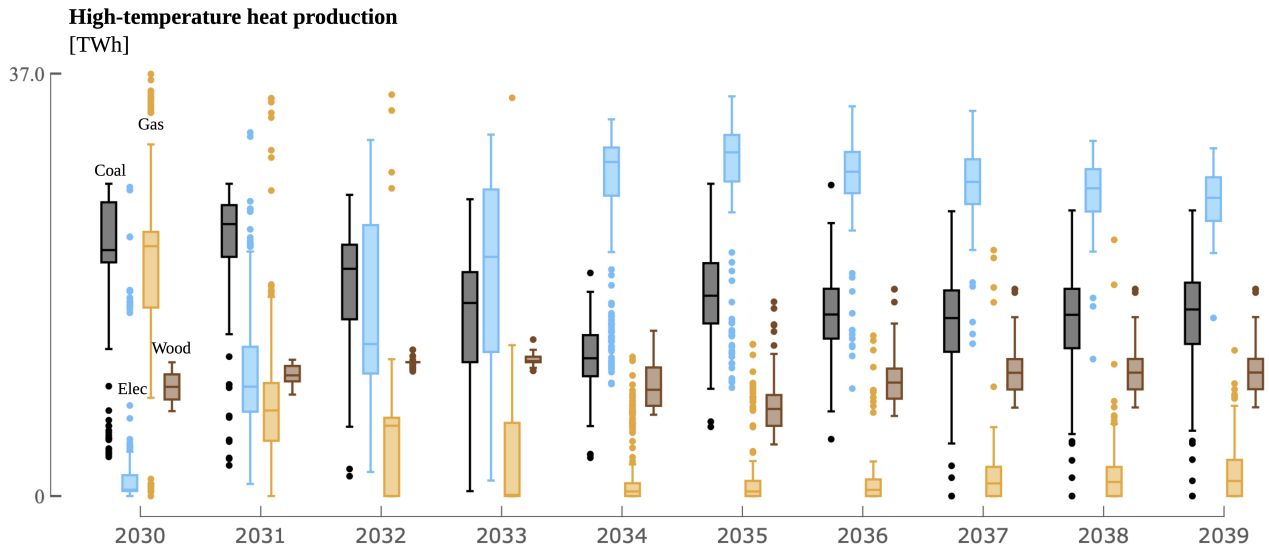


Figure 22: Waste is used at a constant level of 14 TWh and oil has a constant nul production.

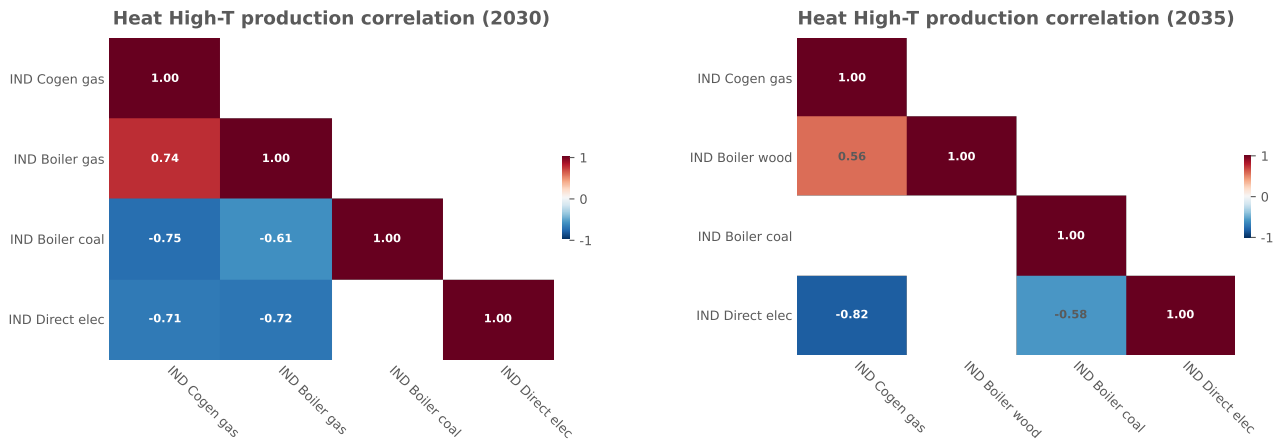


Figure 23: Electric heating emerges as a new contributor with growing production. Gas technologies (CHP and boilers) form a unified bloc with strong positive correlation. This gas bloc shows positive correlation with wood boilers. Electric heating shows negative correlations with gas. Coal boilers are strongly negative correlated with gas-wood, reflecting reduction of coal while electricity production is reduced. Correlations with absolute values below 0.3 are masked in the matrix.

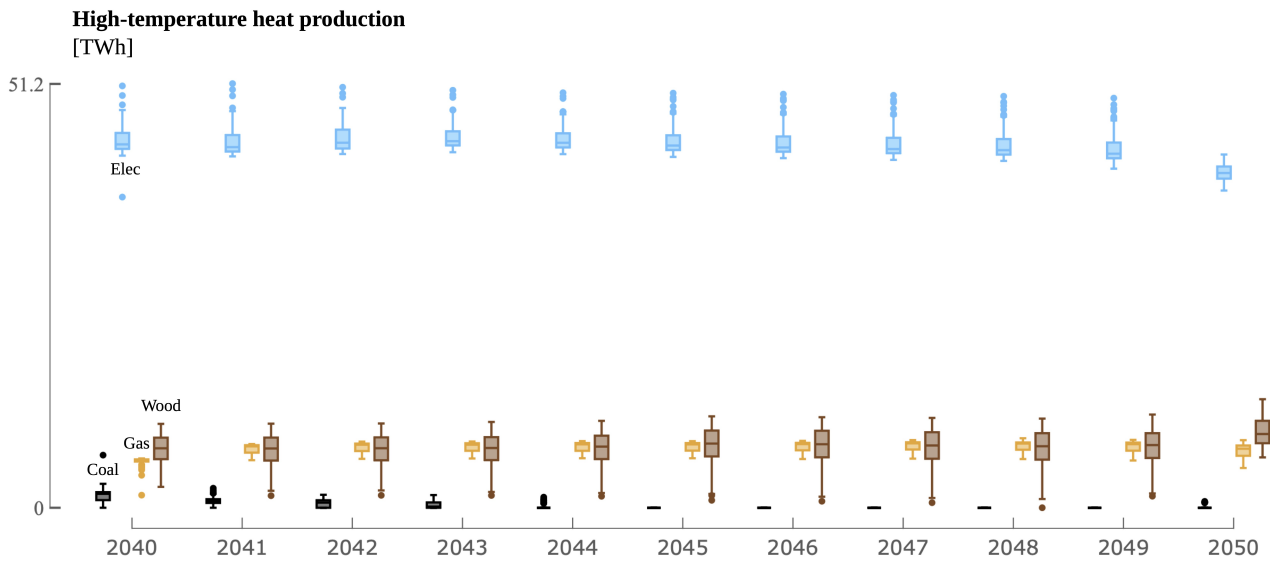


Figure 24: Waste is used at a constant level of 14 TWh and oil has a constant nul production.

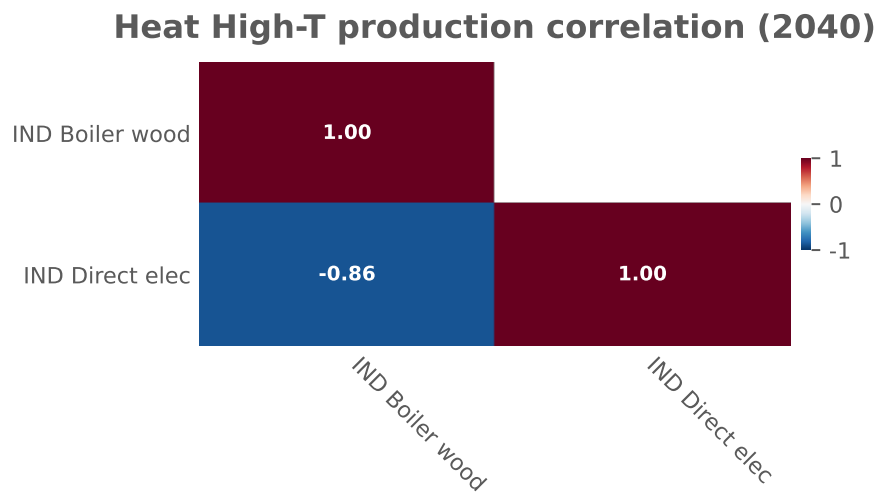


Figure 25: Boiler wood negatively correlated to electrification. Correlations with absolute values below 0.3 are masked in the matrix.

6.9 Commissioned capacity and commissioning time

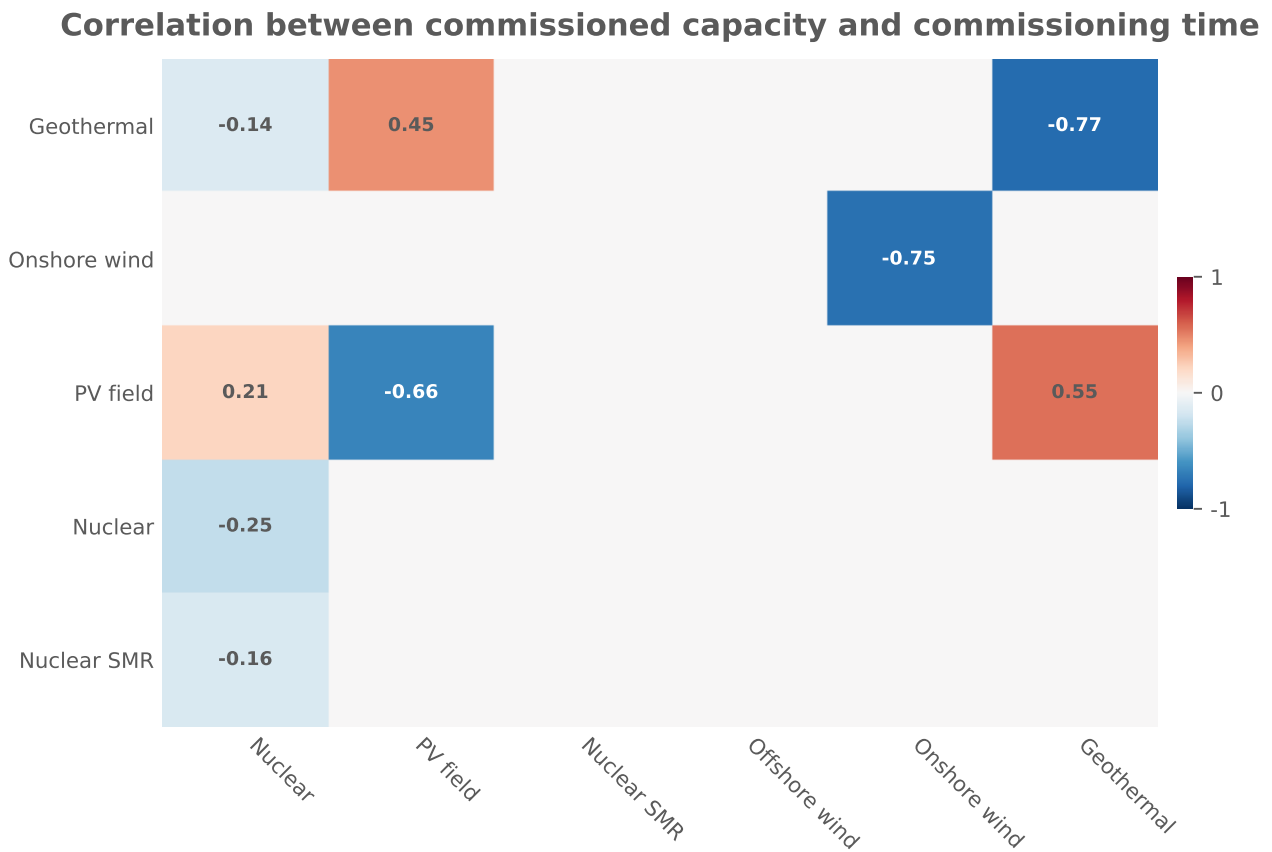


Figure 26: Correlation illustrates that extended commissioning time of geothermal significantly impacts whether or not field PV is deployed.

6.10 Investment cost uncertainty

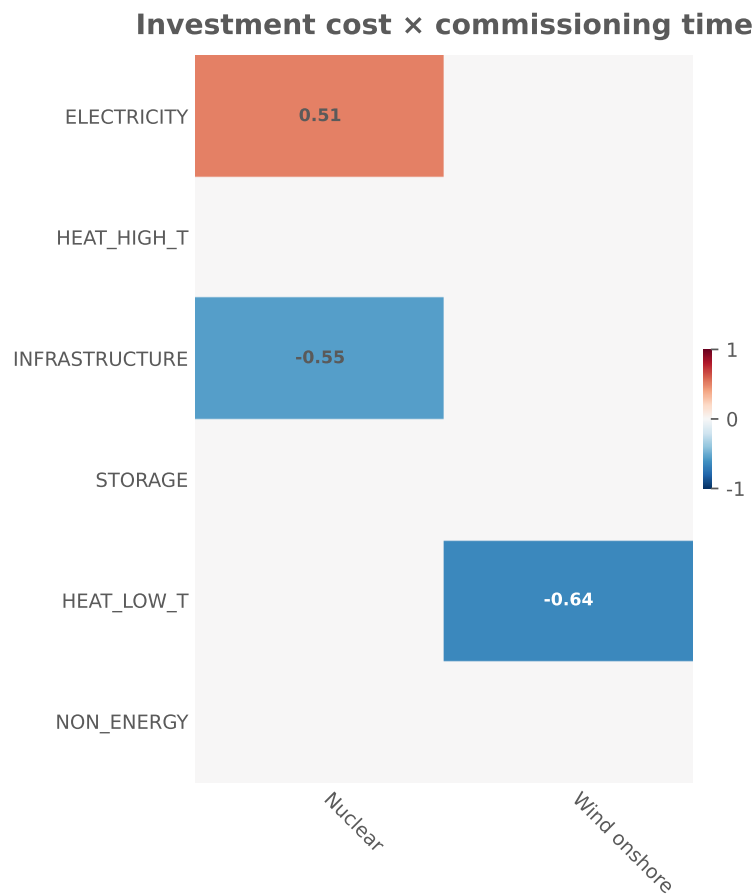


Figure 27: Correlation illustrates that nuclear commissioning time drives uncertainties in electricity and infrastructure investment cost.

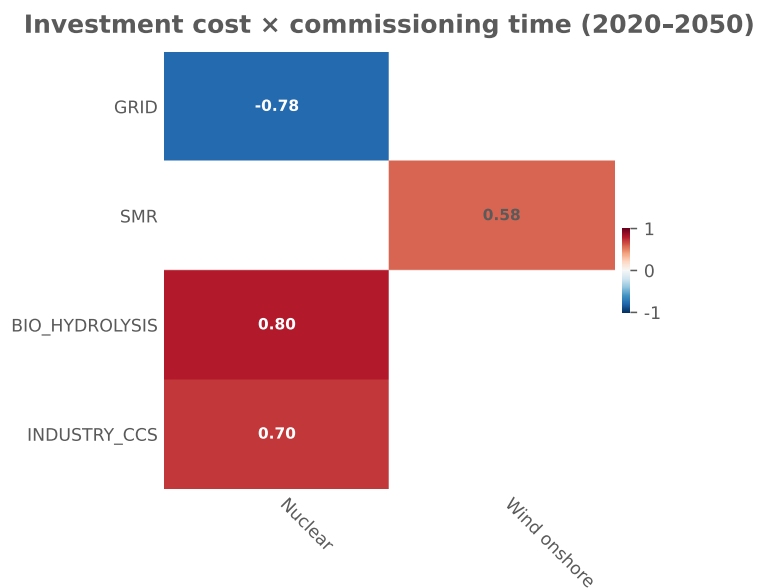


Figure 28: Correlation shows that nuclear commissioning time increases bio-hydrolysis and reduces grid investment. Onshore wind increase steam methane reforming (SMR in the figure) investment.

6.11 Correlation between resource consumption and commissioning time

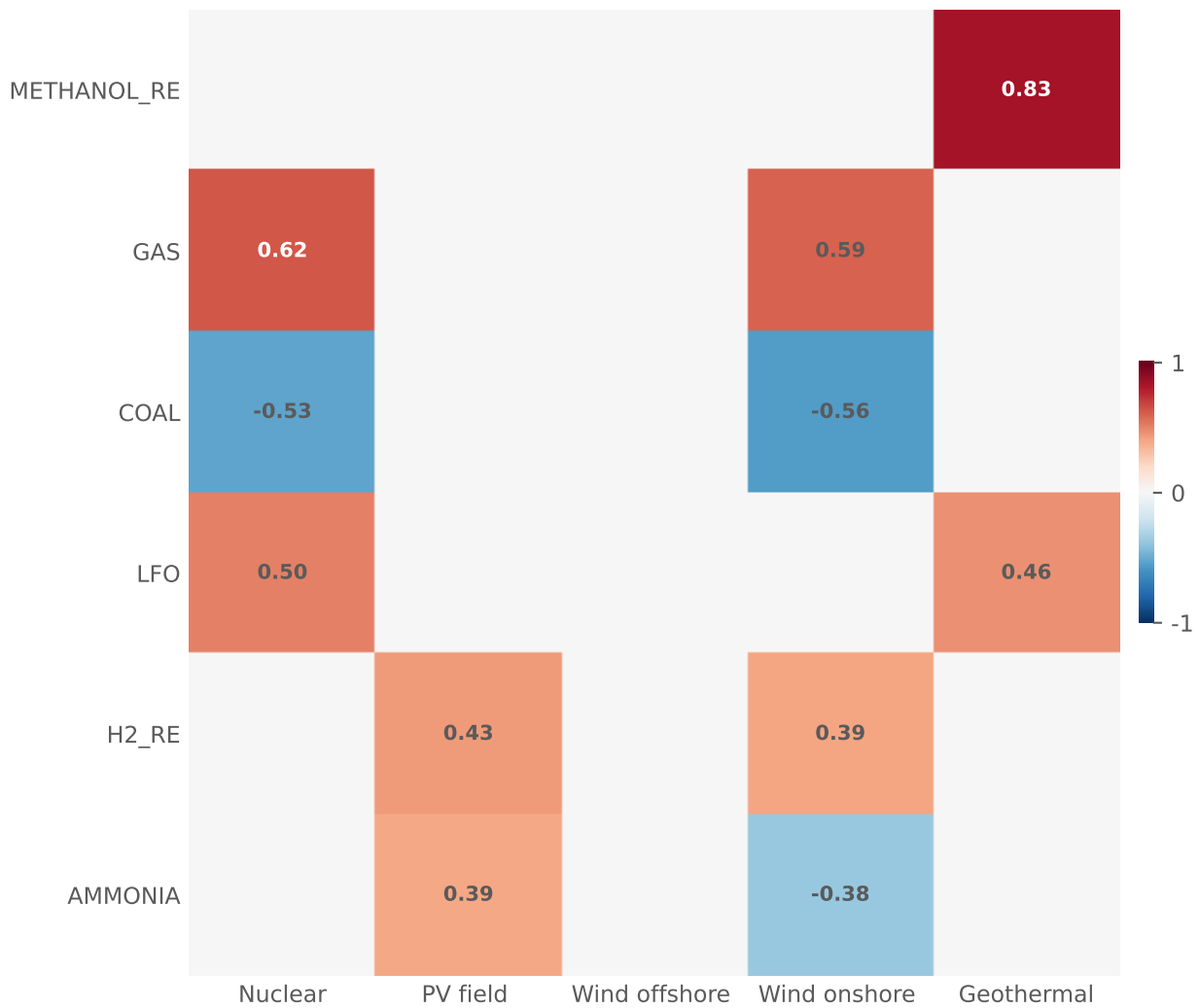


Figure 29: Correlation illustrates that nuclear and onshore wind commissioning time increases gas consumption and reduces coal. Field PV and onshore wind commissioning times increase renewable hydrogen import and geothermal increase renewable methanol.

6.12 Uncertainty of economic parameters

These parameters and their uncertainties come from the study [3].

Parameter	nominal	min	max
$c_{op,fossil}$	1 ^a	-47.3%	+89.9%
$c_{inv,FC}$	1	-39.6%	+39.6%
$c_{inv,car}$	1	-21.6%	+25%
$c_{op,efuels}$	1	-47.3%	+89.9%

Table 20: ^a These parameters affect a group of entities. For instance, $c_{op,fossil}$ represents the variation of the price of fossil hydrocarbons (i.e., coal, natural gas, light fuel oil, gasoline, and diesel). Since these fuels do not have the same reference value (e.g., $c_{op,ref,NG}$ and $c_{op,ref,coal}$ are different), the parameter of variation has a unitary nominal value and affects the corresponding group of parameters by the same range of uncertainty.

6.13 Uncertainty of investment cost with economic uncertainties

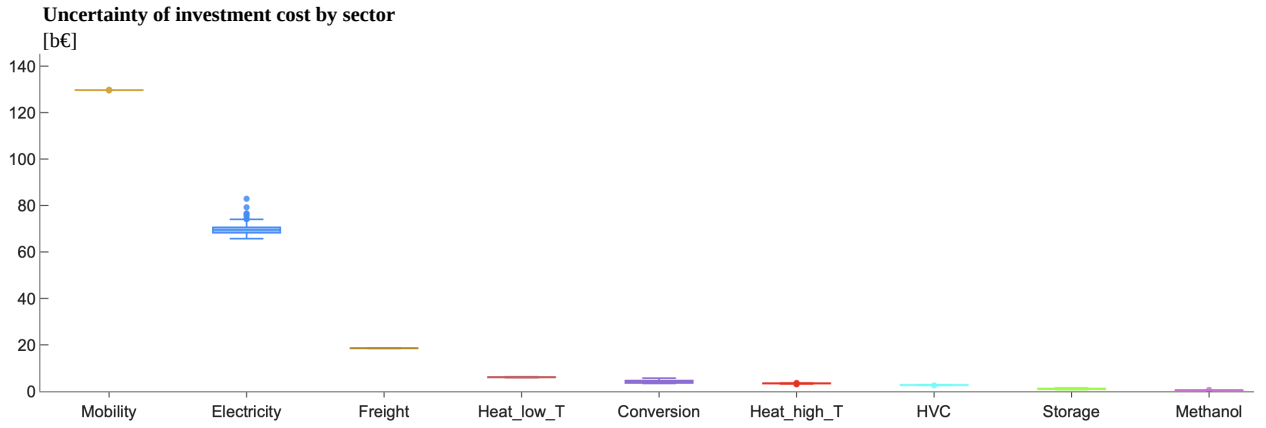


Figure 30: Uncertainty in electricity and infrastructure investment without economic uncertainties.

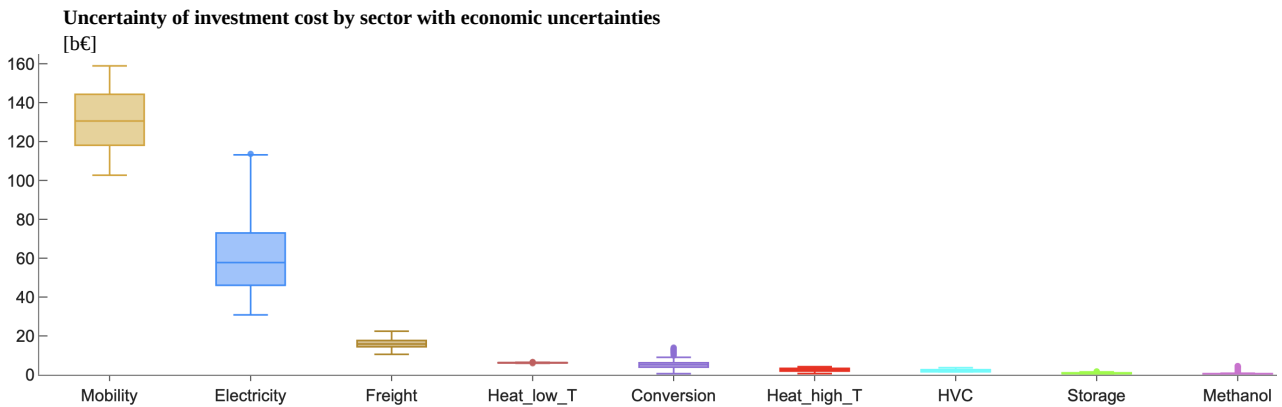


Figure 31: Uncertainty spreads over mobility, freight and is higher in electricity sector than without economic uncertainties.

6.14 Cost uncertainty across the transition with economic uncertainties

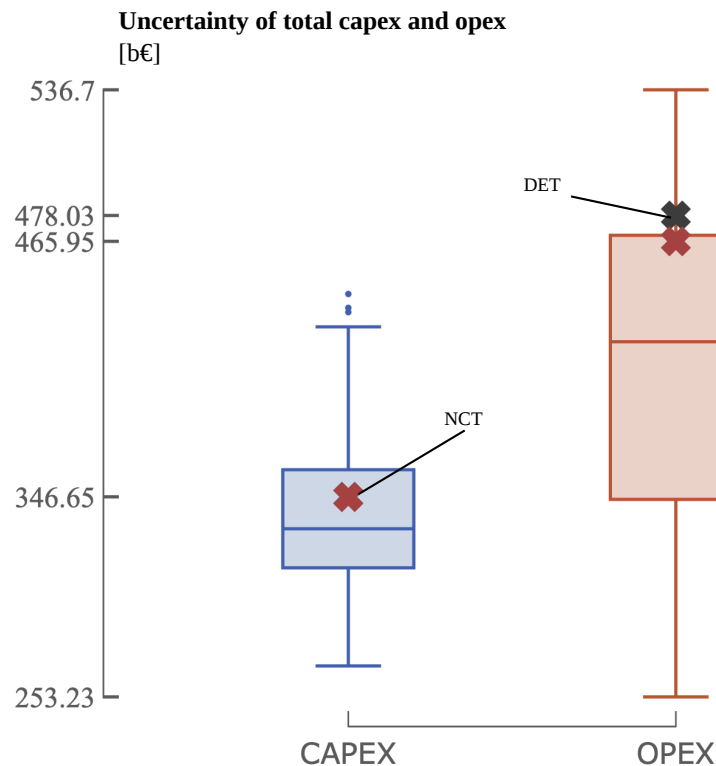


Figure 32: Operational cost is driven by fossil fuel price volatility. Investment cost variation reflects new mobility and bigger electricity sector cost. Cost uncertainty across the transition in Section 6.14.

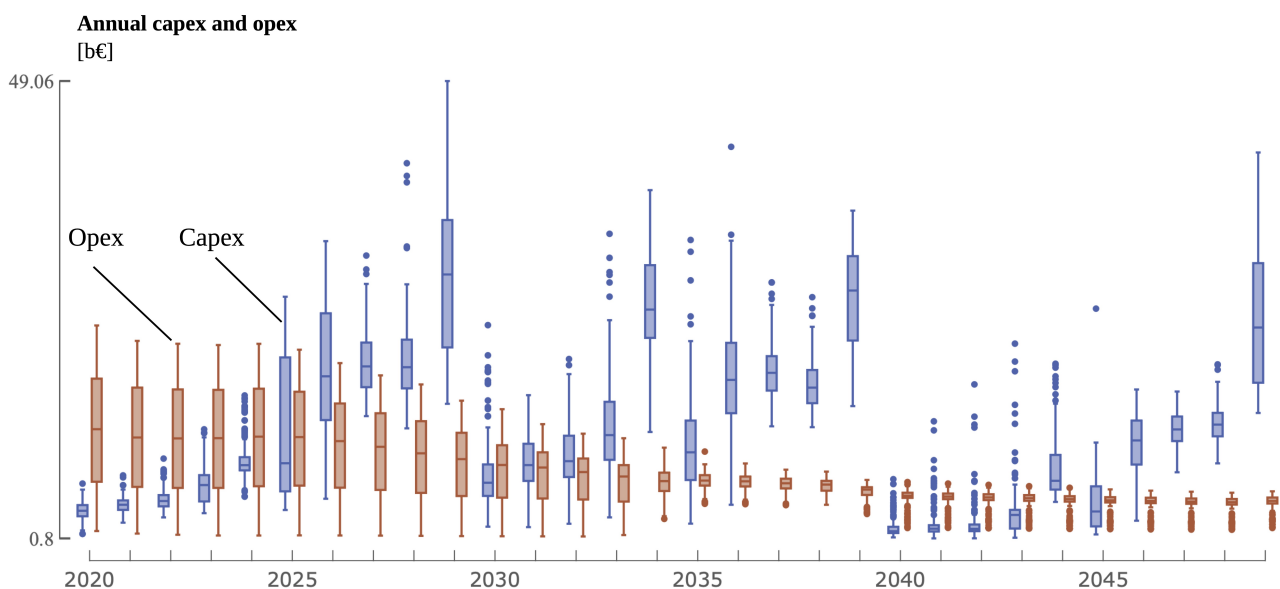


Figure 33: OPEX shows high uncertainty in the first 15 years showing the reliance of fossil fuel. Post-2035, uncertainty gradually declines, reflecting fossil fuel phase-out, replaced by renewable hydrogen and methanol import.

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