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Analyzing the techno-economic role of nuclear power in the transition to the net-zero energy system of the Netherlands using the IESA-Opt-N model

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Abstract

Intending to analyze the role of nuclear power in an integrated energy system, we used the IESA-Opt-N cost minimization model focusing on four key themes: system-wide impacts of nuclear power, uncertain technological costs, flexible generation, and cross-border electricity trade. We demonstrate that the Levelized Cost of Energy (LCOE) alone should not be used to demonstrate the economic feasibility of a power generation technology. For instance, under the default techno-economic assumptions, particularly the 5% discount rate and exogenous electricity trade potentials, it is cost-optimal for the Netherlands to invest in 9.6 GWe nuclear capacity by 2050. However, its LCOE is 34 €/MWh higher than offshore wind. Moreover, we found that nuclear power investments can reduce demand for variable renewable energy sources in the short term and higher energy independence (i.e., lower imports of natural gas, biomass, and electricity) in the long term. Furthermore, investing in nuclear power can reduce the mitigation costs of the Dutch energy system by 1.6% and 6.2% in 2040 and 2050, and 25% lower national CO_2 prices by 2050. However, this cost reduction is not significant given the odds of higher nuclear financing costs and longer construction times. In addition, this study has shown that lower financing costs (e.g., EU taxonomy support) considerably reduce the relevance of nuclear cost uncertainties on its investments. Furthermore, we demonstrate that the economic feasibility of national nuclear power investments can vary considerably depending on the cross-border electricity trade assumptions. Additionally, we found that lowering the cost of small modular reactors has more impact on their economic feasibility than increasing their generation flexibility. In conclusion, under the specific assumptions of this study, nuclear power can play a complementary role (in parallel to the wind and solar power) in supporting the Dutch energy transition from the sole techno-economic point of view.

Keywords: energy system modeling, nuclear power, energy transition, system costs, cost uncertainty

Contents

List of units and conversions

All cost units are reported in euros for 2019 unless specified differently.

The primary energy unit of the study is PJ. However, energy reports regarding the power system are converted to TWh to increase readability.

1 TWh = 3.6 PJ

1 €/MWh = 0.1 c€/KWh = 0.36 M€/PJ

1. Introduction

A recent report by the IEA suggests a massive deployment of all available low carbon energy technologies to reach globally net-zero emission by 2050 [1]. As one of the low-carbon sources of electricity, nuclear can provide an essential contribution to the energy transition. As a result, it is expected that nuclear power will maintain its 10% share of the electricity generation mix globally by 2050 [1], which implies a growth in nuclear power generation as the electrification rate increases globally. China, India, and Africa are expected to account for a significant share of this growth, while developed economies in the US and Europe are expected to extend the operating lifetime of existing nuclear plants to meet decarbonization targets [2].

Several studies analyzed the role of nuclear power in the long-term energy transition. However, each comes with methodology gaps that affect the results and discussion on this role.

In studies based on power system models (PSM), the role of nuclear power in long-term energy planning was analyzed. For instance, the REX model was used for Sweden to minimize the cost of a future low-carbon electricity system without nuclear power [3]. The PLEXOS model of the European power system demonstrates that a fully renewable and non-nuclear European power system is feasible by 2050 at the expense of higher costs [4]. A TIMES electricity model study estimates 30-70% higher electricity supply costs in alternative low-carbon electricity pathways in Switzerland and its neighboring countries under a nuclear phase-out scenario [5]. A power system model is used to investigate the impact of replacing nuclear power with wind turbines on the power system reliability [6]. Another study used detailed power system and nuclear power plant operation models to investigate the benefits of nuclear flexibility in the Southwest United States [7]. Although these PSMs described the power system in detail and accounted for cross-border electricity trade, they did not include all sectors and activities related to the decarbonization targets. Moreover, these PSMs could hardly optimize the endogenous demand-side flexibility supply options such as electric vehicles, heat pumps, and electrolyzers. While PSMs require specifying the power sector's emission cap as an exogenous scenario parameter, energy system models (ESMs) optimally distribute the emission reduction burden between all sectors. The same logic applies to the sectoral availability of sensitive resources such as biomass and CO_2 storage.

Several studies at the national geographical scale represented nuclear power in the energy system models: Although the impact of Finnish nuclear power on demand response was modeled using the EnergyPLAN model [8], the study did not analyze the cost implications of nuclear power. Using the TIMES model, a study investigated the reliability of the French energy system by 2050 [9]. Nevertheless, it does not consider the uncertainty of the nuclear costs in the analyses. Moreover, a study investigates the long-term energy transition strategies of South Korea, including nuclear power using the LEAP model [10]; however, the variability of nuclear power costs and its system implications were not evaluated. Furthermore, several scenarios for Great Britain's power system were investigated using the Calliope energy system model [11]; yet, the cost uncertainties of nuclear were not the focus of the study. Additionally, by applying the LEAP-OSeMOSYS model, the role of nuclear power in several Spanish energy scenarios is analyzed [12] without considering its cost variations. Even though these studies analyze the role of nuclear power in the electricity generation mix, they do not focus on the implications of nuclear power on the energy system.

Since the Netherlands is used as the case study, we review, in addition, the recent Dutch reports that focus on the role of nuclear power in the energy system:

A recent Dutch study, the Berenschot and Kalavasta report (2020), found that nuclear energy is more expensive than renewables, except when nuclear power always takes precedence over the electricity grid, and the government takes on a large part of the financial risks [13]. The role of the social discount rate is thoroughly analyzed for the economic feasibility of nuclear power. However, the study only analyzes the target year 2050 without considering the transition pathway, which can lead to underestimating the resulting system costs by neglecting the system's decommissioning costs, existing stock, and inertia [14].

The ENCO report (2020) claims that nuclear could play an essential complementary role in the Dutch decarbonization pathway by complementing variable renewable energy sources (VRES [15]. However, the conclusions are based on the plant-level Levelized Cost of Energy (LCOE) calculations rather than system-wide LCOE calculations. Consequently, the calculated LCOEs do not correctly reflect the cost of system-wide constraints such as flexibility supply investments, operational constraints, cross-border electricity trade, and infrastructure limitations. Additionally, the ENCO report is criticized with four major drawbacks [19]: assuming high solar and wind costs, ignoring the merit-order curve, deviating from Dutch energy policies, and the absence of system-wide analyses.

The TNO/NRG report (2021) examines the role of nuclear power, particularly the IV generation, in the regional energy transition of a Dutch province [16]. This report concludes that nuclear is not a cost-effective option for the Netherlands based on the results from two other reports: the Berenschot study [13] (already described) and a TNO scenario study [17]. The TNO scenario study used the OPERA optimization model [18] and shows no role of nuclear power in the Dutch energy mix.

The KPMG report (2021) follows a different approach in which it presents interviews with nuclear market parties to identify how nuclear energy can be realized as cost-effective as possible and what governmental interventions are required [19]. This study provides suggestions to the government on several aspects of nuclear power, such as technological choices, financing options, governmental intervention, decommissioning, waste treatment, and optimal location. Nevertheless, this study does not analyze the techno-economic role of nuclear power in an integrated energy system model.

The reviewed studies' major methodological shortcomings and knowledge gaps can be summarized as follows: (1) The system-wide implications of nuclear power in a transition to a net-zero energy system is barely discussed. These implications refer to not only economic feasibility of this technology, but also its impact on other energy sectors, system costs, and flexibility demand and supply. Therefore, integrated energy modeling tools are required to compute the system-wide influence of techno-economic decisions [20]. (2) Moreover, there is a great controversy on the cost data of nuclear and VRES. The range of cost data for these technologies is relatively wide [21], which can significantly affect the cost-optimal power generation mix. (3) Furthermore, small modular reactors (SMR) as flexible nuclear technologies are not included in the reviewed studies. However, they are expected to play an active role in providing flexibility to the power system [22]. (4) Finally, neglecting cross-border electricity trade can overestimate electricity prices by 40% [14]. Moreover, it can significantly affect the optimal electricity import and export levels—subsequently, the power generation mix. Therefore, assumptions regarding the cross-border electricity trade can highly affect the investment and operation of nuclear power.

We address the four knowledge gaps mentioned above using the highly detailed energy system model, IESA-Opt-N. This model optimizes investments of the energy system over the horizon from 2020 to 2060 in 5-year time steps while simultaneously accounting for hourly and daily operational constraints.

The primary contribution of this study can be summarized as "investigating the techno-economic role of nuclear power in a national energy system, considering the current inertia of the energy system and the flexibility requirements identified by hourly operation modeling". This study is framed around four themes, corresponding to the four knowledge gaps (Figure 1): (1) system-wide impact of nuclear power in an integrated energy system, (2) the role of nuclear cost uncertainties on cost-effective nuclear investment decisions, (3) the role of SMR nuclear power as a flexible generation option on cost-effective nuclear investment decisions, and (4) impact of the cross-border electricity trade on economical nuclear investment decisions.

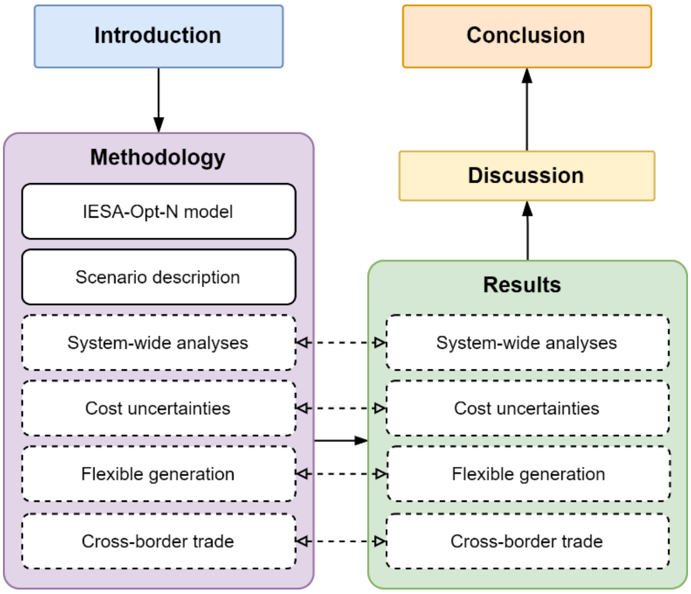

Figure 1. Structure of this study. The methodology behind the analyses on four themes of this study is described in the methodology section, while the results are presented in the results section.

We primarily focus on the techno-economic role of nuclear power. However, this technology faces several other challenges that are not discussed in this study: energy security and independence ([23], [24]), social acceptance ([25], [26]), and radioactive waste management ([27], [28]).

2. Method

This section describes the model used and the improvements we made to the model. Next, we briefly describe the main scenarios used in this study: the reference and nuclear scenarios. Afterward, we use the scenario simulation and comparison approach to identify the role of nuclear on key system indicators in four themes: system-wide costs, sensitive technological costs, flexible generation, and cross-border trade.

2.1. Modifying the IESA-Opt model to make IESA-Opt-N

We use the IESA-Opt model implemented for the Netherlands to capture system-wide effects. This is a detailed open-source optimization ESM at the national level [29]. IESA-Opt models investments of the energy system over the horizon from 2020 to 2050 in 5-year time steps while simultaneously accounting for hourly and daily operational constraints. The model's objective function minimizes the net present value of energy system costs to achieve total energy needs under certain techno-economic and policy constraints (e.g., a specific greenhouse gas (GHG) reduction target in a particular year). It is an open-source and flexible model that can be used for other regions or countries (e.g., the North Sea region [30]).

In the IESA-Opt model, the operation of the electricity sector of the Netherlands and other EU countries (including Norway and Switzerland) is balanced hourly. Since the model's scope is at the national level, power sector investments occur only in the Netherlands. At the same time, the power capacity mix of EU nodes is fixed as exogenous scenario parameters.

The energy infrastructure is modeled in ten networks for different voltage levels of electricity, and different pressures of natural gas, hydrogen, and single carbon capture, utilization, and storage (CCUS) and heat networks. The gaseous networks are balanced daily due to their relatively low intraday variation [29].

The IESA-Opt model reflects the emission constraints of the EU Emission Trading System (ETS), the non-ETS sectors, and the international navigation and aviation sectors. Since ETS sector emissions are traded in the EU ETS market, we assume an exogenous ETS emission price projection as a scenario parameter. Because the national emission reduction policy targets both ETS and non-ETS sectors, we set the aggregate national emission constraint on both sectors. If the constraint is binding, the model generates an aggregated national emission shadow price, equal to the marginal increase in the system cost if the aggregated emission constraint gets one unit tighter.

2.1.1. The IESA-Opt-N model

Although IESA-Opt comes with several capabilities, it has some limitations. Therefore, this study modifies the model in two directions: objective function definition and cross-border electricity trade. The modified model is IESA-Opt-N, which stands for Integrated Energy System Analyses – Optimization – National.

Objective function definition

There are two mainstream ways of dealing with multi-horizon investments in the energy system models: (1) assuming a full overnight cost at the time of investment and a salvage value at the end of horizon (e.g., OSeMOSYS [31]). (2) distributing annualized cost over the lifetime of the technology after the first investment (e.g., Balmorel [32]).

However, the IESA-Opt model’s objective function is formulated slightly differently. It refers to the system’s net present value resulting from the set of decision variables confirmed by annualized investments, decommissioning, retrofitting, and use of technologies. Although this objective function annualizes the investments, it does not account for the annualized cost of technology stock in periods after the investment period. Therefore, the system tends to make more significant investments in earlier periods as it does not pay for the annualized capital cost of those investments in successive periods.

Therefore, we modify the objective function by adding the investment matrix before the capital component to represent total system costs. The binary investment matrix determines the presence of a technology option in each period based on its economic lifetime.

Moreover, we add a social discount factor (SDF) to weigh different periods and account for the net present value of costs (similar to the PyPSA-Eur model [33]). This discount factor is based on the assumed exogenous social discount rate that describes how society values future investments. The social discount rate should not be confused with the capital discount rate. The capital discount rate or Weighted Average Cost of Capital (WACC) is used to annualize the overnight capital investment costs. Although WACC can be different for each technology, we assume a 5% rate for all technologies in the reference scenario. Thus, with the addition of the social discount rate, the new objective function calculates the sum of the net present value of energy transition costs:

$$Objective\ Function_{IESA-Opt-N}:$$
$$\sum_{t,p} SDF_{r_s,p,p_b}\left(IM_{t,p,p^*}\left(i_{t,p}\alpha_t IC_{t,p} + d^{pre}{}_{t,p}\alpha_t IC_{t,p} + r_{t_i,t_j,p}\alpha_{t_j} RC_{t_i,t_j,p} + s_{t,p}FC_{t,p} + u_{t,p}VC_{t,p}\right)\right)$$

Where:

$i_{t,p}\alpha_t IC_{t,p} = annualized\ (\alpha_t)\ investments\ (i_{t,p})\ multiplied\ by\ investment\ costs\ (IC_{t,p})$
$d^{pre}{}_{t,p}\alpha_t IC_{t,p} = annualized\ (\alpha_t)\ investment\ costs\ (IC_{t,p})\ from\ premature\ decommissioning\ (d^{pre}{}_{t,p})$
$r_{t_i,t_j,p}\alpha_{t_j} RC_{t_i,t_j,p} = annualized\ (\alpha_t)\ retrofitting\ costs\ (RC_{t_i,t_j,p})\ of\ retrofitting\ technology\ i\ to\ technology\ j\ (r_{t_i,t_j,p})$
$s_{t,p}FC_{t,p} = fixed\ operational\ and\ maintenance\ costs\ (FC_{t,p})\ of\ the\ technological\ stock\ (s_{t,p})$
$u_{t,p}VC_{t,p} = variable\ operational\ and\ maintenance\ costs\ (VC_{t,p})\ due\ to\ the\ use\ of\ the\ technologies\ (u_{t,p})$

$IM_{t,p,p^*} = the\ binary\ investment\ matrix: the\ presence\ of\ technology\ (t)\ that\ is\ in\ the\ system\ from\ period\ p^*$
$if\ (p^* \leq p \leq p^* + eco_{L_t})\ then\ IM_{t,p,p^*} = 1\ else\ IM_{t,p,p^*} = 0$
$eco_{L_t} = economic\ lifetime\ of\ a\ technology\ (t)$

and

$$SDF_{r_s,p,p_b} = (1 + r_s)^{p_b - p}$$
$r_s = social\ discount\ rate$
$p_b = base\ period$

With the new objective function formulation, the capital cost of technologies is accounted for during their economic lifetime. However, the investments in the last modeling period may be distorted as the benefits of investments after this period are neglected. Since 2050 is crucial in current policies, we do not want these so-called end-of-horizon effects in 2050. Although this effect is already reduced by using annualized investment costs, we add two more periods (i.e., 2055 and 2060) to the model's horizon to further reduce this effect [34]. Since the additional periods aim to represent investment costs better, all energy system definitions, including activity levels and technological costs and potentials, are kept equal to their value in 2050.

Cross-border electricity trade

The IESA-Opt model optimizes the hourly operation of the electricity sector of the Netherlands and other EU countries (including Norway and Switzerland). This requires the evolution of EU generators and interconnection capacities as input to the model. These exogenous values were obtained from the Ten Year Network Development Plan of ENTSO-E [35]. However, the range for capacities is relatively high across different scenarios. Moreover, the power generation plan of each EU member state can vary significantly in time as it is strongly tied to political agendas. Therefore, we decided to decouple these uncertainties from the IESA-Opt model by removing the EU capacities.

The IESA-Opt-N model can use the cross-border electricity trade profile as an exogenous input. This profile determines the hourly availability and price of electricity at each period. Furthermore, the profile can get imported from other power system models (e.g., COMPETES[36] and PyPSA-Eur[37]). This method has two main advantages compared to IESA-Opt: first, the impact of the EU power system on the national system is quantified and measurable, and second, the computational load is lower, and thus the run-times are significantly quicker. However, it comes with one primary disadvantage: the inconsistency between the assumptions of national energy system and international power system models.

The electricity import and export prices and availability profiles vary depending on the underlying assumptions of the Netherlands and its neighboring countries' scenarios. Since the profiles can vary in many directions (i.e., hourly prices multiplied by hourly availabilities), performing a sensitivity analysis is complex. Moreover, measuring the impact of profile variations on national power generation decisions can be problematic. Therefore, we use a flat price to import and export electricity in this study. Moreover, we set a maximum import and export quota for each year. Thus, the model can decide how much to trade at each hour of the period, considering the total trade volume is less than the assigned quota for that period.

In summary, the modifications improve the solution's accuracy considerably (mainly by improving the objective function definition) while increasing the solution's stability and reducing the solving times substantially. Figure 2 demonstrates the visual methodological framework of the IESA-Opt-N model.

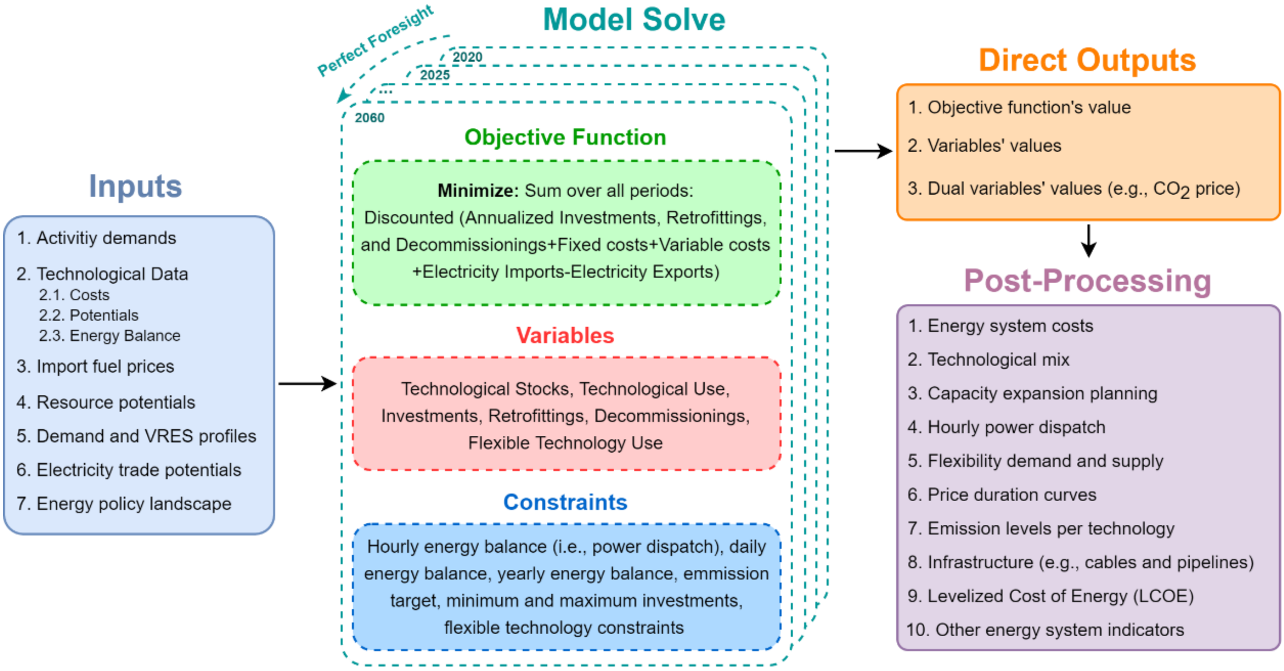

Figure 2. The methodological framework of the IESA-Opt-N model

2.2. Reference and nuclear scenarios of IESA-Opt

Here we provide a brief description of the reference scenario of the IESA-Opt model. Appendix A describes this reference scenario in more detail.

Sanchéz et al. provide a complete description of the required input data and scenario definition elements for the IESA-Opt model [29]. The reference scenario used for this paper aims for a carbon-neutral energy system in 2050 by employing high shares of VRES, biomass, and hydrogen. Figure 3 summarizes the fundamental assumptions of the reference and nuclear scenarios. The rest of this section describes these two scenarios further in detail. First, we describe the main elements of the reference scenario definition, such as demand drivers, fuel and resource costs, technology and resource potentials, technological costs, and emission constraints. Then, we define the nuclear scenario by describing its significant changes compared to the reference scenario.

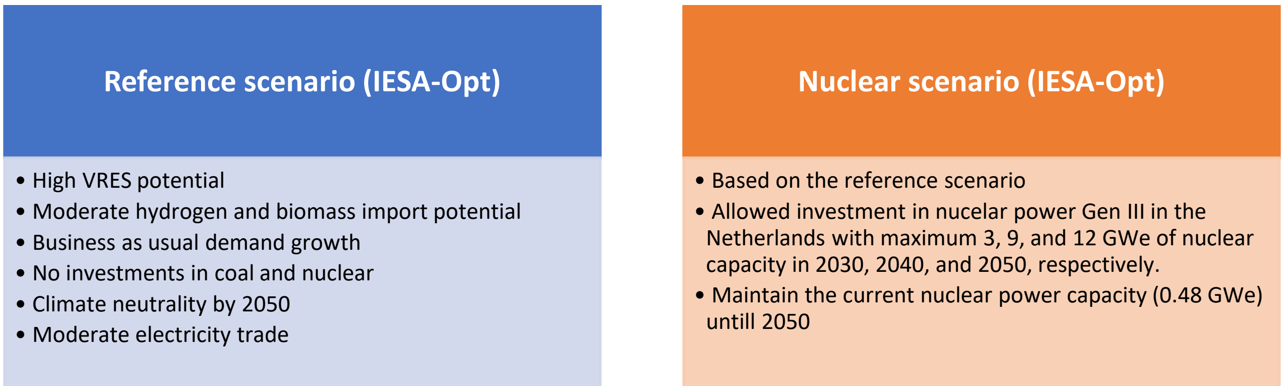

Figure 3. The summary of the reference and nuclear scenarios

2.2.1. Reference scenario

The environmental policy landscape of the Netherlands follows the EU Green Deal [38], where the Netherlands steps up its ambition to reduce its greenhouse gas (GHG) emissions by 55% compared to 1990 levels in 2030 [39], and becomes GHG neutral in 2050 [40].

The projected development of activities and part of the resource costs are extracted from JRC's POTEnCIA central scenario for the Netherlands [41], which is based on GDP growth rates presented in the 2018 aging report [42]. This scenario leans towards business-as-usual economic development, which would fall within the second shared socioeconomic pathway (SSP2) [43]. In addition, the costs of biomass were extracted from the reference storyline of the ENSPRESO database [44], as well as most of the considered potentials for renewable technologies in the Netherlands.

The reference scenario uses data from central scenario descriptions of different sources. Most of the technologies described in IESA-Opt are based on the reference scenario of the ENSYSI model [28], where low-carbon technologies experience a learning rate of at most 20%. Technology data projections of the transport sector are obtained from the POTEnCIA central scenario [41]. In addition, data projections for technologies such as P2Liquid alternatives, electrolyzers, and direct-air-capture units are obtained from TNO's technology factsheets [46].

The reference scenario assumes a moderate public-private interest rate of 5% for all technologies, including nuclear power. Since this rate is an essential factor in determining the economic feasibility of nuclear power, we perform sensitivity analyses on this parameter, explained in Section 2.4.

The complete technology data assumptions, as well as the link to the sources, can be found in the online portal of the model [47].

Resource and technological potentials

The potentials assumed for technologies significantly influence the definition of the scenario. These potentials determine each technology's maximum allowed installed capacity in the transitional period. Many of these assumed potentials influence transition costs, notably, potentials for renewable energy sources (including biomass) and CO_2 storage. The reference scenario bases the storylines of these potentials on the ENSPRESO reference scenario for biomass [44] and TNO's OPERA model reference scenario [18]. The prices for oil and coal are obtained by extrapolating the price estimates provided by Dutch energy outlook (KEV2020 [48]). Table 1 shows the assumed resource and technology potentials for the reference scenario. Due to limited nearshore space for wind offshore, offshore wind potential near is considerably less than wind offshore far. Although wind offshore far has higher potential, it comes with higher infrastructure costs. The potential for imported hydrogen in 2050 is obtained from the "National" scenario of the Dutch energy network operators report [49]. The reference scenario blocks nuclear power after 2033, as currently, there are no policies to maintain or expand its capacity. In addition, the Dutch climate agreement voids the use of coal for power generation after 2030. Although it is not yet evident if it will be allowed in combination with CCUS, we completely blocked investments after 2030 in coal power plants. The CCS upgrade is available in the model for several technologies through the assumption of higher CAPEX value (i.e., modular retrofitting). However, the captured CO2 should be deployed into the CO2 pipelines where it can be either stored or used by other processes. The model endogenously calculates the required CO2 pipeline, while the CO2 storage potential is an exogenous scenario parameter.

	Potentials	Units	Maximum values			
			2020	2030	2040	2050
Technologies	Offshore Wind (far)	[GW]	0	20	40	65
	Offshore Wind (near)	[GW]	1.1	6	13	13
	Onshore Wind	[GW]	3.5	8	10	12
	Solar PV	[GW]	6.7	40	63	75
	Nuclear generation III	[GW]	0.48	0.48	0	0
	Coal Power Plants	[GW]	4.5	9.1	0	0
	Storage of CO_2 (CCS)	[$MtCO_2$/y]	0	10	25	50
Resources	Domestic Biomass	[PJ/y]	174	210	232	254
	Imported Biomass (wood)	[PJ/y]	20	120	220	320

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	Imported Biofuel	[PJ/y]	27	192	402	852
	Imported Hydrogen	[PJ/y]	0	50	150	370
Fuel Prices	Imported Coal	[M€/PJ]	2	2.7	3.3	4
	Imported Oil	[M€/PJ]	7	11	15	19
	Imported Natural Gas	[M€/PJ]	5	6.6	8.2	9.8
	Imported Biomass (wood)	[M€/PJ]	12.5	17.5	22.5	27.5
	Imported Bio Diesel	[M€/PJ]	20	35	50	70
	Imported Bio Kerosene	[M€/PJ]	14	30	53	70
	Imported Hydrogen	[M€/PJ]	72	48	36	30
	Imported Uranium	[M€/PJ]	0.8	0.8	0.8	0.8

Table 1, Key assumed technological and resource potentials and fuel prices in the reference scenario. Sources: [49], [50], [51], [52]

Renewable and nuclear generation costs and constraints

IESA-Opt defines technological costs utilizing Capital Expenditures (CAPEX), Fixed Operational and Maintenance (FOM), and Variable Operational and Maintenance (VOM) cost parameters. These cost parameters are imported from various sources listed in Table 2. CAPEX costs are affected by exogenous learning rates, and only their value in 2050 is presented here. The cost reduction parameter indicates the assumed average cost reduction every five years.

For nuclear power generation, the CAPEX represents the Overnight Construction Costs (OCC), consisting of civil and structural costs, major equipment costs, the balance of plant costs, electrical, instrumentation, and control supply and installation costs, indirect project costs, development costs, and interconnection costs. Generation III (gen III) nuclear costs are obtained from the MIT Nuclear technology study [21]. We assume a linear cost reduction in CAPEX from 7.2 billion € (B€)/GW in 2020 to 6 B€/GW in 2050. The FOM costs are estimated to decrease linearly from 0.16 B€/GW-year in 2020 to 0.13 B€/GW-year in 2050 [53]. Although the decommissioning and waste management costs are estimated to be 15% of the OCC [54], we consider these costs part of the VOM costs. The European Commission report assumes that the decommissioning cost is 0.49 M€/PJ, and waste management cost is estimated at 0.81 M€/PJ [55]. Obtaining the 3.13 M€/PJ variable costs from the MIT report [21], the total VOM is assumed 4.43 M€/PJ in all periods.

Small modular reactors (SMR) generally have less than 300 MWe capacity, and their “modular” feature makes it possible for a single reactor to be grouped with other modules to form a larger nuclear power plant [56]. SMR technology based on generation III reactors can get lifted to technology readiness level (TRL) 9 in approximately one decade, making it a feasible technological option from 2040 onwards [57]. The OCC estimate of SMRs ranges from 4241 to 6703 M€/GW [58]. Also, the CAPEX of SMR nuclear is estimated to be 30% higher than Gen III due to its lower technological readiness [59]. However, in the reference scenario, we assume a linear CAPEX reduction from 7.4 B€/GW in 2020 to 6.72 B€/GW in 2050 [60]. Moreover, we assume the same FOM and VOM costs as the nuclear gen III.

The economic lifetime determines the expected profitability duration of the investment. The technology will be decommissioned and removed from the system at the end of this lifetime. The capacity factor determines the maximum theoretical output of the technology compared to its maximum capacity. Wind and solar capacity factors are obtained from the IEA Net Zero report [1].

Nuclear power plants (NPPs) are usually deployed to supply base-load power. However, NPPs can reduce power output (i.e., through flexible generation or load-following) under certain physic-induced constraints. Among the most limiting constraints is the negative reactivity insertion following every reactor power drop due to the increased concentration of xenon, a strong neutron poison [61]. In practice, countries with large nuclear power shares (France) and high intermittent renewables (Germany), need NPPs to operate load-following [62]. Although lowering the power output can reduce NPP’s revenues (as it does not significantly reduce generating costs), literature has showed that NPP’s load-following can be profitable from social welfare perspective (i.e., such as baseload units' operation, renewables' integration, system operators' balancing, and consumer's price [62]).

However, in this study, we assume nuclear gen III to operate as base-load (i.e., non-flexible) and SMRs to operate as load-following (i.e., flexible generation). In this way, we can demonstrate the impact of nuclear generation flexibility (on several levels) on its economic feasibility (section 2.5). To account for the inflexibility of nuclear gen III generators, we assume a near-zero ramping rate, which is the rate of increase or decrease in the generated power per hour.

The only techno-economic difference between SMR and gen III nuclear in our database is the CAPEX and ramping values. Therefore, to avoid mixing the effect of these two parameters on the feasibility of this technology, we exclude this technology in the reference and nuclear scenarios. Instead, we perform a sensitivity analysis that is described in section 2.5.

Technology	CAPEX [B€/GW]	FOM [B€/GW-y]	VOM [M€/PJ]	Economic Lifetime [y]	Capacity Factor [%]	Ramping [%]
Wind offshore	1.51	0.047	0.1	20	60	100
Wind onshore	1.08	0.017	0.4	20	30	100
Solar fields	0.28	0.002	0.1	20	9	100
Nuclear Gen III	6	0.13	4.43	60	90	0.1*

*Table 2. Assumed VRES and Nuclear technological costs and constraints in 2050 in the reference scenario. * estimated zero (i.e., 0.1). Since IESA-Opt uses an LP formulation, it does not solve unit-commitment problems that require MILP formulation. Sources: [63], [1], [64]*

Electricity trade potential

Electricity trade can play an essential role in determining the cost-effective nuclear investment capacity. However, the outlook of electricity trade volume and prices in 2040 and 2050 is somewhat uncertain. Therefore, we assume a subjective “moderate” electricity trade volume and price projection for the reference and nuclear scenarios (Table 3). The Netherlands imported 22.4 TWh and exported 19.8 TWh of electricity in 2020. We assume an increase in the electricity trade volume from 28 TWh in 2030 to 44 TWh in 2050. Furthermore, the assumed average import price increases from 58 €/TWh in 2030 to 115 €/MWh in 2050. Since this assumption can affect the results considerably, we do a sensitivity analysis on it under the fourth theme.

However, we assume a considerably lower export price. The model can optimally distribute the hourly electricity export with perfect foresight. This assumption is far from reality as the exports increase with an excess of VRES generation, while the neighboring countries also experience this excess. Therefore, we penalize the export price in 2050 (compared to the import price) by 36 €/MWh.

The hourly trade profile is optimized endogenously by the model depending on the national power demand, generation, and cross-border interconnection capacity.

Electricity trade	Units	Periods		
		2030	2040	2050
Import (or export) volume per year	[TWh]	28	33	44
Import price	[€/MWh]	58	86	115
Export price	[€/MWh]	22	50	79

Table 3. Assumed projection of electricity trade volume and prices.

2.2.2. **Nuclear scenario definition**

The nuclear scenario is based on the reference scenario with changes in nuclear investment constraints. The capacity expansion in the Netherlands is maximized at a subjective value of 9 and 12 GWe in 2040 and 2050, respectively (Table 4). Moreover, the lifetime of the current nuclear power plant with 0.484 GW capacity is extended for 20 years (i.e., until 2053). Since this scenario focuses on the economic feasibility of nuclear power, we only allow for nuclear gen III investments by constraining nuclear SMR. Therefore, the feasibility of nuclear SMR is analyzed separately in the SMR and flexible generation theme.

Maximum nuclear capacity (Netherlands)	Units	Periods		
		2030	2040	2050
Nuclear gen III	[GW]	0.48	9.48	12.48
Nuclear SMR	[GW]	0	0	0

Table 4. The assumed nuclear capacity expansion constraints in the nuclear scenario

2.3. Theme one: analyzing system-wide costs

Due to the increase in cross-sectoral energy flows, analyzing a particular technological decision (i.e., investment or operational decision) is rather complex. For instance, the investment decision on wind turbine capacity depends on the hourly electricity demand in other sectors (i.e., electrification rate) and the available flexibility in the system to handle peak hours. However, these variables depend on other demand drivers and other technologies' available potential and cost. Therefore, we require an integrated energy system model to account for the system-wide impacts of certain decisions. To provide further details on the cost flow of the energy transition, the IESA-Opt-N model reports several cost indicators: system costs, mitigation costs, sectoral costs, final energy prices, and LCOEs. Afterward, we describe the flexibility definition and available flexibility options in IESA-Opt-N.

System costs

The model's objective function is to minimize the net present value of all costs stemming from the investment and operational decisions in the national energy system. The system can also incur negative costs (i.e., revenues) by exporting energy. The system costs indicator is divided into four categories: CAPEX, FOM, VOM, and trading costs. The first three elements are obtained by summing up the corresponding cost elements of available technological options. Trading costs are the net balance of import costs and export revenues of electricity, gas, and oil-based products based on hourly and daily energy carrier prices.

To provide more insights into the system costs, also mitigation costs, sectoral costs, average final energy prices, and LCOEs are presented.

Mitigation costs

Although the system costs indicator shows the evolution of all cost components of the energy system, it can be misleading in comparing scenarios. A high share of the system costs depends on the level of energy activity demand drivers, irrespective of environmental targets. Although the system costs can vary under different environmental targets, the inertia of this high share can underestimate the change in the system costs.

Therefore, we use the mitigation costs indicator to report the costs of reducing greenhouse gas emissions. We calculate the mitigation costs as the system costs difference in a specific scenario with and without emission reduction targets. For instance, to measure the mitigation costs of this study's reference scenario, we first calculate the reference scenario’s system costs (including the climate targets by 2030 and 2050). Afterward, we set the maximum allowed carbon emission equal to 1990 levels; then, we recalculate the costs. Finally, we report the difference as the mitigation costs of the reference scenario.

$$Mitigation\ Costs_{scenario\ X} = System\ Costs_{scenario\ X} - System\ Costs_{scenario\ X^*}$$

$$scenario\ X^* = scenario\ X\ with\ maximum\ carbon\ budget\ equal\ to\ 1990\ levels$$

Although this method increases the computational run times of the model (as each scenario needs to be optimized two times), it provides a clear and transparent cost indicator for scenario comparison.

Sectoral costs

Sectoral costs explicitly account for all costs related to the energy technologies in each sector, including the fuel prices paid by each sector based on the market perspective of the energy costs. Therefore, the total sum of sectoral costs will be higher than the system costs as the marginal cost of energy carriers is higher than the average energy costs. Moreover, the sectoral costs include the trading component for the sectors involved in energy trade (e.g., power generation sector). In addition, the infrastructure cost components of each sector are explicitly reported.

Average final energy price

The average final energy price is equal to the weighted average price of each final energy carrier considering its hourly or daily marginal price variations. Therefore, this parameter can be used as a valuable indicator to compare the affordability of the energy for final consumers in different scenarios.

LCOEs

LCOE measures the average net present cost of energy generation for a generating plant over its lifetime. IESA-Opt reports both the theoretical and realized LCOEs. The theoretical LCOE is calculated based on the theoretically generated energy resulting from the exogenous capacity factor. Alternatively, the realized LCOE is calculated based on the generated energy from solving the optimization problem. The added value compared to similar LCOE based studies (that only calculate theoretical LCOEs, e.g. [15]) is that the current study uses an ESM to calculate the realized LCOEs. This accounts for indirect system-wide costs, such as infrastructure or flexibility costs, to balance the power system.

Flexibility supply sources in IESA-Opt-N

Flexibility refers to the ability of the energy system to respond to the variability and uncertainty of the residual power load (i.e., power load minus VRES generation) within the limits of the electricity grid [65]. When the share of intermittent renewables increases, the demand for flexibility in the energy system grows; thus, energy sectors are required to become more interconnected through conversion (e.g., Power to X) and storage technologies.

Flexibility can be measured either in ramping (GW/h), energy (GWh), or capacity units (GW). In this study, we measure the flexibility in energy and capacity units. Based on its direction, flexibility demand can be caused by either upward or downward residual load. We define flexibility in energy units as the surface area under the duration curve of the residual load. Therefore, upward/downward flexibility demand in energy units is the surface area of the residual load curve on the positive/negative side of the curve.

To measure the flexibility in capacity units, we measure the change in the residual load over a certain period [65]. In this regard, upward/downward flexibility in capacity units refers to the need for flexible capacity due to an increase/decrease in the residual power load over a certain period.

In IESA-Opt-N, the flexibility demand can be satisfied by several flexible supply options: flexible generation, curtailment, demand response, storage, and cross-border electricity trade. The demand response refers to load shedding, load shifting, passive storage, and smart charging archetypes. The complete list of technological flexibility supply sources in the IESA-Opt-N model is presented in Table 5. This table indicates the name of the flexibility source, its primary sector, the name of the technology, and the number of different available technological options in the model.

Flexibility options and their underlying formulation in the IESA-Opt model are thoroughly explained [29]. Flexible generation includes power generation units, and CHPs, which provide flexibility in two dimensions: 1) by modifying their fuel input and 2) changing their heat-to-power ratio within a possible deviation range from a reference operation profile [66]. Demand response can be in the form of load shedding or load shifting. Load shedding requires the system to overinvest in the capacity [67] to allow a decrease in operation for hours when electricity is scarce and prices are high [68]. This flexibility form can be applied to various processes such as the production of heat [69], hydrogen [70], methanol [71], methane [72], hydrocarbons [73], chlorine [74], ammonia [75], and other chemicals [68]. In load shifting, the system reallocates the energy demand by increasing and decreasing it at different hours (always within a feasible operating range). For instance, power to X technologies are considered as load shifting technologies. Therefore, load shedding allows only for a one-direction variation in the demand, while load shifting allows for variations in demand in both directions.

As IESA-Op-N comprises all energy-related sectors of a country, it can endogenously determine the optimal mix of flexibility supply options. For instance, in the case of demand response (e.g., power to heat), the optimal amount of hourly heat demand is endogenously optimized based on the availability and hourly marginal price of electricity. This capability is one of the benefits of using a high-resolution ESM instead of a PSM. Although PSMs can provide higher technical resolution by including generation constraints and optimal power flow equations, they can hardly determine endogenous investment flexibility options in other sectors as they use exogenous sectoral demands. Therefore, the cross-sectoral flexibility investment usually remains an exogenous scenario parameter to PSMs.

Flexibility source	Sector	example technologies
Flexible Generation	Waste Disposal	CHP waste incineration
	Heat	CHP gas
		CHP blast furnace gas
		CHP hydrogen
		CHP biomass
	Agriculture	CHP gas
	Power generation	Gas turbine, nuclear SMR plant
Demand Response	Industry	ULCOWIN steel production
		Solid state ammonia synthesis
	Refineries	P2Liquid Fischer–Tropsch
		P2Liquid methanol
	Hydrogen	Electrolyzer (Alkalyne, PEM, Solid Oxide)
	Residential	Electric heat pump with ground water
		Flexible standard electricity consumption
	Services	Flexible standard electricity consumption
Storage	Heat Network	Hot water storage tank
	Power generation	Compressed Air Energy Storage (CAES)
	Residential	Electric heat pump
	Transport	Electric battery vehicle smart charging
	Transport	V2G electric battery vehicle
Curtailment	Power generation	Wind, PV solar

Table 5. Cross-sectoral flexibility supply archetypes and corresponding technologies in the IESA-Opt model

2.4. Theme two: uncertainty in technological costs

One of the critical parameters to determine the optimal investment in technology is its costs. IESA-Opt segregates technological cost parameters into CAPEX, FOM, VOM, and fuel costs[1]. Moreover, four other parameters affect the cost calculations of a technology capacity investment: discount rate, construction time, decommissioning costs, and economic lifetime. Notably, the capital cost of new nuclear plants, construction times, and associated interest during construction (IDC) are significant factors in the decision-making for investments in new nuclear power plants in Western Europe [21]. Moreover, indirect service costs[2] are identified as crucial cost components of nuclear power, among other factors such as equipment costs, supplementary costs, material costs, and labor costs [76]. In this study, we are not interested in the share of each cost component. Therefore, we only use a single CAPEX component, which comprises the overnight construction costs, interest during construction, and other mentioned cost components. A recent study reported a wide range of 3.9 B€/GWe to 7.2 B€/GWe [53] for gen III nuclear capital costs. As there is vast uncertainty on nuclear capital cost estimates, we perform sensitivity analyses on this parameter.

Moreover, assumptions on social discount rates are crucial for the model-based assessment of renewables. Discount rates are used to determine the value of future cash flows. The higher the discount rate, the lower the value we assign to future savings in today's decisions. The assumed discount rate differs widely across technologies and countries [77]. We assume a 5% discount rate for all technologies in the reference and nuclear scenarios. However, to identify the role of the discount rate in the economic feasibility of nuclear power, we perform a sensitivity analysis on this parameter.

We investigate the impact of technological cost variation on the cost-optimal investment decision in two separate sensitivity analyses. First, we fix VRES technological costs and analyze the change in nuclear

[1] For nuclear power, we consider the decommissioning and waste management costs as part of the VOM costs.

[2] Indirect services costs comprise field indirect costs, construction supervision, commissioning and startup costs, demonstration test run, design services off- and onsite, project/construction management services off- and onsite, and contingency on indirect services cost [109].

investments by varying nuclear interest rates and CAPEX. Second, we fix the interest rate and analyze the impact of variations in VRES and nuclear CAPEX on investment decisions.

The nuclear scenario is used as the base for sensitivity analyses. Moreover, all sensitivity analyses are solved for the 2030, 2040, 2050, and 2060 periods to account for the energy transition dynamics.

2.4.1. Nuclear specific discount rate compared to nuclear capital cost

We analyze the sensitivity of the interest rate and capital costs on the investment in nuclear power plants. This analysis adopts optimistic VRES costs as described in Table 2. We assume four interest rate levels for investments in nuclear power generation depending on the source: 3% for public investments, 5% for public-private investments, 7% for low-risk private investments, and 9% for high-risk private investments. Furthermore, we vary the capital cost component of nuclear power generation from 3 B€/GW to 10 B€/GW with 0.5 B€/GW increments to account for variations in construction time and other cost variations.

2.4.2. VRES compared to nuclear capital cost

This sensitivity analysis demonstrates the impact of VRES and nuclear CAPEX changes on capacity investments. Here, we fix the interest rate for all technologies by assuming a public-private investment source with a 5% interest rate. We modify the capital cost component of nuclear power generation from 3 B€/GW to 10 B€/GW with 0.5 B€/GW increments. To account for changes in VRES costs, we change the CAPEX component of VRES across the minimum and maximum values we found in the literature. Table 6 demonstrates the utilized capital cost ranges for VRES technologies in 2050.

Technology	Lowest	Low	Mid	High	Highest
Wind offshore [M€/GW]	850	1250	1650	2050	2450
Wind onshore [M€/GW]	800	937.5	1075	1212.5	1350
Solar PV [M€/GW]	220	270	320	370	420

Table 6. The CAPEX cost range estimates for VRES technologies in 2050. Sources: [1], [78]

2.5. Theme three: SMR and flexible generation

Nuclear SMRs can change their output power by shutting down each small reactor, thus providing flexibility to the power system. However, the rate of power output change can differ for each design. Moreover, since SMRs are currently in low TRL levels, their cost estimates can vary significantly with the realization of projects. Using the nuclear scenario as the base, we frame a sensitivity analysis that changes two parameters.

First, we modify the ramping rate of SMR technology in three subjective levels: 5%, 10%, 20%, and 60%. For instance, with the 5% ramping rate, the power output can increase or decrease only by 5% in each hour. This is rather a pessimistic assumption as standard load-following NPPs should ramp their output equal to 3% of nominal power per minute [78]. However, the aim here is to show the economic value of SMR flexibility in several ramping rate levels.

Second, we modify the capital cost of SMR in 2050 in the range of 5 B€/GW to 6.5 B€/GW with 0.1 B€/GW increments. The capital cost of gen III remains 6 B€/GW in 2050, as mentioned in the nuclear scenario definition. Therefore, we allow for investments in nuclear SMR while the total national installed capacity of gen III and SMR is capped at 12.48 GWe in 2050.

2.6. Theme four: analyzing cross-border electricity trade

Cross-border trade can play an essential role in supplying flexibility to the energy system [79]. However, the available cross-border electricity supply and demand and associated prices depend highly on the energy system states of the neighboring countries, which can vary drastically based on socio-political policies.

For instance, an in-depth review of model-based electricity generation scenarios of Germany and France is provided by Thimet et al. [80]. The power demand and generation mix in 2050 vary considerably across different scenarios for Germany. While some scenarios assume high shares of coal and natural gas in the power generation sector (e.g., [81], [82], and [83]), some others assume high shares of VRES (e.g., [84] and [81]). Moreover, the net imported electricity per year varies from 200 TWh [85] to more than -200 TWh [81] exports. Furthermore, the power demand varies from 500 TWh [82] to 1000 TWh [81] and even more than 1400 TWh [84].

Similarly, France's range of power demand and generation mix estimates in 2050 is moderately broad. In most scenarios, nuclear power and VRES remain the core of power generation in France (e.g., [86] and [87]). However, nuclear [9] or VRES [82] is the dominant power generator type in some scenarios. Moreover, the net imported electricity per year ranges from 50 TWh [88] to more than -200 TWh [9] exports in nuclear-based scenarios. While the French power demand ranges from slightly less than 300 TWh [89] to more than 700 TWh [87], most scenarios use demand values near 500 TWh.

This wide range of power demand and generation mix uncertainty across scenarios results in a wide range of estimated electricity prices and available cross-border trade capacity. Moreover, the range for Dutch electricity price estimates in 2050 is relatively wide: Koirala et al. [90] estimate the average Dutch electricity price of 148 €/MWh in 2050, which is highly sensitive to VRES capacity and electricity demand. Sijm et al. [91] report an average Dutch electricity price of 26 €/MWh assuming high investments in solar PV. However, IESA-Opt-N assumes lower solar potential, which results in higher electricity prices.

Power demand, generation mix, price, and trade capacity, can heavily affect the cost-effectiveness of national nuclear power investments. However, the estimations of these parameters for each neighboring country vary considerably. Thus, estimating the cross-border electricity price and volume projection can be demanding. In order to reflect this uncertainty on national nuclear investment decisions, we perform a set of sensitivity analyses. Taking the nuclear scenario as a base, we change the cross-border electricity price and its yearly volume to produce a set of sensitivity scenarios. Based on the available literature, we modify the electricity import price in the subjective range of 36 €/MWh to 155 €/MWh with 11 €/MWh increments. Since the model can decide when to export with the perfect foresight, we subjectively penalize the electricity export value by assuming the electricity export price equals 36 €/MWh lower than the import price at each step. Moreover, to account for the wide range of net imported electricity, we assume a moderately wide range of 0 to 111 TWh yearly electricity import (or export) volume. The model can invest in interconnection capacities if required; however, the total amount of imported or exported electricity remains under this maximum constraint.

3. Results and discussion

Following the same structure as the method section, the results are presented in four main themes: system-wide analyses, sensitivity analyses on technological costs, flexible generation, and cross-border trade. The reported values in this section are rounded to one or zero decimal digits to facilitate reading tables.

3.1. Theme one: system-wide analyses

Allowing for investment in nuclear power in the Netherlands has a significant impact on the energy system. Here we demonstrate this impact by comparing the reference and nuclear scenarios for major system indicators such as system costs, energy price, emission price, energy mix, flexibility volumes, and electricity trade.

Electricity mix

Under assumptions of the nuclear scenario, the model minimizes system costs by investing in 3, 5.9, and 9.6 GWe nuclear capacity in 2030, 2040, and 2050, respectively. Investments in nuclear power affect the power system in two ways: less VRES capacity and transmission line capacity requirements. In 2030, the 3 GWe nuclear capacity reduces offshore wind capacity by 4.7 GW and offshore transmission line capacity by 4.5 GW. In 2040, the wind offshore and its transmission line capacities will correspondingly reduce by 10.6 and 9 GW. Additionally, the import transmission line capacity reduces by 3.3 GW compared to the reference scenario. In 2050, the 9.6 GW baseload nuclear relieves the system from excessive investments in infrastructure, resulting in 5.7 and 10.9 GW less required capacity in offshore and cross-border transmission lines (Table 7).

Therefore, in early periods of the energy transition, nuclear power reduces the spatial challenges of VRES deployment by installing less offshore wind capacity. Moreover, in the long term, nuclear power contributes to a lower need for transmission line capacity, particularly cross-border and offshore capacities. However, the need for national transmission line capacity remains. Furthermore, the VRES capacities remain the same in 2050, as both scenarios hit the maximum VRES potential constraints.

Scenarios	**Reference**			**Nuclear**			**Difference**		
Periods	2030	2040	2050	2030	2040	2050	2030	2040	2050
Offshore (far) Wind	13.3	36.1	65	8.6	25.5	65	-4.7	-10.6	0
Offshore (near) Wind	6	13	13	6	13	13	0	0	0
Onshore Wind	8	10	12	8	10	12	0	0	0
Solar (grouped)	40	63	75	40	63	75	0	0	0
Gas Turbines (grouped)	10.3	0	0	10.3	0	0	0	0	0
Nuclear	0.5	0	0	3.5	5.9	9.6	3	5.9	9.6
Other	4.6	0	0	4.6	0	0	0	0	0
Generation Capacity	82.7	122.2	165	81	117.5	174.6	-1.7	-4.7	9.6
Import interconnection capacity	10.8	26.6	39.2	10.8	23.3	32	0	-3.3	-7.2
Export interconnection capacity	10.8	10.8	24.3	10.8	10.8	20.6	0	0	-3.7
Offshore transmission capacity	14.1	33.8	71	9.6	24.8	65.3	-4.5	-9	-5.7
National transmission capacity	32	61.7	105.9	31	59	107.8	-1	-2.7	1.9
Total Capacity	150.4	255.1	405.4	143.2	235.4	400.3	-7.2	-19.7	-5.1

Table 7. Evolution of electricity capacity mix in the reference and nuclear scenarios. Capacity values are rounded to one digit, and the units are in GW.

In the reference scenario, all electricity generation comes from VRES from 2040 onwards (Table 8). In the nuclear scenario, nuclear power contributes to 15% of electricity generation in 2040 and 2050, while offshore wind remains the primary cost-effective electricity generation source for the Netherlands.

Scenarios	**Reference**			**Nuclear**			**Difference**		
Periods	2030	2040	2050	2030	2040	2050	2030	2040	2050
Offshore (far) Wind	64.6	166.8	321.8	42.2	118.8	312.8	-22.4	-48	-9
Offshore (near) Wind	31.7	68.6	68.6	31.7	68.6	68.6	0	0	0
Onshore Wind	20	21.3	28.4	20.2	22.1	28.3	0.2	0.8	-0.1
Solar (grouped)	31.2	49	58.3	31.2	49	58.3	0	0	0
Gas Turbine (grouped)	1.8	0	0	1	0	0	-0.8	0	0
Nuclear	3.8	0	0	27.5	46.5	75.8	23.7	46.5	75.8
National Generation	153.2	305.8	477.1	153.9	305.1	543.8	0.7	-0.7	66.7
Imported Electricity	27.8	33.3	34	27.8	33.3	15.5	0	0	-18.5
Exported Electricity	3.6	22.3	44.4	3	21.4	44.4	-0.6	-0.9	0
Total Electricity Demand	177.4	316.8	466.7	178.7	317	514.9	1.3	0.2	48.2

Table 8. Evolution of electricity generation mix in the reference and nuclear scenarios. Units are in TWh. Values are rounded to one digit.

Moreover, investments in nuclear power decrease the Dutch electricity dependence on neighboring countries resulting in 18.5 TWh less import in 2050. The imported and exported electricity amounts are

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low compared to the transmission line capacities, meaning that the model uses the cross-border electricity trade as a peak shaver with capacity factors between 0.16 (imports) and 0.31 (exports) in the nuclear scenario. Therefore, the cross-border electricity price plays an essential role in determining the hourly merit order curve and the need for investments in nuclear power. The sensitivity analyses in section 3.4 explore further the role of cross-border trade.

Although the electricity demand does not differ between the scenarios in 2030 and 2040, it increases considerably in the nuclear scenario in 2050. This increase is mainly due to higher electricity demand in producing hydrogen, by Solid Oxide Electrolyzer, and ammonia, by Solid State Ammonia Synthesis. The produced hydrogen is used in hydrogen boilers, resulting in a lower need for natural gas. In addition, the Solid-State Ammonia Synthesis production replaces the Haber Bosch Steam Methane Reforming technology, consequently reducing natural gas demand. Due to lower natural gas demand, the need for syngas production from biomass gasification reduces. Therefore, investments in nuclear power result in lower electricity, natural gas, and biomass imports (Figure 4).

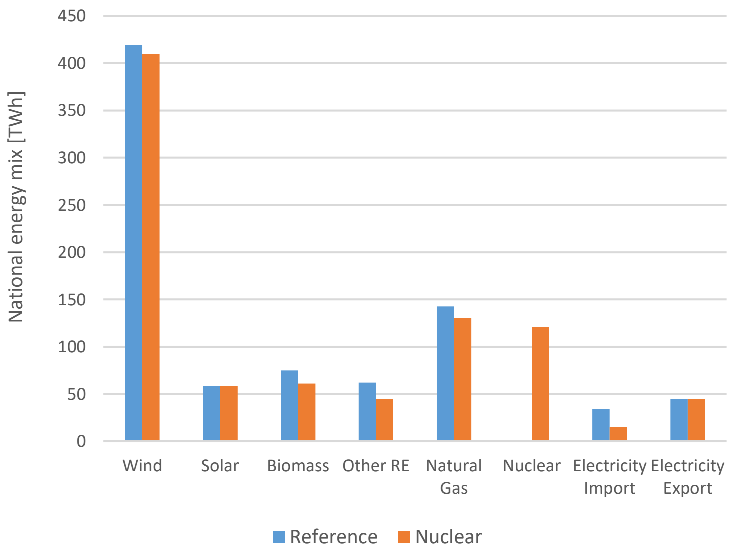
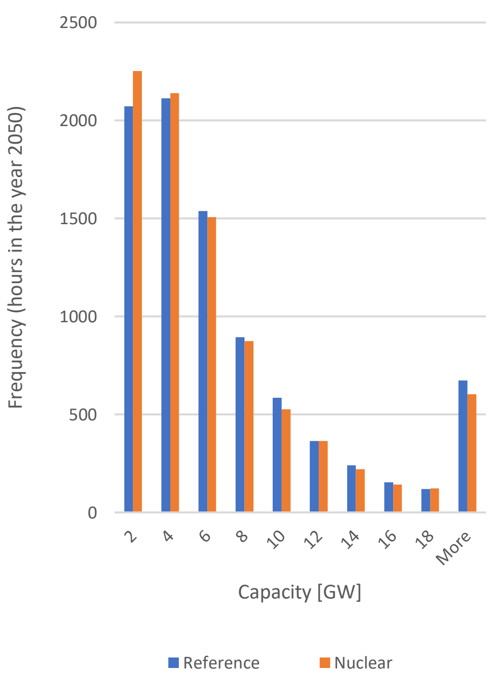


Figure 4. The 2050 primary energy mix in the reference and nuclear scenarios in the Netherlands.



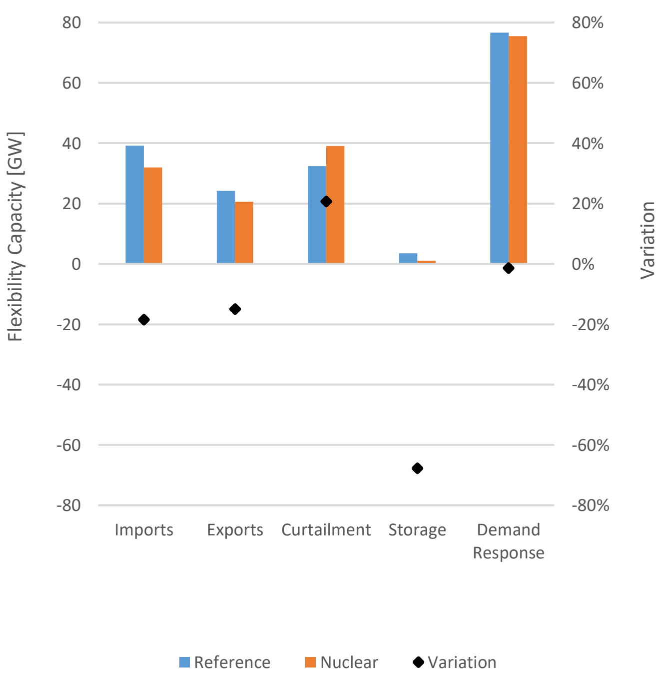


Figure 5. Flexibility supply by capacity.

Left: the cumulative histogram of the flexibility capacity demand in the reference and nuclear scenarios in 2050. Right: variations in flexibility supply capacity by source in the nuclear scenario compared to the reference scenario in 2050.

Flexibility supply in units of capacity (GW)

Figure 5-left demonstrates the histogram of the required flexibility capacity to balance the hourly variations in the residual load in 2050. Both scenarios require high levels of flexible capacity. However, there are more hours with low flexibility capacity in the nuclear scenario and fewer hours with high flexibility capacity. Therefore, the flexibility demand shifts from higher to lower capacities in the nuclear scenario.

Although Figure 5-left demonstrates the trend in lower demand for flexibility in the nuclear scenario, it does not provide details regarding the flexibility supply sources. The flexibility demand is satisfied by several flexibility supply sources that are presented in Figure 5-right. The values in this figure refer to the maximum capacity supplied by each source during each hour of 2050. In the nuclear scenario, the capacity required to satisfy the flexibility demand reduces by all sources, except curtailment, which increases mainly due to lower investments in the offshore wind transmission line. Moreover, the required storage capacity is reduced by 68% in the nuclear scenario. Therefore, investments in nuclear can highly influence the demand for electricity storage and cross-border transmission line capacity. The reduction in the required demand response capacity is negligible, suggesting that the energy system also relies heavily on demand response by 2050 with low carbon baseload power generation.

Flexibility supply in units of energy (TWh)

Figure 6 demonstrates the hourly residual load curve and flexibility supply sources of the reference scenario in 2050. In order to balance the residual load, the energy system can use several flexibility supply options such as flexible generation, storage, demand response, curtailment, and cross-border trade (i.e., electricity imports and exports). The positive residual load can be balanced by flexible generation, storage, demand response, or electricity import and the negative residual load by demand response, storage, curtailment, and electricity exports.

Since VRES dominates the reference scenario, the residual load is negative in most hours. However, this negative residual load is mainly balanced by high demand response and curtailment values. The demand response here mainly refers to the production of hydrogen (i.e., electrolyzers), ammonia (i.e., solid-state synthesis), and methanol (P2Liquids).

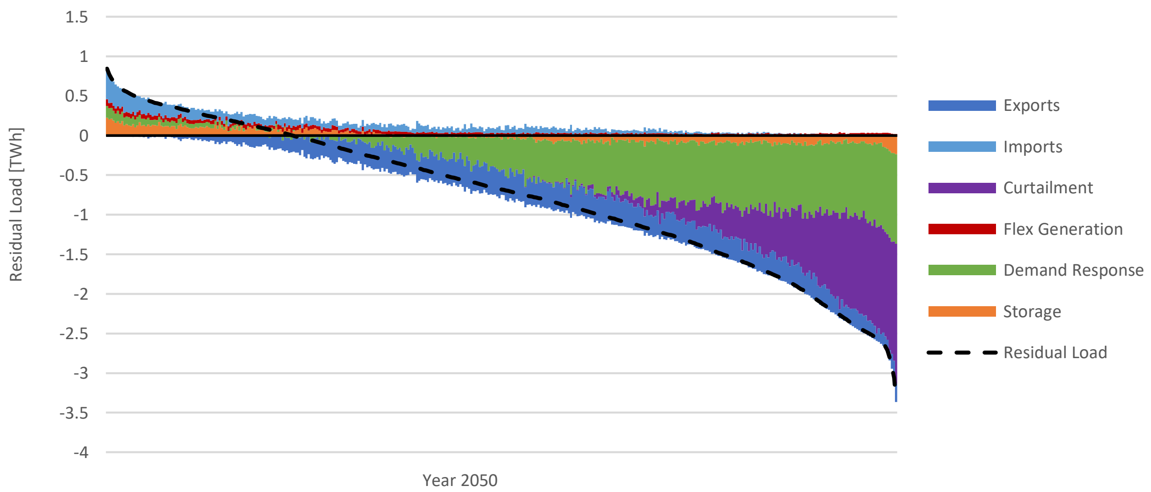


Figure 6. The reference scenario's residual load curve and flexibility supply sources in 2050. The substantial negative residual load is mostly balanced through demand response and curtailment.

By adding all hourly volumes of flexibility supply in Figure 6, we can compare yearly flexibility supply volumes in the reference and nuclear scenario in Figure 7. The demand for flexibility volume increases by 54.4 TWh (equal to 30%) in the nuclear scenario in 2050. This considerable increase is mainly due to overinvestments in producing syngas from Solid-Oxide electrolyzer technology resulting in higher load shedding volumes. Due to lower electricity prices, the extra investments in these technologies become cost-effective in the nuclear scenario. Additionally, the curtailment volume increases by 35%, meaning that the model prefers to avoid the high costs of the offshore transmission line as the average electricity price in 2050 is reduced by 16% in the nuclear scenario. However, since VRES curtailment depends on exogenous wind and solar profiles, we might observe an utterly different curtailment behavior by the system with a slightly different set of profiles. Moreover, the need for electricity storage options reduces by 6.7 TWh in the nuclear scenario due to lower Compressed Air Underground Storage utilization.

Although the electricity export volume remains the same, the electricity import volume decreases by 54% in the nuclear scenario. The reduction in electricity import both in capacity and volume suggests that investments in nuclear power directly reduce the Netherlands' long-term dependency on electricity trade.

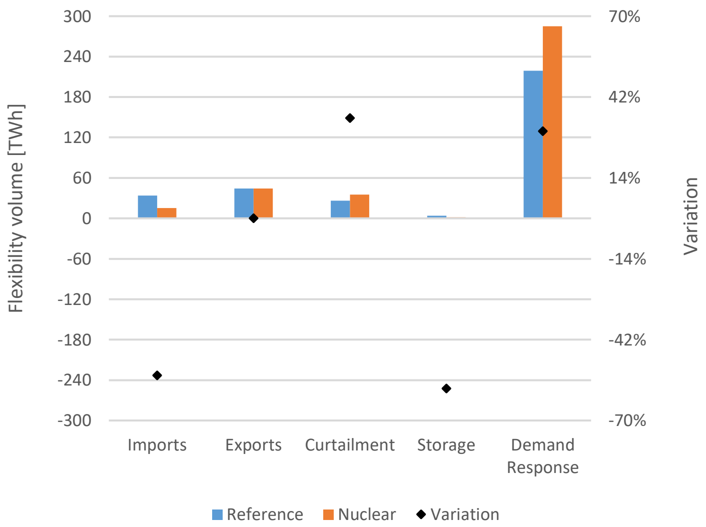


Figure 7. Variations in the flexibility volume by source in the nuclear scenario compared to the reference scenario in 2050.

System costs

Investments in nuclear power reduce the national system costs by 0.19 B€ (equal to 0.2%) and 1.24 B€ (equal to 1.1%) in 2040 and 2050, respectively (Table 9). This outcome may sound counterintuitive considering the higher costs of nuclear power than other electricity generation sources. However, nuclear investments affect the whole energy system. Although the capital and fixed operational costs increase (mainly due to higher nuclear investments), the variable operational and trading costs reduce substantially (mainly due to lower electricity import costs), resulting in lower overall system costs in 2050. In conclusion, given all the cost uncertainties, the system cost reduction is not significant.

In the short term (i.e., 2030), although capital costs decrease in the nuclear scenario (due to lower investments in offshore wind), the system costs increase slightly. This is due to a higher fixed operational cost of nuclear power and higher trading costs (i.e., lower export revenues). On the other hand, the lower export revenue results from the export product cost reduction, mainly due to cheaper electricity prices in the nuclear scenario.

Scenarios	**Reference**			**Nuclear**			**Difference**		
Periods	2030	2040	2050	2030	2040	2050	2030	2040	2050
Capital Cost	51.9	61.1	63.3	51.6	60.4	64.6	-0.32	-0.64	1.24
Fixed Operational Cost	30.0	32.6	38.5	30.2	32.7	39.5	0.16	0.03	1.01
Variable Operational Cost	96.8	79.6	10.0	96.9	80.1	8.7	0.08	0.49	-1.37
Trading Cost	-67.2	-48.3	0.4	-66.9	-48.4	-1.7	0.31	-0.07	-2.13
Total System Cost [B€]	111.6	125.0	112.2	111.8	124.8	111.0	0.24	-0.19	-1.24

Table 9. National system cost (in B€$_{2019}$) evolution in the reference and nuclear scenarios. System costs are 0.2% and 1.1% lower in the nuclear scenario in 2040 and 2050.

Mitigation costs

Comparing the mitigation costs provides a better indication of system-wide cost implications of a specific energy policy. Compared to the reference scenario, the sum of mitigation costs in the transition pathway is lower in the nuclear scenario (Figure 8-left). In 2030, the mitigation costs will increase slightly by 2.8% (equal to 0.2 B€) in the nuclear scenario. However, in the long term, nuclear investments reduce the mitigation costs by 1.6% (0.3 B€) and 6.2% (1.3 B€) in 2040 and 2050, respectively.

These cost values refer to annualized costs occurring in a specific year. In order to estimate the cumulative mitigation costs, we can linearly interpolate the cost values for the years in-between (Figure 8-right). Consequently, the estimated cumulative mitigation costs from 2030 to 2050 are equal to 361.2 B€ and 352.2 B€ in the reference and nuclear scenarios, respectively. Therefore, investments in nuclear power can reduce the cumulative mitigation costs by 2.5% (9 B€) up to 2050.

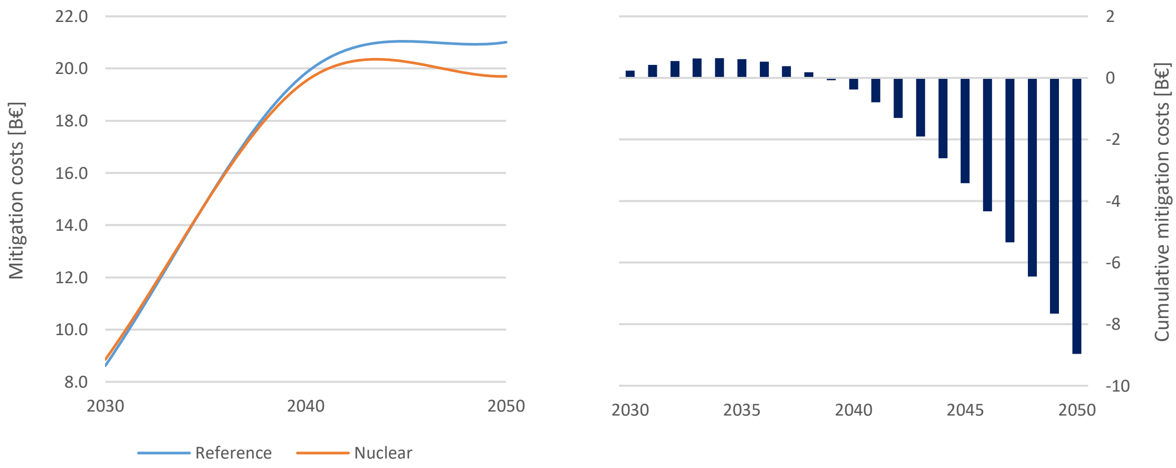


Figure 8. Mitigation costs.
Left: Mitigation costs ($B€_{2019}$) evolution in the reference and nuclear scenarios. Nuclear scenario mitigation costs increase slightly in 2030 but reduce in the long term.
Right: The interpolated cumulative mitigation costs in the nuclear scenario minus the reference scenario. Investments in nuclear power reduce cumulative mitigation costs by 9 B€ in the long term.

Final sectoral costs

In the nuclear scenario, most final sectors experience cost reduction in 2050 (Figure 9-left). Residential and services sectors experience 10% cost reduction, mainly due to lower electricity prices. Similarly, the cost reduction in the industrial (12%) and transport (4%) sectors results mainly from lower fuel costs as the endogenous price of electricity, bio ethanol, hydrogen, syngas, and bio kerosene fuels decreases.

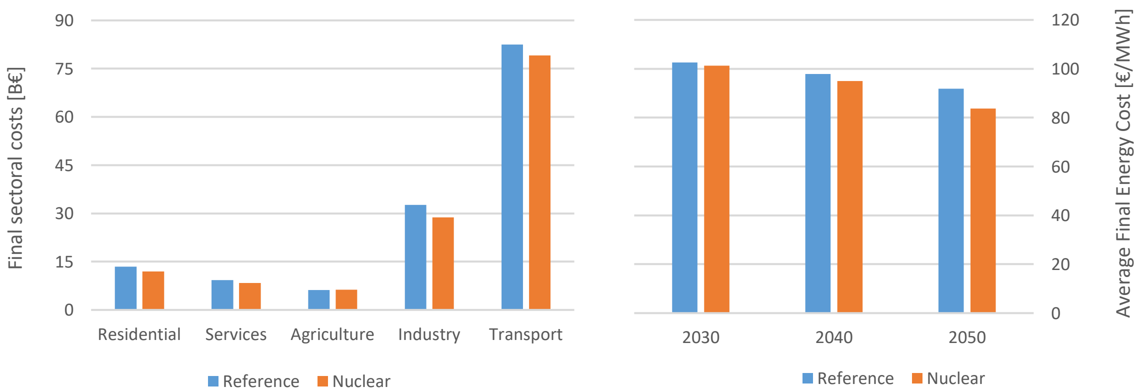


Figure 9. Final sectoral costs.
Left: Final system costs by sector in the reference and nuclear scenarios in 2050 (in $B€_{2019}$).
Right: Average final energy cost evolution in the reference and nuclear scenarios.

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The average final energy cost in both scenarios reduces in the long term. This is mainly due to the higher share of VRES in power generation and, thus, lower electricity prices. Compared to the reference scenario, the final energy cost in the nuclear scenario decreases by 1%, 3%, and 9% in 2030, 2040, and 2050, respectively (Figure 9-right). This reduction is mainly due to the higher electrification rate and cheaper electricity prices in the nuclear scenario, particularly in 2050. Thus, on average, investments in nuclear power reduce the final consumer's energy costs.

Power generation sector costs

Power generation costs increase by 2%, 4%, and 9% in 2030, 2040, and 2050, respectively (Table 10). The cost increase in 2030 and 2040 is mainly due to the higher FOM and VOM of nuclear power. In 2050, the cost will increase considerably, mainly due to higher electricity demand and extra investments in nuclear power. However, import costs are reduced by more than half compared to the reference scenario.

The endogenous power demand in 2050 increases considerably in the nuclear scenario. Thus, we compare power sector costs per total electricity demand. We see a 1% and 3% cost increase in the nuclear scenario in 2030 and 2040, respectively, compared to the reference scenario. However, in 2050, the power sector costs per unit of electricity demand will be reduced by 1% with investments in nuclear. Therefore, although the total power sector costs increase in the nuclear scenario, the cost per unit of demand decreases, which results in a 16% lower average electricity price in 2050.

Scenarios		**Reference**			**Nuclear**			**Difference**		
Periods		2030	2040	2050	2030	2040	2050	2030	2040	2050
Balancing	CAPEX [B€]	10.1	15.2	21.9	9.8	14.8	24	-0.3	-0.4	2.1
	FOM [B€]	2.1	4	6.4	2.3	4.1	7.5	0.2	0.1	1.1
	VOM [B€]	0.2	0.2	0.3	0.5	1	1.6	0.3	0.8	1.3
	Fuel Costs [B€]	0.1	0	0	0.2	0.2	0.4	0.1	0.2	0.4
	Import Costs [B€]	1.6	2.9	3.9	1.6	2.9	1.8	0	0	-2.1
	Export Revenues [B€]	-0.1	-1.1	-3.5	-0.1	-1.1	-3.5	0	0	0
Total Costs [B€]		14.1	21.2	29.1	14.3	21.9	31.7	0	1	3
Capacity (generation + transmission) [GW]		150.4	255.1	405.4	143.2	235.4	400.3	-7	-20	-5
Demand [TWh]		178.1	347.1	408	182.9	465.8	553.3	4.8	118.7	145.3
Average Electricity Price [€/MWh]		119.8	89	91.9	111.8	85.2	77.2	-8	-4	-15

Table 10. Decomposition of power generation sector costs in the reference and nuclear scenarios, 2030-2050 (in B€$_{2019}$).

The average electricity price refers to the average hourly shadow price of the electricity balancing constraint. Investments in nuclear power decrease the average electricity price by 7%, 4%, and 16% in 2030, 2040, and 2050, respectively. Investments in relatively expensive nuclear power decrease electricity prices because it reduces the need for flexibility supply options. The price duration curve in Figure 10 demonstrates that the nuclear scenario has lower electricity prices than the reference scenario in most hours of the year.

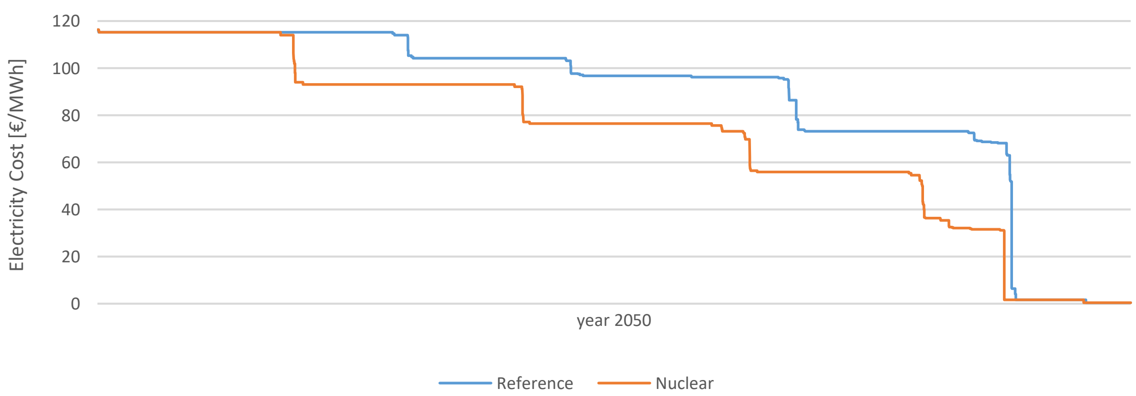

Figure 10. The electricity price duration curve of the Netherlands in the reference and nuclear scenarios in 2050.

Emissions

The model optimally distributes the emissions between ETS and non-ETS sectors to achieve the 55%, 77%, and 100% emission reduction targets in 2030, 2040, and 2050, respectively. Investing in nuclear power allows for 5.6 Mton (20%) more non-ETS emissions in 2050, as the ETS sector can utilize the cheaper electricity to capture emissions further. The higher negative ETS emission mainly comes from the lower emitted CO_2 from the Haber Bosch ammonia production with Steam Methane Reforming. Due to higher negative emissions, the non-ETS sector increases its emissions, which are emitted from gas boilers in the residential sector.

We report the national CO_2 shadow price as an output of the model for the national emission constraint that covers both ETS and non-ETS emissions. The emission price in both scenarios decreases in the long term. Although the CO_2 price does not change noticeably in 2030 and 2040, it is reduced by 25% in the nuclear scenario in 2050. The lower emission price is directly related to cheaper electricity prices, resulting in higher electrification of the industry.

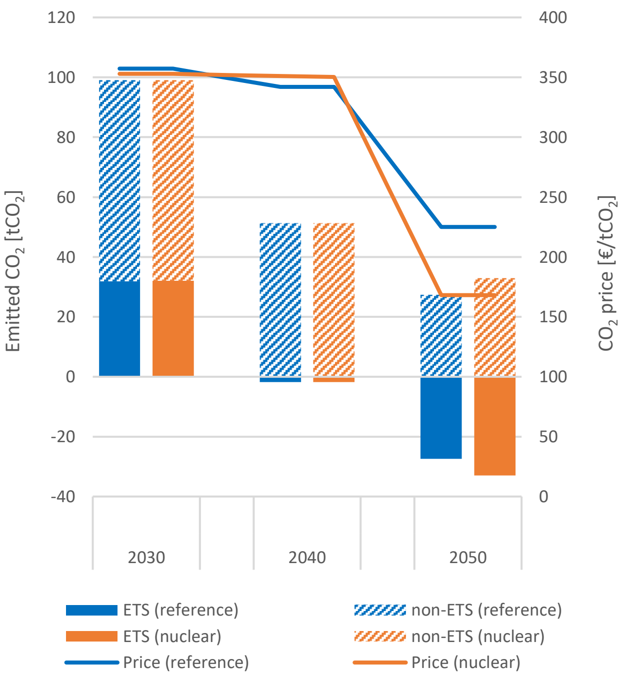

Figure 11. The evolution of ETS and non-ETS emissions and total CO_2 shadow price in the reference and nuclear scenarios.

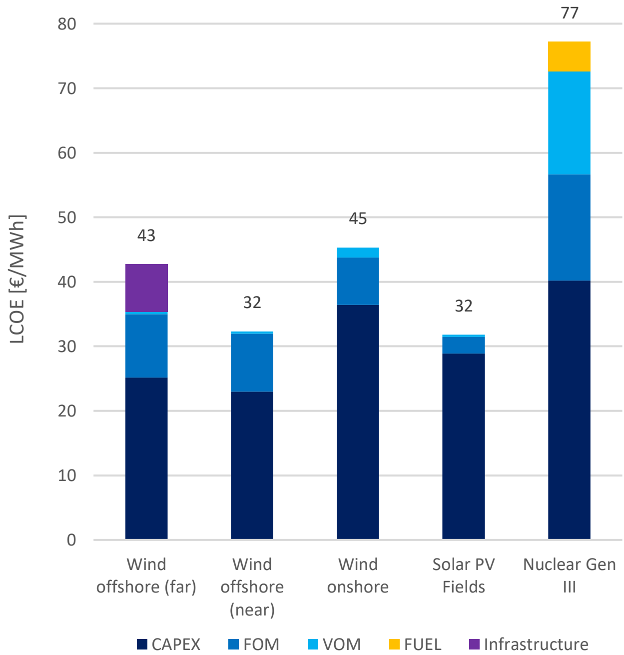

Figure 12. The realized LCOEs under the nuclear scenario in 2050 for intermittent renewables and nuclear technologies.

LCOEs

Resulting from the nuclear scenario, Figure 12 presents the realized LCOE of VRES and nuclear power generation technologies in 2050. Wind offshore LCOE includes an infrastructure component that refers to required extra investments in submarine cables to connect far offshore wind farms to the national grid. However, the national grid infrastructure cost component is not included as all generation technologies share this infrastructure. Although nuclear power has a considerably higher LCOE than wind offshore, the system invests in it to avoid relatively higher indirect system-wide costs such as higher flexibility supply costs and higher infrastructure capacity demand. For instance, since nuclear power partly substitutes wind offshore, the indirect system-wide cost component of LCOE for wind offshore is at least equal to the difference between the wind and nuclear LCOEs, which is 34 €/MWh. However, the indirect system-wide cost component of LCOE is highly dependent on the system configuration, scenario assumptions, and exogenous VRES profiles. Therefore, assuming a specific value as the indirect system cost across different scenarios can be misleading. Instead, we suggest applying a whole energy system-wide modeling approach, as it is done in this study, to account for system-wide costs in energy system planning analyses. In conclusion, relying merely on LCOE analyses can underestimate the role of nuclear power in the energy system. This is in line with the conclusion from Hansen [92] that looking beyond LCOE values significantly changes the energy system's priorities.

3.2. Theme two: Uncertain technological costs

We run the nuclear scenario for the sensitivities in 2030, 2040, 2050, and 2060 periods. However, only the 2050 values are reported here. Furthermore, we decreased the model's temporal resolution to save computational time.

3.2.1. Interest rate compared to nuclear capital costs

The financial source of the investment can significantly impact the economic feasibility of nuclear power. Figure 13 demonstrates that in higher discount rates, the investments in nuclear power become more sensitive to nuclear capital cost variations. Moreover, assuming a public investment, nuclear power is a cost-effective technology option in 2030 and 2050.

In 2050, with public investments in nuclear (i.e., 3% discount rate), capital costs up to 10 B€/GW are still economical. With public-private investments (i.e., a 5% discount rate), the maximum economical nuclear capital cost is around 9 M€/GW. In contrast, low-risk private investments in nuclear (i.e., 7% discount rate) reduce the maximum economic nuclear capital cost to 6.5 B€/GW. However, with high private investment risks (i.e., a 9% discount rate), only capital costs less than 5 B€/GW can be cost-effective. In 2030, nuclear investments become more sensitive to nuclear capital cost variations in higher discount rates. While the system invests the maximum allowed nuclear capacity with the public discount rate, the maximum economic nuclear capital cost reduces to 8.5, 6, and 4.5 B€/GW with discount rates of 5%, 7%, and 9%, respectively. Therefore, assuming public interest rates for financing nuclear power investments can significantly reduce the relevance of nuclear capital cost uncertainties both in the short and long term.

This outcome is highly relevant to the EU sustainable finance taxonomy. The EU taxonomy would provide companies, investors, and policymakers with appropriate definitions for which economic activities can be considered environmentally sustainable. In this way, it creates security for investors in environmentally sustainable activities [93]. Since nuclear power can drastically reduce mitigation costs, the European Commission has investigated including nuclear power in the EU taxonomy list [94]. Although nuclear power is not listed in the primary definition of EU taxonomy, the European Commission approved a Complementary Climate Delegated Act, in which nuclear power is added to the list under certain conditions [95]. As a result, the wide range of nuclear CAPEX estimates has a limited impact on nuclear power investments as it benefits from EU taxonomy.

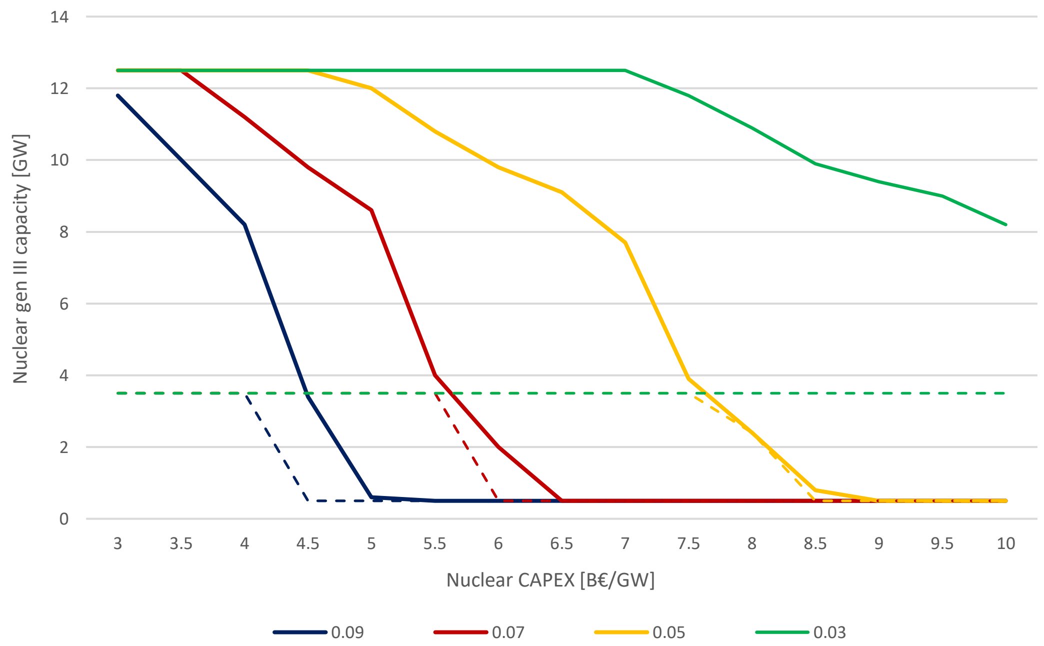

Figure 13. The installed nuclear gen III capacity variations with different nuclear interest rates and capital costs. Straight lines refer to 2050 investments, while dashed lines indicate the investments in 2030.

3.2.2. VRES compared to nuclear capital costs

As shown in Table 11, by assuming an equal discount rate of 5% for all technologies, nuclear with 9.5 B€/GW CAPEX and above is not competitive unless VRES costs reach the highest estimates. However, even with optimistic VRES CAPEX estimates, investments in nuclear power can be cost-effective with nuclear CAPEX under 8 B€/GW. Although with higher VRES CAPEX values, the nuclear investments' range shifts to more expensive nuclear CAPEX values, the range of this sensitivity remains almost the same. Therefore, variations in VRES CAPEX estimates do not change nuclear investments' sensitivity on nuclear CAPEX values.

VRES CAPEX	Nuclear gen III capacity [GWe] in 2050											
Highest	12.5	12.5	12.5	12.5	12.5	9.5	7.6	3.7	3.5	3.5	1.2	0.5
High	12.5	12.5	12.5	9.5	9.4	8.2	4.5	3.5	3.5	1.3	0.5	0.5
Mid	12.5	12	10.9	9.6	8.9	7.7	3.9	3.5	1.2	0.5	0.5	0.5
Low	12.5	12	10.9	9.8	8.8	7.7	4	2.1	0.5	0.5	0.5	0.5
Lowest	12.5	12	10.9	9.8	8.7	8	4	1.9	0.5	0.5	0.5	0.5
Nuclear CAPEX [B€/GW]	4.5	5	5.5	6	6.5	7	7.5	8	8.5	9	9.5	10

Table 11. Installed nuclear generation capacity with variations in the VRES capital costs against nuclear capital costs. The numerical values of VRES CAPEX are described in Section 2.4.2.

VRES capacity in Table 12 refers to the sum of wind offshore, wind onshore, and solar PV capacities in 2050. In the low and lowest VRES CAPEX estimates, the VRES capacity investments hit the maximum exogenous potential, irrespective of nuclear CAPEX value. With higher VRES CAPEX estimates, the VRES investments reduce by lower nuclear CAPEX values. However, this variation is not significantly sensitive to nuclear CAPEX values. Moreover, with the highest estimates of VRES CAPEX, the installed capacity reduces by 3% compared to the lowest cost estimates. Therefore, VRES investments are cost-optimal for the energy system irrespective of VRES and nuclear CAPEX estimate levels under the nuclear scenario assumptions.

VRES CAPEX	VRES generation capacity [GWe] in 2050									
Highest	158.7	158.7	158.7	158.7	158.7	158.7	158.7	158.7	162.7	165
High	161.3	161.3	161.3	161.3	161.3	161.3	165	165	165	165
Mid	164.7	164.7	164.7	164.7	165	165	165	165	165	165
Low	165	165	165	165	165	165	165	165	165	165
Lowest	165	165	165	165	165	165	165	165	165	165
Nuclear CAPEX [B€/GW]	3	3.5	4	4.5	5	5.5	6	6.5	7	7.5

Table 12. VRES generation capacity with variations in the VRES capital costs against nuclear capital costs. The numerical values of VRES CAPEX are described in Section 2.4.2.

3.3. Theme three: Flexible generation

The cost-optimal national SMR investment can vary considerably with its ramping rate and CAPEX estimates. The assumed nuclear gen III CAPEX value in 2050 is 6 B€/GW.

Table 13 shows that at the 6 B€/GW SMR CAPEX value, the investments in SMR increase slightly with higher ramping rates. With 0.2 B€/GW more SMR CAPEX value, the model only adopts this technology if its ramping rate is more than 60%. Therefore, the provided generation flexibility of SMR can only make up for 0.2 B€/GW higher CAPEX costs compared to gen III. Moreover, SMR investments are highly susceptible to variations in the SMR CAPEX value, irrespective of their ramping rate. Therefore, any cost reduction in SMR compared to gen III leads to considerably higher investments in SMR. Additionally, although the investments in SMR capacity increase with higher ramping rates (i.e., generation flexibility), this increase does not change considerably in different CAPEX values. Thus, compared to SMR ramping rate (i.e., providing generation flexibility), the SMR CAPEX value is the dominant parameter in determining its investments.

In conclusion, the investment choice between SMR or gen III depends highly on their CAPEX rather than the flexibility of SMR. The value of SMR flexibility supply becomes noticeable only in a narrow range of SMR CAPEX. Therefore, decreasing SMR CAPEX can considerably impact its economic feasibility compared to increasing its flexible generation potential.

Ramping Rate	Nuclear SMR capacity [GWe] in 2050							
60 %	9	9	8.6	8	7.4	6.8	6.4	0
20 %	9	8.8	8.2	7.5	7	6.5	0	0
10 %	9	8.4	7.9	7.2	6.8	6.3	0	0
5 %	8.9	8.3	7.8	7.1	6.7	6.2	0	0
	5	**5.2**	**5.4**	**5.6**	**5.8**	**6**	**6.2**	**6.4**
	SMR CAPEX [B€/GW]							

Table 13. Investments in SMR nuclear with variations in its ramping rate and CAPEX in 2050.

3.4. Theme four: Cross-border electricity trade

This section aims to quantify the sensitivity of national nuclear power investments to cross-border electricity trade potential, notably its price and volume. Therefore, the presented numbers in the tables should not be used as a conclusion per se, but the overall behavior of the energy system as a response to variations in cross-border trade parameters.

Electricity Price [€/MWh]	Nuclear gen III capacity [GWe] in 2050								
155	10.4	9.5	10.9	12.3	12.5	12.5	12.5	12.5	12.5
144	10.4	9.5	10.4	11.5	12.5	12.5	12.5	12.5	12.5
133	10.4	9.5	9.7	10.8	12.3	12.5	12.5	12.5	12.5
122	10.4	9.5	9.2	9.9	11.2	12.5	12.5	12.5	12.5
112	10.4	9.5	8.4	8.8	10.3	12	12.5	12.5	12.5
101	10.4	9.5	7.3	7.8	9.5	9.7	9.7	9.7	9.8
90	10.4	9.5	5.1	4	3.5	3.5	3.5	2.6	1.1
79	10.4	9.5	4.7	3.5	3.5	3.5	2.6	0.5	0.5
68	9.9	9.5	4.6	3.5	3.5	3.5	2.2	0.5	0.5
58	9.9	9.4	4.4	3.5	3.5	3.4	1.9	0.5	0.5
47	9.9	9.1	4.3	3.5	3.5	2.4	1	0.5	0.5
36	9.9	9.1	4.3	3.5	3.5	2.3	0.8	0.5	0.5
	0	**14**	**28**	**42**	**56**	**69**	**83**	**97**	**111**
	Electricity trade (import or export) quota in 2050 [TWh]								

Table 14. Investments in nuclear gen III capacity with variation in electricity price and trade quota in 2050. Area A (i.e., cells with a red border) and B (i.e., cells with a blue border) are further examined in the following sensitivity analyses.

The electricity price and trade volume quota can considerably affect the investments in nuclear power (Table 14). The electricity quota indicates the maximum yearly traded electricity in imports or exports. In low trade quotas (i.e., no trade or a maximum of 14 TWh), the investments in nuclear do not change with electricity price variations. With higher trade quotas, nuclear power becomes more cost-effective or less, depending on electricity prices. With lower electricity prices (i.e., under 90 €/MWh), nuclear investments reduce with the higher trade quota, as the imported electricity can substitute nuclear power demand. With higher electricity prices, the model increases the investments in nuclear power as the higher exported electricity revenue justifies nuclear power costs. Consequently, investments in nuclear are not noticeably sensitive to electricity trade volumes by assuming imported electricity prices higher than 112 €/MWh in 2050.

From 14 TWh to 28 TWh quota, the investments in nuclear drop considerably at lower prices. Therefore, a red cell border in Table 14 determines this sensitive area (i.e., area A). Moreover, investments in nuclear increase significantly from 90 to 112 €/MWh import prices. Therefore, this sensitive area (i.e., area B) is indicated with a blue cell border. In the following, we zoom into these sensitive areas.

Area A

In low electricity prices, the cost-effective investments in nuclear power depend considerably on trade quotas (Table 15). By increasing the trade quota by 14 TWh, the need for nuclear capacity can reduce by half. However, in higher electricity prices, this reduction is considerably lower (i.e., only 1 GW reduction). Therefore, cost-effective nuclear investments can be susceptible to trade volumes in low electricity price forecasts.

Electricity Price [€/MWh]	Nuclear gen III capacity [GWe] in 2050					
112	9.5	9	8.6	8.2	8.2	8.4
101	9.5	8.7	8.3	7.8	7.3	7.3
90	9.5	8.3	7.9	7.1	6.3	5.1
79	9.5	8.3	7.4	6.5	5.8	4.7
	14	17	19	22	25	28
	Electricity trade quota in 2050 [TWh]					

Table 15. The zoom-in area A of Table 14

Area B

With a high electricity trade volume, nuclear power investments increase considerably with electricity prices higher than 94 €/MWh. With these prices, nuclear capacity can contribute to higher revenues from exports; thus, nuclear investments increase with higher trade quotas. Therefore, with high electricity trade volumes, the cost-optimal nuclear power investments are susceptible to electricity price variations in 90 to 112 €/MWh.

Electricity Price [€/MWh]	Nuclear gen III capacity [GWe] in 2050								
112	10.4	9.5	8.4	8.8	10.3	12	12.5	12.5	12.5
108	10.4	9.5	8	8.3	9.9	11.9	12.5	12.5	12.5
104	10.4	9.5	7.7	8	9.8	11.7	12.5	12.5	12.5
101	10.4	9.5	7.3	7.8	9.5	9.7	9.7	9.7	9.8
97	10.4	9.5	6.7	7.6	6.2	6.5	6.6	7	7.1
94	10.4	9.5	5.7	4.9	3.5	3.5	3.5	3.5	2
90	10.4	9.5	5.1	4	3.5	3.5	3.5	2.6	1.1
	0	14	28	42	56	69	83	97	111
	Electricity import and export quota in 2050 [TWh]								

Table 16. The zoom-in area B of Table 14

4. Discussion

There are not many studies focusing on the role of nuclear power in the national energy transition, using a highly detailed energy system optimization model, so opportunities to compare our results with other works have been limited. While some reviewed studies suggest the economic feasibility of nuclear power, some others disagree. Furthermore, we have shown that cost-effective nuclear investments depend on several techno-economic parameters. Thus, conclusions on the economic feasibility of nuclear power in an energy system with high shares of VRES should be accompanied either by robust reasoning regarding cost and cross-border trade assumptions or sensitivity analyses.

Assumed discount rates

To avoid any bias for VRES or nuclear, we assumed the same 5% discount rate for all technologies in the reference and nuclear scenarios. However, the sensitivity results showed that the value of the discount rate considerably affects the cost-effectiveness of nuclear investments. Therefore, for future studies, we suggest using technological-specific discount rates based on national or international policies (e.g., EU taxonomy).

Social Discount rate

In the empirical literature, there exist many studies that support a social discount rate that is declining over time ([96], [97], [98]). This is relevant for studies that base their conclusions on the social discount rate value (e.g., discounted cash flow analyses). However, we use the social discount rate to weigh different periods in the objective function. For example, the weight of each period in the objective function is 1/3 if we assume a zero social discount rate; while assuming a 2% social discount rate, the weights are 0.4, 0.33, 0.27 for the 2030, 2040, and 2050 periods, respectively. In this formulation, changing the social discount rate (through using a declining social discount rate) does not affect the conclusions considerably.

Cross-border electricity trade

The sensitivity analyses on cross-border trade indicate that the electricity trade price and quota considerably affect the investments in nuclear power. Additionally, the evolution of the European electricity market, particularly the Netherlands' neighboring countries, is highly uncertain. Therefore, following a coordinated electricity trade policy with neighboring countries significantly reduces the uncertainty of nuclear power investments.

Nuclear cogeneration

This study analyzed the nuclear energy source as a power generation technology only. However, fission heat can also be used directly for district heating or as a process-heat in the industry, thus replacing carbon-intensive heat sources like natural gas. Additionally, nuclear plants can be operated in cogeneration mode and deliver a share of fission heat as a final heat source while generating electricity. The resulting higher efficiency may result in more profitable power plants.

Worldwide already sixty-seven nuclear reactors are being operated in cogeneration mode, satisfying district heating, desalination, and industrial process heat demands [99]. Nuclear cogeneration can satisfy process heat demand requiring steam at temperatures up to 550 °C [100]. This process heat has the highest potential in the chemical, refinery, paper, metal, and bioenergy industrial sectors with small capacities (i.e., 50–250 MWth) [101]. Moreover, it can be combined with the (onsite) generated electricity to produce green hydrogen [102]. Depending on the type of the process, the nuclear-based produced hydrogen can be cost-competitive compared to conventional steam reforming, coal gasification, or renewable-based water electrolysis.

We investigated the economic feasibility of nuclear heat or hydrogen cogeneration combined with power generation in Gen III power plants in extra sensitivity analyses. Similar to El-Emam et al. [103], we conclude that the economic feasibility of these technologies primarily depends on the CAPEX. Therefore, as shown in the sensitivity analysis, nuclear cogeneration merely enhances the power system's flexibility and economic feasibility of the investments when nuclear power is cost-effective.

Additional scenario: the low potential of imported biomass, biofuels, and hydrogen

In the nuclear scenario, we assumed a high import potential of critical low-carbon energy sources: biomass, bioethanol, biodiesel, biokerosene, and hydrogen. However, their import potential and price significantly depend on global and regional energy market developments in the coming decades. Therefore, we investigated the impact of lower import capacities of these energy sources on nuclear investments. Thus, we modified the nuclear scenario by fixing the import capacities to 2020 levels.

We find that low biomass and hydrogen import levels increase the need for investments in offshore wind capacity in the short term and nuclear power plants in the long term. In 2030 and 2040, the model builds 11.4 and 14.6 GWe more offshore wind capacity (together with 15.7 and 14.7 GW more offshore transmission line capacity). The extra VRES electricity substitutes the lower biomass and biofuel imports by investing more in high-temperature hybrid boilers and electrolyzers in the short term. Moreover, nuclear investments increase by 0.2 and 1.85 GW in 2040 and 2050. Overall, the lower import levels lead to a substantially higher CO_2 price of 113, 22, and 19%, respectively, in 2030, 2040, and 2050.

Additional scenario: new nuclear investments from 2040 onwards

The country can invest in nuclear from 2030 onwards in the nuclear scenario. It is assumed that nuclear power plants can become available as an off-the-shelf option from international markets (e.g., South Korean reactors). However, licensing and building the nuclear power plant can become moderately lengthy. Therefore, we investigated the implications of allowing new nuclear power capacity available from 2040 onwards.

The results show a 4.4 GW higher need for offshore wind capacity (together with 4.1 GW more offshore transmission line capacity) in 2030, which substitutes the 3 GW nuclear capacity of the nuclear scenario. Moreover, the cost-effective nuclear capacities in 2040 and 2050 vary marginally from the nuclear scenario. Therefore, the exclusion of nuclear power in 2030 leads to slightly lower system costs (i.e., 0.1%) in this period while increasing system costs by 0.4% and 0.3% correspondingly in 2040 and 2050, compared to the nuclear scenario. Therefore, delaying the nuclear investments stimulates higher demand for offshore wind investments in the short term while slightly increasing system costs in the long term.

Additional scenario: higher natural gas prices

In the reference and nuclear scenarios, the imported natural gas price grows moderately to 35 €/MWh in 2050. Since the energy system of the Netherlands in both scenarios still depend on imported natural gas, a higher natural gas price can impact the energy transition. We investigated this impact by assuming higher natural gas price projections from 70 €/MWh in 2030 to 145 €/MWh in 2050. As a result, system costs increased by more than 8% in 2050, 2.8 GWe more nuclear capacity (hitting the maximum 12.48 GW constraint) was built in 2050, and more offshore wind was installed in 2030 and 2040. As expected, the higher imported natural gas prices result in higher dependency on domestic nuclear power and VRES capacities.

5. Conclusion

This study sets out to analyze the techno-economic role of nuclear power in reaching national emission reduction targets. Accordingly, we framed this study in four themes: system-wide analyses, cost uncertainties, flexible generation, and cross-border trade. We sourced the IESA-Opt model and modified its methodology to develop the IESA-Opt-N model. The new model has been improved in three aspects: modified objective function in line with system costs definition, more transparent assumptions regarding hourly cross-border electricity trade, and considerably lower computational intensity.

The IESA-Opt-N model offers a suitable approach to analyze the energy system planning because it minimizes the system costs of the national energy system by planning the long-term investments and hourly operation of all energy-related technology options. In addition, the model describes the demand and supply of flexibility (i.e., variations in residual load) for both the energy use and generation sides. Moreover, it includes advanced energy conversion pathways such as green and grey hydrogen, synthetic (gas, kerosene, fuels, and naphtha), and ammonia as a fuel. By using such a modeling approach, the primary outcomes of the study are summarized:

Theme 1: System-wide analyses

The impact of nuclear power on the national integrated energy system is represented by comparing the reference and nuclear scenarios. Both scenarios assume a wide optimization in which the cost-minimization model determines the configuration of the energy system based on techno-economic parameters. Therefore, only a few constraints are imposed on the scenarios that are explained in the method section. Moreover, nuclear power's major cost uncertainty parameters, namely, construction time and financing costs, are aggregated into the nuclear CAPEX value. Therefore,

Under the default assumptions of the nuclear scenario – notably the wide optimization, carbon-neutrality target by 2050, and the assumed discount rate of 5% for all technologies, including nuclear investments, it is cost-optimal for the Netherlands to invest in 3, 5.9, and 9.6 GWe nuclear capacity in 2030, 2040, and 2050, respectively. In the early periods of the energy transition, nuclear power investments reduce the need for offshore wind capacity by 4.7 and 10.6 GW in 2030 and 2040, respectively. While in the long term (i.e., 2050), it contributes to a 16.6 GW lower demand for transmission lines, particularly cross-border and offshore transmission line capacities. Consequently, nuclear power investments can reduce spatial challenges of VRES deployment in the short term, and lower energy imports (except uranium) in the long term. However, given all the cost assumption uncertainties (e.g., uncertainties around nuclear construction time, financing, and dismantling costs), the system cost reduction in the nuclear scenario is not significant.

Moreover, under the assumptions of the nuclear scenario (notably allowing maximum nuclear investments of 3, 9, and 12 GWe capacity in 2030, 2040, and 2050 and maintaining the current 0.48 GWe nuclear power plant), investing in nuclear power reduces Dutch energy system mitigation costs by 1.6 % (i.e., 0.3 B€) and 6.2 % (i.e., 1.3 B€) in 2040 and 2050, respectively. This can be translated into 9 B€ lower cumulative mitigation costs and 25 % lower CO_2 prices (i.e., from 225 to 168 €/tCO_2) by 2050.

In addition, relying merely on LCOE analyses can underestimate the role of nuclear power in the energy system. For instance, based on the assumed cost values of the nuclear scenario, although nuclear power has 34 €/MWh higher LCOE than wind offshore, the model invests in it to avoid relatively higher indirect energy system-wide costs such as high flexibility supply costs and higher infrastructure capacity demand.

Theme 2: Cost uncertainties

The origin of the capital and the resulting interest rate significantly impact nuclear power's economic feasibility. Under the assumptions of the nuclear scenario, even with a high discount rate of 9 %, nuclear can be economical up to a CAPEX value of 5 B€/GW in 2050. On the other hand, the Netherlands adopts nuclear even in CAPEX values up to 10 B€/GW assuming a low interest rate of 3 %. This outcome is highly relevant to the EU sustainable finance taxonomy since nuclear power has been recently added to the list. Therefore, with governmental support (i.e., low financing discount rates), the relevance of nuclear cost uncertainties on the cost-optimal nuclear power investments is considerably reduced.

VRES CAPEX estimates can moderately affect the cost-optimal nuclear CAPEX range. For instance, with low VRES CAPEX estimates (e.g., wind offshore CAPEX value of 0.85 B€/GW), investments in nuclear power can be cost-effective with nuclear CAPEX below 8 B€/GW. Moreover, under the nuclear scenario assumptions, VRES investments are cost-optimal for the energy system in 2050, irrespective of VRES and nuclear CAPEX estimate levels. Therefore, nuclear power does not substitute the long-term need for high Dutch investments in VRES.

It should be noted that Gen III nuclear power is assumed to operate as a base-load power generator with an exogenous capacity factor of 95 %. Therefore, even in the high availability of variable renewable energy sources (VRES), which have low marginal costs, the installed nuclear power capacity has the operational priority at each hour. In these events, the IESA-Opt-N model balances the excess electricity by several means of flexibility supply options such as curtailment, cross-border trade, storage, and demand response.

Theme 3: Flexible generation

SMRs with a 0.2 B€/GW higher CAPEX than Gen III, are only adopted if their ramping rate is more than 60%. Therefore, the investment choice between SMR or gen III depends much more on the CAPEX difference than the flexibility advantage of SMR (i.e., higher ramping rate). The value of SMR flexibility supply becomes noticeable only in a narrow range of SMR CAPEX. Thus, decreasing SMR CAPEX has a higher impact on its economic feasibility than increasing its generation flexibility. For instance, under the assumptions of the nuclear scenario, reducing the SMR CAPEX by 17% compared to gen III can result in 43% higher SMR capacity investments.

Theme 4: Cross-border trade

We demonstrated that the economic feasibility of national nuclear power investments could vary considerably depending on the cross-border electricity trade assumptions. Depending on the cross-border electricity price and available trade volume, nuclear investments follow three primary behaviors: First, with low trade volumes, the model invests in nuclear power to avoid high costs of flexibility supply options. Second, with high trade volumes and high import prices, the model invests in nuclear to avoid high import costs. Third, with high trade volumes and low import prices, the model substitutes nuclear power with cross-border trade volumes.

In addition, we briefly analyzed the role of nuclear cogeneration and other additional scenarios. Nuclear cogeneration can enhance the flexibility and economic feasibility of the investments provided that nuclear power is a cost-effective option. Moreover, low biomass and hydrogen import levels increase the demand for offshore wind capacity in the short term (until it hits the maximum assumed potentials) while increasing nuclear investments in the long term. Additionally, investing in new nuclear power from 2040 onwards (instead of 2030) stimulates higher demand for offshore wind investments in the short term while increasing system costs in the long term. Furthermore, assuming higher imported natural gas prices (i.e., 145 €/MWh by 2050) results in higher short-term investments in VRES and higher long-term investments in nuclear power capacity (i.e., 2.8 GW that hits the maximum 12.48 GW constraint by 2050).

In conclusion, under the cost and trade assumptions of the nuclear scenario, the decision to invest in national nuclear power appears to be cost-optimal according to a high-resolution integrated energy system model. However, the system cost reduction is not considerable considering the cost uncertainties, notably higher financing costs and longer construction time. Moreover, the investments in VRES remain essential for the energy system transition in both scenarios. Therefore, nuclear power can play a complementary role (in parallel to VRES) in achieving Dutch carbon reduction targets. However, the sensitivity analyses show how these results depend on uncertain parameters such as the nuclear CAPEX, discount rate, and cross-border electricity trade. Moreover, the results depend highly on other exogenous assumptions, such as the availability and price of natural gas, biomass, hydrogen, and other imported fuels. The major limitation of this study is that other nuclear-related critical factors are not considered: nuclear waste, social acceptance, energy security, geo-politics of nuclear fuel supply, energy independence, and regional and spatial challenges of building nuclear power reactors.

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Appendix A The reference scenario description of the IESA-Opt-N model

Energy demand drivers in the Netherlands

The energy demand in IESA-Opt-N is derived from certain economic activities, which require a specific energy supply. Appendix Table 1 shows the assumed evolution of these activities in the Netherlands until 2050. These activities are endogenously translated into energy requirements by the model, based on the choice of technology. For instance, there is an exogenous requirement to produce 7.3 Mt of steel in 2050. This amount of steel can be produced using several technologies such as blast furnaces, blast furnaces with CCS, Hisarna, Hisarna with CCS, and Ulcowin. The model decides which technology is the most cost-effective option considering several parameters and constraints such as its costs, efficiency, and emissions.

Sector	Driver	Units	Values				Source
			2020	2030	2040	2050	
General	Heat degree days	[HDD]	2900	2800	2700	2600	[104]
Residential	Appliances electricity demand	[PJ]	84.7	88.1	90.5	92.1	[105]
	Number of houses	[Mhouses]	8.2	8.8	9.2	9.6	[105],[45]
Services	Appliances electricity demand	[PJ]	129.9	131.6	133.3	135	[105]
	Used space	[Mm^2]	515	540	555	560	[105]
Agriculture	Appliances electricity demand	[PJ]	36.8	38	42.5	47	[105]
	Heat demand for horticulture	[PJ]	87.2	92	96.8	101.5	[105] ,[45]
	Heat demand for agriculture	[PJ]	8.4	8.8	9.2	9.6	[105] ,[45]
	Machinery consumption	[PJ]	22.8	25.3	27.7	30.2	[105]
Industry	Steel production	[Mton]	7	7	7	7	[105]
	Aluminum production	[Mton]	0.2	0.2	0.2	0.2	[105] ,[45]
	Ammonia production	[Mton]	2.8	3	3.2	3.4	[106]
	High value chemicals production	[Mton]	7.2	7.7	8.3	8.7	[105] ,[45]
	Other ETS chemical industry	[Index]	1	1.2	1.3	1.6	[105] ,[45]
	Other ETS industry	[Index]	1	1.1	1.1	1.1	[105] ,[45]
	Other non-ETS industry	[Index]	1	1	1	1	[105] ,[45]
	Machinery consumption	[PJ]	43	45.2	47.0	49.5	[105]
Waste	Waste incineration	[Mton]	7.6	9.1	10.6	12.3	[105] ,[45]
	Waste sewage	[PJ]	3.7	4.3	5.0	5.6	[45]
	Waste landfill	[PJ]	0.4	0.1	-	-	[45]
Transport	Motorcycles	[Gvkm]	5.1	5.9	6.5	7.2	[105]
	Passenger cars	[Gvkm]	110.5	114.3	119.2	125.3	[105]
	Light-duty vehicles	[Gvkm]	21.1	24.3	27.4	32.3	[105]
	Heavy-duty vehicles	[Gvkm]	7.4	7.7	8	8.3	[105]
	Buses	[Mvkm]	617.2	624.5	637.3	650	[105]
	Rail	[Mvkm]	170	200	215	230	[105]
	Intra-EU aviation	[Mvkm]	210	260	340	430	[105]
	Extra-EU aviation	[Mvkm]	670	740	790	850	[105]
	Inland-domestic navigation	[Mvkm]	55	70	80	90	[105]
	International navigation	[Mvkm]	110	125	135	145	[105]
Exports	Natural Gas	[PJ]	2000	1600	600	0	[D]
	Natural Gas LNG	[PJ]	150	140	80	0	[D]
	Crude Oil	[PJ]	1700	1200	800	0	[D]
	Heavy Oil for Shipping	[PJ]	400	400	200	0	[D]
	Residual Heavy Oil Products	[PJ]	700	700	350	0	[D]
	Kerosene	[PJ]	350	310	180	0	[D]
	Road Fuel	[PJ]	1100	800	450	0	[D]

Appendix Table 1. Activity volumes that are considered in the reference scenario.

Assumed fuels and resources costs

The model satisfies the need for energy demands by combining primary energy supply, conversion of primary energy in final energy, and final energy imports. Therefore, the costs assumed for the primary resources supplied to the system are direct input to the model and a crucial part of the scenario definition. These primary resources can be distinguished as conventional fuels, biomass sources, hydrogen, and ETS allowances. The price or cost data for the reference scenario used in this paper are derived from the following sources (Appendix Table 2). First, conventional fuel price projections are retrieved from POTEnCIA's Central Scenario database [105]. Then, the price projections of the bio-resources are based on the ENSPRESO-BIOMASS reference scenario [44]. Finally, the ETS allowance cost projections are retrieved from two sources, the 2019 Netherland's Climate and Energy Outlook [106] for the 2020-2030 period, and the CPB high-efficiency scenario projections [107] for 2030-2050. Imported hydrogen cost in the

Netherlands is estimated to be slightly more than 2 €/Kg by 2030 [108]. Therefore, we assume an imported hydrogen price of roughly 2 €/Kg by 2050.

Commodity	Units	Values				Source
		2020	2030	2040	2050	
Coal	[$€_{2019}$/GJ]	2	2.7	3.3	4	[105]
Oil	[$€_{2019}$/GJ]	7	11	15	19	[105]
Natural Gas	[$€_{2019}$/GJ]	5	6.6	8.2	9.8	[105]
Uranium	[$€_{2019}$/GJ]	0.8	0.8	0.8	0.8	[106]
Waste	[$€_{2019}$/GJ]	7	7	7	7	[52]
Manure	[$€_{2019}$/GJ]	0.1	0.1	0.1	0.1	[52]
Dry Organic Matter	[$€_{2019}$/GJ]	4.5	4.5	4.5	4.5	[52]
Grass Crops	[$€_{2019}$/GJ]	9.5	8.7	8.4	8.2	[52]
Wood (crops, and others)	[$€_{2019}$/GJ]	10	14	18	22	[52]
Sugars	[$€_{2019}$/GJ]	4.6	4.6	4.6	4.6	[52]
Starch	[$€_{2019}$/GJ]	16	21	21.5	22	[52]
Vegetable Oil	[$€_{2019}$/GJ]	30	45	45	45	[52]
Hydrogen	[$€_{2019}$/GJ]	72	48	36	30	[108],[D]
ETS Allowance	[$€_{2019}$/tCO_2]	30	80	110	150	[106],[107]

Appendix Table 2. Fuel and resource cost assumptions in the reference scenario, 2020-2050.

Emission constraints

IESA-Opt accounts for emissions from non-energy sources such as enteric fermentation, fertilizers, manure management, refrigeration fluids, and emissions from energy sources divided into national ETS and non-ETS emissions. If it is profitable for the system, National ETS sectors can achieve negative emissions. Therefore, the energy system can reduce emissions more than the climate-neutral target by 2050. Although the Dutch emission reduction policy only targets the years 2030 and 2050, we assume a linear interpolation of the emission reduction target in the interim periods (Appendix Table 3). For the international aviation and navigation emissions, we only set the carbon-neutral target in 2050.

Emission constraints	Units	Values				Source
		2020	2030	2040	2050	
CO_2 National	[Mt_CO2/y]	166.4	99	49.5	0	[38], [39]
CO_2 National reduction (compared to 1990 levels)	[%]	25.5	55	77	100	
CO_2 International (Aviation and Navigation)	[Mt_CO2/y]	100	100	100	0	[D]

Appendix Table 3. The assumed national and international emission constraints