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Strategies for short-term intermittency in long-term prospective scenarios in the French power system

Rodica Loisel^{1,2}, Lionel Lemiale², Silvana Mima³, Adrien Bidaud⁴

Abstract

This paper depicts the power system adequacy with respect to nuclear strategies by coupling investment with dispatching. The long-term energy model POLES simulates the Paris Agreement worldwide and is soft-linked with a power market model applied to France, EconUK. The nuclear flexibility is described by cycling frequency and amplitude, constrained by reactors minimum rated power and half-hour ramping rates. Results in 2050 show that the French power system made of 26% nuclear and 71% renewables in POLES needs deeper and longer flexibility with nuclear and gas in EconUK, due mainly to higher granular time-steps than the prospective model; and that reactors perform more deep cycles than allowed by their license (230 instead of 200). We show that scenarios with high shares of renewables build on the arbitrage between nuclear and gas, notably during peak loads in winter and night periods. Meeting the double target to reduce nuclear and carbon emissions requires more renewables, hence significant gas and nuclear power for adequacy, facing the dilemma nuclear versus emissions. Coupling short-term operation with long-term investment indicates that nuclear flexibility varies with the time-step of intermittency modeling, so scenarios need to include reactors constraints to reach an informed decision on renewables and nuclear.

Keywords: scenarios, nuclear, load-following, long-term investment, short-term operation.

Highlights

- Long-term energy planning embeds short-term operation to assess flexibility adequacy.
- Nuclear ramping and minimum rated power are the critical parameters of coupling.
- Power mix diversity needs to trade-off between nuclear energy and capacity.
- Excessive nuclear cycling indicates the need of faster reactors in the future.
- Revision of reactor transient limits would prevent early upgrading or retirement.

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1. Introduction

With the worldwide energy system transformation towards increased energy independence and decarbonisation, most energy scenarios describe mix evolutions based on three main generation sources such as renewable energy, natural gas and nuclear power (IEA, 2021). While many energy models evaluate the way variable renewable energies can be balanced (Lopez et al., 2022), the **research question on system flexibility** has gained interest to demonstrate the technical feasibility of targets on renewables. This paper depicts decarbonisation strategies with political long-run objectives embedding short-run temporal resolution, such as to provide a deeper understanding of the influence of the power system characteristics, nuclear power plants in particular, on the flexibility assessment.

With future energy systems massively relying on variable renewables, flexibility requirements will increase to balance fluctuations, based on thermal power plants, energy storage and measures such as energy curtailment, demand-side management, sector coupling and grid interconnections. The flexibility is generally defined as a modification of the generation or consumption in support the power system stability (Heilmann et al., 2020), at two time-scales: large load variations or load-following which result from the economic dispatch of power flows (Carpentier, 1979); and minor time-scale variations, known as automatic generation control, which maintain the frequency of the grid (Apostolopoulou et al., 2016). This paper deals with the flexibility provided by nuclear plants to cover *large* variations in load, also known as nuclear load-following.

The effect of load variability has been investigated in the literature since a while for fossil fuel power plants (Gonzalez-Salazar et al., 2018; Troy et al., 2010; Goransson et al., 2017), yet the experience with **nuclear load-following** due to renewable intermittency, is limited. Since the seminal work of OECD-NEA (2011), numerous studies have investigated the interaction between renewables and nuclear, globally outlining the impact of large share of renewables on nuclear plant operation, and the contribution of nuclear load-following to the system adequacy. The topic has been developed from an engineer point of view to analyze the physical and chemical consequences of load-following (Lynch et al., 2022; Morilhat et al., 2019; WNA, 2020), and to assess the market effect from technical-economic perspective (Bruynooghe et al., 2010; OECD-NEA, 2011, 2019; Bertsch et al., 2016; IAEA, 2018; Mantripragada and Rubin, 2018). Among flexibility indicators there are the number of start-up and shut-down events (Cany et al., 2018b), the loss or gains in profits (OCDE-NEA, 2015; Ponciroli et al., 2017; Jenkins et al., 2018), the number of transients and the system cost (ANL, 2018; Loisel et al., 2018).

Models in general defend different views on the power system adequacy and give various mix solutions in terms of grid, flexible nuclear, gas, hydro power and storage. Among key assumptions, flexibility representation at a short time scale is of the highest importance, and hourly resolution is considered most suitable to represent the impact of renewables on system adequacy (Lopez et al., 2022). Kraan et al. (2019) note that representing scenarios with only installed capacities of technologies and their annual capacity factors, is unrepresentative of the physical momentary potential of conventional technologies to fit the variability of renewables.

At a country level, Teirila (2020) shows that maintaining nuclear power in Germany, even with low flexibility provision, reduces total integration cost of renewables in comparison with a nuclear phase-out scenario, but it increases the needs for flexible conventional thermal power, the start-up cost and balancing cost, compensated however by nuclear low generation cost. Mezosi et al. (2020) investigate seven interconnected eastern European countries (Czech Republic, Hungary, Poland, Slovakia, Bulgaria and Romania) and find a cannibalization effect between variable renewables and nuclear power, through reduced nuclear load factor and increased renewables' curtailment, which strengthens the competition for export between nuclear power plants (OECD-NEA, 2011). Zhao et al. (2022) find that inflexible nuclear faces

a crowding-out effect from renewables in two US nodes (Electric Reliability Council of Texas, ERCOT, and Pennsylvania-New Jersey-Maryland Interconnection, PJM), at a ratio of 1% more renewables to more than 1% of nuclear power excluded from market, partly replaced by conventional fossil fuels, enhancing thus carbon emissions. These effects are also obtained by Saygin et al. (2021) in the Turkish context. Laleman and Albrecht (2016) find that slowing the nuclear phase-out in Belgium improves system adequacy in front of increased renewables. Zhang et al. (2020) find that nuclear load-following in coal-dominated power systems like Shandong province in China, allows increasing wind and solar power generation in comparison with a nuclear baseload scenario, and that even at 5% nuclear share in the total capacity, flexible nuclear saves coal consumption and CO₂ emissions, through reduced coal plant start-ups and shut-downs. Zakeri et al. (2015) and Pilpola and Lund (2019) show that low flexible power plants in Finland act as a barrier to solar and wind integration, requiring more investment in other flexible sources (DSM, power-to-X). Al Kindi et al. (2022) test nuclear flexibility improvement in United Kingdom by coupling nuclear with energy storage, which enables solar and wind power penetration, and lowers conventional thermal power. Lynch et al. (2022) show the sensitivity of the French power market to the nuclear load-following schedule, and the way it can limit the negative market price events.

In France, several studies on flexibility with scenarios have accurately embedded policy targets and technology constraints. Alimou et al. (2020) detailed the adequacy needs in the French power system in 2050 by linking investment (TIMES) with dispatching (ANTARES), with technology constraints like ramping. Després et al. (2017) couple the energy planning model POLES with dispatching (EUCAD) to study the potential of storage to support renewables. POLES is further coupled with a grid expansion module to evaluate the flexibility potential of the network (Allard et al., 2020). Seck et al. (2020) explore a set of scenarios with TIMES to evaluate the power system stability under the grid constraints and find that kinetic reserves contribute to avoid oversizing the power system, yet stability indicators tend to decrease renewables installed, optimally sized at 65% in the mix.

While flexibility is extensively discussed in the energy system community, the instantaneous effects of long-term government decisions are not sufficiently quantified from the point of view of nuclear cycling. Our **study complements** the existing assessments with power generation adequacy in the operational stage, and builds the bridge between the energy planning and the operational step to conclude on the use of nuclear. We embed two time-frames by coupling long-term planning of capacities with short-term operation of the power system, i.e. half-hour step. The technical-economic model POLES (*Prospective Outlook on Long-term Energy Systems*) simulates the world energy system until 2100 under carbon emission constraints, and projects the French power system that is further integrated into a power market model, EconUK (*Economic dispatching of NUClear reactors*) to optimise the operation of the nuclear power.

The main contributions of the paper are as follows: 1) it brings economic insights into plausible scenarios by means of an investment exploratory model embedding normative goals on climate and nuclear; 2) it depicts the infra-hourly operation of nuclear power in front of massive renewables to build a framework of analysis for industry organization with respect to the fleet management; 3) it opens the political field to physics to show the way the technological provisions such as nuclear ramping and reactor minimum rated power alter the system adequacy; and 4) it covers key features of the demand evolution, such as the total flow and extreme peaks, to measure the system sensitivity to power and energy planning.

The main findings focus on the drivers of the flexibility, such as the nuclear plant operation (compression effect and cycling), nuclear and gas trade-off, renewable curtailment, demand evolution, market balance and stress situations through extreme shadow prices, demand curtailment, CO₂ emissions, and net export flows. We show that high shares of intermittent

renewables in France by 2050 put pressure on nuclear power plants in terms of ramping and cycling, and push nuclear reactors to retire earlier. The nuclear fleet will have a lower capacity than today (24 GW instead of 61 GW), but it will be used more often and more flexibly. The future power system will need large capacities available over some hundreds hours, in particular during winter and night time, and should therefore arbitrate between nuclear and gas. Yet, deciding to phase-out nuclear and switch to gas, should account for the substitution ratio of 1 MWh of nuclear out to more than 1 MWh of gas needed. In terms of power, removing 1 GW of nuclear power needs also much more dispatchable capacity, due to ramping that constrain the remaining fleet. Policy makers should then express nuclear policy targets in capacity, well calibrated in terms of adequacy, rather than in flows or shares in the generation mix. Our findings could to some extent apply to other European countries under the European Green Deal decarbonation target (EC, 2019, 2020) that intend to pursue their nuclear policy: Slovakia records the second largest share of nuclear in its total generation (53%), followed by Hungary (48%), Bulgaria (41%), Slovenia (38%), Check Republic (37%) and Finland (34%)⁵.

The paper **policy recommendations** address to nuclear operators and decision-makers such as 1) to well anticipate the uranium management for waste infrastructure planning, as any nuclear capacity factor variation makes vary the uranium demand (Krymm and Woite, 1976); 2) the system will need faster reactors in the future (ideally at speed of at least 10% of nominal power per half-hour), able to provide more deep cycles (+ at least 15% more than today); 3) the future nuclear architecture should prior capacities over flows by maintaining as many reactors as necessary to cover peaks, with respect to capacity adequacy and to the stress put on the remaining reactors; and should also prioritize nuclear power over natural gas to avoid carbon emissions, at least over the transition period to renewables. Ultimately, studies on intermittency complement long-term outlooks in the way that excessive cycling of nuclear reactors can be avoided by anticipating the need for flexibility, while assessing the interaction with renewables.

In the following, Section 2 details the case study with respect to scenario alternatives in France and the operation of nuclear reactors at large fleet levels. Section 3 describes the methodology reproducing the final state of a given scenario through coupling, Section 4 presents the main results in support to the analysis of key parameters playing on scenarios' inputs/outputs, and the Final section concludes with energy policy design options.

2. Case study

The French **power mix** is dominated by nuclear power (71% of total generation in 2019), the other sources being hydropower (11%), thermal (7%), wind (6.3%), and solar (2.2%).⁶ The country has started an ambitious programme of decarbonisation and phase-out of coal plants, and designed a planning framework for investment in solar panels, offshore wind and nuclear power. The French Energy Transition Act sets out a roadmap to diversify the energy mix by reducing the nuclear power in favor of renewables (ETA, 2015), mainly motivated by the end of the license period of nuclear reactors. Economic considerations add as well, such as the country full dependence on uranium imports, and the ambiguous business model of a *large* nuclear fleet: the advantage of low cost carbon-free uranium is balanced by the fact that locally power French imports are expensive and exports eventually very cheap. During the winter time, the French nuclear fleet does not cover power peak load and the country needs

⁵ <https://www.statista.com/statistics/270367/share-of-nuclear-power-in-the-power-supply-of-selected-countries/>.

⁶ Recent figures on power generation mix are also available, but affected by the sanitary crises: nuclear (67%), hydropower (13%), wind (7.9%), solar (2.5%), biomass (1.9%) and thermal power (7.5%). www.rte-france.com/actualites/bilan-electrique-francais-2020.

expensive peaking imports. While over the year, it produces excessively and exports power at a low cost, without inframarginal rents to cover all costs.⁷

Nuclear cycling. Nuclear load-following covers predictable events of large load variations, agreed in advance between the grid operator RTE and the plant operator EDF, and the power output is set manually at a lower level of the nominal power (Morilhat et al., 2019). While the use of nuclear is economically efficient at capacity factors of 90%, in practice nuclear load-following compresses the indicator to some 70% in average, and in combination with renewables, nuclear is used at some 60%, mainly due to its flexibility capability and decentralized power market principles (Rigaudiat, 2021). Load-following is measured by the transient from full power to minimum load and back to full power. Technically, the modern light water nuclear reactors can operate flexibly in the range of 100% to 50%-20% of the rated power in 30 minutes, with a ramp rate of up to 5% of rated power per minute (OECD-NEA, 2011). In practice, two situations occur: frequent load-following over a small range of the rated thermal power, the so-called light cycles; and less frequent cycling but over a large range of the rated power, or deep cycles (IAEA, 2018; AREVA-EDF, 2012). Concerning design transients, some 12,000 load variations are authorized over the 40 year license, and the regulation mentions that the frequency of deep cycling should be at most once or twice per day (EUR, 2012; Persson et al., 2012).

Investigation of historical nuclear load-following shows that all reactors operate flexibly in France and 40% of the fleet is significantly involved in load-following (Cany et al., 2018a). By reactor, the maximum number of load-following operations performed in 2015 was 155, and much lower for most of other reactors, demonstrating the remaining potential to supply more flexibility. The main challenge will not be technical but economic, such as the opportunity cost due to load factor decrease. Some technical limits might be reached at 30% renewables in the power mix when the number of nuclear rampings starts increasing (Cany et al., 2018b).

Costs. Flexibility being included in the PWR design, there is no additional major cost until reaching the maximum number of transients allowed by the license. In time, the reactors operation has been adapted to support the supply and demand equilibrium, and has been regularly improved over the years with concern to maneuverability and safety (Cany et al., 2018a). For planned load-following, no fuel cost adds for cycling, as the uranium fueled at the beginning of the campaign adapts to flexibility based on EDF experience (Morilhat et al., 2019). Costs still occur due to more maintenance for component upgrades, equipment life reduction and potential derating of control rod drive mechanisms and of water and steam thermal cycle (IAEA, 2018), yet compatible with vessel ageing. These costs being included in the reactor ageing maintenance, hence into fixed costs, the extra cost is not included into ramping variable cost, based on expert publications (Morilhat et al., 2019).

Our model considers that ramping is free of additional variable cost, as long as ramping is in the range of the regular cycling, but accounts for the number of additional cycles to inform on potential additional solicitation, differentiated by the frequency and deepness of load variations. The amplitude of ramping in the range of 0%-20% of the nominal power describes light cycles (100%-80%-100%), variations of in the range 20%-40% describe mid-cycles (100%-60%-100%) and up to 70% deep cycles (100%-30%-100%). The license budget by cycle type per year is of 200 deep cycles, some 300 mid-cycles and 3,000 light cycles (see Ludwig et al. (2010) for comparable orders of magnitude). By explicitly looking at the cycles' profile, we detect cases of excessive cycling to give a normative vision on the way the nuclear could adapt to increased intermittency in the future.

⁷ The cost is estimated at 60 €/MWh and covers the investment cost, the operation of reactors, the maintenance and safety measures, the dismantling provision and the investment for modernization and license extension program, called *grand carénage* (Cour des Comptes, 2014).

3. Modeling the power system

For nuclear load-following modeling, we combine three types of assessments identified in the literature: (1) capacity expansion models for investment planning with cost-recovery (JRC-EU-TIMES model; JRC, 2013); (2) technology studies on nuclear and renewable matching under physical and economic constraints including start-up costs (Jenkins et al., 2018); and (3) power market models with plant dispatch based on marginal costs (Peng et al., 2018). Our framework embeds capacity planning (POLES) with technology constraints and market operation (EcoNUK): POLES provides the power generation mix over decades and EcoNUK depicts the nuclear operation at detailed time-span. The main focus is on generation adequacy at a system level (Misconel et al., 2022), hence it complements studies on transmission network combining local capacity adequacy with system-wide adequacy issues (Child et al., 2019). Transmission System Operators usually build detailed spatial adequacy models to account for network constraints, yet simplifying plant operation assumptions to can deal with power system complexity (ENTSOE, 2021; RTE, 2021).

3.1. Model coupling

POLES model (Prospective Outlook on Long-term Energy Systems) is a bottom up, long term simulation model, covering both demand and supply of the whole world energy system, energy vectors (electricity, hydrogen) with explicit technological choices and rational economic decisions. The simulation process uses dynamic year-by-year recursive modelling, with endogenous international energy prices and lagged adjustments of supply and demand by world region, which allows for describing full development pathways to 2100 (Criqui et al., 2015; Criqui and Mima, 2012). Energy demand is detailed for the main sectors such as industry, agriculture, service, residential and transport, each having its own demand profile. The electricity demand is endogenous and linked to the GDP and population, and the supply is made of 41 technologies, of which ten are variable renewables. With rich spatial and technology disaggregation, this version of POLES limits the short-term temporal resolution to two-hour representative time-slices over 12 blocks by season, i.e. summer and winter.

EcoNUK dispatching model is run for three simulation years (2035, 2040 and 2050) with data sent by POLES for the installed power generator and storage capacities, the total load, and marginal costs by technology. EcoNUK uses the GAMS optimisation language with the Cplex solver⁸, based on linear programming. The method has already been applied at a European scale to the topic of nuclear load-following, with an hourly loop and more aggregated results in terms of fatigue (Loisel et al., 2018). The version developed here follows similar dynamic principles to describe the system operation with however half-hour time slices and a national loop.

The model simulates a centrally-dispatched market with the objective function of minimizing the system short-term annual cost of operating generators, subject to satisfying the power demand. The operating cost includes variable costs, the carbon price, and variable operation and maintenance costs. When the system cannot absorb the natural inflow of fluctuating renewables (wind, solar, marine energies and hydro run-of-river power), the energy in excess is suppressed, the so-called supply load curtailment. Equations are listed in the Annex 1.

The power plants in EcoNUK are grouped into 12 technologies with similar technical and economic characteristics as in POLES, yet some differences in specifications adapt to nuclear load-following operation. There are two reactor types, used to operate either load-following

⁸ The General Algebraic Modeling System (GAMS) is suitable for modelling linear optimization problems, being especially useful with large database (<https://www.gams.com>). The solver Cplex is designed to solve large, difficult problems quickly (less than five minutes).

(called here Flexible, covering 2/3 of the fleet) or base-load (called Inflexible, 1/3 of the fleet). Although all reactors are technically capable to provide flexibility, the management of the fleet is centralized, i.e. by the EDF operator, and some reactors, at the end of the fuel cycle, are used as base-load units, and some others in flexible mode. Note that the ongoing restructuring of EDF will not change these assumptions.⁹ The technical constraints are minimum operational loads, maximum load factors, and ramping capability of flexible technologies (see Annex 2).

Coupling. The EcoNUK model optimizes the power system for a given investment scenario decided by POLES, together with capacity factors of power plants. A soft-linking one-direction coupling is made, thus no iteration is further made. POLES captures the relevant properties of the global energy system, and EcoNUK responds to the global model time-limitations by finely representing renewables and nuclear dispatch at half-hour time slice.

Figure 1 shows the steps of core linking between the two models. On the top, there are the national targets of the French power mix in terms of renewables, nuclear and carbon emissions. – **Scenario building.** POLES is run at yearly time step subject to cost-effective adequacy in terms of installed capacity, storage and demand use. Then it further transfers the power generation mix to EcoNUK, for the key years 2035, 2040 and 2050 which are of high interest with concern to investments in nuclear and renewables.

– **Plant dispatching.** The model EcoNUK simulates the market operation and returns the power volume generated by each technology, the half-hourly power clearing price, and derived indicators such as actual load factors and curtailment rates. The reactors' flexibility provision is converted into light, mid and deep cycles which are further compared with the license design to conclude on the nature of cycling and the flexibility needs. At the end, aggregated indicators obtained with dispatching will support the long-term planning of flexibility and the nuclear reactor operation.

⁹ EDF is ongoing restructuring and is planned to be split into three entities: nuclear and hydro (EDF Blue), trade and renewables (EDF Green) and dams (EDF Azure), according to Hercules plan. www.euractiv.com/section/energy/news/france-battles-brussels-over-separation-of-edfs-nuclear-arm/ (10/11/2021).

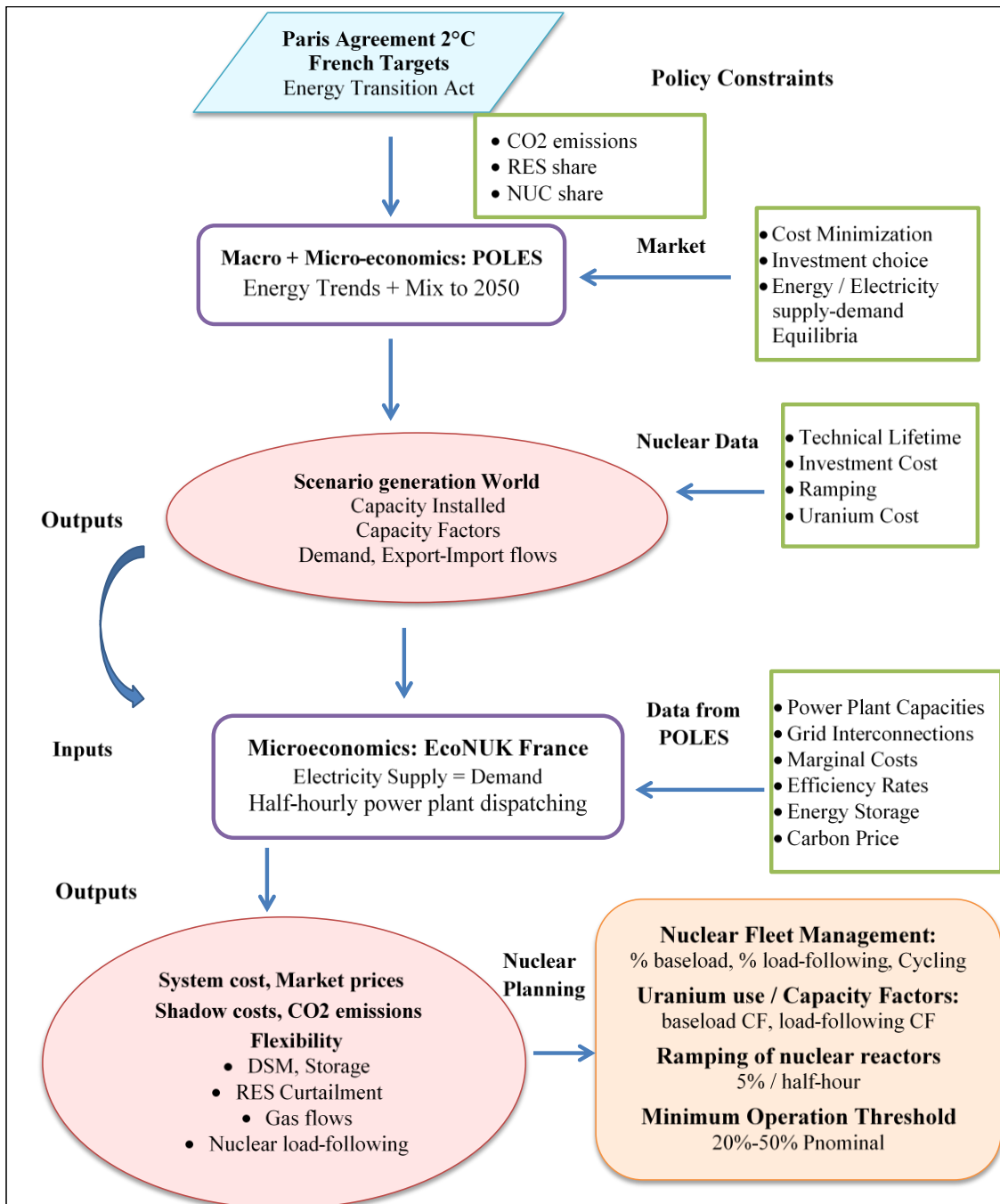


Fig 1. Diagram of soft-coupling of planning model (POLES) with power dispatch model (EcoNUK)

4. Results

4.1. Analysis of scenario building with POLES

The model POLES generates scenarios in line with the French Energy Transition Act aiming at reducing the nuclear power from 75% to 50% by 2035 and increasing renewables to 40% in 2030, and to more than 60% by 2050. Endogenous trajectories are subject to two targets, to reduce nuclear by 2035 and to reach decarbonisation in 2050 in France, and, globally, to limit the temperature to 2°C by 2100 according to the Paris Agreement. Political commitments for emissions targets are supported with carbon taxes, calibrated by POLES in Europe at 200

€₂₀₁₅/tCO₂ in 2030 and 750 €₂₀₁₅/tCO₂ in 2050, close to the French government norms in support to clean projects.¹⁰

For installed *capacities*, Figure 2 shows the prospective trends from POLES to reduce nuclear and to increase renewables, with more details at Annex 3. Power mix in 2035 is close to the scenario of the French system operator, called Ampère (RTE, 2017), which simulates the technology diversity, yet results in POLES deviates at intermediate steps due to normative goals to reach decarbonisation in 2050 in the whole economy based on market mechanisms of investment and operation cost minimization. The optimal nuclear-renewable combination in POLES is 60%-45% in the mix in 2035 (slightly different from the 50%-40% policy targets), as the model proves economically efficient to operate 47 GW of nuclear power in 2035 (24 GW in 2050), based on only existing reactors. In our assumptions, the investment cost of new reactors EPR (Evolutionary Power Reactor) remains high, 10,000 €/kW, in line with national reports (Cour des Comptes, 2020), but below IEA estimates for Generation III plants, in the range of 4,000-5,500 \$/kW (IEA, 2020).

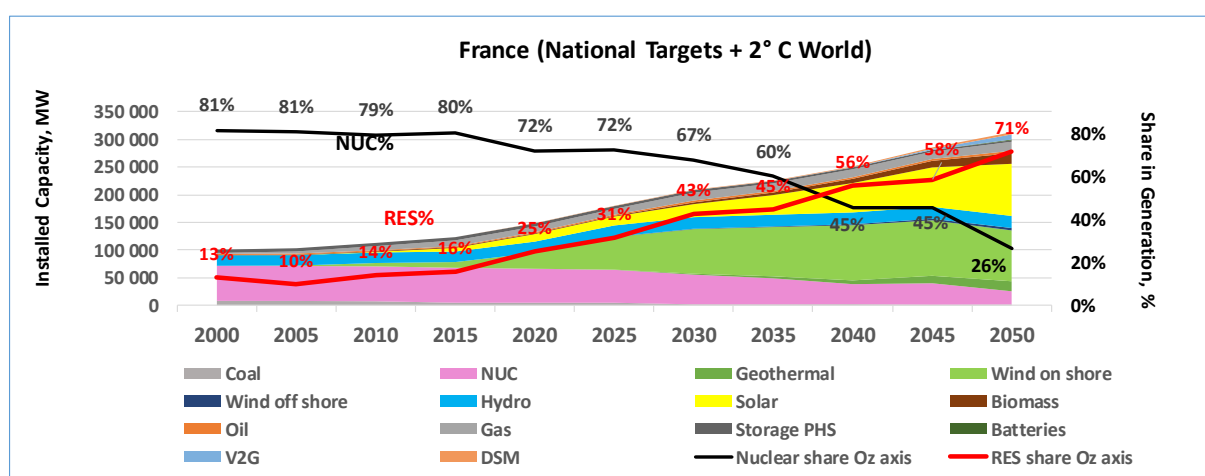


Fig. 2. Scenario generation with POLES for France under 2°C global climate constraint subject to the French Energy Law

For flexible options (Fig. 3) such as storage and demand shedding, the model attains 17 GW in 2050, made of pumped hydro storage (15%), batteries (9%), electrical vehicles in support to the grid (V2G, 53%) and demand side management (DSM, 23%). Another option is possible in the model, such as compressed air energy storage, but not selected due to investment cost estimated at 1,300 \$/kW, relatively higher than for Li-ion batteries, estimated at 350 \$/kW in 2020 (Mongird et al., 2020), and to 1,145 \$/kW and 200 \$/kW in 2050 (Cole et al., 2021) respectively.

¹⁰ The national strategy projects carbon levels of 250 €₂₀₁₈/tCO₂ in 2030, 500 €₂₀₁₈ in 2040 and 775 €₂₀₁₈ in 2050, following Hotelling at 4.5% discount rate (*France Strategie* Commission, Quinet, 2019).

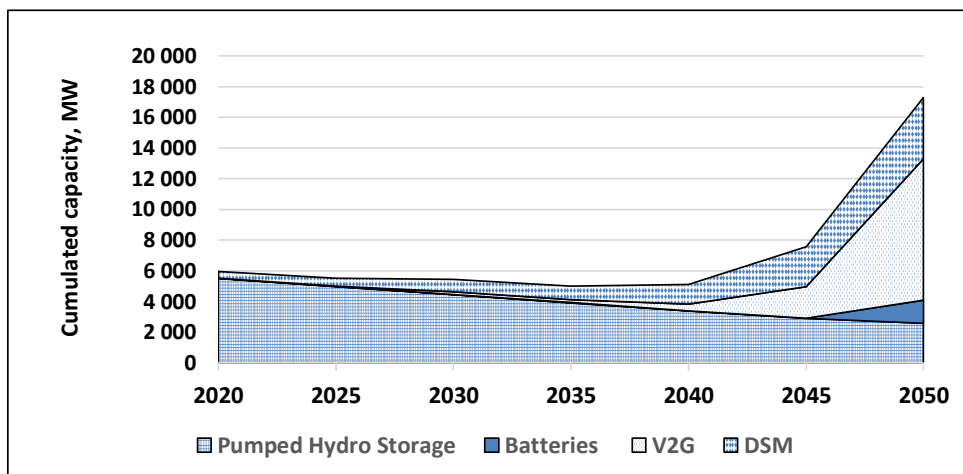


Fig. 3. Results of the model POLES in terms of flexible capacities (MW)

In terms of *energy*, variable renewables (solar, wind, hydro run-of-river and marine energies) reach 56 % of the total generation by 2050, and 71% by including dispatchable renewables (hydro-lake, geothermal and biomass). Figure 4 shows snapshots of the energy mix in 2035, 2040 and 2050, and summarizes the storyline of normative cases constraining the simulations, such as the Energy Transition Act and Paris Agreement embedded with technical-economic mechanisms of POLES. With reduced nuclear power, more intermittency from renewables is supported by high flows of gas, which need to be free of emissions to be in line with the low carbon national strategy. Export flows remain overall high, due to high shares of nuclear and renewables exhibiting large must-run rated power and fatal inputs. Power generation is higher in 2050 despite slight decrease in demand, due to high loss rates of massive decentralized renewables.

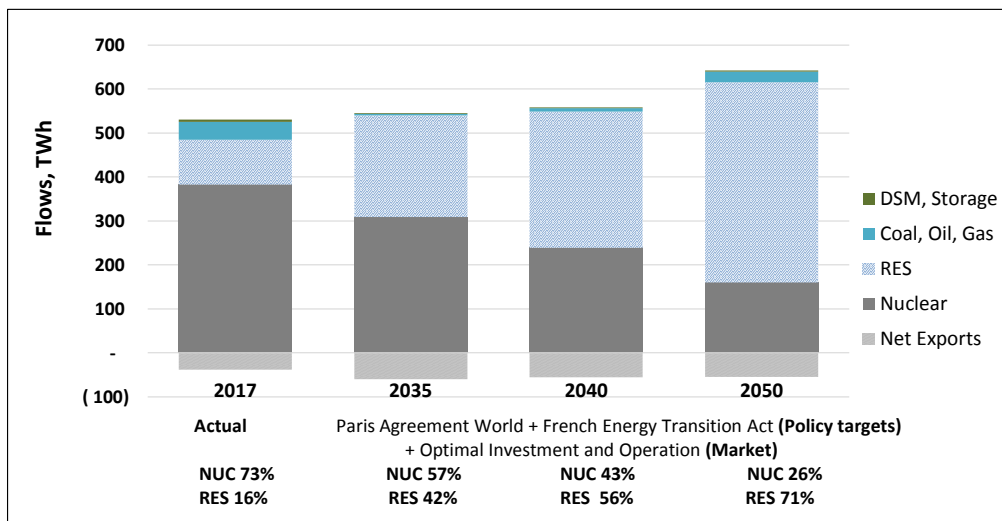


Fig. 4. The energy mix breakdown by flow type and by period, projected with POLES (TWh)

4.2 Analysis of dispatching with EcoNUK

The market model EcoNUK, run at half-hour over one year, allows testing the optimal dispatch of the installed capacities optimized with POLES. The aggregated results over the year and the objective function, which is the short-term system cost, are summarized at Table 1.

Table 1. Annual indicators obtained with EcoNUK

| Power Market Indicator | 2035 | 2040 | 2050 |
|---------------------------------|-------|--------|-------|
| System operational Cost, Mln € | 4 244 | 4 636 | 6 207 |
| Clearing price (average), €/MWh | 48 | 84 | 150 |
| Shadow cost (maximum), €/MWh | 456 | 12 043 | 639 |
| Shadow cost (average), €/MWh | 173 | 203 | 268 |

The system cost, calculated as the sum of variable costs, records increasing levels in time, despite higher renewables with low variable costs, i.e. less than 3 €/MWh. The breakdown by technology at Fig. 5 shows that the largest part is most of the time nuclear operational cost, except for 2050 when the total gas cost dominates, because the nuclear power decreases and gas becomes more expensive. It should be noted that the carbon tax for decarbonizing the French economy applies to gas to make competitive carbon free substitutes to the natural gas, such as hydrogen, gas with carbon capture and storage, synthetic methane and biogas.

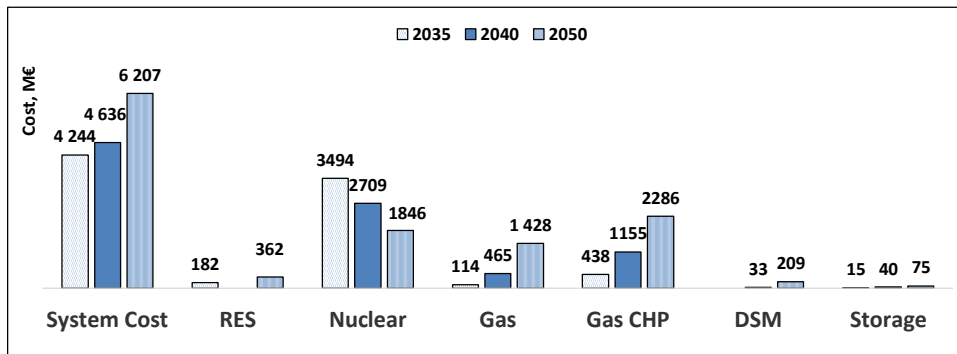


Fig. 5. Operational breakdown cost, by year, by technology, Mln €

Similarly, the **clearing price** increases due to more expensive inputs at the end of the merit order curve. In this system, less expensive technologies, such as renewables, are never the last technology to be called, and they are price-taker all over the three years (Table 2).

Table 2. Marginal Technology, number of hours when the technology sets the price

| | 2035 | 2040 | 2050 |
|-----------------------------|-------|-------|-------|
| Renewables | 0 | 0 | 0 |
| Nuclear | 7 731 | 6 680 | 5 005 |
| Storage | 0 | 0 | 0 |
| Combined-cycle Gas Turbines | 945 | 1 759 | 3 255 |
| Demand Side Management | 4 | 159 | 499 |
| Simple-cycle Gas Turbines | 80 | 152 | 0 |
| Oil Steam Turbines | 1 | 12 | 1 |

Note that the market call is based on marginal cost which means that investment cost is not accounted for; storage systems have then operation costs lower than fossil fuels or nuclear, as they are mostly charged with renewables in excess at a fixed price, set at 10 €/MWh, hence in the model storage is never price-maker. Co-generation gas-fired plants are not marginal either, because electricity is by-product of heat, thus entering the market as price-taker. The model still considers oil steam turbines in the long-run for adequacy purposes and calls them at extreme loads. Combined-cycle gas turbines have ramping limitations as compared to the demand side management, and despite higher costs (324 €/MWh versus 300 €/MWh for DSM in 2050) they are called on the market from base-load to peak-load to substitute the nuclear phased-out. Nuclear power appears very often as marginal technology in 2035, yet its role as price-maker diminishes by 2050.

The model EconUK computes the clearing power price based on marginal costs, thus the model does not allow for negative prices (Fig. 6). In practice, there are hours with negative prices, due in particular to large inflows of renewables over low demand periods, yet their number in France is typically low (25 hours in 2019, about 100 hours in 2020 due to

pandemic crisis). In the model, the average prices are of 48 €/MWh in 2035, 84 €/MWh in 2040 and 150 €/MWh in 2050, compared with the actual prices in the range of 32-39 €/MWh over the period 2019-2020, and 78 €/MWh in some projections to 2040¹¹.

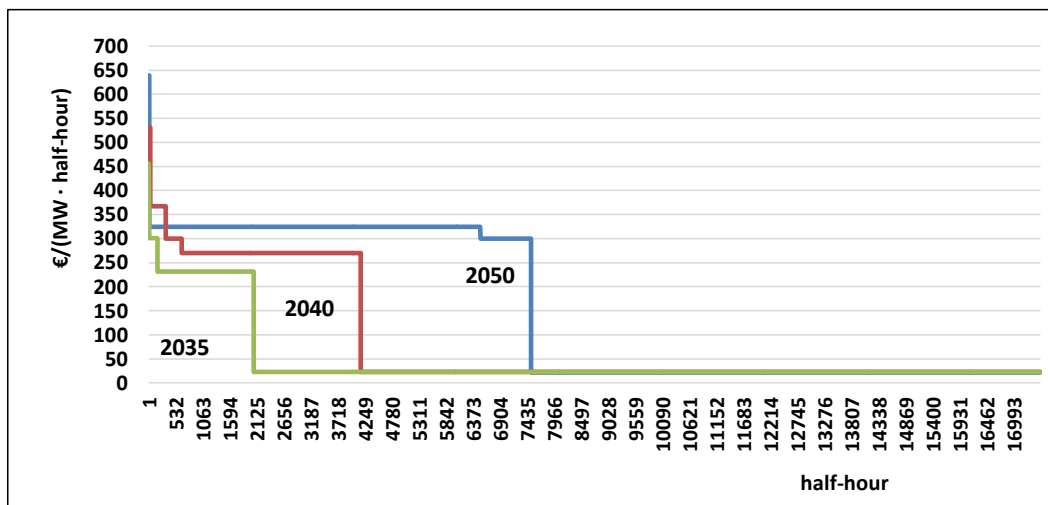


Fig. 6. Electricity price by year, ranked descending, results of EcoNUK

The highest tension for adequacy is obtained in 2040, as shown by the **shadow price** of the equilibrium between supply and demand (12,043 €/MWh). This reveals challenges in ramping up generators and the need for an additional unit to meet the marginal MWh of demand over the year; the value of this tension is close to the cost of installing one more MW of the technology with the lowest fixed cost, i.e. 16,000 €/MW for an open-cycle gas turbine (Jenkins et al., 2016). This highlights a capacity adequacy issue showing that a mix in 2040 made of 43% nuclear and 56% RES is not well enough calibrated for EcoNUK to easily meet the demand at any moment, yet the *average* shadow price is lower in 2040 than in 2050 showing that the number of hours with capacity tensions is low. In 2050, the capacity adequacy documented with POLES fits better the inputs and constraints of EcoNUK in the way that the mix made of 26% nuclear and 71% renewables anticipates more DSM and storage, along with lower exports.

If market prices here are always positive due to the marginal cost setting price assumption, shadow price could be negative when supply cannot easily adjust to low loads, e.g. during high renewable inflows with thermal plant ramping constraints. Instead, the model assumption that wind and solar in excess are stored or curtailed, enables the supply adjustment and avoids negative shadow prices to occur. The impact on plant revenues is not discussed here as the focus is on the adequacy capacity and flows, yet Lynch et al. (2022) notice that nuclear load-following allows avoiding a large number of negative price events, having therefore a positive impact on the revenues of market participants.

4.3. Analysis of coupling matching

Results obtained with long-term models are typically different from high temporal resolution models, due to the mismatch between constraints and wind and solar data among models (Poncelet et al., 2004; Alimou et al., 2020). Flows obtained with POLES are also different from half-hourly generation dispatched with EcoNUK, so that **more flexibility** is necessary in the later model. More particularly, the use of gas units increases along with the renewable penetration. Annex 4 shows the differences between POLES and EcoNUK by technology and by period. It should be noted that simulations with EcoNUK are run such as to respect the shares of nuclear and renewables obtained with POLES. These targets being constrained, the

¹¹ <https://www.statista.com/statistics/753239/electricity-price-forecast-france/> accessed 28 October 2021.

adjustment variables for adequacy fulfillment are the usage of gas and storage, and curtailment of demand and renewables, namely much higher in EcoNUK than in POLES (Fig.7).

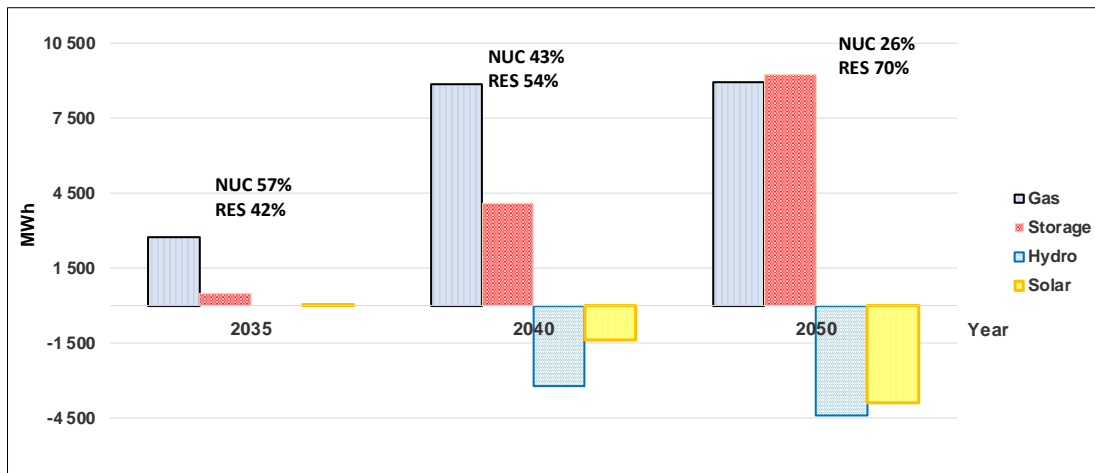


Fig. 7. Additional flexibility in EcoNUK compared with POLES by flow type, by year

Nuclear flows being kept constant among the two models, the need for flexibility increases in time, following the upward trend of renewables and the downward trend of phasing-out nuclear. **Gas flows** are higher in EcoNUK than in Poles (with 2.7 TWh in 2035, and 8.9 TWh in 2050), to cover the low wind and solar energy events and the missing load from decreased nuclear. The additional gas in EcoNUK covers the punctual lack of capacity to ensure adequacy and supplies also positive flexibility when the system faces constraints to ramp-up generators.

The volume of demand shedding is close among the two models, and complementarily the model EcoNUK informs about the frequency of DSM: there are 280 events in 2040 and 640 in 2050, meaning that demand management acts as a reserve 7% of the year, in average supplying 260 MWh and at maximum 4,000 MW per half-hour.

Renewables. The model EcoNUK shows that the profile of solar, wind and hydro inflows, combined with the plant size, results in a significant **capacity credit** (Tapetado and Usaola, 2019). The capacity credit, computed as the sum of all renewables available at each half-hour, is the minimum renewable energy available over the year. It results in a capacity credit of 3.9 GW available at any moment in 2035, 6.8 GW in 2040, and 14 GW in 2050, meaning that variable renewables can fully substitute conventional dispatchable power, at a ratio of 1 MW of renewables to 1 MW of nuclear or gas, provided that the ramping constraints of the later do not eventually inhibit the substitution. The capacity credit accounts for the available wind and solar energy at each moment over the year based on resource proliferation, hence perfect substitution dispatchable units with renewables applies in the limit of the capacity credit.¹²

For inflows of renewables higher than the demand, the first to be evicted from the market are the most expensive technologies, ranked in the descending order of their marginal costs: oil-fueled units, simple-cycle gas turbines, combined-cycle gas turbines, demand side management, nuclear power, storage and renewables. Hence, all operational plants participate to the negative flexibility when demand is lower than supply, and once ramping-down possibilities are exhausted, the system **curtails** renewable energy in excess. With the

¹² The capacity credit is the minimum renewable power available each half-hour over the year, all renewable sources cumulated per half-hour. For instance, on January 1st, wind power is of 18 GW at 3 p.m. and 34 GW at 10 p.m., solar power is of 29 GW at 3 p.m and 0 at 10 p.m., and hydropower is 4 GW at 3 p.m. and 11 GW at 10 p.m., hence capacity credit per hour is 51 GW at 3 p.m and 45 GW at 10 p.m., then the capacity credit over the two events is $\min(51, 45) = 45$ GW.

deployment of renewables, their curtailment increases in time (see Table 3). In 2035, the scenario is made of 57% nuclear and 42% renewables, showing that these ratios seem to be a convenient combination for matching conventional generators with intermittent inflows resulting in zero curtailment. For higher renewables, the system shows some limits to absorb all flows (5.4 TWh of curtailment in 2050), the solar power in particular; the first to be curtailed is the hydro-power, due to its variable cost higher than for wind and solar, which makes hydro power to rank before wind and solar within the merit curve (Benhmad and Percebois, 2017), hence hydro is displaced before wind and solar in case of supply excess or ramping constraints.

Table 3. Curtailment of renewables in EcoNUK

| Curtailment, GWh | 2035 | 2040 | 2050 |
|-------------------------|-------------|--------------|--------------|
| Wind On-shore | 0 | 111 | 79 |
| Wind Off-shore | 0 | 38 | 28 |
| Solar PV | 0 | 1 355 | 3 878 |
| Hydro Run-of-river | 0.18 | 1 002 | 1 449 |
| Total, GWh | 0.18 | 2 507 | 5 435 |

4.4. Nuclear operation with EcoNUK

The nuclear operation with EcoNUK results in **capacity factors** in the range of 74%-80% which vary with the year and the flexibility type (see Table 4).

- The baseload fleet, covering one third of reactors, are assumed to operate steady-state¹³ constrained by low ramping rates of 0.1% of their nominal power per half-hour, and a threshold of minimum operation of 30% of the nominal capacity. This shows a limited dynamics in time with however some power variation, since generating continuously becomes impossible at full load during low residual demand periods. Therefore, eventually nuclear plants operate at less than 100% of their nominal power, as illustrates results in EcoNUK (74% in 2035, 80% in 2050).
- The fleet operating load-following has a flexibility capability of 5% ramping per half-hour, which describes how fast power plants can modulate the output from one half-hour to the next one. During periods with large variable inflows, technologies are displaced in descending order of their marginal cost, nuclear included, subject to ramping and minimum threshold constraints.

Table 4. Capacity factor of the nuclear fleet, by model and by operating mode

| Capacity Factor / Year | 2035 | 2040 | 2050 |
|-----------------------------------|-------------|-------------|-------------|
| Flexible Nuclear in EcoNUK | 75% | 75% | 79% |
| Baseload Nuclear in EcoNUK | 74% | 78% | 80% |
| All Fleet (POLES = EcoNUK) | 75% | 76% | 79% |

Due to higher use of flexible nuclear in 2050, more deep cycles are performed than before (Table 5). This suggests a higher need of flexibility and challenging **cycling**, with 229 events, largely overpassing the license of 200 deep cycles per year. As a trend, light and mid cycles are decreasing over the period 2035-2050, while deep cycles are increasing, showing that large deployment of renewables comes with larger load variations and deeper and longer flexibility needs rather than frequent short oscillations observed in 2035.

Table 5. The number of cycles of flexible nuclear fleet in EcoNUK

¹³ It should be noted that baseload does not necessarily imply high load factors, but means steady state operation.

| | Cycle Type | | |
|------|------------|-----|------|
| Year | Light | Mid | Deep |
| 2035 | 1 411 | 279 | 83 |
| 2040 | 603 | 167 | 179 |
| 2050 | 139 | 88 | 229 |

Table reading. *Cycle Type* shows the amplitude of load-following: light cycles have an amplitude in the range of 0%-20% of the nominal power (100%-80%-100%), mid cycles are up to 40% (100%-60%-100%) and deep cycles are up to 70% of the reactor rated power (100%-30%-100%).

The budget for both light and mid cycles is respected over the three periods, provided that the management follows the schedule of EcoNUK:

- The dispatch of the fleet baseload – load-following occurs at the ratio of 1 : 2.
- The minimum rated threshold is 30% of the nominal power.
- The speed of reaction of flexible reactors is 5%/half-hour.

Any change in these **assumptions** has consequences on the nuclear dispatch, on renewables' integration and curtailment, and on gas-based flows. The sensitivity is next tested by changing each value while keeping the other indicators constant. Annex 5 indicates the sensitivity of results to these parameters for the year 2050.

The speed of ramping. Results show that faster reactors substitute gas supply and storage, and renewables are better integrated as indicated by lower curtailment. This suggests that in the baseline, storage supports renewables in excess but also technologies with ramping constraints, like nuclear reactors. At fixed total nuclear flows, the split by operating mode is favorable to load-following over baseload: higher capacity factors of the load-following fleet. Yet, increased flexibility comes with costs in terms of reactor cycling (deep cycles), which further raises the issue of compliance with the annual budget preventing earlier maintenance of ageing components. At slower response of reactors, tested at 1%/half-hour speed, results show more gas power needed and more curtailment, despite higher use of storage in support to flexibility.

The minimum rated power threshold. The indicator tested at lower rate (20%) and also at higher level (50%) of the nominal power shows little sensitivity to the baseline, run at minimum rate of 30%. Results vary however in the expected way: at lower minimum threshold, nuclear substitutes for gas power as more flexible capacity is available, and allows renewables to enter the market to a larger extent. At higher minimum thresholds, the opposite occurs: higher gas supply and higher curtailment of renewables.

The schedule of flexible nuclear fleet. A lower share of baseload is favorable to more Load-Following fleet operation, hence more flexible nuclear capacity is made available to the system; load-following does not necessarily occur more often, but the magnitude of flexibility varies, with an eviction effect of the gas supply from the market. In contrast, a higher share of baseload puts more pressure on the remaining flexible reactors which cycle more; the effect from a lower flexible fleet is similar to the above tests, i.e. higher gas supply, higher curtailment, and more storage use. These results are in line with Teirila (2020) and Zhao et al. (2022).

To summarize, the highest sensitivity of results is obtained for ramping speeds, affecting on nuclear cycling, gas supply and renewables integration.

The mix **diversification** by decreasing nuclear share generally implies either decreased nuclear capacity, which raises the issue of adequacy, or using the same fleet but less often but ensuring this way the adequacy over high peak loads. The trade-off between power (GW) and energy (GWh) for mix diversity significantly plays on the use of nuclear plants and on reactors aging in case of excessive cycling. Two cases are tested with EcoNUK: 1) one reactor out of operation, and 2) one reactor added to the fleet.

1) Having *one 1 GW reactor out of operation* allows measuring the margins of the system in case of technology risk of unavailability. Results show that in 2050 there is enough capacity to meet the demand, since there is no increase in the shadow cost for an eventual lack of supply. The equivalent energy of the reactor phased-out is 760 GWh of additional gas over the year, and 663 GWh of renewables which are curtailed due to ramping constraints of the remaining reactors. The period where gas substitutes the missing reactor covers in general those hours without solar power, and by seasonality, events are more frequent during winter. The number of events where the reactor needs additional gas is around 5,300, or 31% over the half-hour interval, which is relatively significant. Interestingly, the substitution does not occur 1 MWh of nuclear (less) for 1 MWh of gas (more), as less than 1 MWh of additional gas is needed for 1 MWh of nuclear out. The reactor phased-out is partly replaced by another operational reactor with spare capacity; hence, the remaining reactors run more, attaining capacity factors of 82% instead of 79% initially.

A major finding is in terms of power needed to substitute one nuclear reactor. The maximum gas supplied over the year is of 4,800 MW, showing that removing 1,000 MW of nuclear needs much more dispatchable capacity, due to stress and ramping constraining the remaining fleet. The model assumes that the flexibility supplied is uniformly distributed among reactors, therefore one reactor less means eventually more flexibility provided with the remaining reactors.

2) *One reactor more* makes the system cost decreasing with 115 Mln€ over the year due to the substitution of nuclear with gas, following nonlinear substitution ratios: an additional GW flexible nuclear capacity generates 6.18 TWh power detrimental to inflexible nuclear power, and allows a better integration of renewables (+ 604 GWh) and less gas power (-707 GWh). As less inflexible nuclear power is called and less renewables are in excess, storage decreases too (-200 GWh). The model reduces less combined-cycle gas turbines, yet more expensive, which demonstrates the need of the system for flexibility and that, to some extent, flexibility is prior to costs, due to ramping constraints.

The message from these tests is more general and concerns the policy targets set on nuclear share in the generation mix, in the way that reaching 50% of nuclear in 2035 or 25% in 2050, needs a higher understanding of the ability of the technology mix to cover peak load periods.

4.5. Alternative scenarios on nuclear and demand with EcoNUK

1) No target on nuclear flows during model coupling. The two-model coupling being based on the assumption that similar nuclear flows are obtained in both models, we have shown that a more granular model like EcoNUK needs more gas flows. In the following, we relax this assumption and test the operation of reactors without limit on the total nuclear power (NUCfree), while keeping the same capacity installed as above.

Results show that the model calls for more flexible nuclear power (+14.4 TWh) compared with the Baseline (NUCpoles). The new mix is made of renewables (69.1%), nuclear (28.2%), gas (2.7%) and storage (1.9%). Initially, the Baseline power mix was made of renewables (70%), nuclear (26%), gas (4.1%) and storage (1.7%). The scenario NUCfree in EcoNUK replaces almost all combined-cycle gas flows (-8.7 TWh) with nuclear power and tends to curtail more renewables (-3.9 TWh) rather than ramping down nuclear reactors as it also seems to suggest a higher usage of storage. Nuclear power becomes price-maker most of the time, which implies a significant decrease in the clearing price that attains 30 €/MWh in average. The system cost drops too (-1.4 Bln €), due to massive replacement of gas flows.

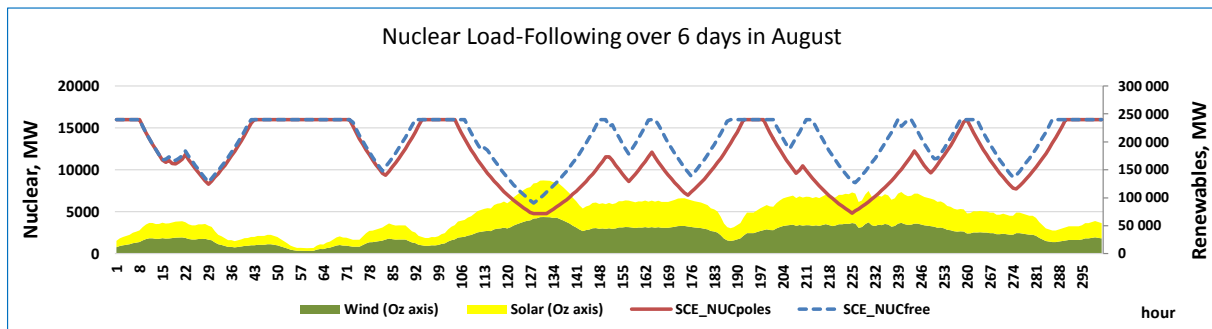


Fig. 8. Flexible nuclear supply in EcoNUK in Scenario with no coupling target on nuclear (Sce_NUCfree) and Scenario matching POLES nuclear flow (Sce_NUCpoles)

The nuclear follows the same path as in the Baseline, but at higher magnitude and deeper rampings up and down to substitute for gas. More nuclear supplies both positive and negative flexibility, as shown at Figure 8, where nuclear load-following is represented in August which records high inflows of solar power and large load variations. Interestingly, the number of nuclear mid- cycles increases by 14% and for deep cycles decreases by 4% compared to the constant nuclear scenario, meaning that flexibility is rather needed for mid-load variations; moreover, without nuclear flow constraint (SCE_NUCfree) reactors perform longer over energy blocks with less cycling constraint, which implies that policy makers should express targets in capacity, well calibrated in terms of adequacy, rather than in flows (relative or absolute) as this could constrain the operation beyond technological physical standards.

2) Higher demand - in volume and in peak loads

Uncertainties on the evolution of the future power demand are enhanced by factors acting downward, like energy savings, and upward like the electrification of industry, housing and transport. We test the resilience of the system in 2050 to two shocks: 1) demand increases uniformly, along with peak loads, requiring punctually more capacity; and 2) demand increases but extreme peaks remain at the same level as in the reference case (91.6 GW).

Increased demand and peaks. Successive tests with EcoNUK in 2050 show that the model stands a maximum demand increase of 11% from the initial level (471 TWh), representing a new demand of 523 TWh and maximum peak load of 102 GW. Above 11%, the model proves infeasible revealing that punctually the demand cannot be met with the capacity documented by POLES. For comparison, the demand in 2019, before the pandemic, was 473 TWh and the peak load of 88.5 GW.

Results show that a higher demand triggers the nuclear usage at 90%, and the nuclear share increases to 27% in the power mix. Higher nuclear output (+23 TWh) makes nuclear reactors operating more and cycling less. Higher demand triggers gas flows too (+35 TWh or 8.8% in the mix), renewables are better integrated (curtailment drops by half), and storage decreases due to less ramping and to less renewables in excess (-1.5 GWh).

Increased demand, constant peaks. At similar peak loads of 91.6 GW as in the reference, a higher demand can be met, +15%, or 541 TWh. The fact that extreme peaks are at the same level means that power plants supply more power outside peaks (blue air at Fig. 9), which seems to benefit to nuclear plants that supply more power in a less flexible way, hence cycling less. At given installed capacity, supplying more than 540 TWh needs more conventional power, such as gas, which increases significantly (+55 TWh).

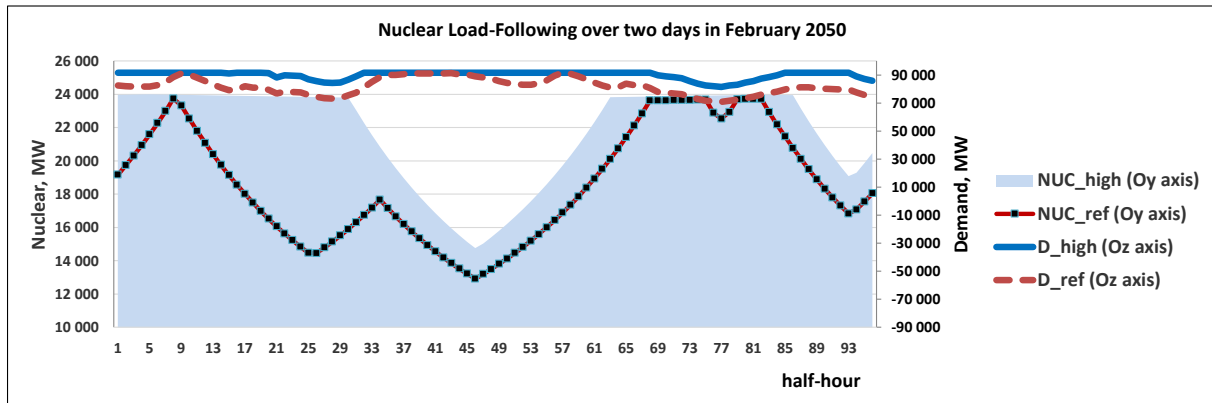


Fig. 9. Nuclear supply for the reference demand (curve, Oz axis) and for high demand and constant peak (area, Oy axis)

Higher demand enables nuclear power to operate in a more continuous way and prevents excessive cycling; an increase in demand needs also other dispatchable flows, like gas. Alternatives to a general increase in demand is to enable reactors to run continuously and to fill the gap while reactors ramp down, by supplying electricity to other sectors, like transport and industry, and hydrogen (Scamman and Newborough, 2016; Cany et al., 2017). Power to heat in the residential sector seems also to be a viable option for the French reactors, although dependent on economies of density and the proximity with consumers so that the distribution network costs decrease (Leurent et al., 2018).

5. Conclusions and Policy Implications

The evolution of the future power mix in France has been explored by means of a simulation prospective tool coupled with a dispatching model, based on political plans and on technological and economic considerations. Coupling the long-term prospective model POLES with the market model EcoNUK has enabled to highlight the importance of key parameters such as nuclear ramping and minimum rated power while testing scenarios with political targets. In the absence of infra-hourly technical constraints, long-term energy models usually need less flexibility than time-disaggregated models, yet other model specificities add such as demand paths, heat demand, etc (Lopez et al., 2022; Misconel et al., 2022). The dispatching model showed higher flexibility needs mostly supplied with nuclear power rather than gas power, due to high costs of clean gas triggered by carbon taxes. On the demand side, it showed the importance of assumptions on the peak amplitude and the management of extreme loads with energy and capacities, revealing the importance of reasoning in terms of instantaneous balance on a continuous basis, instead of averages.

The technological capability of power systems to face the instantaneous variability of renewables makes in general energy scenarios ambiguous and new metrics to assess their feasibility are necessary, such as power plant cycling. The one-direction model coupling has transferred the planning strategy to the market operation to make a loop on the load-following with nuclear power. More specifically we showed that high shares of intermittent renewables in France by 2050 add pressure on nuclear power plants in terms of ramping and cycling, and according to the current license provision, could push nuclear reactors to retire earlier. The metrics of the system flexibility in terms of technology cycling are necessary to steer climate policy and investment decisions based on high-fidelity short-term representation of the system.

5.1. Policy Implications

Two policy topics are issued, at the address of the nuclear operator facing higher uranium demand by plant and faster reactor needs; and for decision-makers while planning the energy mix.

1. The nuclear fleet in 2050 will have a lower capacity than today (24 GW instead of 61 GW), but it will be used more often and more flexibly, requiring thus to well anticipate the uranium management and the type of reactors needed in the future mix.

Anticipation of the uranium use. The demand of uranium is closely related to the nuclear fuel cycle services, which is reflected into the plant load factor. Well defining the capacity factor allows planning the refueling campaign, since the material flow inventory takes into account the reactor cycling, i.e. a variation of 10 points of the load factor, from 70% to 60% for instance makes decrease the uranium demand by 10% (Krymm and Woite, 1976). Nuclear-renewable interaction at half-hour step resulted in an increase in the capacity factor in 2050, from the current 74%¹⁴ to 80% in average, which can be used in support to fuel estimation, and further to waste infrastructure planning.

New design of reactors. The power system simulated will need faster reactors and longer and deeper cycling units. Within the current license, integrating more renewables implies reactors to perform excessive cycling and bear additional fatigue, calling for two solutions: refurbishment or early decommissioning, with additional cost for plant upgrading; alternatively, regulation could upgrade the limit of deep cycles admitted per year. Our scenarios contained information on the gradients of the load variations and manoeuvres (speed of 5%/half-hour) and boundaries of operation of a reactor (200 deep cycles/year, minimum rate of 30% of nominal power). New types of solicitation will change the reactor design such as higher speed (10%/half-hour) and more deep cycles (+15%), for both new reactors and those under modernization, and should integrate at their early stage of design the capability to operate more flexibly.

2. Flexibility assessment can support policy makers with respect to the capacity targeted for nuclear and gas-fired units.

Nuclear planning: power over energy criteria. Considerations on the future power mix aiming at reducing the nuclear share are mostly political and social (ETA, 2015). Hence the future architecture of the nuclear fleet should prior capacities over flows by maintaining as many reactors as necessary to cover peaks but using them less, attaining still the objective of 50% nuclear share in the mix in 2035-2040. EcoNUK results have shown large capacity needed over some hundreds hours per year, in particular during winter and night time, with large load variations over short seasons, like days. Decreasing therefore the nuclear share should account not for the total flow but for the capacity needed over peak periods and for the additional stress put on the remaining plants while closing reactors.

The trade-off between Nuclear and Gas. Integrating large shares of renewables will require more flexible back-up units such as gas and nuclear power, but their intensive use appear conflictual with the double French target, i.e. to reduce nuclear power and to lower carbon emissions. Similarly, Guerra et al. (2022) show that decarbonisation targets in Spain are not realistic with respect to flexibility, which will be largely supplied with natural gas units. In Europe, certain nuclear and gas activities¹⁵ have been included in the technology mix allowing to attain European Union's climate objectives, such as to accelerate the private investment in nuclear and gas shifting coal generation. In the next decades, renewables will have priority but will be insufficient, and gas and nuclear remain

¹⁴ <https://world-nuclear.org/information-library/country-profiles/countries-a-f/france.aspx>

¹⁵ Nuclear power and gas units need to fulfil the criteria of gradual phase-out, best available technologies adoption, radioactive waste disposal and replacement of coal power plants (EC, 2022). https://ec.europa.eu/commission/presscorner/detail/en/IP_22_711

key technologies to the carbon-neutral transition. Within climate emergency and needs for more energy independence from imported natural gas, policy makers tend to reinforce the nuclear policy as a low-carbon solution limiting global warming. In France, the financial recovery plan supports flexible small modular reactors, between 10 and 400 MW (the project NUWARD¹⁶) and bio-gas and green hydrogen projects, selected based on industry, climate and social acceptance considerations, detrimental to natural gas. Therefore policy makers could prioritize nuclear power as a substitute to natural gas, at least over the transition period to renewables.

5.2. Work Perspectives

The study conclusions could be exploratory in understanding the way the scenarios on nuclear trajectories fuel scientific and policy debates, and should also include social aspects of resilience and sustainability (Cazcarro et al., 2022). Further developments should cover the cycling normalization of modern reactors by means of physics, but beyond technical requirements of codes and standards, flexibility will need human resources for special controls and monitoring (IAEA, 2018). As any innovative organization process, the timespan will cover not only the human resource training, but will face inertia of the historical load-following instrumentation (Tillement and Hayes, 2019), hence more disciplinary fields are needed to tackle the managerial aspects of work organization and the sociological perspective of the large spectrum of stakeholders involved in the nuclear flexibility (Skea et al., 2021).

The system flexibility is not restricted to a momentary power adjustment, but it is a long decision process which needs prior organization of the work and staff training, the coordination between regulators, plant operator, grid operator and waste reprocessing facility, along with the support and the expertise of scientists, general public and policy-makers. Nuclear flexibility provision seems ultimately a rigid long process with prior organization, regulation and innovation, hence long-term scenarios should more comprehensively include all stakeholders to reach an informed decision on the need of nuclear flexible operation.

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¹⁶ <https://world-nuclear-news.org/Articles/French-developed-SMR-design-unveiled>.

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Annex 1. Model equations

Symbols

NPP – nuclear power plants

Index

tech – technology type (1 to 12)

h – half-hours over one year (1 to 8760 x 2)

Fixed Variables (Inputs)

Cvom – variable cost of operation and maintenance (€/MWh_{output})

Cfuel – cost of fuel (€/MWh_{input})

K_{tech} – capacity installed by technology (MW)

P_M – price of imports (€/MWh)

TaxCO₂ – carbon tax (€/t CO₂)

Variables (Outputs)

CostFuel – annual fuel cost of NPP operators (€)

CostVOM – annual variable costs of NPP operators (€)

Cycle_{up_h} – the amplitude of positive flexibility of NPP at hour *h* (MW·h)

Cycle_{down_h} – the amplitude of negative flexibility of NPP at hour *h* (MW·h)

D_h – hourly power demand (MW·h)

EG – annual energy sale of nuclear power (MW·h)

Emiss_{CO₂} – total annual carbon emissions (t)

Fobj – the objective function of the system operator (€)

Gen_{tech} – power generation by technology (MW·h)

Curt_h – output suppression (MW·h)

M_h – hourly power imports (MW·h)

REV – annual revenue of the nuclear operator from the sale of energy (€)

Sout_h – hourly power generated with the storage system (MW·h)

Sin_h – hourly power filled in the storage technology at hour *h* (MW·h)

St_h – cumulated energy stored at hour *h* (MW·h)

St_{h-1} – cumulated energy stored at hour *h-1* (MW·h)

X_h – hourly power exports (MW·h)

Parameters

AF_{tech} – plant availability annual factor (%)

cf_{tech} – carbon emission coefficient by technology (tCO₂/MWh_{input})

Eff_s – efficiency of storage technology (%)

Eff_{tech} – efficiency of power generation by technology (%)

MinLoad_{h,tech} – minimum generation level (%)

LF_{h,tech} – hourly load factors of variable renewables (in the range 0-1)

τ^{loss} – transport and distribution loss rate (%)

τ_{tech}^{rampup} – ramp up rate, by technology (%)

τ_{tech}^{rampdown} – ramp down rate, by technology (%)

Eq 1. The objective function = System costs minimisation:

$$Fobj = \sum_{h=1}^{8760} \left[P_M \cdot M_h + \sum_{tech=1}^{12} Gen_{h,tech} \left(Cvom_{tech} + \frac{Cfuel_{tech} + TaxCO2 \times cf_{tech}}{Eff_{tech}} \right) \right]$$

Eq 2. Hourly power market equilibrium Supply = Demand:

$$\sum_{tech=1}^{12} Gen_{h,tech} + M_h + Sout_h = (D_h + X_h) / (1 - \tau^{loss}) + Sin_h$$

Eq 3. Ramping constraints:

$$1 - \tau_{tech}^{rampdown} < \frac{Gen_{h+1,tech}}{Gen_{h,tech}} < 1 + \tau_{tech}^{rampup}$$

Eq 4. Used capacities are lower than installed capacities times the annual availability factor and the natural input inflows for renewable energy technologies:

$$Gen_{h,tech} \leq LF_{h,tech} AF_{tech} K_{tech}$$

Eq 5. Minimum load condition = hourly generation has a minimum level of production:

$$Gen_{h,tech} \geq MinLoad_{h,tech} LF_{h,tech} AF_{tech} K_{tech}$$

Eq 6. Storage dynamics:

$$St_{h+1} = St_h + Sin_h \times Effs - \frac{Sout_h}{Effs}$$

Eq 7. Power discharged is lower than the power charged over the year:

$$\sum_{h=1}^{8760} \frac{Sout_h}{Effs} \leq \sum_{h=1}^{8760} Sin_h \times Effs$$

Eq 8. Total system CO2 emissions:

$$Emiss_{CO2} = \sum_{h=1}^{8760} \sum_{tech=1}^{12} \frac{Gen_{h,tech} \times cf_{tech}}{Eff_{tech}}$$

Eq 9. Total curtailment of on and off-shore wind power, hydro power and solar power:

$$\begin{aligned} Curt_h = & (LF_{h,wind} \times AF_{h,wind} \times K_{wind} - Gen_{h,wind}) \\ & + (LF_{h,solar} \times AF_{h,solar} \times K_{wind,solar} - Gen_{h,solar}) \\ & + (LF_{h,hydro} \times AF_{h,hydro} \times K_{hydro} - Gen_{h,hydro}) \end{aligned}$$

Eq 10. Cycling accounting:

$$\begin{aligned} Cycle_h & = Gen_{h,nuc} - Gen_{h-1,nuc}, \text{ if } >0 \\ Cycle_{down_h} & = Gen_{h,nuc} - Gen_{h-1,nuc}, \text{ if } <0 \end{aligned}$$

Annex 2. Inputs of the model, by technology type in 2050

| Technology | Efficiency | Max Availability | Ramp | VOM CO2= 767 €/t |
|---------------------------------|------------|------------------|-------------|---------------------|
| | % | %/year | %/half-hour | €/MWh |
| Nuclear Inflexible | 36% | 90% | 0.1% | 22 |
| Nuclear Flexible | 36% | 90% | 5% | 22 |
| Hydro River | 100% | 42% | 100% | 3 |
| Hydro Lake | 100% | 28% | 100% | 3 |
| Coal | 40% | 70% | 25% | 509 |
| Oil steam turbine | 41% | 70% | 50% | 639 |
| CCGT (Combined cycles gas | 55% | 80% | 10% | 324 |
| NGGT (Natural gas gas turbines) | 40% | 100% | 90% | 452 |
| CHP (Combined heat and power) | 70% | 70% | 10% | 258 |
| Wind On-shore | 100% | 24% | 100% | 1 |
| Wind Off-shore | 100% | 38% | 100% | 1 |
| Solar | 100% | 13% | 100% | 1 |
| Other RES | 100% | 25% | 100% | 1 |

Note. Max Availability is the maximum load factors and defines the maximum use of a technology due to a limited natural resource inflow, to the power plant unavailability, or to political will to limit the use of imported fuels.

Annex 3. Scenarios obtained with the model POLES for the years 2035, 2040 and 2050

| Technology | Actual mix, 2017 | | | Scenario POLES 2035 | | | Scenario POLES 2040 | | | Scenario POLES 2050 | | |
|----------------------------------|------------------|-------------------|------------|---------------------|-------------------|------------|---------------------|-------------------|------------|---------------------|-------------------|------------|
| | Capacity MW | Generation GWh | CF % | Capacity MW | Generation GWh | CF % | Capacity MW | Generation GWh | CF % | Capacity MW | Generation GWh | CF % |
| Nuclear | 63 130 | 382 320 | 69% | 47 225 | 309 175 | 75% | 36 353 | 240 821 | 76% | 24 030 | 166 311 | 79% |
| Coal | 2 930 | 5 310 | 21% | | | | | | | | | |
| Oil | 6 550 | 5 310 | 9% | 2 955 | | | 2 815 | | | 4 330 | | |
| Gas | 12 120 | 30 207 | 28% | 13 660 | 3 212 | 3% | 14 458 | 5 584 | 4% | 16 301 | 17 578 | 12% |
| Hydro River | 10 327 | 42 000 | 46% | 5 727 | 21 152 | 42% | 5 741 | 21 205 | 42% | 5 766 | 21 297 | 42% |
| Hydro Lake | 8 231 | 16 410 | 23% | 15 393 | 37 923 | 28% | 15 632 | 38 513 | 28% | 16 085 | 39 630 | 28% |
| Wind On-shore | 11 790 | 21 210 | 21% | 89 039 | 130 080 | 17% | 99 832 | 171 823 | 20% | 91 929 | 192 293 | 24% |
| Wind Off-shore | 10 | 30 | 34% | 1 114 | 2 623 | 27% | 1 716 | 4 760 | 32% | 4 355 | 14 558 | 38% |
| Solar | 6 550 | 10 620 | 19% | 35 598 | 32 072 | 10% | 53 033 | 53 488 | 12% | 94 240 | 106 376 | 13% |
| Other RES | 4 397 | 12 270 | 32% | 8 265 | 7 279 | 10% | 14 478 | 20 267 | 16% | 37 289 | 81 484 | 25% |
| Total | 126 035 | 525 687 | 48% | 218 977 | 543 516 | 28% | 244 058 | 556 461 | 26% | 294 325 | 639 528 | 25% |
| DSM | | | | 873 | 82 | 1% | 1 270 | 277 | 2.5% | 3 979 | 1 304 | 4% |
| Storage (PHS + CAES + Batteries) | 4 965 | 5 310 | 12% | 3 940 | 1 644 | 5% | 3 518 | 1 752 | 5.7% | 7 599 | 1 647 | 2% |
| Connections Imports, MW | 11 000 | | | 23 000 | | | 25 000 | | | 27 000 | | |
| Connections Exports, MW | 17 000 | | | 28 000 | | | 31 000 | | | 34 000 | | |
| National Demand, GWh | 480 000 | | | 413 276 | | | 427 420 | | | 471 478 | | |
| Net Exports, GWh | 38 000 | | | 60 084 | | | 55 524 | | | 54 611 | | |
| Losses, GWh | 7 687 | 1.5% | | 70 156 | 12.9% | | 73 517 | 13.2% | | 113 438 | 17.7% | |

Annex 4. Results with models POLES and EcoNUK; variations are computed as Δ = POLES - EcoNUK

| Technology | 2035 | | | 2040 | | | 2050 | | |
|------------------|----------------|----------------|---------------|----------------|----------------|---------------|----------------|----------------|--------------|
| | POLES | EcoNUK | Δ | POLES | EcoNUK | Δ | POLES | EcoNUK | Δ |
| Nuclear | 309 175 | 309 175 | 0 | 240 821 | 240 821 | -0 | 166 311 | 166 311 | 0 |
| Oil | - | 0 | 0 | 0 | 13 | -13 | - | 1 | -1 |
| Gas | 3 212 | 5 936 | -2 724 | 5 584 | 14 432 | -8 848 | 17 578 | 26 540 | -8 962 |
| Hydro-Power | 59 075 | 59 077 | -2 | 59 718 | 56 494 | 3 224 | 60 927 | 56 539 | 4 389 |
| Wind On-shore | 130 080 | 130 080 | 0 | 171 823 | 171 712 | 111 | 192 293 | 192 213 | 79 |
| Wind Off-shore | 2 623 | 2 621 | 1 | 4 760 | 4 720 | 39 | 14 558 | 14 531 | 27 |
| Solar | 32 072 | 32 072 | 0 | 53 488 | 52 133 | 1 355 | 106 376 | 102 499 | 3 878 |
| Other RES | 7 279 | 7 279 | 0 | 20 267 | 20 267 | 0 | 81 484 | 81 485 | 0 |
| Total | 545 159 | 546 240 | -1 081 | 558 213 | 560 592 | -2 380 | 641 175 | 640 119 | 1 056 |
| DSM | 82 | 13 | 69 | 277 | 223 | 55 | 1 304 | 1 394 | -90 |
| Storage | 1 644 | 2 150 | -506 | 1 752 | 5 847 | -4 095 | 1 647 | 10 900 | -9 253 |
| NUC / Generation | 57% | 57% | 0% | 43% | 43% | 0% | 26% | 26% | 0% |
| RES / Generation | 42% | 42% | 0% | 56% | 54% | 1% | 71% | 70% | 1% |
| vRES / Demand | 47% | 47% | 0% | 64% | 65% | -2% | 88% | 87% | 1% |

Annex 5. Sensitivity of baseline to changes in ramping rates, minimum rated power and baseload share

| 2050 | Baseline | Ramping | | | Minimum rated power | | Baseload Share | |
|-------------------------|-------------------------------|--------------|---------------|---------------|---------------------|--------|----------------|--------|
| | Ramp 5% Pmin 30% BL 33% | 1%/half-hour | 10%/half-hour | 20%/half-hour | 20% | 50% | 10% | 50% |
| Cycling | | | | | | | | |
| Light | 139 | 264 | 179 | 218 | 132 | 171 | 169 | 121 |
| Mid | 88 | 87 | 65 | 70 | 86 | 102 | 93 | 86 |
| Deep | 229 | 11 | 291 | 314 | 228 | 218 | 222 | 233 |
| Capacity factors | | | | | | | | |
| Baseload | 80% | 72% | 78% | 75% | 81% | 70% | 79% | 79% |
| Load-Following | 79% | 83% | 80% | 81% | 78% | 83% | 79% | 79% |
| Dispatching | | | | | | | | |
| Gas, GWh | 26 540 | 31 496 | 24 364 | 23 175 | 26 442 | 27 380 | 24 303 | 28 262 |
| Storage, GWh | 10 900 | 12 343 | 9 697 | 8 594 | 10 908 | 10 752 | 10 234 | 11 340 |
| Curtailement, GWh | 5 435 | 8 520 | 4 399 | 4 004 | 5 346 | 6 241 | 4 051 | 6 571 |