Load-following with nuclear power: Market effects and welfare implications

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Abstract

This paper analyses the economic factors that drive nuclear power load-following in future European electricity systems. A power plant dispatching model is built to simulate deregulated markets, in order to identify to what extent additional flexibility is needed from nuclear power due to more renewables. We contribute to the literature with an economic perspective of the nuclear load-following by means of numerical simulations of several European power systems that will pursue the nuclear policy in 2050. Results show that intermittency would make flexible nuclear reactors cycling more often and retire earlier. The highest requirements for flexibility would be in systems with high shares of nuclear, renewables or coal-fired plants (Central-Western Europe and certain Central-Eastern European countries) and in systems with low grid interconnections (Western Europe and South-West). Load-following implies lower capacity factors for nuclear plants, except for Central-Western Europe where operating flexibly would allow reactors to supply more output than in steady-state mode. The lowest generation cost is found in Nordic countries where most of the flexibility is provided by hydro-units, and hence nuclear power plants operate mostly baseload. Ensuring flexibility becomes financially interesting when nuclear power plants are not the marginal technology setting the clearing price; in this way the infra-marginal rent allows operators to capture high revenues. It is shown that nuclear flexibility is profitable from a broader social welfare perspective, such as safe baseload units' operation, renewables' integration, system operators' balancing, and consumer's price.

Keywords: intermittency, nuclear, load-following, system costs, social welfare.

Highlights

Nuclear load-following is constrained by the transient budget of reactor licence.
Load-following has long-lasting deep cycles in 2012 and short cycles-fast provision in 2050.
Intermittency would make nuclear reactors cycling more often and retire earlier.
Nuclear flexibility is profitable to baseload units, renewables, system operators, consumers.

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[1] Université de Nantes, IEMN-IEA, Lemna, France. Corresponding author: rodica.loisel@univ-nantes.fr.
[2] alexeeva@gmx.de. Any views or opinions reflected here are those of the author, expressed in a personal capacity, and do not necessarily reflect those of her employer.
[3] Andreas.ZUCKER@ec.europa.eu, European Commission, DG Joint Research Centre, Institute for Energy and Transport, The Netherlands.
[4] DEShropshire@gmail.com. Any views or opinions reflected here are those of the author, expressed in a personal capacity, and do not necessarily reflect those of his employer.

1. Introduction

The European Energy Roadmap to 2050 frames the energy transition by setting out four routes to decarbonisation, such as energy efficiency, renewables, nuclear energy and carbon capture and storage (EC, 2011). The decarbonisation objective involves high rates of renewables, e.g. between 55% and 97% in the final power demand by 2050, along with a significant contribution from nuclear energy in those countries where a pro nuclear policy is pursued. The interaction between intermittent renewables and the conventional technology mix is a matter of concern for policy makers for both short-run dispatching of generators and long-run investment planning in new power plants.

This research evaluates the requirements for nuclear flexibility and the cost-benefit aspects in various power systems in European Union (EU). Countries have been selected due the variety of drivers influencing the operation of nuclear power plants (NPP), such as different renewables levels, generation technology mix and grid interconnection with the neighbouring markets.

The literature is rich in papers dedicated to the flexibility of power plants and their ability to follow the load. Firstly, cycling comes with costs. Kumar et al. (2012) estimate that from cold to warm and hot start, load-following costs in the United States are in the range of 0.6-1.9$/MW for gas-fired units and of 2.0-3.4$/MW for coal-fired units. Troy et al. (2010) show that the number of start-ups of thermal units in the Irish power system increases with the wind energy share; yet at higher than 30% wind rates, the start-ups for coal units decrease with raising primary reserve supply. Flexible NPPs operating load-following will bear additional costs with the retrofit and design conversion, O&M costs due to the wear of components, some fuel costs, staff costs and intensified safety measures (IAEA, 2018).

Secondly, load-following compresses load factors of conventional generators, down to 62% for nuclear power plants and to 7% for gas-fired units in Europe, which could reduce the financial incentives to invest in baseload and peak capacities (Ketterer, 2014, Wurzburg et al., 2013, Bertsch et al., 2016). The compression effect could be even stronger, e.g. 40%, if nuclear was to substitute all flexible technologies and imports (Cany et al., 2016). Currently, the loss due to the load-following is estimated at 135,000-250,000 €/day for a nuclear plant of 1,400MW operating in Europe (OECD-NEA, 2012a). It is shown that a viable model of baseload operation in front of renewables is possible only if nuclear plants co-generate power and heat as well, e.g. for district heating, desalination and hydrogen production (Locatelli et al., 2017), or for biomass conversion into liquid transport fuels (Forsberg, 2009).

From a system perspective, nuclear load-following can maximise the social welfare, as shown in Lykidi and Gourdel (2015) by means of an optimisation model with monthly time-steps. These aggregated models often ignore significant ramping ups and downs and the daily and hourly pressure put on reactors. Instead, highly detailed time-resolution models are needed to accurately test the ramping requirements (Komiyama and Fujii, 2015). The need for nuclear power generation to be more flexible with faster ramping rates is one of the important factors in determining the design of the future nuclear reactors, such as to follow the development of energy markets (Magwood and Paillere, 2018; Nourbakhsh et al., 2018).

This research builds tools to simulate future power markets and the cycling needs from NPPs. For potential excessive cycling, we use cost estimates of reactors' upgrading and assess the potential benefits from operating load-following. We next define the capability of NPP to operate flexibly. Then we describe the methodology based on power plant dispatching. Numerical findings will depict the value of the nuclear flexibility provision and the key drivers of nuclear power economics in the future.

2. Nuclear capability to provide flexibility

By definition, load-following represents the change in the generation of electricity to match the expected electricity demand as closely as possible (IAEA, 2018). In practice, countries with large nuclear power shares (France) and high intermittent renewables (Germany), need NPPs to operate load-following. In other systems, load-following is currently not licensed (Spain) or needs approval from system operators and nuclear national safety authorities (USA; EPRI, 2014).

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 once or twice per day in the range of 100% to 50%-25% of the rated power, with a ramp rate of up to 5% of rated power per minute (OECD-NEA, 2011). The number of cycles is limited to 2 operations per day, 5 per week, cumulatively 200 per year (EUR, 2012). 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). The amplitude is in the range of 100%-60% of the nominal power for light cycles, and between 100%-25% for deep cycles (AREVA, 2009; EDF, 2013). Figure 1 represents cycles with different durations and amplitudes, distinguishing short from long cycles and deep from light cycles.

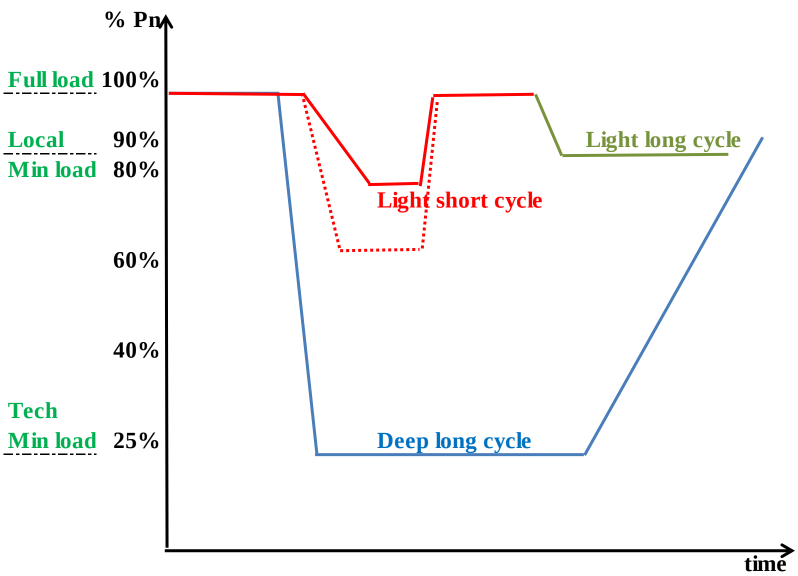

Fig. 1. Load-following capability of a PWR by cycle type

Ludwig et al. (2010) analyse the licence of a German Pressurized Water Reactor (PWR) and define the transient budget of cycles, as being the number of cycles with bounded amplitude allowed over the plant lifetime.

Table 1. The design of PWR Konvoi reactor showing the allowed number of cycles by deepness

Load cycle (% power rate)	Number of cycles
100-90-100	100 000
100-80-100	100 000
100-60-100	15 000
100-40-100	12 000

Sources: Ludwig et al. (2010).

Table Reading. A PWR reactor could perform 100,000 cycles of 10% of the rated power amplitude over the plant lifetime (a 10% depth cycle goes from 100% of the rated power to 90% and back to 100%). The reactor can also perform 100,000 cycles of 20% depth, 15,000 cycles of 40% depth and 12,000 cycles of 60% depth.

Load-following allowed by the licence of a flexible reactor (Table 1) is provided for in a planned manner[4], and this enhances no additional cost. By contrast, unplanned cycling would account for more fuel costs due to a reduced usage of uranium during one refuelling cycle, e.g. in the range of 17-34% of the initial fuel cost (Persson et al., 2012). Planning load-following requires a good management of the NPP fuel, such as to anticipate the usage rate of the uranium at the beginning of the cycle (IAEA, 2018). However, neither practice nor literature could defend a robust cost estimate of cycling based on the speed and the frequency of generator ramping up and down. Next the effective operation of NPPs in terms of cycling is compared with the licensed transient budget in order to identify cases with additional reactor fatigue requiring upgrading.

3. Methodology. Model. Scenarios

3.1. Methodology

Assumptions. A power plant dispatching model is built to simulate major technology types in the European power systems and to ensure the hourly equilibrium supply-demand (Fig.2). The study case covers deregulated power markets, which implies that power plants are called as a function of their position in the merit order curve.[5] The study case selects deregulated markets

[4] *Planned* load-following refers to changes in the electrical output and associated thermal power which are planned weeks or days in advance. *Unplanned* changes occur within a few minutes of a request from the grid system operator, and achieves a significant change in output within 10-20 minutes (IAEA, 2015).

[5] Merit order curve is the electricity supply curve built by ranking the power generators by ascending order of their short-run marginal cost of production. Power plants are dispatched together with the amount of energy to be generated, from low merit-order baseload units to high merit-order peak-load units.

where the nuclear plants are paid at the spot market price. Regulated markets instead would apply a full-cost recovery policy, based on nuclear levelised cost of electricity.

The model simulates the base year 2012 and the projection year 2050 in those countries with future nuclear power projects. The EU-28 Member States are grouped into five market regions. By 2050, thirteen countries plan to pursue using nuclear energy, according to the EU Reference Scenario EC (2013).[6] By region, these countries are as follows: 1) Region North - Finland and Sweden; 2) Region Central-Western Europe (CWE) - France and The Netherlands; 3) Region Central-Eastern Europe (CEE) - Bulgaria, Czech Republic, Hungary, Lithuania, Poland, Romania and Slovakia; 4) Region Western Europe (WEE) - United Kingdom; 5) Region South-Western Europe (SWE) - Spain.

The model we build integrates the installed generation capacities such as projected by the European Commission (EC, 2013), and assumes fixed power demand at each hour and endogenous export-import flows, constrained by the power interconnection grid capacity.

Inputs. The model simulates power system operation in 2012 and 2050. Model inputs are the power plants' installed capacity (see section 3.3), operating costs and technological parameters such as efficiency, ramping rates, carbon emission coefficients, availability of plants, maximum capacity factors, and minimum security operation constraints.

Outputs. After simulation, the model returns the power volume generated by each technology, the hourly power price, the system cost and derived indicators such as actual load factors, curtailment rates and carbon emissions. The reactors' flexibility provision is converted into light and deep cycles which are further compared with the licenced design to conclude on the nature of cycling and potential upgrading. The economics of the nuclear power is set with the indicators of the Net Present Value and the Levelised Cost of Electricity (Annex 1).

[6] An update of this scenario (EC, 2016) presents different trends of the nuclear capacities in Europe by 2050, e.g. one third lower. We simulate however the scenario described in EC (2013) as an alternative to nuclear decreased capacity, as nuclear power is defended by the public and the political support in countries like Netherlands and Spain where nuclear would decrease according to new projections (WNA, 2016a).

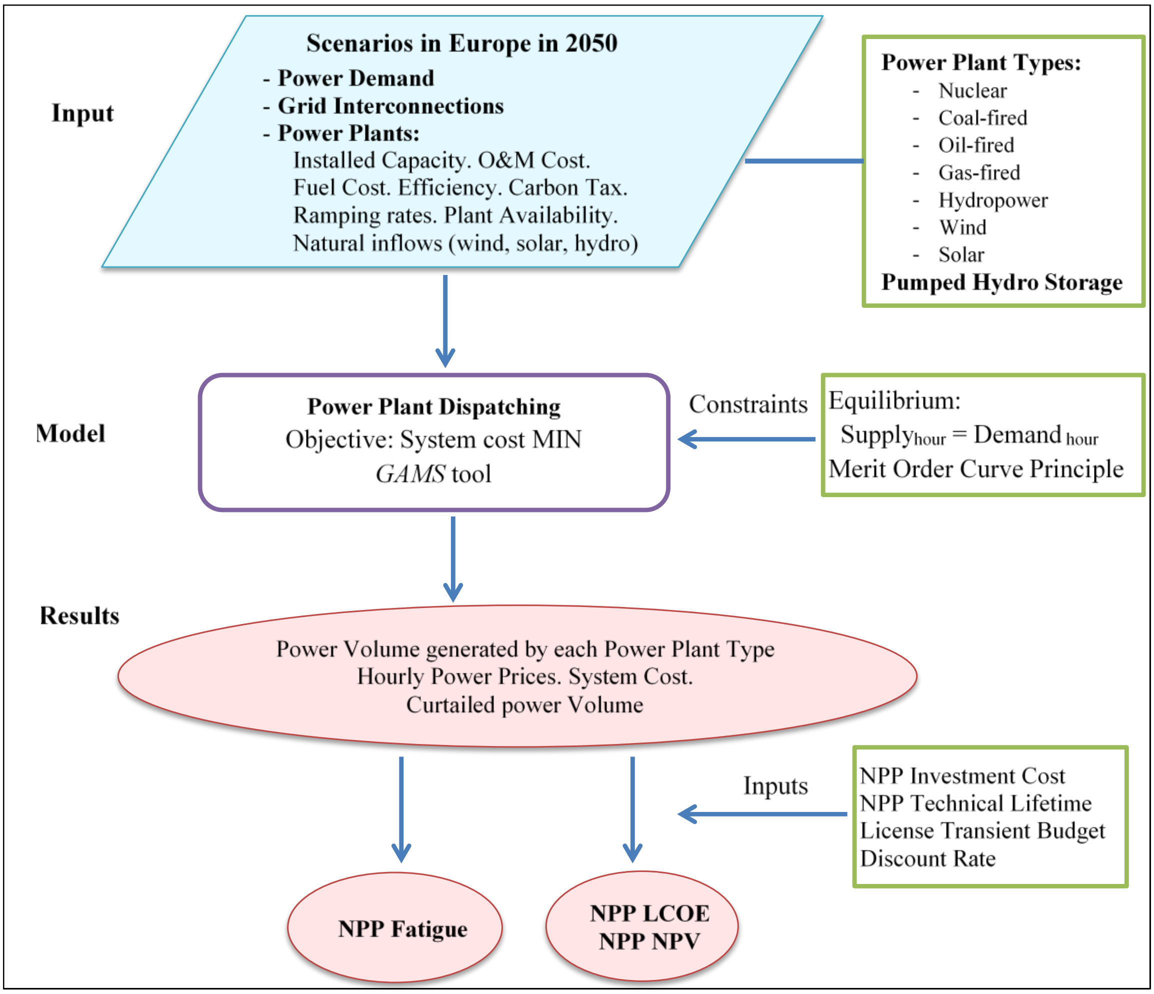

Fig. 2. Model's Input-Output flows representation

A reactor can use the cycling budget before the lifetime ending, leading to early retirement or to baseload operation for the remaining lifetime. In case of upgrading, the plant could continue operating flexibly after reinvestments into components renewal and additional corrective actions. Based on the experience of European reactors modernisation, this cost would be around 1,000 €/kWe (OECD-NEA 2012b; The French Court of Auditors, 2016).

3.2. Power plant dispatching model

A partial equilibrium model is built to endogenously select power supplying technologies such as to meet fixed demand on an hourly basis. The literature is rich with energy models adapted to various topics, such as the investment planning of the energy infrastructure (JRC-EU-TIMES model; JRC, 2013), the cost of system balancing (OCDE-NEA, 2012a), and the effect of renewables on electricity prices (Clo and D'Adamo, 2015; Ketterer, 2014; Wurzburg et al., 2013; Traber and Kemfert, 2011), etc.

Our power plant dispatching model is based on linear programming, implemented in the GAMS software with the Cplex solver.[7] The method used for solving the linear problem is a deterministic gradient-free method, where the objective function and the design variables are associated with bounds and constraints in order to ensure the global optimal solution. Equations are listed in the Annex 1. The program minimises the annual system costs of operating power plants, defined as the sum of variable costs, the carbon price, the variable operation and maintenance costs, and the import costs. Note that this is a short-term system cost, which excludes the long-run investment in the generation and transmission infrastructure. The model assumes thus fixed installed capacities over the simulation period.

Dynamic principles describe the system operation over one year, with 8,760 time slices. The hourly power market equilibrium is insured such that the supply from domestic technologies and imports equals the national demand and exports, including losses and charging storage plants. When the system cannot absorb the natural inflow of fluctuating renewables (wind, solar and hydro run-of-river power), the energy excess is supressed, the so-called curtailment or lost load.

The technical constraints are minimum operational loads, maximum load factors, and ramping capability of flexible technologies (see Table 2.1 in the Annex 2).

Minimum load factors are fixed for combined heat and power (CHP) plants, for nuclear plants and hydropower plants. Constraints on CHP are set at 10% of the nominal capacity, to reflect the obligation to produce heat and to deal with the missing heat demand in the model. Minimum load constraints for nuclear are set at 40% of the nominal capacity, in order to account for limitations at the beginning and the end of refuelling campaign, and to avoid low efficiency rates and ancillary disturbances in the operation and maintenance of the reactors.[8] Constraints are set at 5% of the nominal power for hydropower plants with reservoirs to avoid complete filling out.

Maximum load factors define 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.

Load-following with flexible technologies is made possible with hourly ramping rates, which describe how fast power plants can modulate the output from one hour to the next one. Flexible nuclear power reactors have full speed of ramping up and down during one hour, in line with the capability of a PWR, e.g. 3-5% of the nominal power by minute. The model assumes that only half of the EU-28 reactors operate load-following, such as to reflect the regulation limitations in some countries and the system operator strategy to optimize the fleet by using some reactors at baseload and some others load-following. The management of the

[7] The General Algebraic Modeling System (GAMS) is suitable for modelling linear optimisation problems, being especially useful with large database (https://www.gams.com). The GAMS solver Cplex is designed to solve large, difficult problems quickly. These advantages are fully exploited here to solve the power system problem of system cost minimisation in a short execution time (less than five minutes).

[8] Technically a PWR type could go beyond 40% of rated power, but it is not allowed to operate flexibly for a limited time at the beginning and at the very end of the operational cycle, due to fuel conditions restrictions (EUR, 2012).

flexibility is done at the level of the entire nuclear fleet with an equal distribution of the depreciation among flexible reactors.

The model applies to EU-28 first, where all capacity types, demands and grid interconnections are aggregated, and then thirteen models applies to each of (thirteen) countries with nuclear power in 2050. Models at country level integrates national constraints in terms of grid limit, specific demand profiles over the year and the technology mix projected in 2050.

3.3. Inputs and Scenarios in the future European power markets

Installed generation capacities in 2050 anticipate changes in the generation mix, issued from the model PRIMES, which is an energy system model based on views of each EU country experts used by the EU institutions for roadmaps and policy decisions (EC, 2013).[9]

The European electrical utilities adjust their mix to adapt to increased electricity demand, to carbon constraints, to higher renewable rates and new trading capacities. Our inputs on the hourly demand in 2012 are extracted from the ENTSO-E website[10], and on the supply side, the figures on installed capacities are based on projections of the European Commission with the model PRIMES (EC, 2013). These show that renewables represent 50% in the total power demand in 2050, out of which intermittent renewables (IRES) account for 31%. Nuclear generation shares in the EU final energy demand are of 31% in 2012 (128 GW) and of 23% in 2050 (122 GW).

Table 2. The main assumptions driving the flexibility of nuclear plants in 2050

Region	Assumptions						
	% IRES	NUC, MW	NUC, %	Load, GWh	Min Load, MWh	Max Load, MWh	Intercon degree, %
CEE	12%	31 006	55%	496 178	34 768	82 560	32%
CWE	39%	55 940	35%	748 760	48 466	150 456	17%
North	17%	18 054	61%	250 841	16 072	44 843	39%
WEE	19%	9 600	52%	410 534	25 624	73 967	7%
SWE	34%	7 393	16%	373 027	26 174	63 363	4%

Table reading. The column 'Min Load' in Table 2 is the minimum level of the demand over the year, and it draws expected results in terms of flexibility needs. If its value is higher than the nuclear installed capacity (the column 'NUC'), the demand is able to absorb the output generated by NPPs at their maximum capacity factor. Otherwise, nuclear generation is greater

[9] PRIMES is an energy system model covering the energy demand and supply, energy markets and CO2 emissions. The power sector module of PRIMES represents in detail the fleet of power plants in Europe and projects the decommissioning, refurbishment and new constructions. The model is used to test policy measures, to evaluate the cost of emission reduction and to project the demand and supply of electricity, to compute investment costs and related CO_2 emissions per country in Europe (EC, 2013).

[10] https://www.entsoe.eu/data/data-portal/consumption/

than the demand and the system should curtail or export the overgeneration (E3, 2014). The capability to export the surplus is framed in the indicator ‘Interconnection degree’.

Interconnections. The interconnection degree by region is defined by the grid capacity over the electricity generation capacity. The model assumes increased EU interconnection grid from the current 34 GW to 43 GW, which is higher than targets of the European Commission’s Energy Union Package by 2020 (plus 10%; EC, 2015a), but lower than levels of the European Climate Foundation’s ‘Roadmap to 2050’ (plus 150%; ECF, 2010). Some countries record low rates despite large grid capacity extension, because the production capacity increases more than the grid extension, due to low IRES capacity factors (20% for on-shore wind and 14% for solar power).

Inputs on nuclear power reactors. The Pressurized Water Reactor (PWR) is the most common type of reactor of the European nuclear fleet (80%). Currently, Europe is about to deploy the third generation of the PWR, the European Pressurised Reactor (EPR), with two first of a kind EPRs under construction, in Finland and in France. Next, we will assess the economics and the operation of the EPR with financial and technological characteristics shown in Table 3.

Table 3. Economic characteristics of an EPR power plant of 1,650 MW in 2050

Technical Lifetime	**Investment Cost**	**Finance Cost**	**Construc tion time**	**Total Inv. Cost**	**Fixed O&M Cost**	**Decommis sioning Cost**	**WACC**	**Annual Total Cost**	**Fuel cost**	**VOM**
years	*M€/MW*	*M€/MW*	*years*	*M€/MW*	*€/MW/yr*	*M€/MW*	*%*	*M€*	*€/MWh _output*	*€/MWh*
60	3 740	0.95	6	4 690	68 354	0.561	9%	257	24.7	10.9

Source: OECD-NEA (2015).

The Weighted Average Cost of Capital (WACC) includes the cost induced by borrowing the capital, and represents the minimum return that the investor must earn on the expected asset base. The heavy investment required by the nuclear project leads to levels of 9% for each WACC and the discount rate, which is relatively close to the private discount rate of 8% in OECD-NEA (2012b).

The present value of the total cost of building and operating the nuclear plant is used to compute the Levelised cost of electricity of the NPP (see formula in Appendix 1). Costs divided by energy production over the NPP lifetime represent the minimum price an investor should receive to cover all costs. The inputs are the expected overnight capital cost of EPR construction in 2050, the operation & maintenance (O&M) costs, and the fuel-cycle costs, and also important influencing parameters are the expected energy generation, the duration of construction, and the costs of financing (D’haeseleer, 2013). Although the duration of building first EPRs in Europe is currently exceeding ten years, it is assumed that by 2050 the standardization of reactors will benefit directly from experience and learning spillovers and will reduce both the investment cost and the construction time.

4. Model results analysis

Results are first analysed at the EU level, in aggregated terms (section 4.1), and then by region (section 4.2) and by stakeholder (section 4.3).

4.1. Effects of intermittency on the nuclear power provision at the EU level

NPP cycling. The model's results in terms of cycling are compared to the reactor licence in order to assess if additional cycles are performed and if a certain fatigue would be induced. The publication of IAEA on load-following (2018) makes a comprehensive assessment of the fatigue which can be associated with flexible operation of PWR technologies. It is stated that flexible operation can have an impact on the core physics parameters of the NPP with relevant impacts on the thermal stress, which would induce fatigue, and on the reactivity of the reactor core, which will cause more and deeper movements of the control rods.

In our calculus, the *Reactor design* in Table 4 shows the number of yearly cycles obtained by dividing the number of cycles allowed by the licence by the number of the years of lifetime, e.g. 60. A flexible reactor could perform cycles with depths from 10% to 60%, affecting differently the reactor performance, as a function of the fatigue induced, be it mechanical or thermal (IAEA, 2018). Cycles of 10% amplitude (% of the rated power) are limited to 1,667 (denoted C0), and cycles with deepness of 20%, 40% and 60% are denoted C1, C2, and C3 respectively.

Table 4. Results of a NPPs cycling in 2012 and in 2050

Reactor design in terms of cycling	**C0**	**C1**	**C2**	**C3**
Cycle deepness	10%	20%	40%	60%
Annual budget of cycles, by fatigue type	**1 667**	**1 667**	**250**	**200**
Weight of each cycle type in the total fatigue	0.01%	0.03%	0.06%	0.08%
Model results, 2012				
Simulated number of cycles, by fatigue type	**88**	**79**	**191**	**278**
Reduced reactor lifetime, by cycle type, in days	0	0	0	24
Reduced reactor total lifetime, in days	**24**	0	0	0
Model results, 2050				
Simulated number of cycles, by fatigue type	**57**	**63**	**86**	**259**
Reduced reactor lifetime, by cycle type, in days	0	0	0	18
Reduced reactor total lifetime, in days	**18**	0	0	0

Results show that during both the calibration year and the projection year there is an excessive cycling of flexible NPPs (row *Annual budget of cycles* is compared to tow *Simulated number of cycles*). Requirements for load-following would be larger in 2012 than in 2050, partly due to renewables but more particularly due to baseload over-capacity in 2012 (see rows *Simulated number of cycles* by year). By 2050, trends are reversed, with more renewables and less installed baseload generators. Cycling reactors more often implies additional plant fatigue and shorter lifetime, reducing the annual transient budget with 24 days in 2012 and with 18 days in 2050. Prior to the expected lifetime of 60 years, if the reactor would behave in the same way each year as in the hypothetical scenario in 2050, this would leave an average NPP out of operation three years earlier. The deepness of cycles is different by year (Fig. 3) as reactors perform fast and deep cycles in 2050 driven by more intermittency, and shorter but long lasting cycles with large plateau effects in 2012, driven by baseload generators.

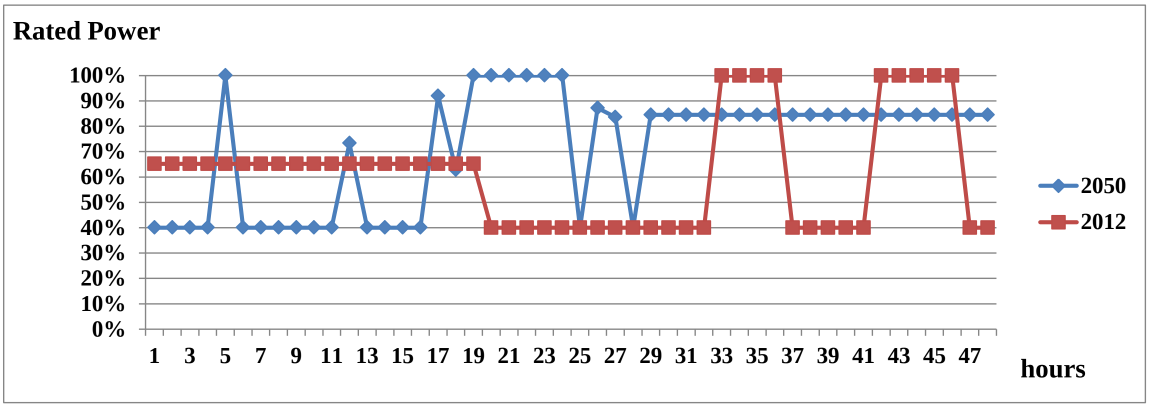

Fig. 3. Operation of an average flexible NPP over two days, model results in the EU

NPP load factors. Load-following leads to low load factors in 2012, due to lower output. Interestingly, operating inflexible NPP at steady state by 2050 is possible at low load factors only, e.g. 72% instead of 96% in 2012. That is, baseload does not necessarily imply high load factors, but means steady state operation. According to IAEA (2018), the baseload operation of

a generating unit refers to operation at steady full rated thermal power and full rated electrical output. So generating continuously becomes impossible at full load, but at lower rates, i.e. at steady state.

Fig. 4 shows two different operating baseload modes, in 2012 and in 2050, and it also compares two operating modes in 2050, load-following versus baseload. It is shown that the load factor in 2012 in higher than in 2050, i.e. 90% versus 59%, due to more variability in 2050 and to more constraints for power variations. It should be noted also that baseload operation, defined as full rated power operation, become a steady state operating mode, since the NPP runs at less than 100% of the nominal power; besides, some power variation is needed even in the case named Baseload, with however limited dynamics in time.

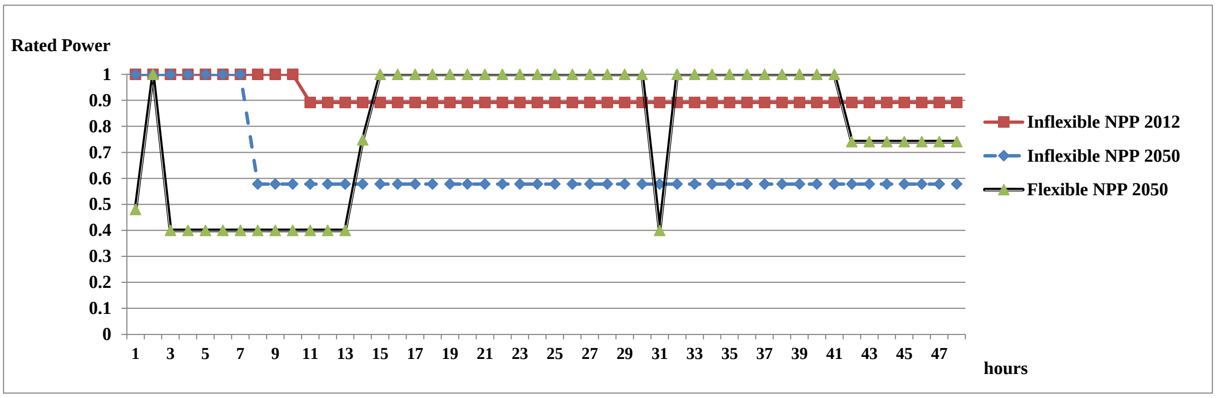

Fig. 4. Simulated baseload operation of inflexible NPPs in 2012 and in 2050 over two days

The comparison between Flexible and Inflexible operating modes shows that a flexible NPP could locally supply more than if the NPP would operate baseload only, suggesting that from an economic perspective a NPP could be viable in future power systems by only operating flexibly such as to increase the power output. If the NPP would operate only baseload, the operator would supply low output knowing that at critical points (hours 31 and 41 in Fig. 4), the NPP could not decrease the output as required by the system.

In general, capital intensive technologies prove viable if their load factors are higher than 90% such as to recover their high capital cost. But besides volumes, profits largely rely on power market prices.

NPP economics. Flexible NPP profits are evaluated at two price levels to account for uncertainties of future power prices, one price calibrated against historical market average prices (the column ‘Market Price’), and another price obtained with the dispatching model, varying at each hour (the column ‘Model Price’ is the average of our results). It is assumed that by 2050, market prices decrease by 10% compared to 2012 levels, based on EC (2013; 2015b) and EFC (2010): long-run prices would rise until 2030 due to high costs with decarbonisation, replacement of old generation capacity, grid extension, storage and balancing capacity; but will decline by 2050, due to high shares of already mature renewables, technology efficiency and diversified technologies with profusion effects. This decreasing effect by 2050 overtakes the cost increase of gas (+14%), coal (+33%) and carbon tax (100 €/t CO2) such as assumed in the model in 2050, based on the model PRIMES used by the European Commission for policy making (EC, 2013). Model prices are much higher than the real market prices, since the model ignores equilibrium tensions and operators power on the market and local congestions which could make must-run operators selling the electricity under their marginal cost. Therefore the model results should be considered with caution.

Table 5. The economics of a flexible NPP, model results in 2012 and in 2050

Model results by year	Market Price	Model Price
Model results in 2012		
LCOE, €/MWh	66.9	66.9
Price, €/MWh	45.9	84.4
NPV, M€	-2 183	1 815
Model results in 2050		
LCOE, €/MWh	61.9	61.9
Price, €/MWh	41.4	76.0
NPV, M€	**-2 564**	9 092

Results show negative profits in both the baseyear and the projection year, when the output generated with flexible NPP is evaluated at the actual market power price (see negative NPV in Table 5). A lower market price in 2050 engenders higher losses, despite higher load factor than in 2012, meaning that a (higher) volume effect is not compensated by a (lower) price effect. The NPV is definitely sensitive to the load factor, but non-linearly because the lifetime, the volume and prices are all interdependent. The situation would reverse if power prices were to be set at the model price level (76 €/MWh in 2050). By calibration it is obtained that the optimal price should be at least 55 €/MWh in order to cover the NPP capital cost.

The cost of generation (LCOE) improves in 2050 because it is not price dependent, and thus it highly depends on the volume, triggered by higher load factor. However, excessive cycling has an additional cost for plant upgrading to avoid early retirement. Results are here subject to perfect knowledge of the time when components need replacement and modernisation, following the regulator and operator description of the licence. In practice, it is particularly difficult to estimate the cost of all components affected. Cycling-related damage may not be immediately apparent and it can take up to seven years for an increase in the failure rate to become apparent after switching from baseload to load-following (Troy et al., 2010). Including costs and cycling uncertainty would negatively affect profits on one hand, but the salvage value of decommissioned components which could still be used, would increase the NPP value.

4.2. Assessment of the economics of flexible NPPs by region

This section depicts the fatigue of flexible NPPs by region in 2050, and highlights the value of the load-following as the opportunity cost of not operating baseload. It compares therefore two scenarios: NPPs operating load-following (LF in Table 6) and NPP operating baseload (noted BL). For the cost-benefit indicators, it should be noted that upgrading is not integrated within this section, to cope with the above uncertainty of the salvage value in case of NPP modernisation. It will be further on the regulator and on the investor to assess the financial interest in upgrading a reactor which is close to its end-of-life. According to our calculations, upgrading would increase the cost from 1.2% to 7.5% depending on the region, in comparison with the case without fatigue (see a description of modernisation costs in IAEA, 2018).

Table 6. Results on the economics of flexible nuclear power by region in 2050

Region	**Reduced lifetime, days**	**Load Factor**			**LCOE, €/MWh**			**NPV at the Model Price, M€**			**Model Price**
	Load-Following	Load Following LF %	Base-load BL %	**Variation LF-BL hours**	Load Following LF €/MWh	Baseload BL €/MWh	**Variation LF-BL €/MWh**	Load Following LF, M€	Baseload BL, M€	**Variation LF-BL, M€**	Average €/MWh
CEE	9	87%	95%	**-716**	56.7	54.5	**2.2**	11 454	12 472	**-1 018**	74.9
CWE	24	84%	79%	**425**	58.4	59.6	**-1.2**	7 610	6 250	**1 360**	49.4
North	0	94%	98%	**-350**	54.1	53.7	**0.4**	16 204	13 445	**2 759**	58.5
WEE	61	90%	98%	**-701**	57.7	53.7	**4**	14 145	14 306	**-161**	55.8
SWE	37	90%	98%	**-701**	56.7	53.7	**3**	14 035	15 278	**-1 242**	53.7

NPP lifetime. Model results show that all regions record excessive cycling and shortened lifetime of flexible reactors, except for the North market (Table 6, column 'Reduced lifetime'). The highest requirements for flexibility are in regions with high shares of nuclear and renewables (Central-Western Europe) and low interconnections (Western Europe and South-West). Some regions need deep short cycles and some others exhaust the transient budget with light frequent cycles. In North and Central-East, this budget is well balanced between all cycle types; moreover, the number of cycles does not exceed the licensed design in most of countries, except for Poland, where significant baseload capacities, mostly coal-fired units, require more flexibility.

Load factors. Load-following implies lower generation in all regions, except for the Central-Western Europe, where operating baseload is only possible at lower rates. This is the only region where operating flexibly would allow NPPs to supply more volume and to increase thus the usage rate. The technology mix, as given by the model PRIMES which documents our assumptions on installed capacities (EC, 2013), implicitly requires load-following in this region due to large nuclear fleet in 2050.

Levelised cost of electricity (LCOE). The comparison between load-following and baseload shows an increase in costs due to volume compression effect, except in the CWE region, due to higher load-factors. The lowest LCOE can be found in the Nordic countries (54 €/MWh) where the NPP load factor is rather high under load-following (94%). Here, most of the flexibility is provided by hydro units, therefore the nuclear load-following requirements are low. By contrast, the highest levelised costs of electricity are recorded in Central-Western Europe (58.4 €/MWh), due to low load factors (84%).

In other studies, LCOE are lower than our results (WNA, 2012), between 30-50$\$_{2005}$/MWh at 10% discount rate in 2011. They are higher in OECD-NEA (2015), between 80-120$\$_{2010}$/MWh at 10% discount rate, or for the PWR EPR in the United Kingdom, e.g. estimated at 115$€_{2014}$/MWh due to higher investment costs (WNA, 2016b).

Net Present Value. The economics of NPPs largely depends on the technology mix of each power system which affects the market power price and the volume supplied with NPPs. The model assumes that the EU's objective to complete the internal power market is met by 2050, which means that power prices would converge among regional markets; however temporary deviations will occur within a wide range (ACER, 2014). The convergence remains thus partial by 2050 due to grid limitations, and this is why prices are region specific (the column 'Model Price' in Table 6).

At model price evaluation, flexible reactors record profits from either operating load-following or baseload, with however higher profits from load-following in two regions (CWE and North). In Central-West, there is a volume-effect, as NPPs can supply more energy and increase revenues. In North, there is a price-effect; the downward variation increases the hourly power price as the technology is not marginal, and offsets the decreased load factors. The substitution renewables-nuclear does not occur at equivalent ratios, 1 MWh for 1 MWh, and during downward nuclear operation, and other than renewable-based technologies are integrated. In other words, when NPPs operate flexibly, other technologies, already operating at that time, could increase their production, such as biomass, CHP, gas-fired and coal-fired units.

For a NPP operator is less profitable to invest in load-following in three regions (CEE, WEE, SWE), due to reduced load factors, with the largest loss recorded in South-West, due to low grid interconnectivity.

Results should be interpreted with caution, since the market price obtained with the model integrates a high carbon tax (100 €/t CO2) and excludes some real market tensions, such as operators strategic behaviour and local congestions as mentioned above. The dispatching model sets the price based on the marginal operation cost, and most of the time a thermal generator is the last technology called, therefore model prices are higher than market prices and allows cost recovery.

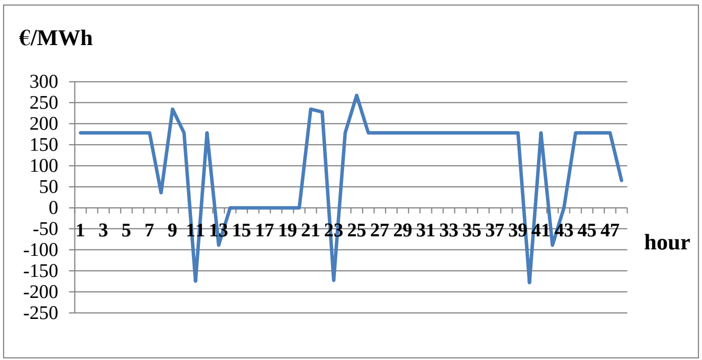

Fig 5. Results of the model power prices in Netherlands over two days

The nuclear operator records high infra-marginal rents, which increase in general with the gas, oil and carbon prices. Yet, punctually, prices could be negative in this model, see for instance the example of the Netherlands recording 340 hours with -100€/MWh in average in 2050. The model proves capable to capture significant equilibrium tensions, such as saturated technical constraints, usually when the demand is low and operating plants are facing minimum load and ramping constraints (Fig.5). Low demands and high power supply have historically enhanced negative prices, and moreover the number of hours with negative prices has been increasing every year, for instance in Germany from 33 hours in 2012 to 146 in 2017, with however less extreme negative values indicating that market players have learned to deal with these situations (the lowest value in 2013 was -200 €/MWh against -83 €/MWh in 2017). [11]

4.3. NPP flexibility assessment by stakeholder by region

Stakeholders involved in this analysis are the nuclear power operators, the consumers and the intermittent renewable energy operators on the one hand (see Table 7), and the system operator and the society from the perspective of CO2 pollution on the other hand (see Table 8). The value of flexibility for the consumer's surplus variation is the price differential between load-following and baseload (column 'Average Consumer Power Price')[12]. The integration of variable energies is measured by the differential of output suppression while load-following compared to baseload (column 'IRES Curtailment' in Table 7).

Table 7. Model results by region and by stakeholder in 2050, by operating mode

Region	NPP operator revenues, €/MW			Average Consumer Power Price, €/MWh			IRES Curtailment, GWh		
	Load Following, LF, €/MW	Baseload, B, €/MW	**Variation, LF-B, €/MW**	Load Following, LF, €/MW	Baseload, B, €/MW	**Variation, LF-B, €/MW**	LF, MWh	B, MWh	**Variation LF-B, GWh**
CEE	528 917	567 908	**-38 991**	74.9	71.8	**3.1**	0	0	**0**
CWE	423 467	372 374	**51 093**	49.4	52.9	**-3.5**	0	2 225	**-2 225**
North	671 807	599 272	**72 535**	58.5	57.2	**1.4**	0	0	**0**
WEE	609 386	622 920	**-13 534**	55.8	55.2	**0.6**	255	759	**-504**
SWE	609 622	649 640	**-40 018**	53.7	52.8	**1.0**	589	874	**-286**

[11] http://www.epexspot.com/

[12] It should be noted that the consumer will pay a tariff and not this real-time market power price. The average which is computed here corresponds to the generation cost only, while other costs and taxes would add up. The generation cost counts in general for one third in the total tariff, and taxes and transmission and distribution fees represent two thirds.

The NPP operators would record gains from operating flexibly compared to a baseload case in two regions (Central-Western Europe and Northern Europe).

Central-Western Europe has high shares of nuclear power. A baseload steady state operation would be possible at only low load factors, due to oversized baseload infrastructure. Interestingly, providing nuclear power upward makes prices decrease (-3.5 €/MWh in average over the year) because the nuclear power is large enough to punctually be the last technology setting the market price. The volume provided is also large and compensates the negative price-effect.

Northern Europe power system is flexible enough to integrate intermittent renewables, since solar and wind curtailment is zero even during baseload operation. When NPPs operate flexibly, other thermal technologies are integrated, which set the market price at a higher level, offsetting the negative volume-effect, e.g. lower NPP volume. An inertia mechanism due to technological and market constraints explains how the market selects more expensive technologies but which are already operating rather than cheaper generators. See for instance CHP operation during winter time. In general, electrical grids with large hydro power can handle the integration of intermittent energies (Matek and Gawell, 2015). Nordic countries simulated have 27% of hydro power in the total generation in 2050 and wouldn't need additional flexibility from nuclear plants, but note that the business case is attractive for a NPP to operate flexibly.

In the other three regions, NPP operators record losses while supplying flexibility.
Central-Eastern countries record a loss of 716 equivalent full hours in the load-following scenario. The renewables share is relatively low (10%), and the energy curtailment is 0. This means that the region would need flexible NPPs rather for higher grid stability due to the overall baseload dominated infrastructure, than for a better integration of intermittent renewables.

Western European countries have poor interconnections and medium shares of IRES (19%), setting a high pressure on flexible NPPs to operate load-following (less 700 full load hours), with therefore less revenues due to large volume reduction. The reactors' flexible operation is however beneficial to the system as a whole as it allows avoiding the curtailment of some 500 GWh of IRES in 2050.

South-Western Europe has the least attractive economic environment for flexible NPP, due to large shares of IRES (34%) and to low interconnectivity (4%), reducing the output supplied with NPP. Both baseload and load-following present high volumes of curtailment, but lower during NPP load-following. The share of nuclear in the total generation mix is relatively low, which explains the low influence the nuclear has on the market average price (+1€/MWh).

Consumer surplus (Table 7) is the differential in the average market price between the two scenarios, with and without NPP flexibility. The average market price is obtained as the total system cost divided by the final demand. The consumer surplus is increasing in only one region (CWE), due to the large influence that nuclear power has on the market price; in the other regions, more expensive technologies offset the positive effects from integrating intermittent renewables with close to zero marginal cost.

The system operator. The objective function of an individual investor (Profit Maximisation) is different from the power system interest modelled here (Total Cost Minimisation). The investor would operate baseload to maximise profits, while under system cost minimisation problem, the NPP operator would be asked to operate flexibly (Lykidi and Gourdel, 2015).

Table 8. System effects from load-following with NPP in 2050, model results

Region	System Cost			CO2 emissions, Mt		
	LF, M€/MW	B, M€/MW	Variation LF-B, €/MWnuc	LF, Mt	B, Mt	Variation LF-B, Mt
CEE	1.3	1.3	**48 147**	18.0	16.5	1.5
CWE	3.9	3.9	**-1 048**	16.6	24.6	-8.0
North	0.9	0.9	**18 832**	7.8	6.8	1.0
WEE	2.6	2.6	**36 160**	59.9	58.5	1.5
SWE	2.7	2.7	**48 117**	54.1	53.1	1.0

Under our system cost minimisation program, the system costs due to flexible NPPs decrease in Central-West only. Here, NPP flexibility allows a better integration of intermittent energies, such as wind and solar power, which substitute other more expensive technologies and make decrease the short-run system cost. In Central-East, the flexible nuclear power allows a better integration of baseload thermal units with higher marginal costs, which increases the total system cost. In West and South-West, reducing the IRES curtailment is not enough to make decrease the system cost, as the substitution nuclear-renewables does not occur MWh for MWh. Consequently, more power from carbon-emitting units make increase the CO2 emissions.

Table 9. Summary of effects of load-following, by stakeholder, by region in 2050

Region	Stakeholder			
	NPP	Consumer	System	IRES operator
CEE	-	-	-	0
CWE	+	+	+	+
North	+	-	-	0
WEE	-	-	-	+
SWE	-	-	-	+

Table 9 shows that a complete win-win situation is obtained in Central-Western Europe only, where all stakeholders record gains from NPP operating flexibly. In other regions, there are winners and losers, and there is at least one winner, the IRES operator. Nuclear flexibility is here a positive externality which benefits to the system, and to the other operators than nuclear, including the final consumer. Additional market provisions and regulatory measures could internalize a part of this social value such as the nuclear operator to capture a share of the rent created with flexible output. In these systems where nuclear load-following does not allow operator to cover the lost load leading to the missing money issue, options such as capacity markets and contracts for differences (in the Nordic market, Kristiansen, 2004; and in United Kingdom, DECC, 2013) complement the energy-only wholesale market[13], aiming to incentivise the investment in low carbon technologies[14]. Another cost-recovery option is to integrate ramping cost and depreciation into the marginal cost and the wholesale market prices, which could however downgrade the position of the NPP in the merit order curve with a further risk of lost load.

5. Conclusions

This study gives insights into the economic factors driving NPP operators to provide flexible output. The economic concern is that the massive inflow of intermittent energies could gradually transform nuclear power from a mainly baseload technology to a back-up capacity provider (OECD-NEA, 2012a, 2012b).

Mathematical optimisation shows that the economics of nuclear is system specific. By region, flexible NPP operation is viable in Central-Western Europe, in the Nordic power system and in certain countries in Central and Eastern Europe. South-Western Europe has a high share of intermittent renewables, large needs for nuclear flexibility and low interconnectivity, putting a too large pressure on reactors. Less attractive systems are also those with large baseload capacities, where load-following needs are too high and the NPP cycling excessive, resulting in shorter technical reactor lifetime.

Ensuring flexibility becomes an interesting case for NPP operators if they can influence the market price to record more revenues than from operating baseload. Among measures in support to low-carbon technologies, carbon taxes could increase the spot market price and thus the nuclear infra-marginal rent. For the current market design, regulated contracts could be another option to hedge against the risk of low spot prices. Reserve provision could represent another revenue stream, but highly dependent on the regulation and the deepness of the market. In the USA, many of the early new nuclear plants proposed are located in areas where electricity markets are still regulated, based on a full cost-recovery policy (WNA, 2012).

The way this study can be generalized to other power systems depends heavily on system specificities, and on the regulator allowing NPPs to operate flexibly, or not. This research identifies the following mix combinations framing a good economic environment for flexible NPPs:

- medium interconnectivity (<50%) + flexible systems (hydro) + medium IRES share (15-30%) + no overgeneration;

[13] http://europa.eu/rapid/press-release_IP-18-682_en.htm

[14] Contracts for difference is a contractual form between the generator and the operator system and consists of paying the low carbon generator a variable top up between the market price and a fixed price level. See an application in the Finish power system, the so-called Mankala business model which is a risk sharing scheme protecting capital-intensive nuclear investors against the increasing prices and volatility of liberalised electricity markets (WNA, 2016c).

- low interconnectivity (<20%) + medium shares of IRES (15-30%) + large shares of nuclear capacity (>60%);
- medium interconnectivity (<50%) + no overgeneration + medium-high IRES share (>15%).

New insights into the operation and the economics of nuclear power could be drawn by extending the study to new power markets, in developing countries and emerging economies, and by expanding the research methodology to new nuclear technologies, such as small medium modular reactors (Locatelli et al., 2015). Fatigue costs need further estimations and non-linearity considerations, due to accumulated fatigue and cross-stress interaction effects. In the future, technical aspects will influence the flexibility provision and the investor decision to innovate such as the new reactor design to avoid operational ramping cost and depreciation.

The modernisation of the policy framework is essential in the context of a rapidly growing share of renewables with impacts on conventional generators. Timely consideration should be given to options for the EU 2030/2050 milestones, such as to ensure flexible supply and sufficient capacity to meet demand. Unless power prices are relatively high in the future, conventional power plants might not be economically viable, and market arrangements are necessary in complement to spot markets to prevent that renewables create barriers to baseload units.

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Appendix 1. Model equations

Symbols

IRES – intermittent renewables

NPP – nuclear power plants

Index

tech – technology type (1 to 12)

h – hours over one year (1 to 8760)

t – year (1 to 60)

Fixed Variables (Inputs)

Cvom – variable cost of operation and maintenance (€/MWh_output)

Cfuel – cost of fuel (€/MWh_input)

INV_0 – total investment cost of NPP (€)

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

P_M – price of imports (€/MWh)

r – discount rate (%)

TaxCO2 – carbon tax (€/t CO_2)

WACC – weighted average capital cost (%)

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 (tCO_2/MWh_input)
Effs – 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 (%)
$\tau_{tech}^{rampdown}$ – 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:

$Cycle\ _h = Gen_{\ h,nuc} - Gen_{\ h-1,nuc}$, if >0

$Cycle_{down_h} = Gen_{\ h,nuc} - Gen_{\ h-1,nuc}$, if <0

Nuclear cost-benefit indicators

Net present value (NPV):

$$NPVnuc = \sum_{t=1}^{60} [(REV_t - CostFuel_t - CostVOM_t)/(1+r)^t] - INV_0$$

Levelised Costs of Electricity (LCOE):

$$LCOE = \frac{INV_0 + \sum_{t=1}^{60} \frac{CostVOM_t + CostFuel_t}{(1+r)^t}}{\sum_{t=1}^{60} \frac{EG_t}{(1+r)^t}}$$

Appendix 2

Table 2.1. Inputs of the model at EU-28 level

Technology	Installed capacity MW		Efficiency	Fuel Cost	CO2	Max Load	Ramp
	2012	2050	%	€/MWh	kg/kWh	%/year	%/hour
Nuclear	128 056	121 993	33%	8,2		100%	100%
Coal	130 547	56 597	36%	18,1	0.34	52%	14%
Hydro	114 618	134 453	100%	0		35%	100%
Oil steam turbine	49 343	22 106	39%	63,4	0.28	11%	100%
CCGT (Combined cycles gas turbines)	120 405	139 583	57%	36,2	0.202	30%	50%
NGGT (Natural gas gas turbines)	60 202	69 791	39%	36,2	0.202	30%	100%
Biomass	20 038	46 130	27%	40,0	0.36	60%	100%
CHP (Combined heat and power)	101 963	138 054	35%	55,0	0.25	60%	50%
Wind On-shore	90 168	289 376	100%	0		18%	100%
Wind Off-shore	10 019	124 018	100%	0		35%	100%
Solar	48 431	230 791	100%	0		16%	100%
Other RES	1 132	10 118	100%	0	0	50%	100%
Total Capacity, MW	**874 922**	**1 383 010**					
Connections Imports, MW	42 950	65 000					
National Demand, TWh	2 912	3 753					
Imports, GWh	6 507	12 500					
Exports, GWh	2 169	37 500					
Losses, GWh	74 662	96 239					

Table 2.2. Outputs of the model at EU-28 level

Technology	2012		2050	
	Generation GWh	Annual Load %	Generation GWh	Annual Load %
Nuclear	901 157	80%	863 605	81%
Coal	628 975	55%	257 811	52%
Hydro	372 353	37%	416 543	35%
Oil steam turbine	-	0%	-	0%
CCGT	316 424	30%	366 824	30%
NGGT	158 211	30%	183 411	30%
Biomass	8 777	5%	242 459	60%
CHP	340 243	38%	319 353	26%
Wind On-shore	150 308	19%	465 157	18%
Wind Off-shore	30 981	35%	383 495	35%
Solar	69 805	16%	332 646	16%
Other RES	4 958	50%	44 317	50%
Total	2 982 192		3 875 620	
Net Imports, GWh	6 507	2%	12 500	2%
CO2 emissions, Mt	1 032		697	
System costs, M€	127 589		204 264	

Table 2.3. Inputs-outputs by region in countries with nuclear policy in 2050

INPUTS (Capacity) - OUTPUTS (Generation) by region in countries with nuclear policy in 2050										
Technology	Northern Europe		Central-Western Europe		Central-Eastern Europe		Western Europe		South-Western Europe	
	Capacity MW	Generation GWh	Capacity MW	Generation GWh	Capacity MW	Generation GWh	Capacity MW	Generation GWh	Capacity MW	Generation GWh
Nuclear	18 054	151 203	55 939	387 264	31 006	245 302	9 600	79 050	7 393	60 877
Coal	264	354	2 501	5 829	24 164	86 680	471	3 548	1 990	11 680
Hydro	22 624	85 429	24 370	79 104	15 511	50 798	1 769	5 408	16 132	36 349
Oil steam turbine	945	-	10 119	244	1 304	-	757	-	1 003	-
CCGT	1 547	2 425	15 639	26 879	10 053	23 725	32 250	70 627	19 861	52 195
NGGT	10 574	4 319	7 820	8 686	5 027	11 864	16 125	35 314	9 931	26 099
Biomass	4 042	15 929	6 264	18 168	3 375	24 163	3 821	18 410	2 388	13 179
CHP	12 371	18 384	19 890	18 774	27 828	59 915	11 465	27 278	7 494	22 671
Wind On-shore	10 005	18 225	49 247	82 013	17 397	33 605	37 134	69 249	34 004	66 437
Wind Off-shore	5 717	17 678	32 139	99 382	3 760	11 627	30 200	93 149	14 573	45 040
Solar	362	338	26 429	35 313	11 946	12 645	9 193	8 562	27 532	50 789
Other RES	-	-	1 716	6 915	251	1 014	26	105	180	725
Total	86 505	314 283	252 073	768 570	151 622	561 338	152 811	410 699	142 481	386 040
Demand, TWh	250		746		497		409		372	
CO2, Mt	16		33		126		60		54	