Market pricing designs for power plants matching: the case of nuclear and renewables

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Abstract

Load-following with nuclear power on the day-ahead market punctually leads to two different margin variations: price drops when nuclear power is evicted from the market; and price remains constant when the nuclear power is not the marginal technology, acting as a price-taker. This paper analysis the social welfare from nuclear flexibility in the French electricity sector, as the sum of short-run outcomes of the power price variations, net of externalities generated on nuclear plant revenues and on the other operating power plants. By means of a stylized dispatching model, the paper shows that internalizing the flexibility costs to match the long-run cost of nuclear power will change the short-run equilibrium and inflate the renewables profits while decreasing the compensation granted. The deadweight loss of nuclear power operating baseload is under a range of social and system benefits which further support new power pricing designs for load-following incentives. Among options, results highlight the advantage of contracts for differences over spot price uplifts tempting to include cost non-convexity due to ramping.

Keywords

nuclear, load-following, ramping constraints, short-run price, long-run cost.

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1. Introduction

Power markets in Europe are based on the day-ahead scheduling for optimal dispatch of the generators, ensuring that the demand is met at minimal cost of units' operation. The market model tries to accurately incorporate costs and the characteristics of the generators, yet major drawbacks remain such as inefficient market schedules (Philipsen et al, 2018), low power prices during capacity-scarce demand peaks (Petitet et al, 2017), and non-convex costs that are not reflected in the marginal cost of energy (Kuang et al, 2019).

With more volatile output from renewables, conventional generators are required to ramp up or down, and to start-up or shut-down more frequently. Additional ramping results in substantial wear and tear costs which are far from being linear as they depend on many technical parameters such as the speed of ramping, the amplitude, the duration and the frequency of the flexible operation (IAEA, 2018). The discretization of the day-ahead market to one hour, i.e. instead of real-time, is proved to be costly and inefficient, as it does not consider the flexibility of the momentary consumption, nor the flexibility of some generators. This increases the reserve capacity contracted on to stand-by in real-time to compensate for deviations from the day-ahead schedule (Philipsen et al, 2018).

Other products or intermediary markets can be designed to account for generator specificities and for demand uncertainty, such as price uplifts and side payments to internalize additional costs within a simple bid (de Sisternes, 2014) or dedicated ramping products to couple the time frame of dispatch to the optimal ramping capability of generators (Navid & Rosenwald 2012). This could partly integrate the issue of non-convexities related to start-up/ shut-down costs and to ramping limits (Joskow & Tirole, 2007), particularly important in deregulated electricity markets.

In the current market pricing design, the ramping costs act with externalities which are absorbed by the dispatchable conventional plants. On traditional power markets, i.e. before massive renewables penetration, the optimal clearing-market pricing was assuming a convex problem where decision variables were continuous and the feasible region defined by the constraints of the problem was also convex (de Sisternes, 2014). Nowadays, the discrete operators' decisions on the commitment state of a plant, on start-up and ramping, can produce situations where equilibrium prices do not reflect the marginal cost of energy, as they do not internalize these nonconvex costs. The spot prices used to reflect scarcity during demand peaks, sending the right signals for investments in capacity such as markets were reaching adequate levels of security (Petitet et al, 2017). Within the current design of the energy-only market, with massive outside-the-market deployment of renewables, conventional power generators experience huge losses such as sunk costs of their assets, or missing money, due to the drop in the wholesale power prices, lowed demand during economic crises and the fall in coal prices.

Worldwide, the general issue of the missing money is due to low operating cost of renewables coupled with high investment costs. This leads to a broader issue of adequacy of capacities and energy planning since the wholesale market power prices alone do not drive investments anymore. The way the national regulators have historically supported investments in new projects (certificates, buying obligations, feed-in tariffs) have also contributed to reduce the role of market prices as investment signals.

In Europe, the power market regulation generally restricts the contract timelines on the wholesale market, e.g. the futures markets do not exceed six years in Germany and four years in France (CRE, 2017), which is low in the perspective of long technical lifetime of plants (20 years for solar power, 40 years for nuclear power). Therefore new contractual forms are necessary to guarantee the investment cost recovery: contracts for differences in United Kingdom, e.g. 15 years for new capacities and three years for refurbished plants[2], long-term subsidies[3] and bilateral contracts[4] in France, capacity markets in several European countries, and corporate Power Purchase Agreement (PPA)[5]. These punctual signals show that wholesale power market signals are weak to trigger investment and needs long-term complements to secure the power generation capacity.

The paper combines the approach of non-convexity of costs due to ramping with the missing money issue on the wholesale market issued from the flexibility provided by the nuclear power plants. By means of an optimization dispatching model, it shows that if the wholesale market pricing based on marginal costs remains appropriate for unit dispatching, it is probably not the right signal to supply flexibility. The market pricing will disconnect the nuclear operators' decision to operate flexibly, from the long-run planning of capacity building and refurbishment. At the end, other instruments are tested in complement to the current market so that the flexibility supplied by the French nuclear fleet is enhanced in the future mix.

The following Section 2 details the case study, Section 3 describes the model used in the simulations with a focus on the modelling of dispatching and reactor' cycling. Section 4 presents and discusses the results, and finally, Section 5 concludes on main policy implications on the power market design.

2. Case study

The case study tests the scenarios documented by the French Transmission System Operator (RTE, 2017) in terms of power generation capacities and projected power demand, to the 2035 horizon time, as the right period to implement the current decisions of investment plans. In these politically-driven scenarios, planning decisions are almost exogenous, disconnected by means of subsidies and political targets from an endogenous entry of new projects which at optimum should be triggered by market mechanisms such as carbon signals or opportunity costs of scare resources.

Several perspectives build TSO energy plans: the economic rationality of market mechanisms that minimize investment costs and operational expenditures; the political factors and commitments of carbon emissions and energy independence; and structural drivers of technology diversity, energy rebounds, market structure and complementarity with neighbor country mix. Social and regulatory factors such as the social acceptability, authorization procedures and potential delays, are not accounted for.

The five scenarios built by the French TSO aim analyzing paths to achieve the targets set by the French Energy Transition Act (ETA, 2015), in terms of CO2 emissions, renewables, nuclear and final demand. Each scenario gives alternatives to attain these goals and highlights

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[2] Contracts for difference (CfD) guarantee the revenue of power generators: when the market price is above the level of the CfD, the operator refunds the difference; if it is below that level it receives a top-up. EDF, as the operator of the nuclear plant at Hinkley Point, signed a CfD with the British government for a total of 18 Bln £, or 110 $€_{2012}$/MWh over 35 years.

[3] In 2017, the European Commission approved subsidies to the gas-fired power plant project located in France, at Landivisiau, of 94 k€/MW/yr over 20 years (CRE, 2017).

[4] In 2008, a 24 year contract has been signed between EDF and industrial consumers (Exeltium consortium), of 311 TWh.

[5] PPA is a 10 to 20 year long-term contract between a generator of electricity and buyers such as multinationals, aiming at supporting the investment in new capacities of renewables by guaranteeing their revenues. Worldwide, PPA contributed to the deployment of some 18 GW in 2016, mostly in the USA, while in Europe, they emerged in the Nordic countries, but not in France to date.

potential issues to handle uncertainties on the evolution of renewables, nuclear decommissioning and refurbishment, the use of gas-fired units, CO2 prices and grid interconnections. Among scenarios, the case study selects the tensioned vision on flexibility in the future mix, the scenario called *Ampere*, where nuclear reactors are decommissioned to the same extent that renewables penetrate the mix until they reach 40% of the demand by 2030. Implicitly it assumes that nuclear and renewables are substitutes, which makes the scenario challenging in terms of flexibility assessment, since more pressure is put on the remaining reactors to operate load-following. The need for additional reserves with increased variable sources remains ambiguous, due to a smoothing effect from their spatial aggregation, and to the demand that in some regions correlates with wind and solar power profiles (de Sisternes, 2014).

Table 1 presents the main assumptions of Ampere in terms of capacity installed and projected power generation in 2035, and allows understanding the transition in comparison with the year 2017. The technology types are in line with the model disaggregation of the power mix. Under carbon constraints, the coal power plants are phased-out and combined heat-and-power capacity is reduced, while more gas-fired plants ensure the security of supply and the capacity adequacy. The scenario assumes the use of demand side management, net export flows, energy storage, and prices of carbon, gas and oil. Table 1 inserts the calculus of the capacity factor and the operation cost which helps building the merit order of plant's entry on the power market.

The market segment simulated next is the wholesale market where all plants bid and supply in real-time, without consideration of the initial rational of their planning. For instance, combined-cycles gas turbines in *Ampere* are mainly meant to be called during peak times and their business model is around ancillary services provision to the grid.

Table 1. Data of the scenario Ampere, by technology, based on RTE (2017)

Technology	2017			AMPERE 2035			
	Capacity MW	Generation GWh	CF %	Capacity MW	Generation GWh	CF %	VOM Total €/MWh
Nuclear	63 130	382 320	69%	48 500	293 800	69%	35
Coal	2 930	5 310	21%	-			
Hydro River	10 327	42 000	46%	10 970	43 890	46%	2.5
Hydro Lake	8 231	16 410	23%	8 231	16 410	23%	3
Oil steam turbine	6 550	5 310	9%	1 000	-		565
CCGT Combined cycles gas turbines	1 620	8 000	56%	6 700	17 000	29%	74
NGGT Natural gas gas turbines	4 500	1 183	3%	1 100	1 200	12%	124
CHP	6 000	21 024	40%	4 400	9 500	25%	70
Wind On-shore	11 790	21 210	21%	52 300	114 600	25%	1.0
Wind Off-shore	10	30	34%	15 000	47 000	36%	1.0
Solar	6 550	10 620	19%	48 500	58 100	14%	0.1
Other RES	4 397	12 270	32%	8 000	26 500	38%	10.0
Total	**126 035**	**525 687**	48%	**204 701**	**635 500**	35%	
PHS Storage	**4 965**	**5 310**	12%	**4 200**	**7 500**		
Connections Imports, MW	11 000			27 000			
Connections Exports	17 000			33 000			
National Demand, GWh	480 000			483 100			
Net Exports, GWh	38 000			134 300			
Losses, GWh	7 687			18 100	2.8%		
NUC / Total Generation	**73%**			**46%**			
NUC / Demand	**80%**			**61%**			
RES/ Generation	**16%**			**46%**			
Variable RES / Demand	**7%**			**45%**			
CO2, Mt	24			12			
Carbon price, €/t CO2	5			108			
Oil price, €/MWh	66			190			
Gas price, €/MWh	13			30			
Curtailment Supply, TWh				9			
DSM, TWh				3			
DSM, MW				2 500			

Note: CF = capacity factor. DSM = Demand Side Management. CHP = combined heat-and-power.

3. Methodology. Power plant dispatching

When modelling the nuclear load-following, three main assessment types can be identified: (1) capacity expansion models for investment planning, which build load duration curves and select optimally flexible nuclear capacities such as to cover both fixed and variables costs (JRC-EU-TIMES model; JRC, 2013); (2) technology studies and unit commitment models, where nuclear and renewables match under a set of physical constraints and economic indicators including start-up costs (Jenkins et al, 2018), with often a residual matching of demand with nuclear power, i.e. the demand net of variable renewables (Cany et al, 2018); and (3) power market models which assess the dispatching of generators based on their marginal cost (Peng et al, 2018). The optimization framework developed in this paper follows the last trend and assumes fixed installed capacities, therefore giving a normative vision on how the nuclear behavior could adapt to increased intermittency in the future.

The model integrates the installed generation capacities such as projected by RTE (2017), and assumes fixed power demand at each half-hour, and endogenous net export flows capped by the power interconnection grid capacity.

The power plant dispatching model is based on linear programming, implemented in the GAMS software with the Cplex solver.[6] The method has already been applied at a European scale to the topic of nuclear load-following, with however different scenarios of the installed capacities and an hourly loop over the year, returning thus more aggregated results in terms of fatigue (Loisel et al, 2018). As described in the above mentioned reference, the model 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 minimizes 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.

Dynamic principles describe the system operation over one year, with half-hour time slices. The model simulates a centrally-dispatched market[7] made of twelve technology types where the objective function is the minimization of the system short-term cost of operating generators and making export-import, subject to satisfying the power demand, including losses and charging storage plants. Two reactor types are analyzed, those used to operate load-following (called here Flexible, covering 2/3 of the fleet) and those used to operate only base-load (called here 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 their license, are used as base-load units, and some others as flexibility providers.

When the system cannot absorb the natural inflow of fluctuating renewables (wind, solar, marine energies and hydro run-of-river power), the energy excess is suppressed, the so-called curtailment or lost load. The technical constraints are minimum operational loads, maximum load factors, and ramping capability of flexible technologies (see Annex 2).

Cycling. Load-following represents the change in the generation of electricity to match the expected electricity demand as closely as possible (IAEA, 2018). 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).

In the literature, many studies have been dedicated to the internalization of the cost of ramping with conventional thermal generators (Kumar et al, 2012). Models dedicated to assessing the effect of nuclear ramping on the power market include the ramping capability

[6] The General Algebraic Modeling System (GAMS) is suitable for modelling linear optimization 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 minimization in a short execution time (less than five minutes).

[7] In contrast, self-dispatch market modeling considers that generators maximize their value and take therefore into account their transaction costs and other non-convex costs, thus generators may have opportunity costs.

and cost into the market clearing objective function, therefore the price reflects at the end the opportunity cost and the availability value (Navid & Rosenwald, 2012; Troy et al, 2010). In contrast, the model built in this study considers cost-free ramping and returns the solicitation types and their frequency, what is next called cycling, and describes the deepness and the length of cycles. This copes with extrapolation of the current load-following while integrating the historical availability profile of nuclear power cycling, and gives a new path of the nuclear reactors behavior. Furthermore, unlike cost estimates, this paper is based on the value of ramping, due to limited experience and data on costs with excessive load-following with nuclear power. The ramping cost becomes the lost value of the nuclear operator when investing in refurbishment or by ceasing operating.

Outputs. After simulation, the model returns the power volume generated by each technology, the half-hourly power clearing 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 licensed design to conclude on the nature of cycling and on losers and winners of the cost-free flexibility provision.

4. Results and Analysis

4.1. Model results

The value of the flexibility supplied with nuclear power is revealed by comparing load-following with baseload scenario (see Table 2). The benefit of ramping could be computed from two perspectives:

- the nuclear operator, as the difference in revenues from operating baseload and alternatively load-following (-4,220 M€);
- and the system operator, where the value is the difference in the system cost between scenarios with baseload nuclear power and flexible nuclear power (-2,205 M€).

The lost value of nuclear power operator while providing flexibility will be retained in the following. Results show that more flexibility of the nuclear power fleet reduces system costs but reduces in the same time the revenues of the nuclear operator. This is a price-effect due to the fall in marginal prices: gas turbines, as marginal technologies, hence price-maker, are less called in the Load-Following case, being substituted with renewables (see a resulting zero flow curtailment). Carbon emissions are only slightly decreasing due to the increase in the CHP supply, since flexible nuclear operation allows more inflexible units to optimize their efficiency and operate steadily.

Table 2. Model results for the scenario Ampere in 2035, Baseload versus Load-Following

Aggregated effects over the year	Base Load	Load Following	LF - BL
Total System Cost, M€	29 807	27 602	-2 205
Nuclear operator Revenue, M€	31 881	27 661	-4 220
Nuclear power Output, Total Fleet, TWh	294	294	0
Nuclear power Output, Inflexible Reactors, TWh	98	122	24
Nuclear power Output, Flexible Reactors, TWh	196	172	-24
Clearing price in average, €/MWh	110	95	-15
CO2 Emissions, Mt	15.1	14.96	-0.14
RES Curtailment, TWh	2	0	-2
(Gas) Combined Heat and Power Output, TWh	8.2	10	1.53
Gas Combined Cycle Output, TWh	17	17	0.00
Gas Turbine Plant Output, TWh	1.06	0.08	-0.98

It should be noticed that the same flow of nuclear power is supplied in both Base-Load and Load-Following, it is only the distribution of the flexibility which is different. Flexible reactors allow a higher use of inflexible reactors, while their output decreases significantly over the year (-12%). The flexibility capability allows reactors supplying more than if they would operate in a steady state (see in Fig.1 a locally higher output than in the scenario Baseload from 0:00 to 2:00 am). However, this increase in output takes place during low price times, thus the total revenue is decreasing. Strategically, flexible units would supply the market during high prices, yet this approach is not revenue-maximizing (or self-dispatch) but system cost-minimization (or centrally-dispatched).

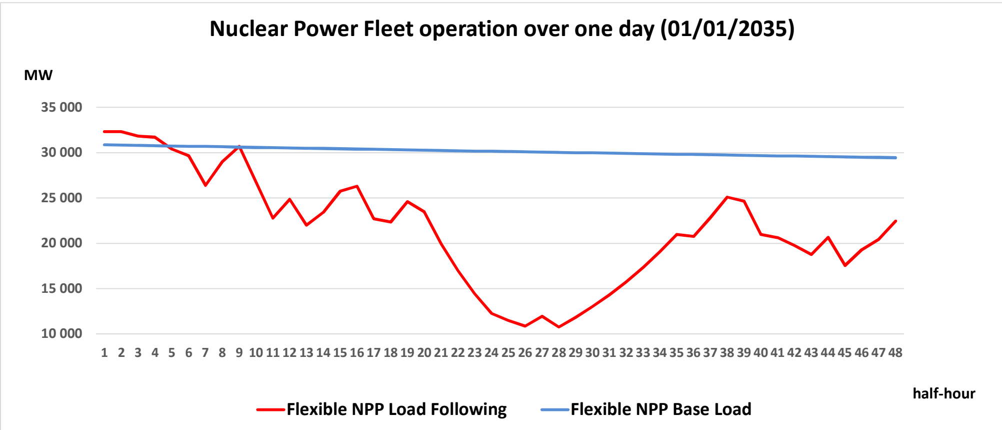


Fig1. Operation of Flexible nuclear reactors in the Load-Following case versus Base-Load

Flexible units in general have ramping limitations, and after ramping down they could face speed limitations and a certain waiting time before ramping up again (Jenkins et al, 2018). Therefore, there could be some events over the year where the revenue of flexible plants might increase due to these technology limitations. Fig. 2 shows the way the system cost might locally increase compared to the Base-Load (at 4 am, or at 9th half-hour of the day).

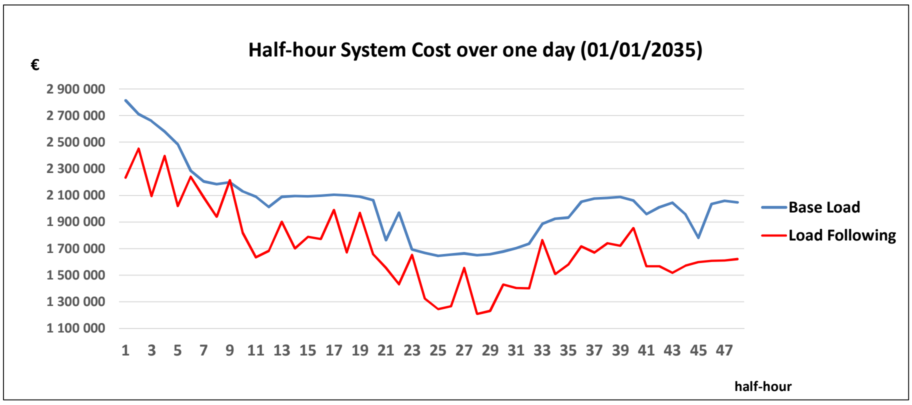


Fig 2. The variation of the System cost, with a general decreasing path

Power system margin variations are varying due to load-following: when the nuclear power is evicted from the market due to load-following, the power market price decreases; when the nuclear power remains price-taker in Load-Following compared to Base-Load, the price remains constant among the two scenarios, and the loss for nuclear operator is due to only a volume-effect, i.e. lower market shares.

Table 3. Marginal Technology, number of hours where the technology sets the price

Technology	Load Following	Base Load
Renewables	0	0
Nuclear	0	320
Combined cycle Gas Turbines	4 373	708
Simple cycle Gas Turbines	176	793
Demand Side Management	4 211	6 939

Table 3 shows that the more expensive technology – Simple cycle gas turbine (124 €/MWh in 2035) is called less on the market (less some 600 hours over the year), and other technologies enter as substitutes, i.e. the next technologies in the merit order – Demand Side Management (80 €/MWh) and Combined cycle gas turbine (74 €/MWh). Nuclear power is not anymore the marginal technology in the Load-Following as it used to be in Base-Load (320 hours), when the revenues were increasing with the inframarginal rent captured from more expensive technologies. Ultimately, the new supply schedule is less profitable as prices are falling compared to Base-Load.

By 2035, more intermittent renewables will add more pressure on nuclear plants in terms of ramping speed and cycling frequency, duration and amplitude. The additional flexibility due to renewables is estimated as being the number of cycles overtaking the license. Table 4 makes the difference between cycles: by fatigue, cycles exceeding the allowed budget are very light (C0: 180 cycles more) and very deep (C3: 27 cycles more).

Table 4. Model results in terms of renewables effect on flexible nuclear reactors

Statistics of NPP operation in Load Following case	C0	C1	C2	C3
Reactor design				
Cycle deepness	10%	20%	40%	60%
Annual budget of cycles, by cycling 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, Ampere 2035				
Number of simulated cycles	**1 847**	**689**	**340**	**227**
Additional fatigue over one year by cycle type	2.5%	0	5.0%	2.21%
Reduced reactor lifetime, days, by cycle type	9.12	0	18	8
Reduced flexible operation lifetime, days	**36**			
Load Factor of **Flexible NPP** in 2035, %	61%			
Load Factor of **Inflexible** NPP, %	86%			
Load Factor **All NPP**, %	69.2%			

Table reading. *Reactor design* shows the number of yearly cycles obtained by dividing the number of cycles allowed by the license 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.

Additional fatigue calls for two solutions, refurbishment or early decommissioning. In the first case, the operator bears the cost of plant upgrading for components replacement, to avoid early retirement. In a purely market driven power system, the signal of this dispatch would be the early decommissioning: the operator does not recover from the market the cost needed to invest in plant modernization, and the nuclear power plants should be decommissioned earlier. This efficient outcome would describe a system with overcapacity; otherwise, the market design sends the signal that flexibility provision is loss-making and operators would be better off by operating steady state.

4.2. Price setting in Load-Following case

In the following, it is graphically represented the effects of renewables on price setting due to load-following with nuclear power. Three situations are depicted corresponding to three demand cases: low, medium and high demand (Fig. 3). For simplicity, three technology types are represented (Renewables, Nuclear, Gas) and another option adds to imbalance settlement on the demand side (DSM or curtailment).

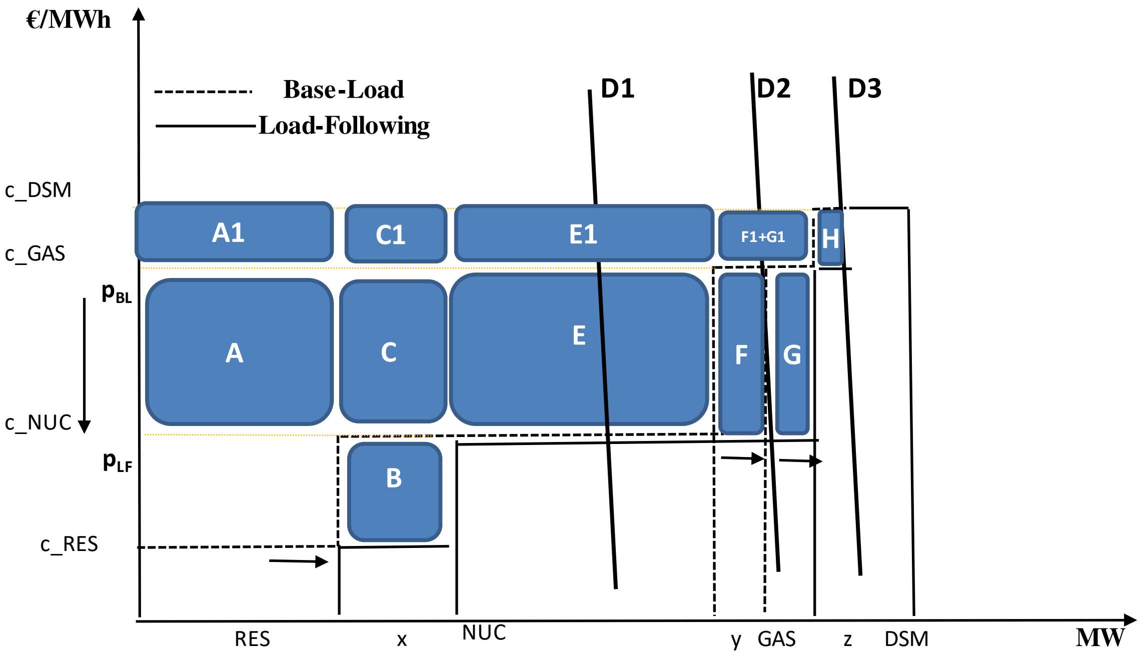


Fig. 3. The merit order of technologies on the market, for three power demand values with nuclear operating Base-Load or Load-Following

1. Case of low demand (D1). This case corresponds to a low demand where the nuclear power remains price-maker, hence the price remains constant during load-following. Due to downward flexibility provision, the nuclear operator loses market shares (segment *x* in Fig.3) and its revenue is decreasing (area B), but not its surplus since the area B represents a cost only. Renewable operators, with undispatched potential during Base-Load, can enter the market and capture the area B lost by the nuclear operator as inframarginal rent; the area B is now an avoided cost for nuclear plant and a surplus for renewables. Here substitution nuclear to renewables is perfect over one hour. The consumer remains neutral to the trade from a price perspective and its surplus remains unchanged. If nuclear power fleet is operating Base-Load, the deadweight loss is the area B, by only considering these trade terms, e.g. without any other externalities while curtailing renewables (the volume *x*).

2. Case of medium demand (D2). The demand is medium and the last technology setting the clearing price in Base-Load is gas-fired, i.e. more expensive, thus at the right of nuclear power generation. The nuclear power is price-taker and captures the rent as the sum of areas C+E+F. During Load-Following, with downward flexibility provision, the entry of more renewables (segment *x*) pushes the gas-fired units toward right until they exit the market and lose the market share (segment z), while nuclear is losing *x* and wining *z* as market volumes. Some nuclear is also evicted from the market (the difference *x-z*), but most significantly, price in Load-Following is falling at the level of the cost of generating power with nuclear plants, hence making nuclear operators losing the rent made of areas C+E+F. The consumer captures the surplus A+C+E+F, the renewables are losing A and winning B. In a Base-Load case, the deadweight loss would be the area (B+F) which is the nuclear cost and the gas-fired cost or an avoided cost for the consumer in Load-Following.

3. Case of high demand (D3). In the high demand case, the price is set at the level of the most expensive technology which is here the lost value of the demand curtailed. Nuclear power remains price-taker in both Base-Load and Load-Following, but prices drop due to nuclear flexibility provision, at the level of the gas-fired unit cost, hence generating a negative externality on nuclear revenues. While nuclear becomes flexible, the consumer surplus is increasing with the areas (A1+C1+E1+F1+G1+H), the renewables have a net surplus of (-A1+B+C), the nuclear surplus becomes (-C1+C-E1+F), the gas plant has a surplus of (-F1+G1), while DSM has an avoided cost of H. Overall, the social surplus of nuclear flexibility is of (B+H+F), as avoided cost of production, or the other way around: if nuclear operates base-load, the deadweight loss is as large as the area (B+F+H).

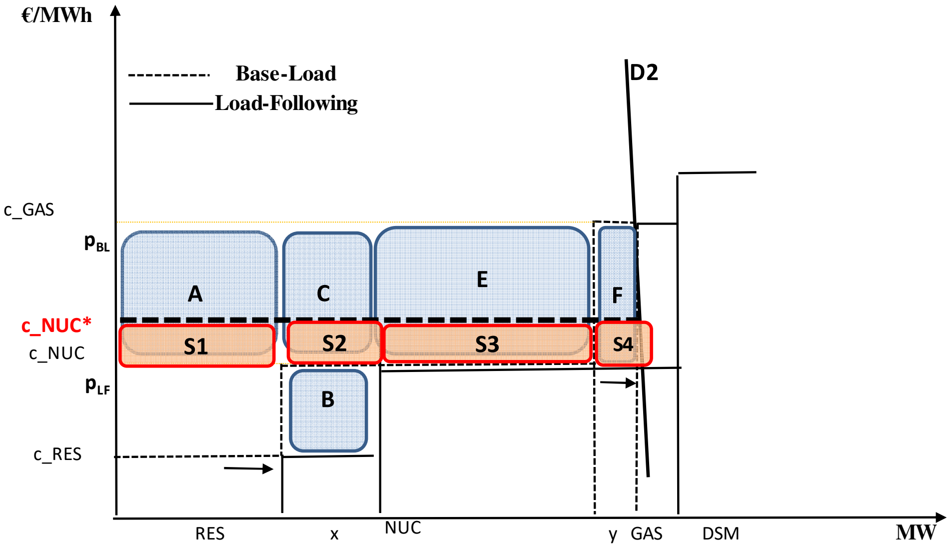
To summarize the effects of the down-ward flexibility, when nuclear is decreasing its market supply to allow renewables to enter the market, the nuclear power operator is losing market shares when it is price-maker, and loses infra-marginal rents when it is price-taker. Beyond the negative externality as missing market opportunities (or missing money), there is another cost, due to ramping, such as accelerated fatigue and refurbishment investment.

4.3 Market redesign

Solutions are next considered on how redistributing nuclear flexibility rents would contribute to improve the social efficiency of the electricity markets. In a base-load provision, it has been shown that more efficient equilibria could be found, since base-load operation despite increased revenues to nuclear operator is not efficient in the sense of Pareto and therefore the regulator intervention is justified. A new pricing scheme would be necessary to incentivize the nuclear plant to operate flexibly, and a reward should cover the missing money recorded by the operator over the year and the fatigue faced before the end of the technical lifetime. The reward should not exceed the system benefit, which is the areas obtained as social surplus (at 4.2) or avoided system cost (at 4.1).

The overall gain should be higher than the missing money of the nuclear operator, thus the loss of income of nuclear should be covered by each winner from the new trade. In this way, distributing shares of the producer and consumer surplus could generalize win-win situations: the nuclear operator would have the financial incentive to provide flexibility, the system operator would optimize the technology mix and the integration of renewables, the consumer would benefit from lower prices, and the society as a whole would benefit from locally generated clean energy based on renewables. Two mechanisms are next discussed, one based on spot market pricing and one on long-term payment through for instance contract for difference or complementary payments.

The first design assumes that the cost of nuclear increases with a share which allows the nuclear operator to cover at least the lost load; what the literature calls as compensation to generators by adding uplift payments (de Siestern, 2014). Let’s consider graphically the second case at 4.2, where the nuclear operator loses the rent (C+E+F). If the cost of nuclear is allowed to include the loss from ramping, it increases from c_NUC to c_NUC* (Fig.4). The regulator would allow marginal costs to increase as long as the deadweight loss is equal or higher than the new surplus of all producers: B+F = S1+S2+S3+S4, such as to guarantee zero-profits over the year.



In this market design, the nuclear operator is losing C+E+F and wins S3+S4. The renewable operator wins the initial rent, B, plus the new rents S1+S2. The consumer still faces lower prices and a new surplus (A+B+C+F – S1-S2-S3-S4), or at least A+C if the producer surplus is equal to the initial deadweight loss. Numerically, the share of nuclear marginal cost increase should cover the cost of flexibility such as to guarantee flexible capacity adequacy of the power system. If renewables still do not recover investment cost from the market and need outside the market support, the new rents (S1+S2) would readjust the payment of compensations, e.g. lower feed-in tariffs. Otherwise, renewables captures the rent created with higher nuclear costs in an unjustified manner, as windfall profits.

A second mechanism is a form of contract for difference, where the nuclear power is compensated at the end of the year such as to cover the fatigue cost due to ramping, i.e. the additional cycling exceeding the license. The instruments cannot oblige the nuclear operator to invest in refurbishment at the end of the license, since, as a reminder, the nuclear power fleet is a monopoly hold by EDF and the new rent might be redistributed differently in the operator's portfolio. The manner the frame of a liberalized electricity market can incentivize operators to supply flexibility over the long run would probably need additional regulatory provisions, such as the binding obligation to operate load-following over the entire technical lifetime. The issue is even more challenging in front of reduced capacity of nuclear power in the future and of limited output of flexible gas turbines due to their emissions. However, covering the missing money problem would at least address the issue of flexible adequacy in the short run, since new prices would partly reflect the scarcity in flexibility and give signals to invest in alternative projects.

5. Conclusion

The paper has addressed the issue of electricity market failure to cover the cost of flexibility provision in the short run as the missing money on the market, and in the long run as the cost of modernization due to additional fatigue. If upward flexibility could increase volumes and profits on the market, downward flexibility enhances externalities on the plant revenues and has less economic rational without additional reward. The situation can result in underinvestment in flexibility and a suboptimal generating capacity mix from the perspective of adequacy. Two ways are suggested to reflect the cost and the lost value of the flexibility: one modifying the short-run pricing, and one which does not alter the current pricing design but compensates the operators each year. Methodologically, prices derived from a dispatching problem will cover the short-run operation and will include a constant share of irregular non-convexities that could make prices coincide with long-run capital cost, including refurbishment and the costs of non-served energy.

Both affects the consumer surplus since the consumer ultimately pays for any on-/off-market premium granted to market players, but at different moments of the bill adjustment. The first one anticipates an increase in the spot market and the bill increase can reflect this effect while reducing the off-market support to renewables. The second one keeps stable the current consumer bill, the spot power price and the support to renewables, but will modify the bill of the next period with the amount allocated to flexibility providers.

The tool which best reconciles the willingness to pay for electricity and the investors' risk aversion in front of short-run market volatility depends on the regulator vision on using pure market-based mechanism by allowing price-uplifts, or a mixed of market and compensations which actually follows the regulation of the internal power market of the European Union (EC, 2014). The article 107 of the TFEU aims at modernizing the system of aid granted to renewables by introducing a market-plus-premium design. Hence the second mechanism in the paper seems to better fit the regulation with respect to renewable support and to generation adequacy.

The legislation clearly supports the State aid measures that cover "short-term concerns brought about by the lack of flexible generation capacity to meet sudden swings in variable wind and solar production" (3.9.1 of the Article 107 of the TFEU). Yet, it seems to rather defend a capacity payment (€/MW) than a payment for the sale of electricity (€/MWh), so defining the metrics of the compensation designed in the paper is necessary. The compensation mechanism at least would reduce the windfall profits that might arise with price uplifts for all technologies with lower marginal cost than the nuclear power. This aspect becomes an issue if those technologies are mature and do not benefit of any state aid needing to be readjusted later. The two designs support changes on the energy-only market and on the capacity-market respectively, and according to the French TSO assessments, the later seems to increase the social welfare provided it is optimally sized (RTE, 2018). Price uplifts could reduce the uncertainty of undersizing the capacity market, but would reduce the social welfare and would increase the risk aversion of operators in front of spot price volatility. With this respect, capacity market appears to be no regret solution.

In France, the market redesign aims at anticipating the need for long-term signals such as the forward capacity market, which is operational since 2017, but has a limited horizon of four years. Other projects are contracts for differences which will concern the new plants during the first seven years of their operation and are meant to secure the investor incomes (CRE, 2017). Changes will also concern the time step of imbalances, which is currently of 30 minutes. By 2025, it must align with the European regulation providing the obligation for all control areas to introduce the imbalance settlement period of 15 minutes, and to bring the generators' bids closer to the real time (EC, 2017). Aligning therefore short-run pricing with long-run cost could avoid misuse of contracts and give operators the incentive for accepting a dispatch solution that does not maximize their profits due to non-internalized ramping cost in the market clearing price; complementary payments seem to be the right alternative, over the pricing design integrating non-convex cost.

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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 CO_2)

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

$\tau^{rampdown}_{tech}$ – 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:

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

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

Annex 2. Inputs of the model, by technology type

Technology	Efficiency	Fuel Cost	CO2	Max CF	Ramp
	%	€/MWh	kg/kWh	%/year	%/half-hour
Nuclear Inflexible	33%	8	0	69%	10%
Nuclear Flexible	33%	8	0	69%	0.1%
Hydro River	36%	0%	0	45%	100%
Hydro Lake	100%	0	0	23%	100%
Oil steam turbine	39%	190	0.28	-	50%
CCGT (Combined cycles gas turbines)	57%	30	0.202	29%	30%
NGGT (Natural gas gas turbines)	39%	30	0.202	12%	90%
CHP (Combined heat and power)	35%	30	0.25	25%	50%
Wind On-shore	100%	0	0	25%	100%
Wind Off-shore	100%	0	0	36%	100%
Solar	100%	0	0	14%	100%
Other RES	100%	0	0	38%	100%

Note. Max CF 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.