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Document de Travail
Working Paper

LEMNA

EA 4272

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2014/04

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Abstract

This study analyses the system integration of wind energy in terms of load balancing and power plants scheduling. The case study is the French power system, which relies on high rates of nuclear power, representing 78% in the total generation (2008). The study evaluates the ability of nuclear reactors to follow the load under several configurations of power plants in 2030 with at least 28 GW wind power representing 11% in the total generation. A dynamic optimization dispatching model is built with a detailed discrete-time formulation under the nuclear power ramp up and down constraints. Results show that operating the French power system with high infeed of wind power by 2030 seems technically feasible but relies heavily on the capacity of nuclear reactors to follow variations, on energy storage to insure flexibility and on the market capacity to allow generators to adapt continuously to the demand. Simulations show that balancing the wind power variation is less a matter of installing more flexible capacities, as load factors might decrease and reduce the investors' interest when prices are relatively low. Balancing becomes more an issue of ramping rates and unit scheduling, power market regulation and real-time market interactions with the day-ahead and intra-day markets.

Keywords: power plants dispatching, flexibility, wind, nuclear, ramping rates.

Introduction

The deployment of renewable energy in the European Union has led to substantial wind power generation, but has also increased the concern over the reliability of power systems [1]. According to estimations of the Global Wind Energy Council, France has the second largest wind potential among Member States. The installed wind capacity is planned to increase from the current 7 GW (2012)[1] to about 25 GW by 2020 [2], out of which the on-shore wind potential is documented to reach 19 GW by 2020 at 24% load factor, and off-shore wind power 6 GW at 34% load factor.

One of the issues raised by the wind power integration concerns the flexibility requirements [3,4]. The literature is rich with computer models simulating power systems with increased wind power levels ([5]-[8]). This study gives an original appreciation of

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the flexibility in systems with a large composition of must-run power plants by analysing the system capability to involve quick-starting and long-lasting capacities on three market segments: the day-ahead market, the positive and the negative regulation markets.

The literature documents different approaches to define reserve requirements. Holttinen [6] shows that wind power variations require additional reserves similarly to the demand variation. Goransson and Johnsson [7] take into account the forecast errors for wind power only when determining the size of the secondary reserve. While Maurer et al. [9] suggests that all variable renewable forecast errors could be balanced through tertiary reserves, because the wind power is forecasted at the same time frame as the tertiary control can be activated. In this study, it is assumed that the balancing of wind fluctuations occurs mostly on the day-ahead market. The issue raised is how the variability of increased wind power will interact with the nuclear power generation, considering the high share in the French electricity generation (78% in 2008), and projections for increased rigidity due to fewer reactors and projected higher utilization rates in the long-term levels [10].

Despite the March 2011 Fukushima accident and adverse public perception of nuclear safety, globally today the nuclear power is back on the policy agendas of many countries, with projections for new nuclear power plants [11]. The main drivers are an increasing energy demand, the concerns over the climate change, the security of supply and the dependence on imports of fossil fuels. Most of the studies show that the nuclear energy is the most cost-effective over the base-load technologies [18], while some others show that in liberalized markets, the cost competitiveness of nuclear power is questionable [11].

This study analyses the nuclear power from a different perspective, and estimates the flexibility capability of nuclear power reactors installed within the French power system. Their capacity to follow the load variations is tested in a system built by 2030 with a short-term perspective from intra-year to an intra-hour timeline. A cost minimization linear programming model has been developed to this aim. Section 2 describes the study case and the methodological approach. Section 3 presents the model results with focus on the dispatching of power plants. Section 4 concludes on the possible solutions to balance the wind variability.

2. Case study framework

2.1. Case definition

The French power system is the second largest in Europe, after the German system. The technological mix in 2008 is mainly composed of nuclear power, providing about 78% of the electricity generation, hydropower (10%), coal (4%), gas (4%), oil (1.1%), wind (1%), and biomass (less than 1%).[2] The share of renewables attains 12% of the French electricity generation in 2008 and is planned to increase to 23% by 2020 [2]. France imports nearly all of its oil, gas and coal, but has a good diversification of its import sources [12]. France benefits from a strategic geographical location in Western Europe and from significant cross-border connections with neighboring countries (15.75 GW).

The perspective of future trends in the French market are closely related to the European power market evolution, such as the decentralization in generation, the reduction of over-capacity and the ageing infrastructure. Particular challenges are related to structural imbalances for meeting the peak demand. The country exports mostly baseload electricity and imports mainly during peak periods. The French government intends to enhance the flexibility of the power grids and to boost investments in peaking capacity.

The nuclear power capacity will decline between 2020 and 2030 due to ageing, with some possibilities to extend the lifetime for some of the reactors. New projects are planned or under construction for European Pressurized Water Reactors (EPRs) and for generation IV reactors beyond 2040 [12]. The nuclear reactors currently used in France are the Pressurized Water Reactor type, which is flexible to some extent and has good technical capacities for load-following [13]. The interaction with higher wind power generation will depend however on technical constraints in providing more flexibility but also on the market design to schedule power plants.

2.2. Model description

A power plant dispatching model is designed to describe the power generators in the French system. The model, called Dispa-SET, is developed within Joint Research Centre in the context of activities undertaken under the Strategic Energy Technology Plan.

Two scenarios are built for 2030 around the issue: how much gas-fired capacities would be installed as back-up for the wind variability? The first scenario is based on installed capacity data from EC [10] and a second one assumes lower gas-fired capacities such as the utilization rate would result in higher profits and increased interest for investors.

A description of the model can be found in Loisel [14], with an application to the energy storage business model, for compressed air energy storage applications. The model is based on linear programming, and it is implemented in GAMS.[3] The program minimizes the annual system costs of operating power generators. The model aggregates major generator types into representative technologies (see Table 1). For a given amount of installed capacity, the model determines the most cost-efficient combination of technologies that meets the demand under the system constraints.

Fixed demands accounting for the national supply and the power export flows are addressed on the spot market and regulated markets. Imports are instead adjusted by the model, as a function of fixed import power prices and system needs to fill the gap between supply and demand. Dynamic principles describe the system over one year, with (8784×2) time slices, according to the French balancing mechanism setting imbalance prices and volumes every half-hour.

Table 1. Main inputs in the model for the years 2008 and 2030

Technology	2008 Installed capacity	Efficiency	Fuel Cost	CO2 emissi	Max Loads	O&M costs	Ramp	2030 Installed capacity, MW		Efficiency	Fuel Cost	Max Loads	O&M costs	Ramp
	MW		€/MWh	kg/kWh	%/year	€/MWh	%/half-hour	EC 2030	GAS 2030		€/MWh	%/year	€/MWh	%/half-hour
Nuclear Old	63360	33%	2.7		75%	1.75	6%	40458	40458	34%	3.01	93%	1.75	1%
Nuclear New								17339	17339	36%	3.01	92%	0.61	2%
Coal	10406	36%	7.7	0.34	27%	1.69	14%	1251	1251	40%	9.13	55%	1	15%
Hydro RoR	10315	100%	0		29%	2.5	100%	21363	21363	100%	0	30%	2.48	100%
Hydro Lake	13824	100%	0		29%	2.5	100%			100%	0	30%	2.48	100%
Oil steam turbine	436	39%	15.4	0.28	9%	0.86	30%	0	0		17.65			
Oil gas turbine	7373	33%			9%	2.1	100%	5826	5826	39%		0.01%	0.86	100%
CCGT	883	57%	20.3	0.20	76%	0.86	50%	16832	2530	65%	24.90	10%	0.4	100%
NGGT	410	39%			76%	0.86	100%	7821	1175	45%		10%	0.4	100%
Biomass	446	27%	23.3	0.36	17%	2.1	100%	2547	2547	30%	37.69	60%	2	100%
CHP	6600	35%	20.3	0.25	42%	8	100%	7377	7377	40%	0.25	50%	6	100%
Wind On-shore	3422	100%	0		19%	0	100%	18939	18939	100%	0	26%	0	100%
Wind Off-shore								9000	9000	100%	0	34%	0	100%
Solar	13	17%	0		8%	0	100%	11090	11090	17%	0	14%	0.01	100%
Other RES								1731	1731	100%	0	38%	2	100%
Storage	4302	81%	0				100%	4000	4000	81%	0			100%
Imports	15570				8%	38.9	80%	20000	20000			25%	22.7	80%
Total Capacity MW	121791							165575	144627					
Demand, GWh	490483							598214	598214					
Export, GWh	58689							46951	46951					
Loss, GWh	10848							12756	12756					

Note. The figures highlighted show the differences between the two scenarios built for 2030.

The objective function is the sum of variable costs only, such as the fuel costs, the carbon price, the variable O&M costs and the import price. Technical constraints are minimum operational loads, the ramping restrictions and the maximum load factors. Minimum operational levels are introduced to avoid high start-up and shut-down costs for nuclear and coal-fired power plants; they can also define power purchase obligations (biomass) and the lack of heat demand for CHP.

Ramping rates define the output variation between two periods, from one half-hour to the next one. They are defined for nuclear and coal-fired plants only. Maximum load factors define the maximum use of a technology due to decreased demand, load-following, limited natural resource inflow or the power plant unavailability during maintenance. The maximum load factors reported in Table 1 are calibrated against the data on the capacity installed and the power generation by technology [10]. These rates increase by 2030 due to technological progress for both wind power and solar power. The values for annual load factors shown in Table 2 are instead the outputs of the model, simulated under the constraint of the above maximum load factor rates.

The model baselines the power system in the reference year 2008. The database is composed of real half-hour figures for power demand and of hourly data for export-import flows and hydro power generation.[4] Technology description is documented by Eurostat[5] and EC [10] for installed capacities, and by SETIS databases for operational parameters[6]. Calibration of ramping rates for nuclear power is based on the real data[7] on hourly generation in 2008, with a maximum ramp-up of the generation of 6% and a ramp-down of -6% per half-hour. Despite this wide range, more than 90% of the number of events of nuclear power variation concentrates within the range of variation of -1% and +1% of the power recorded in the previous half-hour. For 2030, the EC scenario is using higher load factors (90%) for lower installed capacity than in 2008 (57.7 GW against 63.4 GW); thus, a decrease in ramping capability is assumed, i.e. ± 1% in 2030. The storage capacity installed stands for pumped hydropower storage applications, thereby having an efficiency rate as high as 81% [24].

2.3. Scenarios description

Three scenarios are built, one for 2008 and two for 2030.

The reference scenario, EC 2030, is documented by EC projections (the scenario called *Reference* [10]). The model assumes a demand increase from 490 TWh in 2008 to 598 TWh in 2030, with equivalent load spreads between the two periods. The EC projection does not integrate any demand side control measures nor the development of electrical vehicles which could change the demand curve [15].

Most of the planned projects in EC 2030 are for nuclear, natural gas and renewable energies. Nuclear power capacity in 2008 is 63.36 GW composed of 58 nuclear reactors connected to the grid, located on 19 sites. The total nuclear fleet in 2030 would consist of up to 30% new reactors (EPRs), 50% repowered (extended lifetime) reactors, and 20% consisting of reactors remaining from the 2008 fleet ([12], p. 127).

France exports mostly baseload electricity, but with the decrease in the nuclear power in the future, exports will be reduced and imports will become more significant. Additional cross-border capacities are planned to enhance trade with Spain, Italy and Belgium, and to alleviate also transmission congestion. The model assumes an increase in capacities from the current 15750 MW to 20000 MW by 2030. The model assumes that exports decrease by 20% in 2030. Imports are adjusted by the model, driven by the gap between demand and supply, and by price difference between countries.

The alternative case, GAS 2030, assumes a lower amount of installed capacity for combined-cycle gas turbines (CCGT) and natural gas gas-turbines (NGGT). The generation by technology remains unchanged compared to the scenario EC 2030, and the only difference is in the use of the gas-fired units, which results in higher load factors and increased profits for investors. The case GAS 2030 assumes an operation of 3500 hours for CCGT and 1700 hours for NGGT, which improves the economic attractiveness. In the scenario EC 2030, the load factors of gas-fired plants are about 10% for CCGT and 0.7% for NGGT (see Table 1), corresponding roughly to respectively 880 and 60 full hours of operation. The scenario GAS 2030 is representing the case of decentralization in generation and reduced installed capacities.

The model has a perfect forecast of the wind profile, substantiated by further progress in wind forecast techniques [16]. Since the wind power fluctuations are perfectly foreseeable, balancing of wind fluctuations occurs on the day-ahead market.

Sensitivity scenarios test the system flexibility by assuming forecast errors, and alternatively, a lack of wind during one week.

3. Results and discussion

3.1. Power plants dispatching in 2030

Table 2 presents the main results, here aggregated, such as the annual generation and annual load factors. The technology energy mix obtained for 2030 is composed of similar shares in the total power generation between the two scenarios *EC 2030* and *GAS 2030* for nuclear 70%, hydro 9%, coal 1%, oil 0.1%, wind 11%, solar 2% and biomass 1%.

Harder constraints set on gas-fired capacity in the scenario GAS 2030 enhance a different dispatching of power plants, which results in less gas and more CHP-based power generation, as well as in additional storage discharge. More power is generated in the GAS 2030 case, in order to fuel the storage plants and to offer the missing flexibility due to lower gas capacity. Consequently, the load factor of storage technologies increases by 13% between the two cases.

In both scenarios, the wind power generation amounts to 70 TWh in 2030 for an installed capacity of 28 GW, and represents 11% of the total power generation. Wind curtailment occurs occasionally when ramping rates and minimum operational levels constrain the system, but attains low levels over the year (1.3 GWh in the EC 2030 case and 4.9 GWh in GAS 2030 case). In the case GAS 2030, the wind curtailment occurs eight times during the year and enhances a decrease in the spot price down to zero during those events. The low number of curtailments implies that the system is flexible enough to integrate the wind power, due mainly to the nuclear power capacity to follow the load and to the flexibility of hydro and gas-fired technologies.

Table 2. Results of simulations for the years 2008 and 2030

Technology	2008			EC 2030			GAS 2030		
	Generation GWh	Annual Load %	Share in the total Generation	Generation GWh	Annual Load %	Share in the total Generation	Generation GWh	Annual Load %	Share in the total Generation
Nuclear Old	432592	78%	78%	319845	90%	49%	319845	90%	49%
Nuclear New				137075	90%	21%	137075	90%	21%
Coal	24680	27%	4.5%	5824	53%	1%	5824	53%	1%
Hydro RoR	26860	30%	4.8%	57398	31%	9%	57379	31%	9%
Hydro Lake	35999	30%	6.5%						
Oil steam turbine	5829	9%	1.1%	0			0		
Oil gas turbine	345	9%	0.1%	461	0.8%	0.1%	461	0.9%	0.1%
CCGT	5895	76%	1%	14782	10%	2%	8787	40%	1.3%
NGGT	2739	76%	0.5%	470	0.7%	0.1%	1984	19%	0.3%
Biomass	196	5%	0.04%	6712	30%	1.0%	6712	30%	1.0%
CHP	13493	23%	2.4%	19507	30%	3.0%	23605	36%	3.6%
Wind On-shore	5727	19%	1%	43608	26%	6.7%	43608	26%	6.7%
Wind Off-shore				27045	34%	4.1%	27044	34%	4.1%
Solar	9	8%	0%	13638	14%	2.1%	13638	14%	2.1%
Other RES				5807	38%	0.9%	5820	38%	0.9%
Total Generation, GWh	554362			652170			651782		
Storage	2467	7%		3638	10%		4776	0%	
Imports	9135	7%	2%	8000	5%	1%	8000	1%	1%
Export, GWh *(input)*	58689		11%	46951		7%	46951		7%
Net imports, GWh	-49554			-38951			-38951		

Note. Hydro power units are aggregated in one technology in 2030, due to memory constraints.

The scenario EC 2030 records low load factor rates of gas-fired units, which would decrease the profit rate of investors and their incentives to keep operational the entire capacity. To reverse this trend, the scenario Gas 2030 assumes a lower installed gas-fired capacity, which would improve the use and the economics of gas-based units. In support to the scenario EC 2030, it is to be noticed that by 2016, France will develop a market that would compensate utilities for maintaining spare capacity; this would prevent the retirement of unprofitable power stations with low load factors due to increased renewable installed capacities [25].

3.2. Assessment of system flexibility in 2030

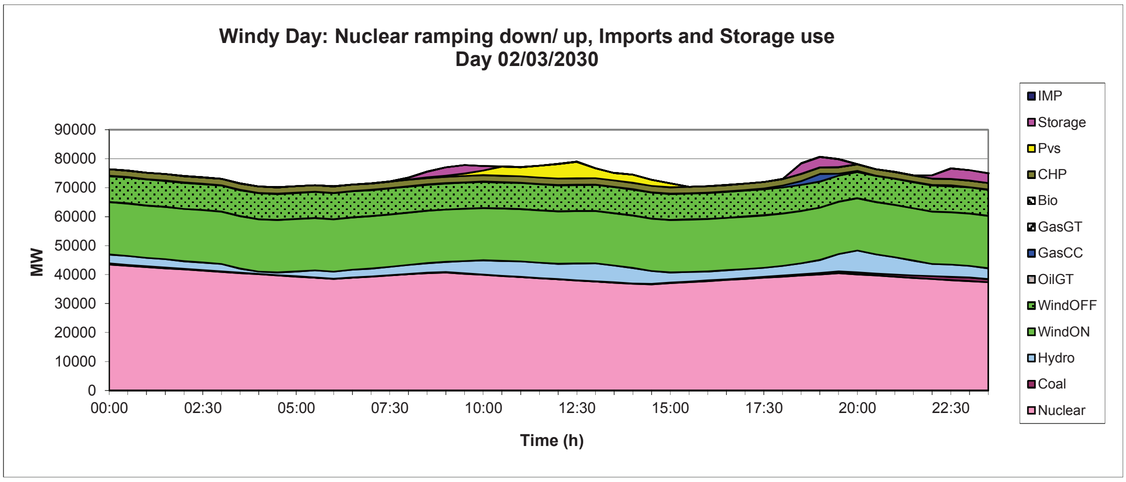
The French nuclear power, with an annual load factor of ~78%, is low when compared with other countries[†], due to the French specificity to use the nuclear power for baseload, semi-base load and regulation provision. Some 46 nuclear power units are endowed with additional control rods for load-following [17] which allow nuclear to play a more active role in providing regulation [13].

Figure 1 illustrates the dispatching of power plants during the 48 half-hour time slices of a weekday (Friday) with a significant wind power infeed. The favourable position of wind power in the merit order curve makes the system dispatch the wind-based technology in substitution to other alternatives. The nuclear power is crowded out during

[†] See IEA statistics at www.iaea.org (website last accessed at 17/10/2012).

low demand at the beginning of the day with a pace within the range ±1% between two half-hour time slices. With the demand increase during that day, the nuclear power is triggered up. Until it gets full power, other options are activated, such as gas-fired units and storage discharge. At noon, PV power generation replaces these peak technologies.

Fig. 1. Power plants dispatching during a windy day, scenario EC 2030



In Table 3, real data recorded for nuclear power in 2008 shows that the average is of 172 MWh/2 for the downward variation and of 190 MWh/2 for the upward variation. These levels increase by 2030 in *EC 2030* case to 468 MWh/2 and to 461 MWh/2 respectively. For ramping rates higher than the level chosen for these simulations (1%), the wind power variability would increase the speed of up- and down-ward variations as shown in the Annexe 1. For instance, if ramp rates are allowed to be lifted toward ± 6%, the number of ramping events becomes more distributed over the range of ramp rates (i.e., 0-1%, 1-2%, etc.). This implies that a more flexible nuclear system would be more effective at reducing the variable supply. By 2030, the load factor increase from 78% in 2008 to 90% which enhances a less flexible nuclear power system. Figure 2 shows the system reaction during the same day as in Fig 1, but considering no ramping constraints on nuclear reactors.

Fig. 2. The nuclear power variation in the scenario EC 2030 with no ramping constraints

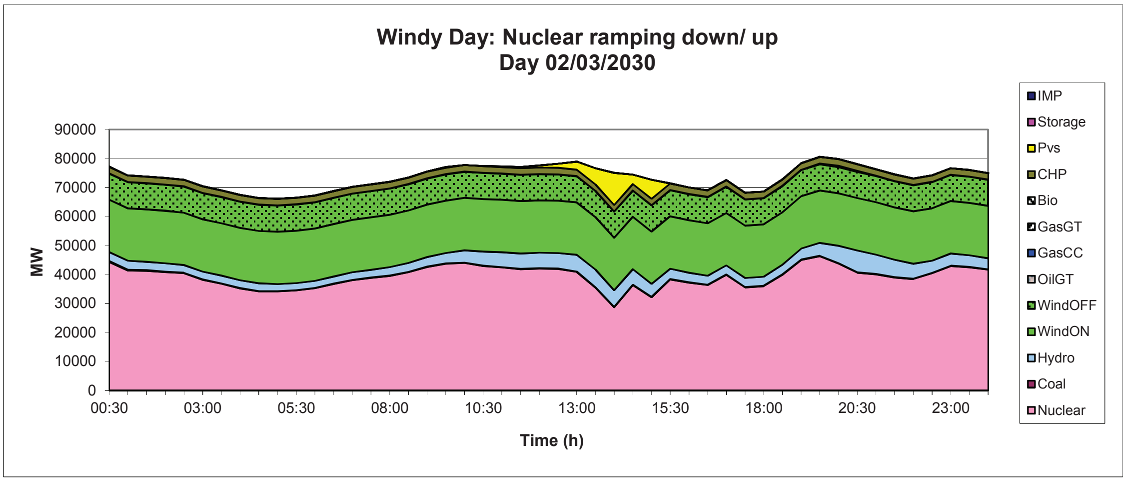


Table 3. Nuclear power statistics from real data and from model simulations: the number # of fluctuations in the range ±6%; and average variations (MWh/2)

Effective Generation, Data RTE 2008			Model											
			2008, ramp allowed = 6%			Model EC2030, ramp < 2%			Model GAS2030, ramp < 2%			Test EC 2030, ramp = 100%		
Ramp %	#		Ramp %	#		Ramp %	#		Ramp %	#		Ramp %	#	
~ 6	1		~ 6	49		~ 6	0		~ 6	0		~ 6	944	
5, 6	7		5, 6	92		5, 6	0		5, 6	0		5, 6	280	
4, 5	13		4, 5	68		4, 5	0		4, 5	0		4, 5	403	
3, 4	37		3, 4	97		3, 4	0		3, 4	0		3, 4	614	
2, 3	115		2, 3	189		2, 3	0		2, 3	0		2, 3	704	
1, 2	642		1, 2	690		1, 2	5256		1, 2	5136		1, 2	887	
0, 1	7549		0, 1	7271		0, 1	881		0, 1	848		0, 1	1226	
~-6	1		~-6	70		~-6	0		~-6	0		~-6	960	
-6, -5	3		-6, -5	112		-6, -5	0		-6, -5	0		-6, -5	307	
-5, -4	2		-5, -4	51		-5, -4	0		-5, -4	0		-5, -4	463	
-4, -3	32		-4, -3	79		-4, -3	0		-4, -3	0		-4, -3	656	
-3, -2	139		-3, -2	181		-3, -2	0		-3, -2	0		-3, -2	861	
-2, -1	515		-2, -1	549		-2, -1	5189		-2, -1	5028		-2, -1	1241	
-1, -0	8119		-1, -0	7800		-1, -0	842		-1, -0	849		-1, -0	1287	
	%	MWh/2		%	MWh/2		%	MWh/2		%	MWh/2		%	MWh/2
Min	-6.4%	-2783	**Min**	-6%	-2861	**Min**	-1.4%	-751	**Min**	-1.4%	-751	**Min**	-26%	-11938
Average down	-0.4%	-171.8	*Average down*	-1%	-268	*Average down*	-1.2%	-583	*Average down*	-1.2%	-581	*Average down*	-3%	-1701
Average up	0.4%	190	*Average up*	1%	282	*Average up*	1.2%	573	*Average up*	1.2%	571	*Average up*	4%	1942
MAX	6.4%	2554	**MAX**	6%	2648	**MAX**	1.4%	741	**MAX**	1.4%	741	**MAX**	56%	14164

In theory, an EPR can load-follow within the range of 25-100% of nominal full power and is designed to change load at most twice per day. A ramping rate of 5% per minute going from 25 to 100% of capacity can be achieved, but would be limited to 100 cycles a year [19].

In practice, data might be different at a system level compared to individual technology parameters. If some equipment can increase their power very quickly, in practice, grid codes and economic costs induce lower ramp rates than the technical potential. In this model, ramping operations are not monetized, while in practice additional monitoring and mechanical constraints would be expected to increase plant costs [17]. Technical aspects add to factors reducing the load factor, since the load-following induces more frequent maintenance and reduces the availability of nuclear power plants. This induces a cost in the system, due to accumulated damages from erosion, fatigue and corrosion, and to additional operations such as the treatment and the discharge of the water. Therefore the ramping rates in this model are fixed at ±1% by 2030, taking into account the statistics of nuclear power in the base year, the results simulations for different ramping values and the high load factor recorded in 2030.

From a market perspective, the power price is set at the equilibrium between supply and demand and is the marginal cost of producing the last unit of electricity. Table 4 shows the prices obtained with the model on spot and reserve power markets. The GAS 2030 scenario shows a lower price on average (23 €/MWh in GAS 2030 against 29 €/MWh in EC 2030 case) due to lower gas consumption (-28%). The power price is based on variable operational cost and on fuel costs, therefore, when it is activated, the gas-fired technology is the marginal plant setting the power price. The peak prices are higher in GAS 2030 case than in EC 2030, due to the market tensions created by lower installed capacities.

Table 4. Prices on the day-ahead and balancing markets

	EC 2030							GAS 2030						
Generation / Prices	Day-ahead	PR+	PR-	SR+	SR-	TR+	TR-	Day-ahead	PR+	PR-	SR+	SR-	TR+	TR-
Total Volume, GWh	652,202	1,082	1,796	187	232	201	1.1	651,801	1,082	1,796	187	232	201	1
Peak Load, MW	107,489	2,219	2,727	782	655	1,195	200	109,229	2,219	2,727	782	655	1,195	200
Average Price, €/MWh	29	30	24	30	29	30	22	23	25	20	25	29	25	29
Maximum Price, €/MWh	38	38	37	37	37	38	22	48	42	37	42	37	39	37
Minimum Price, €/MWh	0.00	1.2	4.4	1.2	22.1	1.2	22.1	0	1.2	4.2	1.2	4.4	1.2	4.4

Note: *PR*, *SR* and *TR* represent primary, secondary and tertiary reserves respectively while +/– correspond to the positive and negative regulations.

The balancing market price could be underestimated by the assumption that the operators can continuously make the trade-off between the day-ahead market and the balancing/ real-time market. Within this design, the generator can make a choice to allocate its supply as an ancillary service or as energy as in [20]. If the arbitrage between markets was not possible, a higher margin of reserve would be necessary to ensure the liquidity on both markets at each moment and would result in lower levels of capacity factors.

The comparison between the EC and GAS scenarios is similar to the trade-off between more flexibility and more efficiency. Several areas are exploited currently in France, at the demand level within smart grid and green city projects; on the supply side, with energy storage applications; and in the trade design, through interconnections and by moving the adjustment mechanism closer to the real-time [12].

3.3. Sensitivity tests

Two sensitivity tests were conducted: a forecast error test (3.3.1) and no wind case (3.3.2). Since the GAS 2030 scenario has lower market liquidity, this scenario is taken further to understand the sensitivity to different wind power profiles. The model tests the system capability to provide positive regulation only. For negative forecast errors, wind power curtailment can occur, since this wind excess is considered to be imputable to the wind power operator and not to the market itself.

3.3.1 The forecast error test analyses the flexibility of the system for short-term wind power variations. Assuming forecast errors during a 6 hour period, the test simulates the system reaction to a lower wind power level, by 5% than predicted. This downward variation is balanced differently by the market according to the duration. During the first half-hour, primary and secondary reserves are activated, the next half-hour the secondary reserve only is still active, the next hour tertiary reserves substitute the secondary reserve, and finally, for the next four hours, balancing needs are provided by the spot market. The test selects a day with high power demand (11th of January, during a weekday-Friday) and high wind potential to evaluate the forecast errors from 16:00 to 22:00.

Table 5 shows the variation by technology for each market segment between the error test and the reference case. The test results in additional regulation requirements of 905 MW on the primary market, and in average 770 MW for secondary adjustment, 850 MW on the tertiary market and 900 MW on the spot market. The reference hour listed in the table is the beginning of the 30 minute period (e.g., 21:30 to 22:00).

Table 5. Results difference in MW between Error test and Reference case, GAS 2030

Hour	**16:00**	**16:00**	**16:30**	**17:00**	**17:30**	**18:00**	**18:30**	**19:00**	**19:30**	**20:00**	**20:30**	**21:00**	**21:30**
Technology/ Market	**PR+**	**SR+**	**SR+**	**TR+**	**TR+**	**Spot**	**Spot**	**Spot**	**Spot**	**Spot**	**Spot**	**Spot**	**Spot**
Nuclear Old	81	204	255	238	289	0	0	0	0	0	0	0	0
Nuclear New	35	173	157	173	173	-18	0	0	0	0	0	-3	0
Coal	63	0	0	0	0	0	0	0	0	-4	-4	0	0
Oil gas turbine	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind On-shore	0	19	0	0	0	0	0	0	0	0	0	0	0
Solar	8	-8	0	50	50	0	0	7	0	0	0	0	0
Wind Off-shore	0	0	0	0	0	69	-3	-9	-1	0	0	0	0
Other RES	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	214	0	0	0	0	0	0	0	0	0	0	0	0
CCGT	110	380	380	380	380	0	0	0	0	0	0	467	930
NGGT	12	0	0	0	0	199	398	795	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0	568	930	372	0
CHP	23	0	0	0	0	0	0	-55	0	0	0	0	0
Imports	-	-	-	-	-	0	0	0	0	0	0	0	0
Tech Fictive	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	360	0	0	0	0	696	532	0	930	362	0	0	0
Total	**905**	**769**	**792**	**841**	**892**	**946**	**927**	**738**	**929**	**926**	**926**	**837**	**930**
Price Difference													
€/MWh	9.3	0.1	0.2	22.7	22.7	12.7	6.6	0.0	0.2	0.4	0	0	0
%	36%	0.4%	1.0%	-	-	57%	29%	0%	1%	2%	0%	0%	0%

The price difference between the sensitivity test and the reference case corresponds to 9 €/MWh on the primary regulation market, and is negligible on the secondary market. The price difference on the tertiary reserve market corresponds to the equilibrium price itself, because the demand for tertiary services is zero during this period in the reference case. On the spot market, the price difference is higher during the first half-hour since the decrease in wind power potential enhances the rescheduling of power plants, and exerts a tension on the market equilibrium. At the end of the test period, the shock is completely absorbed on the spot market, as the price differential becomes zero.

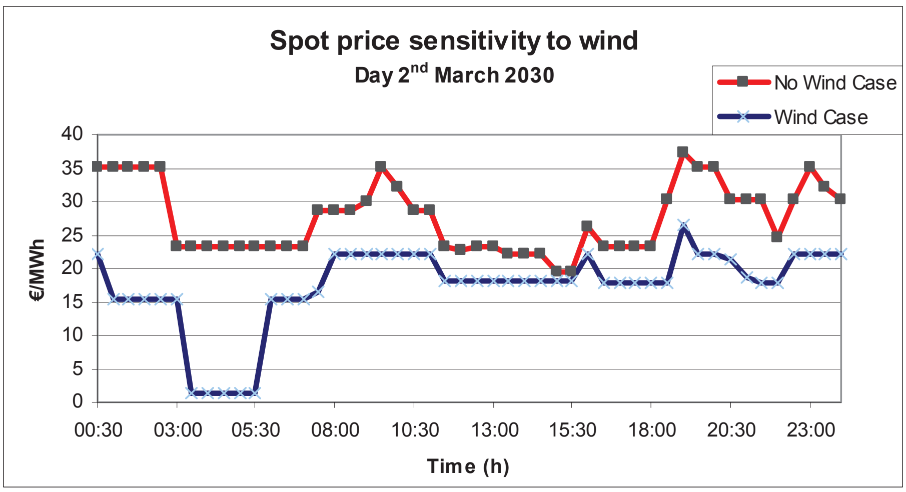
By technology, it has to be noticed the activation of power plants which were already operational – nuclear, coal, CCGT and CHP; and that only NGGT, hydro and storage act as reserves. Solar power is also used for tertiary regulation during an evening time simulation, and corresponds to reliable provision based on concentrated solar power provision. Storage and NGGT are also bidding in the spot market due to price increase which makes transactions attractive. Imports are not modelled as an option for real-time balancing purpose in order to estimate the capability of the generation system itself to balance the wind forecast errors.

The system has proved the robustness to balance wind forecast errors during 6 hours. The way this capability could be aggregated over the entire year depends on the frequency of the event. The balancing need could be satisfied if the event would have by assumption a daily basis frequency. Limits are however to be highlighted, for nuclear power with concern to the load factor in particular, since it attains already a high level (90%); and for hydro-power, since its generation is constrained by resource availability. Alternatives such as CCGT, NGGT and storage by contrast would still have a large capacity to increase their use over the entire year. For pumped hydro storage technology, the potential of high number of cycles allows for increased capacity factors which could moreover increase the storage investment profitability [21].

3.3.2 No wind case tests the capacity of the system to react during one week without wind from 26th of February to 4th of March. This amounts to a loss of wind power of 3.2 TWh over the entire week between the reference case, GAS 2030, and the No Wind Test. Results show that the system offsets the wind power by using following technologies with their respective shares in the total compensated generation: nuclear (47%), coal (4%), oil (1.5%), CCGT (8%), NGGT (3%), biomass (8%), PVS (5%), CHP (8%), imports (10.5%), and other renewables (5%).

Figure 3 shows the spot price difference between a day with significant wind power generation and the same day without wind at all. Results highlight a price difference in range of 1-21 €/MWh during the study day. If extended for a week then the difference ranges from 1-26 €/MWh with an average of 9.6 Euros between the two cases. This is in line with experiences in other European countries with similar rates of wind penetration such as assumed here, showing a price decrease in range of 3-23 €/MWh [22; 23].

Fig. 3. Spot price difference in cases with and without wind, in the scenario GAS 2030



The scenario GAS 2030 proves the system flexibility to balance forecast errors and wind power variations. These effects should be analyzed in relationship with the relatively low level of variable renewables, 13%. Wind and solar decrease the use of thermal generators but they could still remain synchronized to the grid and activated according to the resources variability, which avoids additional investments in back-up capacities.

4. Conclusions

The study shows by means of a dynamic optimization model that operating the French power system with 28 GW of wind power (or 11% of the total generation) by 2030 seems technically feasible for the infrastructure documented in EC [10]. But successful wind integration relies heavily on three factors: 1) the capacity of nuclear reactors to follow variations, 2) storage applications to insure flexibility and 3) market capacity to allow generators to adapt continuously to the demand. Simulations show that balancing the wind power variations is an issue of ramping rates and of unit scheduling.
This study shows that the nuclear power operating at higher load factors (90%) by 2030 as stated in EC [10] is not conflicting with the variable nature of wind power. Given the French fleet of nuclear reactors capability to follow the load, the wind power is almost entirely integrated by the system, as only a negligible share of wind power is curtailed (0.002% of the wind power generated). Further research would be necessary to estimate the value of the flexibility provided with the nuclear power in the French power system; this would improve the economics of nuclear power and the profitability of using the nuclear power to balance the wind power variation.

The market design by 2030 would influence the cost and the mechanism of balancing the wind power fluctuations. Today, intra-day mechanisms that allow rescheduling power plants still remain inflexible to an extent. Market regulation is changing by extending the balancing areas and by opening the market to more operators. Balancing wind fluctuations result in extra costs on real-time and day-ahead markets. To date, the major French generation operator, Electricité de France, EdF, is not paid for the provision of balancing services due to wind power variations, since these costs remain very low. This could become an issue at higher wind penetration rates, requiring in the future the internalisation of balancing costs into the power price. Concluding however on the way the wind power impacts the system cost should at the same time account for the influence that the wind power would have on the nuclear power industry in terms of ramping costs.

The current liberalization of the electricity markets raises challenges for the market organization. If more centralized markets concentrate trades and increase market liquidity, the decentralization instead would decrease the ability to optimize the use of capacities. The choice of the optimal technology mix will be based on the trade-off between more flexible systems and more efficient ones. The system will need a different market design such as the ongoing capacity market development, and new technologies and solutions such as smart grids, demand-side management, interconnections, distributed generation and power storage applications.

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Annex 1. Simulations results for different ramping rates for nuclear power generators in the scenario EC 2030

Ramp rate < 1%				Ramp rate < 2%				Ramp rate < 3%				Ramp rate < 4%				Ramp rate < 5%				Ramp rate < 6%			
Ramp up %	#	Ramp down %	#	Ramp up %	#	Ramp down %	#	Ramp up %	#	Ramp down %	#	Ramp up %	#	Ramp down %	#	Ramp up %	#	Ramp down %	#	Ramp up %	#	Ramp down %	#
5, 6	0	-6, -5	0	5, 6	0	-6, -5	0	5, 6	0	-6, -5	0	5, 6	0	-6, -5	0	5, 6	0	-6, -5	0	5, 6	1349	-6, -5	977
4, 5	0	-5, -4	0	4, 5	0	-5, -4	0	4, 5	0	-5, -4	0	4, 5	0	-5, -4	0	4, 5	1926	-5, -4	1551	4, 5	399	-5, -4	466
3, 4	0	-4, -3	0	3, 4	0	-4, -3	0	3, 4	0	-4, -3	0	3, 4	2876	-4, -3	2450	3, 4	556	-4, -3	646	3, 4	603	-4, -3	671
2, 3	0	-3, -2	0	2, 3	0	-3, -2	0	2, 3	4342	-3, -2	4090	2, 3	613	-3, -2	852	2, 3	705	-3, -2	911	2, 3	702	-3, -2	905
1, 2	0	-2, -1	0	1, 2	5256	-2, -1	5189	1, 2	686	-2, -1	873	1, 2	989	-2, -1	1239	1, 2	1165	-2, -1	1362	1, 2	1191	-2, -1	1421
0, 1	6471	-1, 0	6405	0, 1	881	-1, 0	842	0, 1	895	-1, 0	948	0, 1	1259	-1, 0	1372	0, 1	1309	-1, 0	1399	0, 1	1267	-1, 0	1346

Footnotes

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