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Load-following operating mode at Nuclear Power Plants (NPPs) and incidence on Operation and Maintenance (O&M) costs. Compatibility with wind power variability

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Executive Summary

The European Nuclear Energy Forum is a unique platform founded in 2007 with the aim of gathering all relevant stakeholders in the nuclear field: governments of the 27 EU Member States, European Institutions including the European Parliament and the European Economic and Social Committee, nuclear industry, electricity consumers and the civil society. This initiative encourages broad discussion, free of any taboos, on transparency issues as well as the opportunities and risks of nuclear energy.

In this frame a topic was raised about the capability of nuclear power plants to widely operate in load following mode and in which extend this operating mode can cope with the variability of wind generated electricity and affect the cost of the nuclear generated electricity.

In this report the capability of nuclear power plants to adapt to the demand is examined and several types of regulations needed for this are explained. From design there exists a power fluctuation margin and this is also an important characteristic of the design rules agreed upon by the European Utility Requirements (EUR rules) that should apply to the new builds in Europe. In the last chapter of this report the fluctuation margins as needed from wind farms are estimated from the experience gained in the wind turbines installations from Scandinavia and from the US. This allows an estimation of the compatibility of wind and nuclear generating units in a geographic area.

A central point of this study was to consider to what extent the contribution of NPPs to grid regulation impairs their economical profitability due to possible higher O&M costs. In a liberalised electricity market price components are not communicated. Consequently no precise cost data were available and the study is based on personal communication and on aggregated data from an IAEA database collecting yearly average loss of production of NPPs worldwide. The study shows that the supplementary O&M costs due to load-following like operating mode can be majored by 2% of the theoretical available capacity of a power plant. These supplementary costs allow a power plant to be eligible for regulation which is associated with much higher electricity prices than if the unit is always producing base-load electricity.

The conclusion may need to be reconsidered in case of a larger share of intermittent electricity generation. The decisive factor on this is the price at which reserve capacity is to be sold. This will be the adjustment factor and this last is more dependent on the share of the intermittent energy than of the nature of the backup plants.

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1 Introduction

In the framework of the Memorandum of Understanding n. JRC.BXL n.30897 between DGTREN and the JRC on the "Supply of Scientific and Technical Support to DGTREN on Nuclear Safety, Waste Management, Radiation Protection, and Sustainability of Nuclear Energy", signed on 25/11/2008 in Luxembourg, this report addresses the request of a report on the "effects of Load Following operating mode at NPPs on the O&M costs; coupling issues with smart grids". This task was included in the work plan set up by JRC and DG-TREN in 2009. The deliverable deadline has been in common agreement postponed to the first half of 2010.

This report also represents an official deliverable of the Work Plan of the JRC Action POS (Plant Operation Safety), n.52103, in Task 4.3: "Support to DGTREN in the framework of the MoU between DGTREN and the IE" and of the JRC Action Security of Energy Systems (SES).

It is well known that all issues related to costs are not to be found explicitly in the public domain. This is more than ever true for electricity generating costs in a liberalised market. From this it results that reliable information source is scarce. Apart from operators involved in our ENIQ (European Network for Inspection and Qualification) we relied on the IAEA yearly published report "Operating Experience with Nuclear Power Stations in Member States" in its 2007 issue. The result is the best picture of the incidence of Load Following operating mode on O&M cost achievable in an environment of confidentiality.

The report is organized according to the following scheme:

- Section 2 describes what the term Load Following stands for and consider the situation in fossil fuel and nuclear plants.
- Section 3 presents the power fluctuations acceptable by NPPs in response to load following.
- Section 4 addresses the specific issue of maintenance costs where the study is mainly based on the only publicly available information provided by the IAEA. The limit of the outcome as well as the anticipated economical consequences are discussed.
- Section 5 first introduces the challenges of system operation linked with high penetration of intermittent renewable power and then it touches upon the concepts of smart and super transmission grids.

Sections 2 to 4 are the contribution of the action Plant Operation Safety and Section 5 the contribution of the action Security of Energy Systems. The transients from smart grids are compared with the transients from NPPs (NPPs power margin due to load following) in the Conclusion, in order to identify the power generation flexibility needs.

2 Load-following, cycling

Demand variation is an obvious need linked to the day and seasonal power consumption cycles. This demand evolution can be prognosticated or adapted through commercial incentive. The cycling of the production can also be most of the time well forecast in accordance with the demand. Difficulties arise in front of unexpected high demand (most of the time due to meteorological events) or unexpected loss of production (unexpected outages). For high capacity generating plants (coal, gas, nuclear and hydraulic) the occurrence of unexpected outages is countervailed by adequate maintenance policy including preventive maintenance during the periodical outages. For renewable energy and for wind energy in particular, unplanned unavailability depends on weather conditions. They can be better and better forecast but the most efficient way to counter them is to deploy the production across the network, since according to several studies quoted in ref [1] the variability of renewables becomes lower the wider the area across which they are deployed.

Reaching the balance on an electricity network is essential from the point of view of its security. A mismatch between consumption and production results in a deviation of the network frequency (50 Hz in Europe) and modifies the power flows in the network. Frequency deviations are authorised by design in narrow band: usually 1 Hz, but the regulations in place take care that they are confined in a much narrower band (0.1Hz). Alternators are the main equipments that can be damaged and they disconnect automatically if the frequency deviation becomes too large. In case of production deficit this protective action augments the balance problem. Power flows called from other generating capacities have to transit on lines already charged and transmission lines cannot transport power above a limit protecting them from melting (thermal limit). If they reach the set point they disconnect and the unbalanced situation may worsen.

Cycling operating mode was introduced in the US in the 70' on fossil power plants and it is a usual operation mode for gas and oil power plants. From an economical point of view power plants where investment costs are big in comparison to fuel costs will be preferably operated in base load mode. However this simple picture has to be corrected in two ways: 1) for fossil fuel based generating units the cost of burning unnecessary fuel may be comparable to the cost of start from cold state, 2) for nuclear reactors although the big investment costs might require a full use of the capacity, introducing cycling in their operation helps the necessary flexibility of energy production.

Maintaining the balance between production and consumption requires having reserves that can be automatically available through primary and secondary frequency regulation or through action of the operators (tertiary regulation).

Operating modes at electricity generating power plants include:

- Base load: the plant is operated at its nominal power and is in its optimal operating mode as calculated by the designer.

- Frequency regulation (primary regulation): is the direct picture of the balance between production and consumption. Frequency increases if the production is in excess and decreases if the reverse is true. The primary frequency regulation, which aims at restoring the most feasible operating system conditions in the short-term (between 0 and 15 seconds) after a disturbance, is completely automatic and is decentralised. It is in fact performed on each generation unit connected to the power system by the respective speed governor. In presence of disturbances, the speed governor aims to restore the equilibrium between the mechanical energy (input) and the electric energy (output) at the respective prime mover (turbine)-generator group. The governor of each generator shares then the changes required to respond to the disturbance in a proportional way with the governors of the other generators contributing to the primary regulation ref [21].

- Secondary regulation/Load following. The adaptation to the demand is automatically performed. After a load change and the consequent primary regulation, the system frequency is not generally coincident with the nominal one. For this reason a secondary frequency regulation is needed in order to get the system frequency back to the nominal reference value. The secondary regulation is a control action developed at central level in the power system. It is then executed at generation level by means of signals transmitted to a subset of generators in charge of this type of regulation.

- Tertiary regulation/Load following. The adaptation to the demand is performed by the operator. The tertiary frequency regulation represents a further longer term subdivision of the effects of a load change among the concerned generators with the scope of cost minimisation. This regulation is operated at a constant frequency level.

Any unit part of the primary regulation must produce the power $P(t) = P_0 + K.\ \Delta f(t)$ where P_0 is the programmed power level, $\Delta f(t)$ is the observed frequency deviation and K is the primary regulation gain in MW/Hz. The primary regulation allows recovering the balance production/consumption with a new frequency close to the reference of 50 Hz (in Europe). This is done within a few seconds. Through the primary regulation remains a frequency deviation that has to be corrected in order not to progressively reach the border of the allowed frequency band. This is the role of the secondary regulation whose aim is to bring within less than 15 minutes the frequency back to its reference value and the exchanges between countries or networks back to their contractual value. This way the primary reserve is again available. Secondary regulation is centrally organised with the aim of modifying the production program of the generating units that are participating in this secondary adjustment. The dispatcher sends a signal N(t) in the band [-1, +1] that modulated the amplitude of the power variation P_r the unit has put at disposal of the secondary regulation.
Any unit involved in the primary and secondary regulations has to produce:

$$P(t) = P_0 + K.\ \Delta f(t) + N(t).\ P_r$$

Tertiary regulation corresponds to needs beyond these two regulations. Since tools for the demand forecast are more and more improving, tertiary regulation can be carried out after the occurrence of unexpected events.

Secondary and tertiary regulations are meant by load-following.

Load-following can be seen differently from the engineering and from the operation point of view (ref [2]). The engineering perception considers load cycling and on/off cycling. This emphasizes the effects on the structure load: either staying in hot condition or accumulating hot/cold/hot transitions. In this approach a cycle is considered to start at full load, full temperature/pressure steady-state condition. A typical load cycle is then composed of three phases: load reduction, low load operation, reloading. A typical on/off cycle has four phases: load reduction, idle, restart, and reload.

The operator perception provides a classification based on the typically expected electricity generation demand: (1) Base load with minor load following (like frequency regulation), (2) periodic start-up, load follow daily, reduced load nightly, (3) weekly start-up, load follow daily, reduced load nightly, (4) daily start-up, load follow daily, off-line nightly, (5) start-up to meet daily demand, (ref [2]).

Currently the move from regulated to competitive electricity generation market results in important and at the same time lucrative ancillary services. The U.S. Federal Energy Regulatory Commission, FERC, defined ancillary services (ref [3]) as those services "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities with those control areas to maintain reliable operations of the interconnected transmission system". The ancillary services are categorized as follows: scheduling, system control and dispatch, reactive supply and voltage control, energy imbalance, spinning reserves, non-spinning reserves, replacement reserves, regulation, and frequency response.

From a cost stand-point it is advantageous for an operator to be capable to participate to regulation and frequency response since ancillary services are lucrative. The possibly increase in maintenance costs involved will be considered in relation to the increase in income.

2.1 Non nuclear power plants

Most conventional fossil-fired electric generating units were not designed for ancillary service during their design life. According to (ref [2]) 95% of conventional fossil-fired steam-electric generating units in the United States were designed to operate as “baseload with minor load following”.

This is not the case of combined cycle gas turbines which are widely used for covering demand peaks since operating a coal-fired station to meet semi-base load, or short semi-base load, is less cost-effective than operating a combined-cycle gas plant, given the weight of the capital cost. Reservoir-based hydro power, where available, is also widely used to this aim.

Ref [4] gives the following figures reported in Table 1 that allow a comparison about the flexibility of power plant most commonly candidates for load following:

	Startup time	Maximal change in 30s	Maximum ramp rate (%/min)	Maximum ramp rate (%/min) **
Industrial GT*	10 - 20 min	20 - 30 %	20 %/min	100 MW/min
GT Combined Cycle	30 – 60 min	10 - 20 %	5 -10 %/min	25-50 MW/min
Steam turbine plants	60 – 600 min	5 - 10 %	1- 5 %/min	5-25 MW/min

* GT: Gas turbine
** assuming a size of 500MW

Table 1: Regulation capabilities of fossil fuel fired power plants

Minimum practical low load limit for pulverized Fuel (PF)- is in the range 25-60% Pn. Typical ramp rates are in the range 3-5%/min but can be higher, up to 8%/min. To start-up from cold requires a minimum of four to eight hours and to restart a hot unit takes one to one and a half hours (Ref: [5]). This makes the performances of this type of plant close to those of a steam turbine plant.

These figures can be completed by data-sheets that can be found on investor or on service providers' documents. For example Ref [6] indicates for a GT combined-cycle a maximum ramp rate of 7%/min, a start-up time from cold state of 3 hours and a minimum load for cycling of 40%. The indicated nominal power is 530 MW which gives a maximum ramp rate of 37 MW/min. Automatic Generation Control systems are developed to increase the capability of GT or GT- combined cycle to provide load and frequency regulation to the dispatcher. This allows the utility to realize significant potential revenue by providing electricity for peak loads.

However although these generating units are designed having in view their participation to load cycling this does not mean that the flexibility is at no maintenance costs. The "Combined Cycle Users' Group" summarised the issue as follows in its annual meeting 2005 (ref: [7]): "Reduced spark spreads have led to lower capacity factors, more frequent starts and stops, and fewer operating hours per start. All of these consequences of higher natural gas prices have also increased unit ownership costs, even for units that were designed for cycling. The desirable top-level functional characteristics include fast warm-up, a wide load range and a fast ramp rate, automated start-up and shutdown and load changing, and high on-peak availability and starting reliability.

Mitigating deterioration due to enhanced wear and tear experienced by many owners and operators of CC plant turbines requires at least the following steps (ref [7])

- Maintaining water chemistry "in bounds."
- Protecting out-of-service equipment from the elements.
- Monitoring corrosion rates, frequently inspecting areas prone to corrosion, and repairing or replacing corroded components.
- Adding staff to handle the inevitable increase in maintenance needs.

- Retrofitting the additional equipment required for cycling service.

It might happen that although the technical approaches to increasing the robustness of existing plants are reasonably well understood the decision to increase in capital or manpower expenditures is not taken by lack of money. This may result in a unit crash (ref as above).

Heat rate degradation at low load operating levels (see ex. Figure 1), was long thought to be the only significant cost associated with cycling operations. However that cost also includes information on outage trends and plant capital and maintenance expenditures going back thirty years.

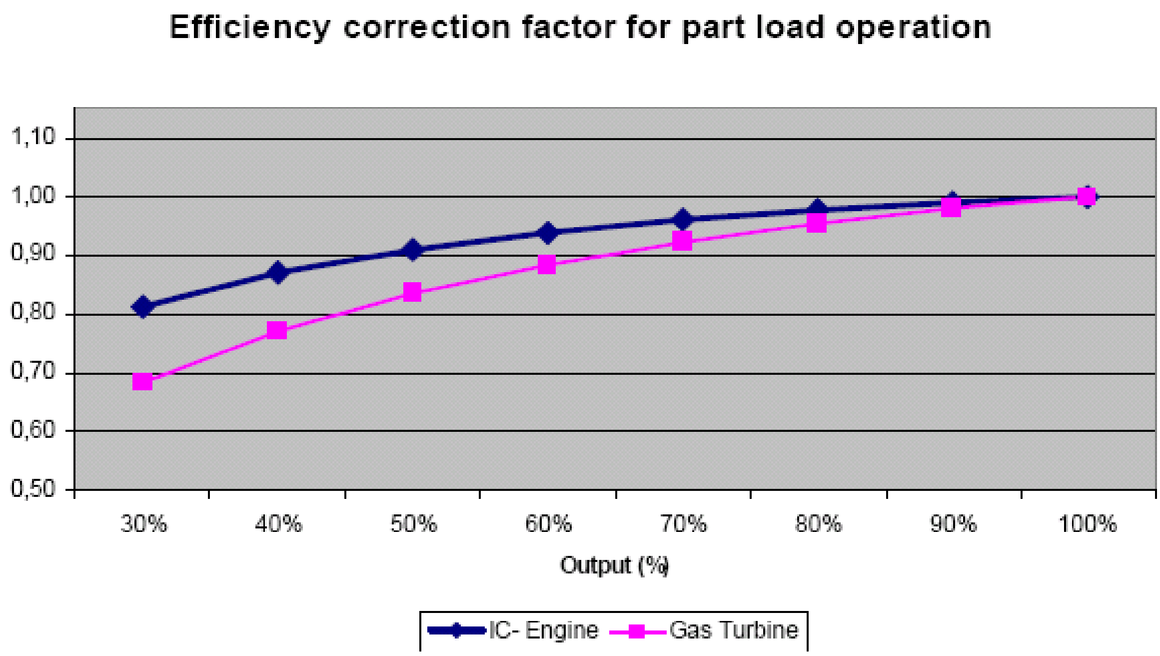

Figure 1: Evolution of the efficiency with the loading factor (from Ref [4])

Engineering studies allow identification of components affected by enhanced wear and tear in relation to deviation from base load operation. This approach does not provide cost estimation by itself but identify the key elements for the cost analysis.

However cycling impacts on costs and performance are difficult to quantify because they are not unique to cycling. According to the Electric Power Research Institute (EPRI), ref [2], cycling effects generally become manifest at the time in a unit's life when equipment aging would also be causing similar effects e.g., poorer reliability and/or increasing costs due to accumulated damage from erosion, corrosion, creep and fatigue. To quantify the portion of these effects attributable to load cycling versus the portion attributable to other drivers, such as aging, is difficult, especially when limited to the experience and data of a few generating units. This statement is to be found in a study dedicated to "Determining the Cost of Cycling and Varied Load Operations" carried out on fossil plants. In line with the statement of the Combined Cycle Users' Group the study recognises that one of the most significant factors influencing the relationship between maintenance expenditures, reliability, and aging is the individual plant's specific history of maintenance practices—dictated not only by the maintenance philosophy of the utility owner/plant manager, but also by the owner's financial ability to provide a budget sufficient to support that philosophy which, in turn, may or may not be within its control.

The strongest correlation for predicting future O&M costs was found with the number of starts and large cycles a plant experienced during the year and the previous years' capacity factor and O&M costs (ref [5]).

In ref [8] EPRI developed a model predicting O&M cost for coal, oil and gas plants. The model adjustment and validation was carried out on power plant having a single unit. The reason for this is that the O&M costs were drawn from the power plant reports (that merges cost related to all units at the plant) and the data related to cycling operation were taken from the public available CEMS database (Continuous Emission Monitoring System) run by the U.S. Environmental Protection Agency where each unit is recorded individually. In this database operated since 1995, every three months, data on hourly operation are made available to the public. From this a plot of unit load versus time was generated for as many plants as possible for each quarter of the year. The study is conclusive for coal plants but the model is not assessed for either oil or gas plants. The aim of the study was to predict O&M costs from load history of the plant. It was determined that steam (boiler and related components) and electric (turbine and related components) should be modelled independently. As can be expected the study does not publish costs incurred by load following but demonstrates the capacity of the model.

For both steam and electric costs the cost in previous years was the dominant variable for predicting the current year's cost. The next strong variable effect was associated with the number of cold starts per year. Other cycling variable effects were the number of warm and hot starts and the number of cycles with a range greater than 60% of capacity. Each of these terms influenced positively the costs as they increased (i.e. the O&M costs increased too).

Further a conclusion of the study is that year-to-year change in cycling variables has less influence than the effect of cost reduction policies, longer-term damage trends, and recent condition of the plant. This is consistent with the concept that the effect of cycling accumulates on the components and may persist for years in the maintenance and repair costs.

Finally the difficulty of the exercise is demonstrated by the fact that although the model could be fitted on more than 500 points the standard error on steam components O&M is +30%, -23%, and the standard error for electrical components O&M costs is +66%, -40%.

Wind energy displays characteristics totally different from those of the fossil plants. Capacity factors are usually in the 30-40 range but are improving over time. Ramps as large as 800 MW of wind energy increases in 30 min (ref [1]) (i.e. for comparison purposes 27 Mw/min) have been observed. This has to be taken into account for optimizing the repartition of wind generated power in a network.

2.2 Nuclear power plants

From an economical point of view installations with a high capital cost should be operated at the highest safely achievable power in order to produce the maximum energy output and improve the return on investment. Consequently installations having high fuel costs should be selected only when energy generating plants of high capital costs are not installed or not available. This is the main reason why nuclear power plants are to be operated preferably in base load mode. However when the situation arises where nuclear power plants cover a big share of the electricity needs, or when this source of electricity is partially used as backup of intermittent energy sources the load following operating mode can be either an option or a necessity.

According to the EU experience the share of nuclear generated electricity has to be high before cycling is adopted for nuclear power plants. This is the option in France with a share close to 75% in the electricity production capacity. Other country with a high share in nuclear generated electricity Slovakia (56.3 %) and Belgium (53.7 %) partly operate in load following mode.

Since load following is less an option for the presently operated nuclear power plants than for the fossil plants its influence on O&M costs has been less considered at least in the open literature. However the same phenomena are at stake in a nuclear power plant as in a fossil power plant when cycling or load following is included in the operating modes. The major difference comes from the strong regulation frame.

In each country operating nuclear power plant a regulatory authority defines the responsibility of the stakeholders. In particular the operator is required to prevent incidents by maintaining the design basis safety level of each plant by (ref [9]):

- Respecting the operational limits and conditions in all operating activities
- Maintaining and checking the availability and reliability of safety related equipment by periodic testing, preventive and corrective servicing (maintenance), re-qualification after repair.

Due to this regulatory frame maintenance on safety related equipment cannot be postponed and its costs are inevitably included by the operator in its economic calculations.

Moreover the nuclear plant authorisation decrees require the approval by the corresponding ministry of the set of general operating rules that contain Technical Operation Specifications and can only be modified after approval of the regulatory body. The first part of this document presents the safety limits (design basis limit for parameters such as: thermal power, neutron flux, flow rates, pressures, temperatures and levels, which cannot be overstepped under normal operating condition).

Taking into account the acceptable limits on the fuel and cladding behaviour results in operation specifications in term of power ramp rate that will provide the acceptable conditions for load following at a given nuclear power plant.

3 Acceptable power fluctuations in NPPs in response to load following

Frequency or primary regulation was discussed in paragraph 1. The acceptable frequency fluctuation band corresponds for a LWR to a power fluctuation band of ± 2% rated power. A scheme of power changes induced by a primary regulation is given on Figure 2. As a result of the primary regulation the new frequency will be inside the authorised margin (± some tens mHz) but can be different from the scheduled one (50 Hz in Europe).

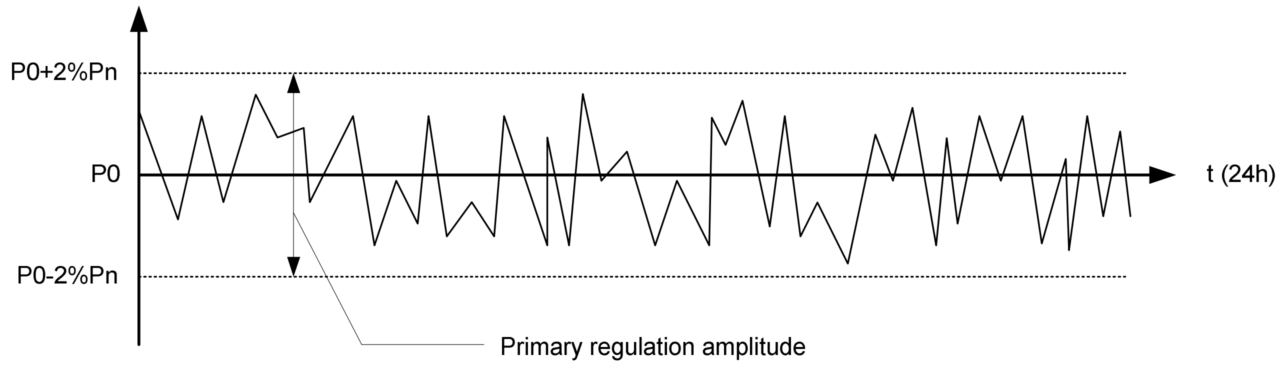

Figure 2: Operating margin of the frequency regulation

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As explained above the secondary regulation asks for a modulation of the reserve put available by the operator and allows longer response time than the primary regulation. A typical secondary regulation programme applied on nuclear reactors in France is given on Figure 3 that shows that the reserve power is ± 5% Pn.

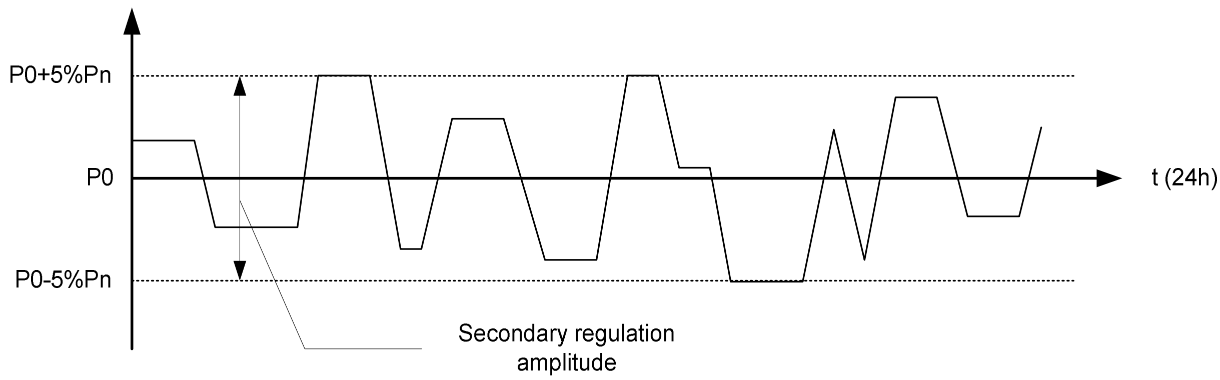


Figure 3: Operating margin of the secondary regulation

3.1 Power margins

Since NPP correspond high investment but low fuel cost they are for economical reasons preferably operated as base load. However with an increasing nuclear electricity share the French utility has implemented a program for optimising the use of the fuel, the time repartition of the maintenance outages and the seasonal production needs. Load following (lower power output than the available one) is part of this optimisation.

This corresponds to allowed power fluctuations in the range of ± 20 MW due to the frequency regulation and ± 50 MW if secondary control is considered, based on a nominal power of 1000 MWe.

With a fleet of 900, 1300 and 1500 MW reactor the reserve for regulations are as reported in Table 2:

Regulation	Amplitude	900 MW	1300 MW	1500 MW
Primary	2% Pn	18 MW	26 MW	30 MW
Secondary	5% Pn	45 MW	65 MW	75 MW

Table 2: NPPs regulation margins

In fact in France 1500 MW reactors are not operated in secondary regulation and as a matter of fact the maximal secondary reserve is by 65 MW.

In the late 90's European utilities have joined together to define common requirements applicable to new LWR reactors. Volume 2 Chapter 3 of the European utility Requirements for LWR nuclear power plants (ref [10]) is devoted to grid requirements and addresses regulation and load following capabilities. According to these requirements:

- The unit shall be capable of continuous operation between 50% and 100% of its rated power (mandatory). The plant designer may provide a standard design that can be operated at a lower ratio, down to 20% (optional)
- Primary control is mandatory and shall be in the range ± 2% of the rated power. Higher values may be agreed between system operators and plant operators though not higher than 5% Pn
- The unit shall be capable of activating within 30 s the total primary range of control requested
- Secondary control is optional. When applied it shall have a range ± 10% of the rated power.
- Load following capability are optional. One load variation is defined as a drop output followed by a plateau and an increase. The plant shall be able to follow planned and unplanned load variations during 90% of the whole fuel cycle. This restriction is due to fuel conditions at the end of the cycle.
- When employed in load-following the unit shall be capable of load-following operation in the range of output 100% Pn down to the minimum load of the unit.
- Under load-following operation the unit shall be expected to go through the following number of load scheduled variations, each variation being defined as a transient from full power to minimum load and back to full power: 2 per day, 5 per week, cumulatively 200 per year.
- If the unit is requested to participate to emergency load variations (agreement between grid operator and operator of the unit) it shall at least be capable to fulfil the following requirements: amplitude down to minimum load of the unit, rate of change 20% of Pn/min. Design is based on the expectation that such a transient is not required more than once per 5 years.

3.2 Power transient speeds

In an industrial steam generating plant the allowed states are carefully limited in the Pressure-Temperature plan to take into account the interaction between systems and components and for limiting fatigue accumulation (see for example ref [9]). In addition in a nuclear power plant a series of limiting criteria are introduced for preventing the integrity of the first barrier (cladding). Under transients of category 1 (normal operating conditions) the effluent release permit limits for the site over the year is of some10 micro Sv. Hence avoiding any clad/pellet interaction that could result in clad rupture is essential.

Criteria have been developed that prevent clad/pellet interaction and ensure that in case of power increase the stress imposed on the clad by the differential dilatation strain does not result in clad rupture. Four transients may result in clad rupture due to clad/pellet interaction: excessive load increase, uncontrolled control rod withdrawal, uncontrolled boric acid dilution, and uncontrolled control rod drop. Among them only the first one has an effect on load following regulation. The safety study of these events shows that the limiting case is related to local power increase. Criteria developed as a result of the related safety studies are:

- Power increase rate should never exceed 5% per minute (50 MW/mn)
- Starting from a cold state (after fuel loading) the power increase rate is not allowed to exceed 3% Pn per hour between 50% and 100% Pn (0.5 MW/mn)

Some refinements to these rules are added taking in consideration the power level during the last seven days. Furthermore during the plant cycle (some 12-18 months according to the fuel management) operating time under intermediate power is limited for thermo-mechanical consideration at the pellet/cladding gap. As a result of this limitation the duration of long operation (> 8 hours per period of 24 hours) at intermediate power (< 90% Pn) is summed up and should not exceed an annual credit of some tens of hours.

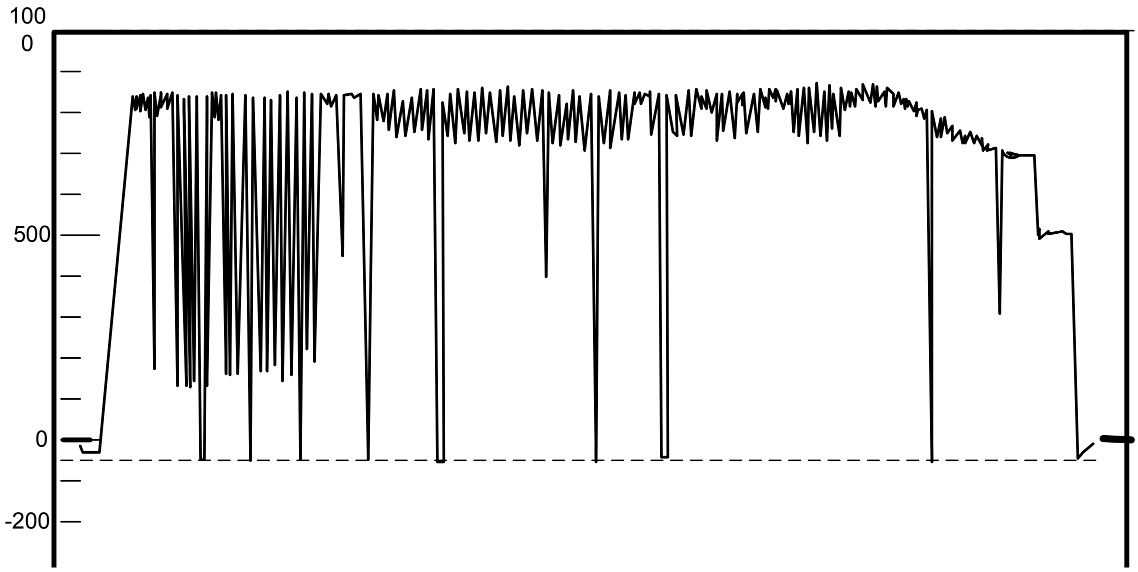


Figure 4: Typical scheme for one yearly cycle for a reactor operating in load-following mode (variation from maximum (minus reserve) to minimum (third part of the cycle, and than in primary and secondary

regulation. When the fuel reactivity reserve is used (last part of the scheme) the reactor is no longer available for regulation.

Two reduced load for more than two hours are acceptable within one day. The amplitude of the load reduction is depending on the progressing in the reactor's cycle. The case illustrated by Figure 4 shows the following scheme: During the first third of the unit cycle load-following is widely used from rated power down to minimum limit. In the following period primary and secondary regulations (RP-RS on the figure) are possible with few exception of operating at intermediate power. In the last period the unit is not available for automatic regulation.

In the EUR document (ref [10]) the transient speeds are given as follow:

- Variation rate shall be ± 1% of Pn/min. Higher values may be agreed between system operators and plant operators though not higher than 5% of Pn/min
- Under load following the rate of change of electric output shall be 3% of Pn/min, higher values may be agreed between system operators and plant operators

3.3 Steering modes

Adaptation to the demand of the grid is obtained through control rod and boron concentration adjustment. Control rod movement allow a rapid adjustment of the power but can create uneven fuel consumption and Xenon oscillations. A complementary adjustment mean is through the boron concentration which, being equally distributed in the core, minimizes unbalanced flux maps. As a result the related systems and components could need increase maintenance.

For enhancing the manoeuvrability of the units characteristics of the control rod have been adapted since the former design. Basically 2 steering modes are used the A mode (very absorbent control rods or black rods) and the G mode (less absorbent control rods or grey rods). Of course their localisation in the core has been adapted accordingly. Compared to the operation in the A mode operating under G mode provides less effluents, smaller flux deformation, can offer the variation ± 5% Pn (instead of ± 3% for the A mode), and transient rate up to ± 5% Pn/min (instead of 2% Pn/min). Another mode the X mode is more sophisticated is applied on the N4 series (1500 MW Pn). However this flexibility may make difficult the calculation of the fuel burn-up and the French plants equipped with X mode control rod adjustment only participate to the primary regulation.

4 Maintenance issues

That maintenance efforts have to be adapted when an electricity generating unit is operated in load following mode compared to a base load mode is obvious. What is not so clear is in which extend and with which economical consequences.

For nuclear power plants safety regulations are recalled that dictate the allowable transient speeds. As can be seen under heading 2.2 limitations are dictated by fuel pellet / cladding interaction and by axial offset considerations. Thermal transient effects on heavy components do not result in stronger limitations. Since the power regulation is based on control rod displacements and on boron concentration adjustment two maintenance issues can be expected:

- A enhanced solicitation of control rod mechanisms
- A enhanced solicitation of the Chemical and Volume Control System

Evidence of these effects can be expected only from reactors having a significant share in load following.

4.1 Maintenance issues identified by some European nuclear power plants

In Europe only countries having a high share of nuclear energy in their electricity production are candidates for considering load following. This applies to France presently and applied to Bulgaria before the shut down of the 4 VVER 440. In Slovakia nuclear generated electricity accounts for 60 % of the installed generation and primary as well as secondary regulation is there a common practice. According to ref [11] it is supposed that this operating mode should have some influence on operating and maintenance (O&M) costs but up to now no significant effect have been observed or could be quantified since no systematic study has been made in this topic. This statement is in line with the EPRI observation (see 1.1) according to which it is difficult to distinguish effects attributable to load cycling versus the portion attributable to other drivers.

Hungarian nuclear power plant Paks is not contributing to regulation but may responds to demands for power reduction. There are few demands from the Transmission System Operator Company that amounted to 0.02 % of the energy produced in 2007 and 2008 and to 0.09% in 2009. Paks is put at the first priority in the electricity production list. However provision are made for operating in power reduction mode with no limitation in the range -5% Pn, one oscillation per day in the range [-5, -10%] and two authorisations per month for a reduction larger than 10% Pn. Incidence of such minor solicitations on O&M costs are of course non detectable Ref [12].

In Europe France is the country where nuclear power plants have a significant participation to regulation. Recently EDF conducted a study aiming at quantifying the loss of production due to outages related to load-following operation mode. Details of the study are confidential but main lines were given at a meeting of the French Nuclear Energy Society (SFEN) [13]:
Ten nuclear power plants operating with load following were compared after several years to ten others operating in base mode (which means frequency adjustment is also allowed). The added outage needed for the load following sample corresponded to a loss of 1.8% of the availability coefficient Kd which is the ratio between the net production that the power plant was able to produce during a period and the net production at full power that could have been produced in the same time. To avoid confusion let's precise that another coefficient, the production coefficient Kp is the ratio of the gross electricity production during a period to the full power gross electricity production during the same period. Kp can be lower than Kd since the effective production can be lower than the possible production. Kd reflects the production availability of a power plant and is not affected by the load-following, where Kp which reflects the actual production is affected by this operation mode.

From this results that the correct value to be compared between the two sets of power plants is Kd. The fact that the load-following set displays a Kd 1.8% lower corresponds to the availability loss due to supplementary outage work needed. According to [13]: the extra maintenance work is related to the Chemical and Volume Control System (boron adjustment) that is more demanded than in the absence of load following.

4.2 Maintenance issues identified from the IAEA database

As can be expected in the frame of a competitive market figures about cost are not public. The only public available indicator about outage can be found in the annual report of the IAEA [14].
This report provides for each year and for the cumulative operating period of a nuclear unit in the world:

- the amount of outage hours and its repartition by causes:
  - (**A**) Plant equipment failure
  - (**B**) Refuelling without a maintenance
  - (**C**) Inspection, maintenance or repair combined with refuelling
  - (**D**) Inspection, maintenance or repair without refuelling
  - (**E**) Testing of plant systems or components
  - (**F**) Major back-fitting, refurbishment or upgrading activities with refuelling
  - (**G**) Major back-fitting, refurbishment or upgrading activities without refuelling
  - (**H**) Nuclear regulatory requirements
  - (**J**) Grid failure or grid unavailability
  - (**K**) Load-following (frequency control, reserve shutdown due to reduced energy demand)
  - (**L**) Human factor related
  - (**M**) Governmental requirements or Court decisions
  - (**N**) Environmental conditions (flood, storm, lightning, lack of cooling water due to dry weather, cooling water temperature limits etc.)
  - (**P**) Fire
  - (**R**) External restrictions on supply and services (lack of funds due to delayed payments from customers, disputes in fuel industries, fuel-rationing, labour strike outside the plant, spare part delivery problems etc.)
  - (**S**) Fuel management limitation (including high flux tilt, stretch out or coastdown operation)
  - (**T**) Offsite heat distribution system unavailability
  - (**U**) Security and access control and other preventive shutdown due to external threats
  - (**Z**) Others
- the amount of outage hours and its repartition by system
  - Nuclear Systems
    - 11.00 **<u>Reactor and Accessories</u>**
    - 11.01 Reactor vessel and main shielding (including penetrations and nozzles)
    - 11.02 Reactor core (including fuel assemblies)

- 11.03 Reactor internals (including steam separators/dryers - BWR, graphite, pressure tubes)
- 11.04 Auxiliary shielding and heat insulation
- 11.05 Moderator and auxiliaries (PHWR)
- 11.06 Annulus gas system (PHWR/RBMK)
- 11.99 None of the above systems
- 12.00 **Reactor I&C Systems**
- 12.01 Control and safety rods (including drives and special power supply)
- 12.02 Neutron monitoring (in-core and ex-core)
- 12.03 Reactor instrumentation (except neutron)
- 12.04 Reactor control system
- 12.05 Reactor protection system
- 12.06 Process computer
- 12.07 Reactor recirculation control (BWR)
- 12.99 None of the above systems
- 13.00 **Reactor Auxiliary Systems**
- 13.01 Primary coolant treatment and clean-up system
- 13.02 Chemical and volume control system
- 13.03 Residual heat removal system (including heat exchangers)
- 13.04 Component cooling system
- 13.05 Gaseous, liquid and solid radwaste treatment systems
- 13.06 Nuclear building ventilation and containment inerting system
- 13.07 Nuclear equipment venting and drainage system (including room floor drainage)
- 13.08 Borated or refuelling water storage system
- 13.09 CO2 injection and storage system (GCR)
- 13.10 Sodium heating system (FBR)
- 13.11 Primary pump oil system (including RCP or make-up pump oil)
- 13.12 D2O leakage collection and dryer system (PHWR)
- 13.13 Essential auxiliary systems (GCR)
- 13.99 None of the above systems hjhkjh
- 14.00 **Safety Systems**
- 14.01 Emergency core cooling systems (including accumulators and core spray system)
- 14.02 High pressure safety injection and emergency poisoning system
- 14.03 Auxiliary and emergency feedwater system
- 14.04 Containment spray system (active)
- 14.05 Containment pressure suppression system (passive)
- 14.06 Containment isolation system (isolation valves, doors, locks and penetrations)
- 14.07 Containment structures
- 14.08 Fire protection system
- 14.99 None of the above systems
- 15.00 **Reactor Cooling Systems**
- 15.01 Reactor coolant pumps/blowers and drives
- 15.02 Reactor coolant piping (including associated valves)

- 15.03 Reactor coolant safety and relief valves (including relief tank)
- 15.04 Reactor coolant pressure control system
- 15.05 Main steam piping and isolation valves (BWR)
- 15.99 None of the above systems
- 16.00 **Steam generation systems**
- 16.01 Steam generator (PWR), boiler (PHWR, AGR), steam drum vessel (RBMK, BWR)
- 16.02 Steam generator blowdown system
- 16.03 Steam drum level control system (RBMK, BWR)
- 16.99 None of the above systems
- 17.00 **Safety I&C Systems (excluding reactor I&C)**
- 17.01 Engineered safeguard feature actuation system
- 17.02 Fire detection system
- 17.03 Containment isolation function
- 17.04 Main steam/feedwater isolation function
- 17.05 Main steam pressure emergency control system (turbine bypass and steam dump valve control)
- 17.06 Failed fuel detection system (DN monitoring system for PHWR)
- 17.07 RCS integrity monitoring system (RBMK)
- 17.99 None of the above systems

- Fuel and Refuelling Systems
- Secondary plant systems
- Electrical Systems

Since the supplementary outages that could result from load-following are expected to concern control rod mechanism and chemical and control volume system only these systems have been considered in what follows. The report provides for each reactor a data sheet made of 6 items as reproduced in Annex 1. From the figures dispatched an analysis was made about a possible relationship between the number of outage hours (loss of production converted in hours) due to load-following (cause **K** in the list above) and the duration (hours) of unavailability for each system. Although the system components are detailed in sub-item (ex. System 13.00 "Reactor Auxiliary Systems" is split in 14 different sub-systems) the table of the reactor sheets provides aggregated data. As a result it is not possible from these aggregated data to get the sole effect of load-following on Chemical and Volume Control System (item 13.02). But also the causes of outages are aggregated: the item "Load-following", item (**K**), does not distinguish frequency control from the reserve shutdown due to reduced energy demand. It has been postulated in our analysis that units that display outages on the cause **K**, "Load-following", and that most often do not contribute to grid adjustment are only operating in frequency regulation.

The above explained limitations would have to be considered when reading the results of the IAEA database analysis.

4.2.1 Presentation of the Data

From the IAEA report the following data have been extracted for all the reactors in EU-27 and are reported in the table of Annex 2.

- NPP in the IAEA classification: Country and NPP identification number
- Yearly average of hours of production lost through load-following (planned, unplanned and due to external events)
- Total amount of production hours lost through load-following (yearly average)
- Period of the average estimation (= operating period of the reactor)
- Yearly average of hours of production lost through outages due to maintenance on safety system (item 14 in the list of heading 3.2)
- Yearly average of hours of production lost through outages due to maintenance on I&C system (item 12 in the list of heading 3.2)
- Yearly average of hours of production lost through outages due to maintenance on auxiliary systems (item 13 in the list of heading 3.2)

From the eight components listed in the group "I&C systems" only item 12.01, "Control and safety rods (including drives and special power supply)", might be impacted by a load following operating mode, but in the IAEA report there is no access to the importance of this equipment in the maintenance compared to the other seven items. From the ten systems and components relevant for LWRs listed in the group "Reactor auxiliary systems" only the "Chemical and volume control system" maintenance outage is expected to bear some influence of a load following operating mode but again there is no access to this individual data.

By displaying the annual average production lost (in hours) for all 129 LWR units in the EU plus Switzerland (Figure 5) it can be seen that reactors not being used in load following mode show an annual average production lost less than 25 hours. In the IAEA report this is however counted in the category "(K) Load-following (frequency control, reserve shutdown due to reduced energy demand)" and it is postulated here to be due to frequency control. 73 reactors (56.6%) fall in this sub-category that will be designed in this report by base load like operation. Among the 56 remaining units 46 are operated in France which utility clearly adopts a load following operating mode. Among those 56 reactors 7 display loss of production hours (yearly average over their operating period) higher than 100 hours, 6 of them are operated in France.

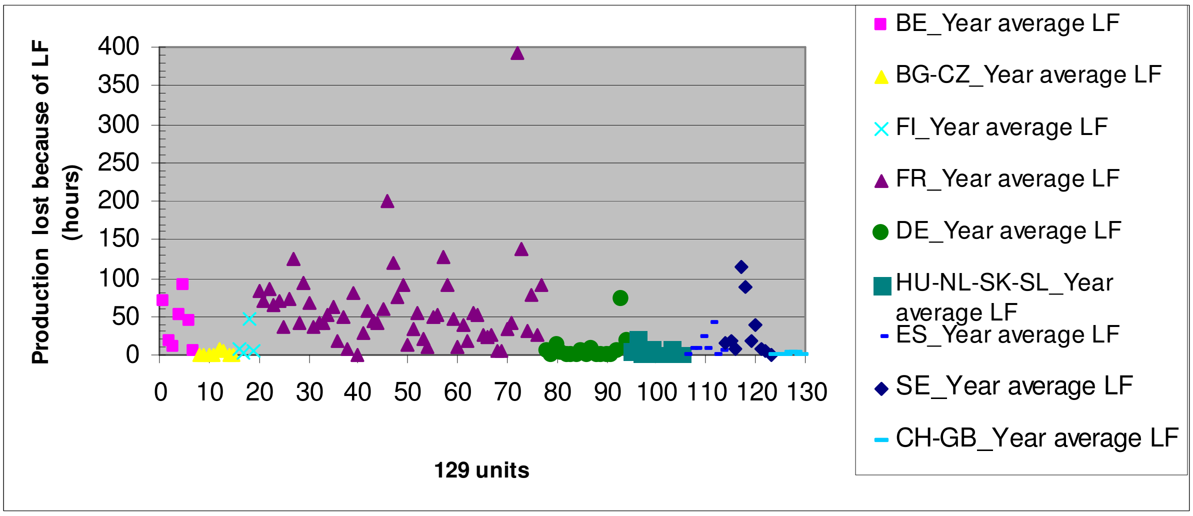


Figure 5: Display of the 129 nuclear power plants in Europe and the number of hours declared as loss of production due to load following (cause (K) from the IAEA list). Full scale on the Y-axis (200 and 400 hours declared under the heading (K) at 2 plants)

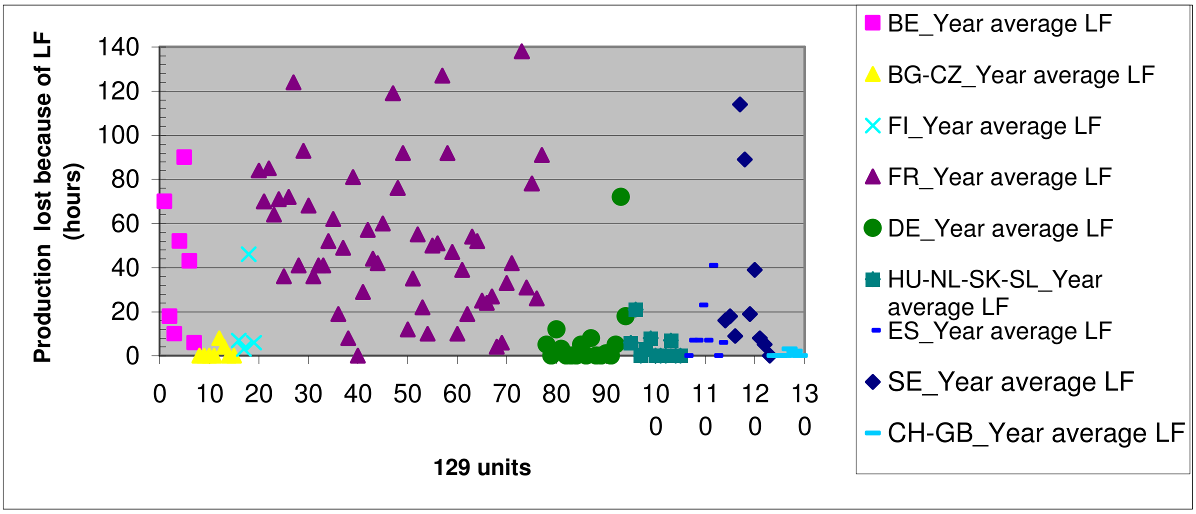
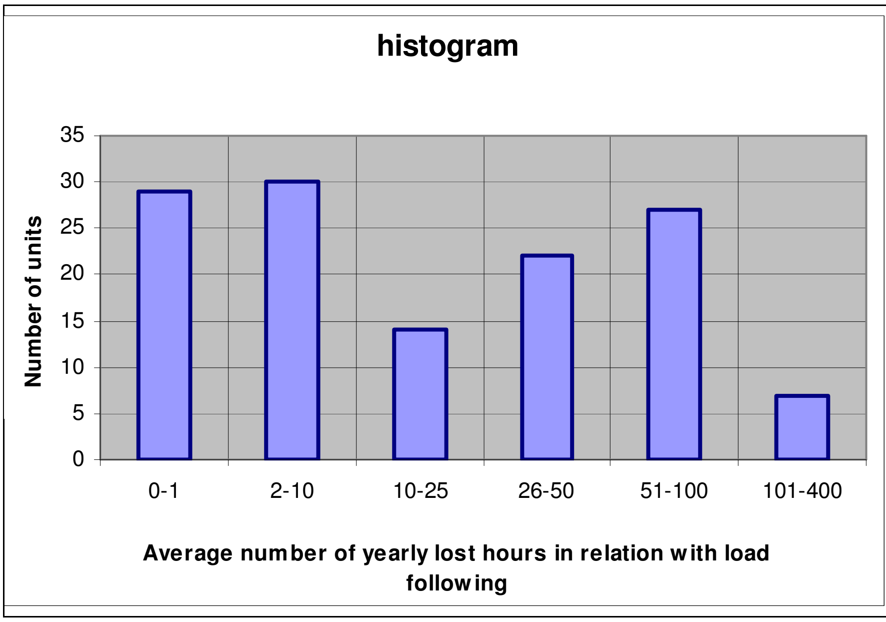


Figure 6: Same data as above but zoomed in on the Y-axis in the range [0-140]

The histogram of the number of units dispatched in 6 bins is given in Figure 7 and related Table.



bins of yearly average hours lost for LF	number of units
0-1	29
2-10	30
10-25	14
26-50	22
51-100	27
101-400	7

Figure 7: Distribution of units based on the hours lost declared under heading (K) from the IAEA list

Figure 6 suggests that most of units that do not currently operate in regulation or load-following mode declared lost hours under the heading **(K)** of the IAEA list less than 20 s yearly average. From this observation it is anticipated that if load following has an effect on maintenance outage this should be recognised in the cases where the loss of generation hours is more than 20 in year average.

The statistical analysis of the data shows that there is indeed a difference in the mean year average time spent for outages on the three selected systems for the analysis: Auxiliary system (system 13) that includes the Chemical and Volume Control System, I&C system (system 12)) that includes Control and safety rods, and safety system (system 14). For that system however it is not clear which of the item of the IAEA list should be more involved in case of frequent load following.

Figure 8 shows that the 59 units having up to 10 hours of production loss due to load-following or regulation operation display basic outage needs with a yearly average of 5 to 10 hours. This is however a mean value on the 59 units with a high standard deviation between 7 and 15 hours. The 61 units having more than 20 hours of production loss due to load-following or regulation operation experienced outage needs corresponding to a yearly average of 15 to 30 hours. Again this a mean value calculated on the 61 units and the standard deviation is also high: between 13 and 25 hours. The 9 units in the middle (loss of 11 to 20 hours due to load-following or regulation) display mean values of maintenance needs in between of the 2 populations above mentioned with the same range for the standard deviation.

In Figure 9 the intermediate population (units having lost between 11 and 25 hours in load-following or regulation operation) is split differently than in Figure 8. Outages hours for system 14 and 13 are evolving from a base line (corresponding to the bins [0-1] and [2-10]) towards an increasing amount for the three other bins quite the same way in the two figures. As far as system 12 is concerned the result reflects the fact that 2 units have close to 100 hours (yearly average) of outage on I&C systems as defined in the IAEA report.

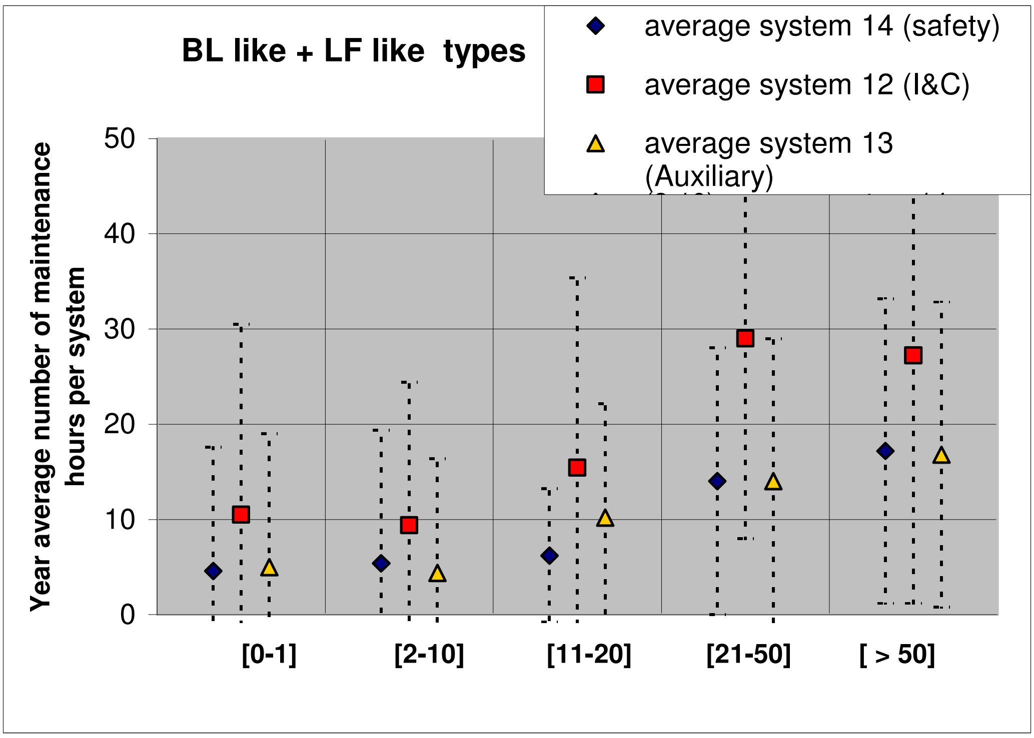


Figure 8: Difference in amount of outage hours (year average) for 3 systems and for 5 bins of load-following like operation

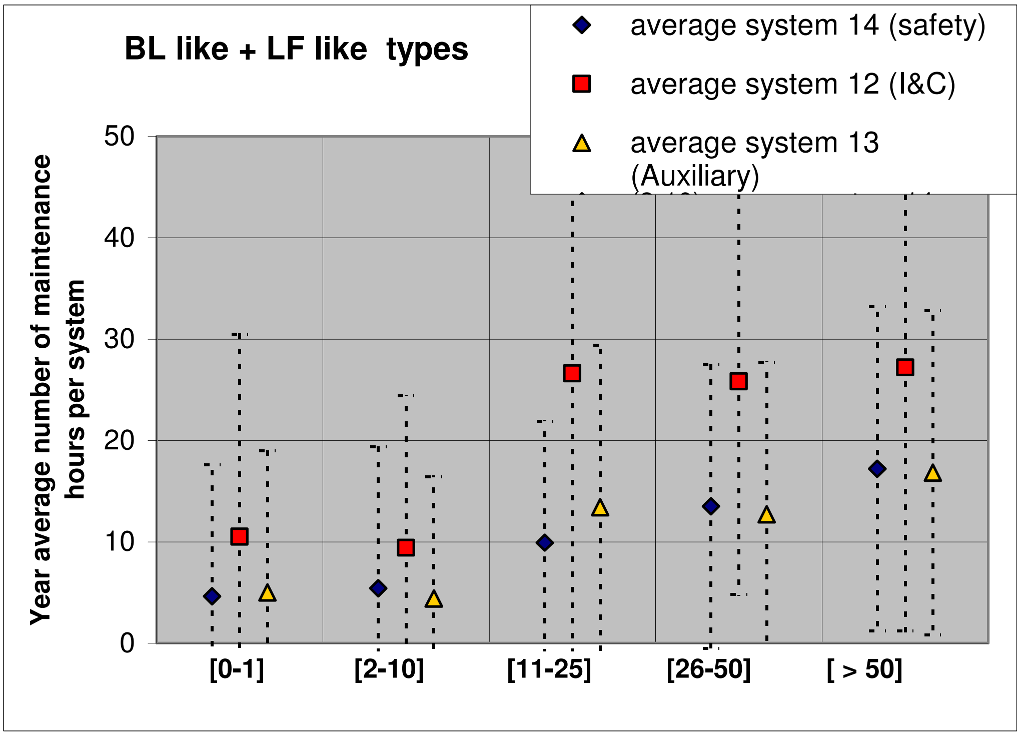


Figure 9: Difference in amount of outage hours (year average) for 3 systems and for 5 bins of load-following like operation. Middle bins differ from those in Figure 8

4.2.2 Data analysis with the Benzecri's Correspondence Analysis

Method:
The Benzécri Correspondence Analysis has been applied in order to detect a possible non-linear dependency between the two analyzed variables: number of hours of load following and number of hours of maintenance of each unit.

Mathematical details of the Benzécri Correspondence Analysis (BCA) can be found in [19]. The theoretical objective of BCA is to test the hypothesis of independence between the two analyzed variables, and to represent the analyzed data in a low dimensional space called factorial space.

For each type of maintenance (systems, I&C, auxiliary), a so-called contingency table has been generated as illustrated by table 3. These contingency tables are bi-dimensional histograms that show the repartition of units according two criteria: (i) number of hours lost due to load following and (ii) number of hours lost for maintenance of each type. For each of these two variables, 5 bins have been considered to construct the contingency table. These bins respectively represent (i) very low load following (resp. maintenance), (ii) low load following (resp. maintenance), (iii) medium load following (resp. maintenance), (iv) high load following (resp. maintenance), and (v) very high load following (resp. maintenance).

There are two possible representations of the contingency table as points in a multidimensional space: (1) row profiles can be represented by points in a first space whose dimension is equal to the number of columns, (2) column profiles can be represented by points in a second dual space whose dimension is equal to the number of rows. The analysis of the set of points in one of these two spaces can be derived from the analysis of the set of points in the other space, and vice-versa. Each analysis is performed using the distributional chi-2 distance to construct an inertia matrix. Eigenvectors of this inertia matrix are extracted and sorted by decreasing order of their eigenvalues. The projection of points on various eigenvectors provides the so-called factors. Hence, we get so-called factors on rows and factors on columns that can be computed simultaneously and are linked by the so-called transition formula. Finally, each factor explains a share of the total variance.

From a practical point of view, the objective of BCA is to provide a graphical representation of the analyzed contingency table, in order to put in evidence a possible data structure that would contradict the hypothesis of independence between rows and columns of the contingency table.

The BCA can be used to test the existence of a non-linear dependency between analyzed variables. In fact, in such a case, the principal diagonal of the contingency table and its adjacent diagonals would be dominant and a parabola would appear in the factorial plane F1-F2 or G1-G2, where F1 and F2 (resp. G1 and G2) are the two first factors on rows (resp. on columns). In our case, the existence of a monotonous dependency can also be tested since bins are sorted according to the level of each analyzed variable.

But the non existence of a parabola does not mean that there is no structure at all in the analyzed contingency table. In fact, a structure can be identified when an interpretation can be given to the first factors of the BCA and when these factors explain more than about 80% of the total variance, as a practical rule.

Results

The following bins were selected:

- 5 bins: [0-1], [2-10], [11-20], [21-50] and [> 50] for the amount (in hours) of production lost due to load following. This repartition was suggested by the previous analysis;
- 5 bins: [0-1], [2-7], [8-15], [16-30] and [> 30] for the amount (in hours) equipment related full outages on system 14 and 13;
- 5 bins: [0-5], [6-10], [11-20], [21-45] and [> 45] for the amount (in hours) of equipment related full outages on system 12.

The distribution of the 129 units in the 3 contingency tables is displayed on Table 3:

		A	Outage System 14					Outage System 12					Outage System 13				
			0-1	2-7	8-15	16-30	>30	0-5	6-10	11-20	21-45	>45	0-1	2-7	8-15	16-30	>30
B		129	51	29	16	15	18	44	25	25	19	16	51	19	31	12	16
lost hours due to LF	0-1	29	22	4	1	0	2	18	5	2	3	1	20	5	2	0	2
	2-10	30	17	7	4	0	2	15	6	6	2	1	18	5	2	2	3
	11-20	9	4	1	2	2	0	3	2	2	1	1	2	3	2	1	1
	21-50	27	6	6	2	8	5	4	3	8	6	6	6	5	10	1	5
	>50	34	2	11	7	5	9	4	9	7	7	7	5	1	15	8	5

Table 3: Contingency tables for the distribution of 129 units

The contingency tables of table 3 show the repartition of the units according to their hours lost for maintenance on systems and to their production hours lost due to load following (LF).

Column **A** is the same for all three tables since the same 5 bins applied to the LF hours repartition is used.

Row **B** gives the maintenance hours' distribution for each system.

If a strict monotone dependency were to be observed mostly the diagonal of the table would be populated (low LF, low maintenance outages; high LF, high maintenance outages), together with the 2 next diagonals. This is not the case so we cannot conclude to a monotone dependency. However what is observed is that:

- Low LF goes along with low outages for the three systems considered (22, 18 and 20 units out of 29 are in this case for respectively system 14, 12 and 13, this is roughly 2/3 of the population)
- Significant LF goes along with almost evenly distributed outages inside the 5 bins.

The factorial analysis identifies in the distribution the axe of the longest elongation. This is the so called first factor and its perpendicular is the 2nd factor, the perpendicular to that plane is the 3rd etc… An important result of such an analysis is the ratio of the total variance explained by each of the factors. If the ratio is evenly distributed among the factors the analysed set is randomly distributed. In the case analysed here the first factor explains 77 up to 88% of the variance while the second one explains 8 up to 16%. This means that the set of data is not randomly distributed and a structure in the data, a dependency exists.

The projection of the data on the first factor is shown on Figures 10 to 12

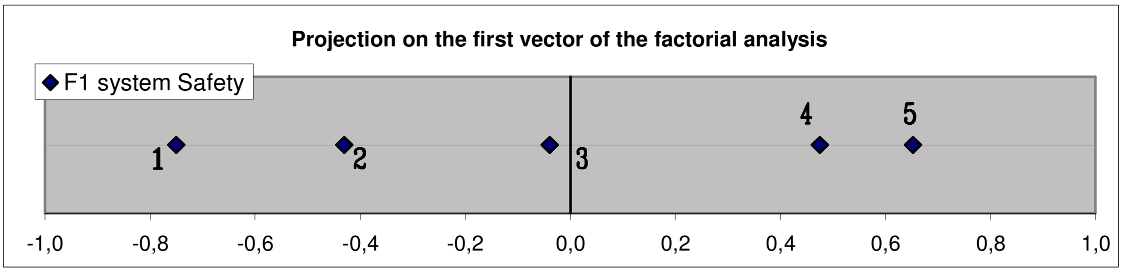


Figure 10: Projection of the data on the first factor of the factorial analysis for each of the systems

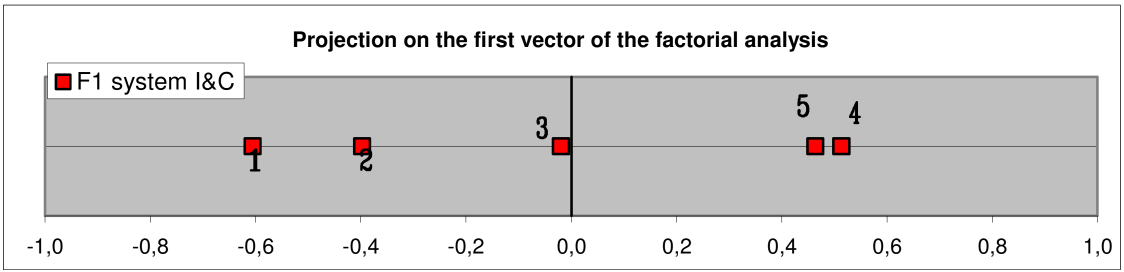


Figure 11: Projection of the data on the first factor of the factorial analysis for each of the systems

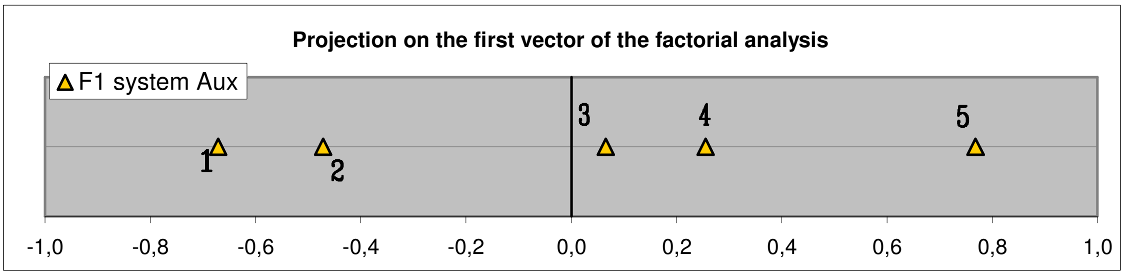


Figure 12: Projection of the data on the first factor of the factorial analysis for each of the systems

Figure 10, 11, 12 display an essential result of the factorial analysis: the distribution of the data when projected on the first factor which in the case of the present analysis explains about 72 % of the variance (77% for system Safety, 88% for system I&C and 81% for system Auxiliary). This means that most of the information about the dependency between LF and equipment related full outage is visible on this figure:

Each point corresponds to the data collected in each of the 5 bins for LF ([0-1], [2-10], [11-20], [21-50] and [> 50]). The projection shows that there is an opposition between bins 1 and 2, (all together collecting 59 units) from one side and bins 4 and 5 (all together collecting 60 units) at the opposite side. This indicates that units having operated with grid regulation, display different profiles, as far as the equipment related full outage is concerned, than units having practically no LF.

This is seen in the contingency tables where the distribution in the 2 first lines is peaked in the first bin of the equipment related full outage distribution, while the distribution in the 3 other lines is more or less evenly distributed with a peak, if any, in the second or third bin of the equipment related full outage distribution.

Similarly each point in Figure 11 corresponds to the data collected in each of the 5 bins for equipment related full outage [0-1], [2-7], [8-15], [16-30] and [> 30] in relation to systems Safety and Auxiliary and [0-5], [6-10], [11-20], [21-45] and [> 45] in relation to systems I&C).

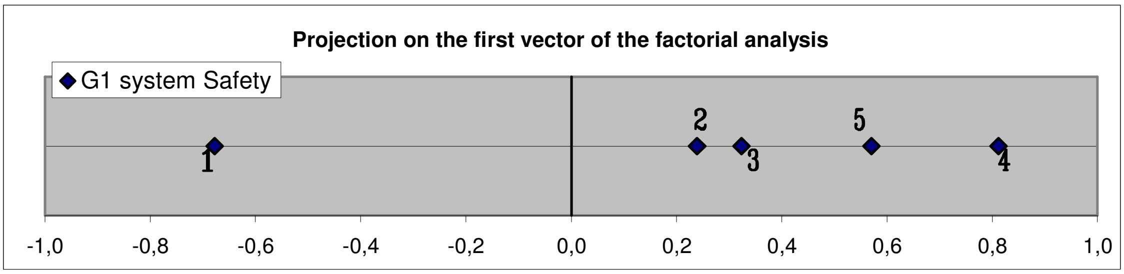


Figure 13: Projection of the data on the first factor of the factorial analysis for each of the systems

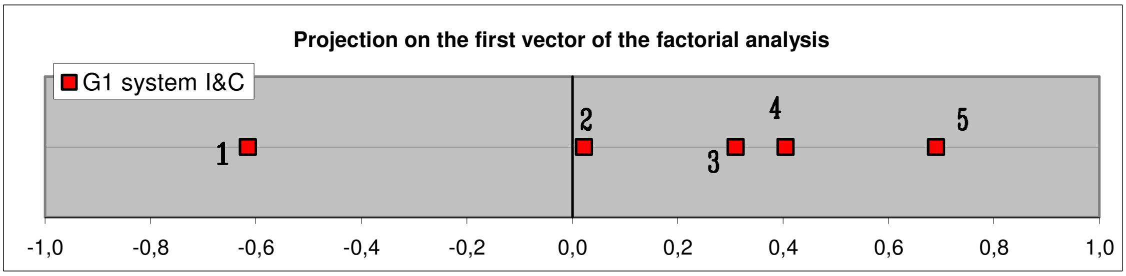


Figure 14: Projection of the data on the first factor of the factorial analysis for each of the systems

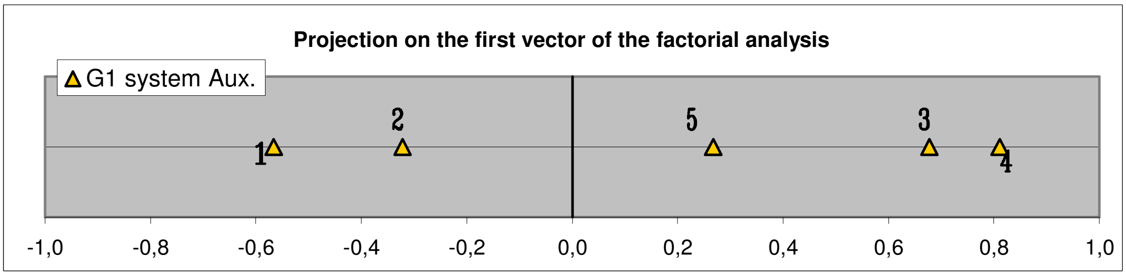


Figure 15: Projection of the data on the first factor of the factorial analysis for each of the systems

The projection shows that there is essentially an opposition between bins 1 (collecting 51 or 44 units, depending on the system considered) and the others. This indicates that units having low equipment related full outage have a different LF profile than the other ones.

All together the different analyses develop a coherent picture indicating that:

- Operation with a very low participation to grid adjustment (59 units adding LF bins 1 and 2) can be associated with low amount of equipment related full outage. This is observed by 2/3 of the units.
- Little amount of equipment related full outage is related to low participation to grid adjustment: 26, 23 and 25 units (adding bins 1 and 2 of the outage distribution) out of 29 are in this case, i.e. 80-90%.
- Operation with a significant participation to grid adjustment (60 units adding LF bins 4 and 5 have a different profile concerning the equipment related full outage. Their needs for equipment related full outage will be higher but a monotonous dependency is not provided.

4.3 Limit of the study

From this statistical study tendencies can be drawn:

- There is, in yearly average, a basic need of 5 to 10 hours of loss of production due to equipment related full outages on safety, auxiliary or I&C systems as defined the IAEA report (see list in paragraph 3.2)
- This need is increasing and reaches the range 15-30 hours of loss of production (yearly average) if the units are operating in load-following or regulation mode for the equivalent of more than 20 hours (yearly average) loss of production.
- It has been verified that systems on which grid regulation cannot have any incidence (system 17 for example) are not showing any dependency between lost hours due to outage on that systems and load following hours equivalent.

All values taken from the IAEA report are yearly average. As a result the study cannot follow the specific annual loss of production due to outages or load-following like operation. On another hand maintenance needs resulting from specific operation mode are not necessarily arising shortly after that operation mode. They can appear and be handled somehow later, so that the operation mode during one year will have consequences one or several years later. With this in mind using yearly averages during the operating time is a better representation than working with figures of a single year.

Standard deviations are high most often in the range 100-120% of the mean value. This is to be compared to the study carried out in Ref [8] where with a database of more than 500 fossil units, the standard deviation reached 60 % of the O&M estimated cost for electrical equipment. These high standard deviations reflect the fact that maintenance policy highly differ among operators and that inside a fleet some major refurbishment can be performed that will strongly increase the yearly average equipment related full outage.

The most limiting feature of this study is the aggregation of outage hours in systems. The items 13.02 and 12.01 (see list in paragraph 3.2) are the ones that possibly need enhanced maintenance action if the unit is operating in regulation or load following mode. But these items are not specifically recorded in the IAEA report; they are included in the corresponding system including other components. As a consequence only tendencies can be revealed by this study.

4.4 Economical incidence

From the tendency revealed by the present study, it can be supposed an increased outage need of 20 hours (yearly average) for each considered system if the reactor is operated under grid adjustment mode. Supposing this applies to 3 systems and considering the high standard deviation of 100% the need can be estimated to 60 hours x 2, i.e. 120 hours. The average amount of lost hours due to LF (restricted to the 57 French reactors that in the IAEA report declare positive value for LF) is 62 as yearly average. Adding the two amounts comes to O&M cost of roughly 180 hours. On a yearly theoretical production of 8760 hours the postulated amount corresponds to about 2% of possible production loss due to unavailability on top of the usual outages not triggered by operating under regulation mode. The estimation made by EdF in its confidential study indicates an effect on O&M costs of 1.8% which corresponds to about 150 hours of loss of availability.

Neglecting or delaying maintenance needs that would have an incidence on any safety relevant systems is not an option at nuclear power plants since non conformity is strongly controlled by regulatory bodies and the consequence of a longer shutdown at a time that was not previously optimised by the operator himself would undermine the profitability of the investment. Furthermore it has been demonstrated on the fossil plants that this attitude increases costs to come or results in shutdown of the plant.

Operating in regulation mode needs to have reserve for this. With the figures given in paragraph 3 a unit should be operated at 95% for it to take part in the secondary regulation. This corresponds to a voluntary renouncement to 5% production. However a significant incentive to adopt this mode of production is that this loss is perfectly balanced by the higher price of regulation power.

Taking the upper bound of the present study and of the EDF one as 2 % corresponds to a further voluntary renouncement to 2% of the availability factor. This means that the price increase for balancing this increase of the O&M costs as a result of operation in regulation mode needs to be larger than 100/93 time the base-load price, which is obviously the reality.

However considering the future situation where wind energy could have a substantial share (Ex. In France: 25 GW in 2020 compared to ≈ 65 GW nuclear generated electricity) a study, [15], concludes:

- peaking and reserves capacities may be required to ensure security
- Current market remuneration conditions might be reconsidered to provide sufficient incentives for investing in such reinforcements
- Dealing with extreme cases might become more complex, might impact availability and future maintenance costs of nuclear.

With this O&M cost analysis in mind it is anticipated that O&M costs are not expected to play a significant role because of the price given to peak reserve electricity compensate them without restrictions.

In case of high share of intermittent energy generation the investment price for back-up units (either nuclear or not) should be by far more significant on the peak price of the electricity than the O&M costs expected from extended LF operation.

5 Wind power variations and grid evolution

The purpose of this Section is to give examples of wind intermittency from various studies, with the aim of providing an understanding of the range of the problem. Additionally, possible developments in the power system architecture and operation are touched upon.

5.1 Variability in wind power

When considering the introduction of wind power in to the electricity system it is vital to study its intermittency. This becomes more important as the share of wind power, to the total generation capacity installed in the system, increases. A substantial expansion of wind power in the energy system will impose increased capacity elsewhere in the system for regulation of the power balance. In contrast to conventional power sources wind power will require more regulation capacity, due to large and unpredictable variation in production.

The magnitude of the capacity for regulation as the share of wind power increases will e.g. depend on the variation of wind power production both in time and space.
The variation of power output depends primarily on local wind speed, but several factors need to be considered when studying the problem (wind patterns characteristics vary during the day and time of the years, precise local geographical and meteorological conditions).

It is also of importance to distinguish between the variability of individual wind turbines, isolated wind farms, and a system of wind turbines/farms with a significant geographical distribution. In the former case, changes turn out to be large and quick. In the latter case, a sufficient distribution in space can smoothen out the variations considerably.

If a larger geographical area is considered effects of local wind conditions are to some degree evened out. For a larger area the total output from all installed wind power generations typically newer reaches its extreme values (i.e. zero or full power).
In Sweden large hydropower is used for regulation. It is considered by far the best and cheapest alternative for regulation. The available alternative, though much more expensive, is gas turbines.

On the question: How fast and by how much is wind power output varying? one can not give a precise answer, but real cases with defined conditions must be considered. Also, the significance of the change is very much depending on the design of the whole power system where it is integrated, and the availability of regulating power (e.g. cheap fast hydropower).

Thus, if wind power is to be a substantial part of the energy system its intermittency, and the corresponding need for regulating power must be considered together.

5.1.1 The Case of Sweden

The case for large scale expansion of wind power in Sweden has been studied extensively, including meteorological conditions and intermittency of wind power production (ELFORSK is a joint Swedish company for research on power production and delivery).

A future expansion of wind power may lead to shortage in the Swedish regulation capacity. In the case of northern Sweden there is readily available hydropower, which is often the best alternative, being fast and cheap, for achieving regulation. However, most of hydropower capacity for regulation is already taken into account in today energy balance regulation. Thus, if wind power is to be a substantial part of the energy system its intermittency, and the corresponding need for regulating power must be considered.

The case of 4000 MW installed capacity was studied [17]. The study assumed a nation wide distribution of wind power, but with a concentration in southern Sweden, and 75% of installed wind capacity is off-shore. Predictions of meteorological conditions were based on a climate database covering the period 1992-2001.

Statistics show that a loss of wind generation capacity of 50 per cent during a six-hour period happens once a year on average. This is valid for the total installed wind power capacity for the whole of Sweden. The correspondent number for a one-hour period is a loss of capacity of 10 per cent. The study also showed the effect of an extreme weather situation with large geographical distribution causing variation of 65% over a 24 h period.

A specific and severe real weather event with large geographical coverage was analysed, with respect to its impact on wind energy production in three regions and nation wide. It includes wind conditions of 25m/s, above which wind turbines are taken out of operation. The calculated output is shown in Figure 16.

Nation wide we see a 2 hour increase during the night from 1300 to 2760 MWh/h, followed by a 12h decrease during the day, down to ~820 MWh/h.

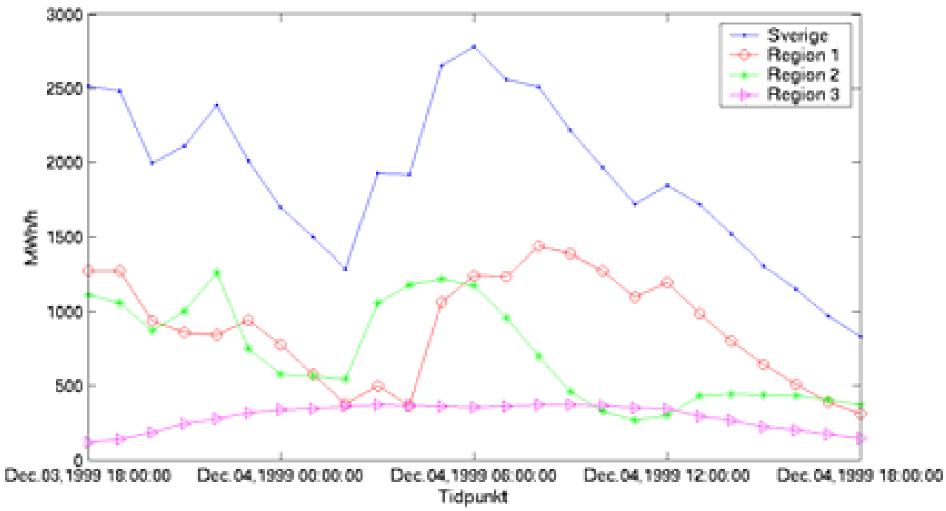


Figure 16: Variation in wind power production, hourly during 24 hours

Additional examples are found in a later report by the same organisation [18]. The report is using various reported methods in order to analyse requirements should 4000 MW of wind power be installed on 56 locations in Sweden (producing some 10 TWh annually). The analysis is based on input from the same meteorological databases mentioned above containing conditions in the considered geographical locations during 1992-2001. Four different scenarios, with varying degree of penetration of wind power (from 2000 to 8000 MW installed effect), were considered.

Variations in wind power output for the given conditions were calculated for 1 hour time horizon. The wind power caused increase in maximum hourly variations (positive and negative) is tabulated below in Table 4, for the four different levels of penetration (scenario 1 to 4).

	Scenario 1 **1996-2001**	**Scenario 2** **1996-2001**	**Scenario 3** **1996-2001**	**Scenario 4** **1996-2001**
Wind Power (MW)	2000	4000	6000	8000
Wind Power penetration (% of gross demand)	3.3	6.6	9.9	13.2
Maximum hourly variation of wind (MW)	385/-343	769/-686	1154/-1029	1538/-1372
Standard deviation wind power hourly variations (MW)	37	73	110	146

Table 4: Variation in wind power output at different level of wind penetration in Sweden

It should be stressed that the above data is in relation to all assumed wind power with a considerable distribution from north to south of Sweden, and as said before effects are smoothened out through the system due to variability in wind conditions.

The detailed output from a single fictitious wind farm, off-shore, 300 MW installed, is shown in Figure 17, for conditions in January 1997. It clearly shows variations from 0 to ~240 MW in short time. As the resolution in time is low, it is difficult to calculate the actual slope, but it can be estimated to 240 MW/12 hours (i.e. 8% or 20 MW per hour)

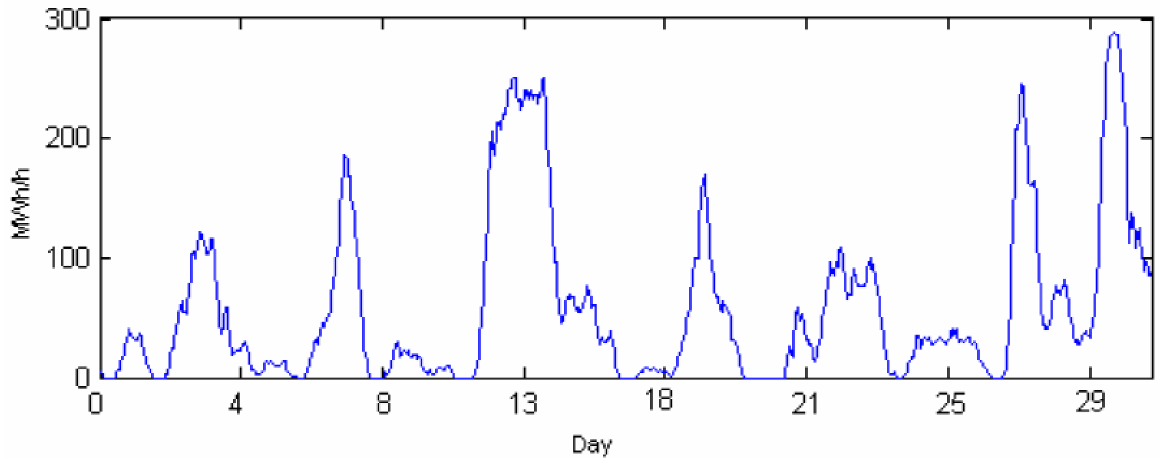


Figure 17: The calculated wind power production from Kriegers Flak January 1997, a fictitious wind farm that has an installed capacity of 300 MW (source ref [18])

Usually, the lower output from wind turbines is due to weak wind conditions or no wind at all. Equally important is to consider conditions with strong winds. Wind turbines are stopped when the wind is too strong, typically at 25m/s. This means in fact the output may drop from full power to zero suddenly, for individual wind turbines as well as for individual wind farms.

The study above considered simulations of 6 wind farms in the region of Skåne, south Sweden, under storm conditions. The 6 wind farms, being less than 100 km apart, had a combined installed power of 890 MW. The hourly variation during the storm conditions in 1999 was as large as -700 MW and +700 MW.

5.1.2 The Case of Denmark

An additional example from the same report [18] is real conditions in Jutland, Denmark. Measurements reported in Figure 18 were taken during the infamous hurricane "Gudrun" in 2005. The total installed wind power capacity on Jutland was around 2400 MW. It can be seen that output was around 2250 MW until before mid-day (green line/Faktisk). What happened then was that wind speeds exceeded 25 m/s and consequently several wind turbines were stopped and power rapidly decreased by some 2000 MW, or about 85%, which lasted about 6 hours. The decrease was roughly 400 MW/h or 17% of installed capacity/h.

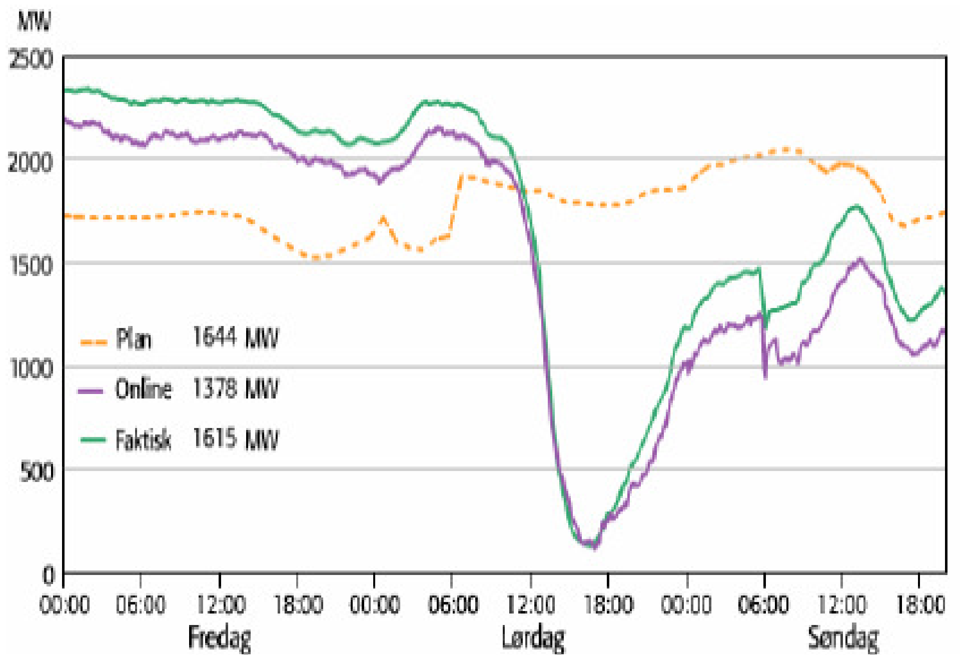


Figure 18: Wind power production and forecasts in Denmark, Jutland during the hurricane "Gudrun". The green line is the actual wind power generation from measurements on all wind power units. The dotted (red) line is the wind power generation according to plan based on the dayahead forecast (ref [18]).

5.1.3 International comparison

A comparison of the hourly variation in wind power production was made between the whole of Sweden, Denmark and Germany [18] (the report also includes studies of 4-hour and 6 hour variations). Wind farms are assumed to be evenly spread out.

Table 5 show how maximum hourly variations as well as standard deviations for specific conditions during 1 year.

Country	Period	Maximum variation (%)	Standard deviation (%)
Sweden	2001	12 / -9	1.8
Denmark	2003	18 / -20	2.9
Germany	2003	16 / -13	1.9

Table 5: Maximum hourly variations in wind power production, and standard deviation, measured as % of installed wind power capacity

5.1.4 The Case of US East Coast

Kempton et al. [19] studied the hypothesis that wind power output could be stabilized if wind turbines were located in a meteorologically designed configuration. This study is based on 5yr of wind data and 11 locations distributed along the 2500 km long US east cost. Hourly output is calculated for individual wind power sites assuming future construction, as well as for the whole system. The output rarely reaches either low or full power.

The study also refers to data showing that smoothing of the output due to geographical dispersion reaches an optimum at 800-1000 km, beyond which adding stations farther away will bring no or little additional benefits. Kempton et al. [19] analyses the statistical correlation between pairs of stations located along the US East coast with various distances between them. A higher correlation, with $r > 0.6$, occurs for pairs of stations less than 350 km apart. For stations more then 1300 km apart correlations are below 0.1.

Individual sites
Figure 19 shows, as an example the simulated capacity factor, CF, during one month (November 1999) for two of the sites, labelled S2 and S10. As seen, the two stations exhibit frequent changes in power output, including from zero to full power, in a few hours. The lower part represents hourly change in power output. Each line represents one hour and a line up to 0.5 means a 50% increase in power output. For individual sites S2 and S10 we see changes over 50%/h about 20 times in a month

Large scale grid
The black line in Figure 19 represents the whole system of 11 sites. In contrast to individual stations, the whole system changes no more than 10% of its capacity in any 1h. The benefits of having a larger grid of wind power are here shown in two ways. Firstly, the output fluctuates less quickly, allowing smother regulation. Secondly, the system produces a more even power, at mid level, seldom reaching the extremes zero or full power.

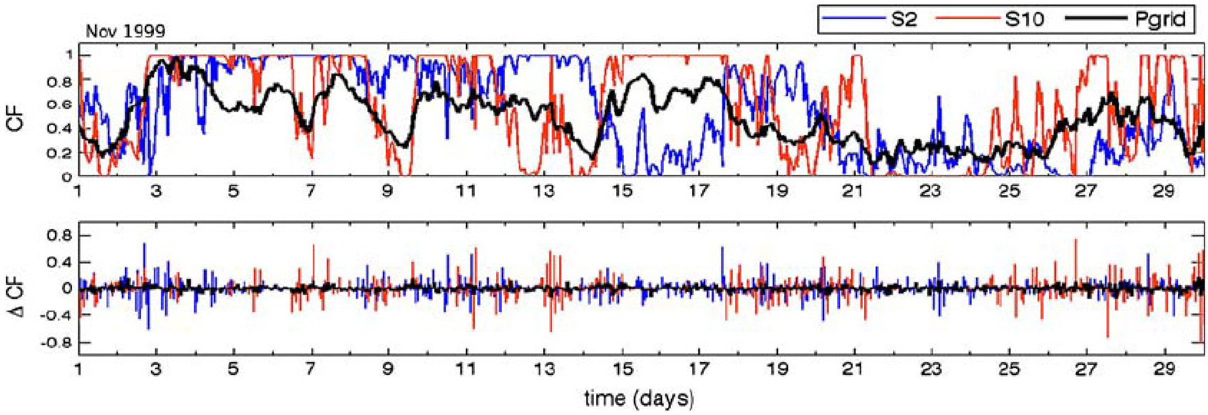


Figure 19: Top: One month of power output, expressed as Capacity Factor, CF, from two separated wind farms S2 and S10, as well as the whole system of 11 wind farms, Pgrid. Bottom: Comparison of hourly changes in CF, again for stations S2 and S10 and the whole system, Pgrid (Source ref [19])

5.1.5 IEA Wind Energy initiative

The International Energy Agency (IEA) operates the "Implementing Agreement for Co-operation in the Research, Development, and Deployment of Wind Energy", with a large number of participating bodies (industry, research, academia), and specifically the Task 25, labelled "Design and operation of power systems with large amounts of wind power" is of interest here (http://www.ieawind.org/).

A recent report by the group is a summary of several case studies addressing the impact of wind power variability and uncertainty on energy system reliability and cost [20]. Wind power production introduces additional variability and uncertainty into the operation of the power system. The impact will depend on many local factors: level of wind penetration, required flexibility of the power system, and how much flexibility already exists. Each country, region or power system characteristics are unique with respect to integration of wind power.

The case studies covered in the report look not only at intermittency of wind power but also address different impacts: balancing the power system on different short term time-scales; grid congestion, reinforcement and stability as well as power adequacy; reasons behind the wide range of results for costs of wind integration; definitions for wind penetration; reserves and costs; different power system and load characteristics and operational rules; underlying assumptions on variability of wind, generation mix and fuel costs, size of balancing area, etc.

Concerning variability of wind power the report discusses the smoothing effect of geographical distribution on the power output variability, as was discussed already above. The report concludes, based on several case studies, that variability decreases as there are more wind turbines spread over a large area. Larger areas also decrease the number of hours with zero output. Practically output is always above zero for very large areas. The variability is also considered for various time scales, with a decrease in variability for shorter time scales. The second and minute variability of large scale wind is generally small, but variability over the hour scale may be large even for large distributed wind power. They also stress the importance of wind power forecasting for times of several hours and day-ahead.

The report contains details on extreme variations of large scale wind for various time scales (10-15 min, 1h, 4h, 12h); comparison of long term variability of output between a single wind turbine, a group of wind turbine plants and all wind turbines in Germany; wind power step changes (average magnitude and standard deviation) as a function of the number of wind turbines, on various time scales (1 sec, 1 min, 10 min, 1 h); and other statistical data of variability of wind power output.

Table 6 shows, for a large number of large scale wind power regions, extreme values of variations in output for various observed times. The largest hourly step changes recorded range from ± 10 % to ± 35 % depending on region size and how dispersed the wind power plants are. Based on further detailed analysis, the report [20] concludes that most of the time the hourly variations will be within ± 5 % of installed capacity. The German example illustrates this: wind power changes are inside ±1 % of the installed power 84 % of time for 15 minute intervals and 70 % of the time for 1 hour time intervals.

			10–15 minutes		1 hour		4 hours		12 hours	
Region	Region size	Number of sites	max decrease	max increase	max decrease	max increase	max decrease	max increase	max decrease	max increase
Denmark	300x300 km^2	>100			-23 %	+20 %	-62 %	+53 %	-74 %	+79 %
-West Denmark	200x200 km^2	>100			-26 %	+20 %	-70 %	+57 %	-74 %	+84 %
-East Denmark	200x200 km^2	>100			-25 %	+36 %	-65 %	+72 %	-74 %	+72 %
Ireland	280x480 km^2	11	-12 %	+12 %	-30 %	+30 %	-50 %	+50 %	-70 %	+70 %
Portugal	300x800 km^2	29	-12 %	+12 %	-16 %	+13 %	-34 %	+23 %	-52 %	+43 %
Germany	400x400 km^2	>100	-6 %	+6 %	-17 %	+12 %	-40 %	+27 %		
Finland	400x900 km^2	30			-16 %	+16 %	-41 %	+40 %	-66 %	+59 %
Sweden	400x900 km^2	56			-17 %	+19 %	-40 %	+40 %		
US Midwest	200x200 km^2	3	-34 %	+30 %	-39 %	+35 %	-58 %	+60 %	-78 %	+81 %
US Texas	490x490 km^2	3	-39 %	+39 %	-38 %	+36 %	-59 %	+55 %	-74 %	+76 %
US Midwest+OK	1 200x1 200km^2	4	-26 %	+27 %	-31 %	+28 %	-48 %	+52 %	-73 %	+75 %

Table 6: Extreme variations of large scale regional wind power (% of installed capacity). Source: ref [20]

For longer time scales, 4-12 hours, the variation is stronger. The report also studies the effect of storms, when wind turbines are taken out of operation more or less instantaneously. Storm fronts take 4-6 hours to pass over areas of several hundreds of kilometres. Some extreme ramp rates recorded are:

- Denmark: 2000 MW (58% of installed capacity) decrease in 6-8 hours, or 12 MW per minute.
- North Germany: over 4000 MW (84% of installed capacity) decrease in 10 hours, or 16 MW per minute at the most.
- Portugal: 700 MW (60% of installed capacity) decrease in 8 hours, about 2MW per minute.
- Spain: 800 MW (7 %) increase in 45 minutes (ramp rate of 1 067 MW/h, 9 % of capacity or 18 MW per minute), and 1 000 MW (9 %) decrease in 1 hour and 45 minutes (ramp rate -10 MW per minute, 5 % of capacity).

5.2 Drivers and challenges towards super and smart grids

The evolution of the European power grids is expected to be predominantly steered by the increasingly swift diffusion of:

- Renewable Energy Sources for Electricity (RES-E), ranging from offshore and onshore wind, solar power, to other energy forms, such as marine or new ways to convert (and store) already deployed renewable energies, and,
- Distributed Energy Resources (DER), defined as small-sized power demand- and supply-side resources, such as Distributed Generation (including RES-E based units) and storage/conversion technologies (including electric vehicles).

The RES-E deployment driver, as far as large-sized power generation is concerned, will impact on the evolution of the transmission arteries towards super grid concepts. A super grid can be defined as an electricity transmission system, most likely based on direct current technologies, designed to transport large-scale power generation from remote areas to consumption centres. The DER penetration driver will mainly push the evolution of the distribution network towards smart grid concepts. A smart grid is an electricity grid that connects DER and uses advanced Information and Communication Technology (ICT) to deliver electricity more cost effectively, in a more sustainable way and in response to consumer needs.

A radical change in the topology, control and operation of the electricity transmission and distribution grids is expected, to allow a high penetration of renewable electricity and to optimise backup and storage capacity. In order to make the (super) transmission and (smart) distribution grids work together efficiently and safely, an increased coordination in the development and operation of the transmission-distribution interfaces shall be accomplished. Both transmission and distribution shall be developed, not only in terms of carrying capacity but also via advanced ICT infrastructure and communication and control platforms. Massive investments shall be mobilised to keep on developing flexible, coordinated and adequate electricity networks, designed according to new architectural schemes and embedding innovative technological solutions.

The European transmission system shall be redesigned to better operate with large yearly and seasonal variations of natural resources (especially renewable) and possible mismatch between short-term forecasted and actual renewable production.

The development and improvement of cost-effective and coordinated high-power energy storage systems can play a vital role in facilitating a larger penetration of DER by decoupling generation and energy use. A number of technologies will be viable options for electrical energy storage, each with benefits and drawbacks in terms of energy storage capacity, peak power capability and response time, among other variables. These features shall be carefully assessed in order to properly design and operate the future transmission and distribution systems.

Massive investment in the interconnections of the grid infrastructure: In 2050, the EU system will be soundly interconnected with the Southern Mediterranean area, through a Ring which would evolve in a trans-Mediterranean supergrid, and with the systems of Russia, Ukraine, Belorussia, Moldova and the Baltic (and other) states. The following investment clusters, already identified as short-to-medium term priorities, might offer opportunities/needs for expansion also at the 2050 horizon: renewable integration in the northern part (mainly wind) and the southern part (mainly wind, hydro and solar) of Europe, entailing generation connection to the grid, increased onshore transmission capacity and efficient balancing of the system via offshore interconnections and optimised usage of storage; reinforcements in the South-East and Central South Europe dictated by the power balances, the market prices, the strong increase of generation and hydro pumping capacity (especially on the Alps), and the interconnections of transnational synchronous systems. The future European power grid will therefore be connected to neighbouring systems at its Southern and Eastern borders, extending from north of the polar circle to the Sahara with a close network both onshore and offshore.

6 Conclusion

This report is a contribution to the question if nuclear power plant can contribute to grid regulation in a context of larger spread of renewable energy. This new context is restricted in our study to the consideration of wind energy that is typically an intermittent source of electricity. In addition, some challenges for the operation and the development of future power grids architectures are accounted for.

The design capacity of nuclear power plant to adapt their production to the grid need has been studied. According to the EUR rules [10] primary regulation can be supported under a recommended rate of 1% Pn per minute, higher rates may be agreed though not higher than 5% Pn per minute. This regulation is available within less than 30 s and the accepted deviation is within the limit of ± 2% of rated power. Under load following regulation the rate shall be 3% Pn per minute, and is available within a longer delay of roughly 20 minutes. This means that from NPP in the range 1000 - 1500 MW about 10 to 15 MW can be available through the primary regulation and the secondary regulation adds again within some delay a flexibility of 30-45 MW per minute. Having more flexibility can be agreed between the electricity system operators and the plant operators.

These transient figures compare well with the transients observed under storm condition at wind farms from Denmark, Germany, Portugal and Spain. Under such conditions nuclear power plants are capable to respond to the production variation. Although in the considered storm cases the requested capacity adaptation is available from a single power plant it has in a real case to be supported by two power plants since at the end of a fuel cycle load following cannot be provided by a NPP.

A further point of this study was to consider to what extent the contribution of NPPs to grid regulation impairs their economical profitability due to possible higher O&M costs. In a liberalised electricity market price components are not communicated. Consequently no precise cost data were available and the study is based on personal communication and on aggregated data from an IAEA database collecting yearly average loss of production of NPPs worldwide. The study shows that the supplementary O&M costs due to load-following like operating mode can be majored by 2% of the theoretical available capacity of a power plant. These supplementary costs allow a power plant to be eligible for regulation which is associated with much higher electricity prices than if the unit is always producing base-load electricity.

The conclusion may need to be reconsidered in case of a larger share of intermittent electricity generation. The decisive factor on this is the price at which reserve capacity is to be sold. This will be the adjustment factor and this last is more dependent on the share of the intermittent energy than of the nature of the backup plants.

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ANNEX 1: Reproduction of a data sheet of ref [14] for illustration purposes:

2007 Operating Experience

DE-32 BROKDORF (KBR)

Operator: E.ON (E.ON Kernkraft GmbH)
Contractor: KWU (SIEMENS KRAFTWERK UNION AG)

1. Station Details

Type:	PWR
Net Reference Unit Power at the beginning of 2007:	1370.0 MW(e)
Design Net Capacity:	1307.0 MW(e)
Design Discharge Burnup:	34000 MW.d/t
Status at end of year:	Operational

2. Production Summary 2007

Net Energy Production:	11425.6 GW(e).h
Energy Availability Factor:	94.3%
Load Factor:	95.2%
Operating Factor:	94.7%
Energy Unavailability Factor:	5.7%
Total Off–line Time:	468 hours

3. 2007 Monthly Performance Data

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
GW(e).h	1009.4	927.5	1004.1	984.2	800.9	531.4	1033.3	1028.2	1008.3	1047.0	1013.4	1038.0	11425.6
EAF (%)	100.0	99.6	100.0	99.9	79.0	53.4	99.9	100.0	100.0	100.0	100.0	100.0	94.3
UCF (%)	100.0	99.6	100.0	99.9	81.0	53.4	99.9	100.0	100.0	100.0	100.0	100.0	94.5
LF (%)	99.0	100.7	98.5	99.8	78.6	53.9	101.4	100.9	102.2	102.6	102.7	101.8	95.2
OF (%)	100.0	100.0	99.9	100.0	81.5	54.3	100.0	100.0	100.0	100.0	100.0	100.0	94.7
EUF (%)	0.0	0.4	0.0	0.1	21.0	46.6	0.1	0.0	0.0	0.0	0.0	0.0	5.7
PUF (%)	0.0	0.0	0.0	0.1	19.0	42.9	0.0	0.0	0.0	0.0	0.0	0.0	5.2
UCLF (%)	0.0	0.4	0.0	0.0	0.0	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.3
XUF (%)	0.0	0.0	0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

UCLF replaces previously used UUF.

4. 2007 Summary of Operation

THERMICAL POWER WAS INCREASED TO 3900 MW

5. Historical Summary

Date of Construction Start:	01 Jan 1976
Date of First Criticality:	08 Oct 1986
Date of Grid Connection:	14 Oct 1986
Date of Commercial Operation:	22 Dec 1986

Lifetime Generation:	220028.9 GW(e).h
Cumulative Energy Availability Factor:	90.2%
Cumulative Load Factor:	88.1%
Cumulative Unit Capability Factor:	90.4%
Cumulative Energy Unavailability Factor:	9.8%

Year	Energy GW(e).h	Capacity MW(e)	Performance for Full Years of Commercial Operation							
			Unit Capability Factor (in %)		Energy Availability Factor (in %)		Load Factor (in %)		Annual Time Online	
			Annual	Cumul.	Annual	Cumul.	Annual	Cumul.	Hours	of (%)
1986	296.8	1307.0	100.0	100.0	100.0	100.0	30.5	30.5	228	30.6
1987	9481.3	1307.0	85.2	86.3	85.2	86.3	82.8	78.7	7477	85.4
1988	8581.8	1326.0	85.2	85.8	85.2	85.8	73.7	76.3	7014	79.8
1989	8991.3	1326.0	80.0	83.9	80.0	83.9	77.4	76.6	7134	81.4
1990	8337.2	1326.0	72.5	81.1	72.5	81.1	71.8	75.4	6447	73.6
1991	9492.7	1326.0	85.7	82.0	85.7	82.0	81.7	76.7	7542	86.1
1992	10788.0	1326.0	96.0	84.3	96.0	84.3	92.6	79.3	8461	96.3
1993	9447.1	1326.0	85.6	84.5	84.8	84.4	81.3	79.6	7441	84.9
1994	10228.6	1326.0	88.7	85.0	88.7	84.9	88.1	80.6	7793	89.0
1995	9912.4	1326.0	86.6	85.2	86.6	85.1	85.3	81.2	7833	89.4
1996	10555.4	1326.0	93.2	86.0	93.2	85.9	90.6	82.1	8212	93.5
1997	11249.3	1326.0	95.1	86.8	95.1	86.7	96.8	83.4	8328	95.1
1998	10752.3	1326.0	92.6	87.3	90.4	87.0	92.6	84.2	7966	90.9
1999	11093.3	1370.0	93.3	87.8	93.3	87.5	92.4	84.8	8177	93.3
2000	11335.1	1370.0	95.6	88.3	95.6	88.1	94.2	85.5	8397	95.6
2001	11215.4	1370.0	95.0	88.8	95.0	88.6	93.5	86.1	8331	95.1
2002	11336.9	1370.0	95.8	89.2	95.8	89.0	94.5	86.6	8405	95.9
2003	10564.6	1370.0	90.1	89.3	90.1	89.1	88.0	86.7	7903	90.2
2004	11040.8	1370.0	94.7	89.6	94.7	89.4	91.7	87.0	8327	94.8
2005	11400.7	1370.0	96.1	89.9	95.9	89.8	95.0	87.4	8433	96.3
2006	11201.3	1370.0	94.7	90.2	93.7	90.0	93.3	87.7	8307	94.8
2007	11425.6	1370.0	94.5	90.4	94.3	90.2	95.2	88.1	8293	94.7

6. Full Outages, Analysis by Cause

Outage Cause	2007 Hours Lost			1987 to 2007 Average Hours Lost Per Year		
	Planned	Unplanned	External	Planned	Unplanned	External
A. Plant equipment problem/failure					88	
B. Refuelling without a maintenance					15	
C. Inspection, maintenance or repair combined with refuelling	447			604		
D. Inspection, maintenance or repair without refuelling				8		
H. Nuclear regulatory requirements					49	8
K. Load-following (frequency control, reserve shutdown due to reduced energy demand)					9	3
L. Human factor related		20				
Z. Others					15	
Subtotal	447	20	0	612	176	11
Total	467			799		

7. Equipment Related Full Outages, Analysis by System

System	2007 Hours Lost	1987 to 2007 Average Hours Lost Per Year
13. Reactor Auxiliary Systems		8
16. Steam generation systems		2
31. Turbine and auxiliaries		0
32. Feedwater and Main Steam System		1
41. Main Generator Systems		75
Total	0	86

ANNEX 2: outage data extracted from ref [14] IAEA

LF means Load following as described in the cause (K) reported in 3.2. The column LF total has been used for the study: it sums-up the LF outages planned, unplanned or due to external causes. The column "Total outages" sums-up the hours lost for outages independently of the system under maintenance.

NPP	LF Planned	LF Unplanned	LF Ext	LF Total hours (year average)	Period	Outage due to Safety systems (hours)	Outage due to I&C systems (hours)	Outage due to Aux. systems (hours)	Total Outages (hours)
BE-2	24	46	0	70	1974-2007	9	12	0	186
BE-4	8	10	0	18	1975-2007	9	10	9	274
BE-5	0	10	0	10	1983-2007	0	2	1	156
BE-7	0	52	0	52	1987-2007	6	1	0	271
BE-3	0	4	86	90	1975-2007	2	9	0	96
BE-6	15	28	0	43	1983-2007	2	6	0	98
BE-8	6	0	0	6	1986-2007	0	6	0	123
BG-5	0	0	0	0	1988-2007	0	10	0	176
BG-6	0	0	0	0	1992-2007	32	6	0	205
CZ-4	0	0	0	0	1985-2007	6	4	0	55
CZ-5	0	0	0	0	1986-2007	0	8	0	43
CZ-8	0	8	0	8	1987-2007	0	2	0	86
CZ-9	0	0	4	4	1987-2007	0	6	0	20
CZ-23	0	0	0	0	2003-2007	0	41	0	573
CZ-24	0	0	0	0	2004-2007	0	0	0	365
FI-1	0	2	5	7	1977-2007	4	14	0	216
FI-2	1	2	0	3	1980-2007	5	5	0	87
FI-3	0	46	0	46	1979-2007	5	2	0	87
FI-4	0	2	4	6	1980-2007	2	0	0	334
FR-54	0	83	1	84	1987-2007	36	75	47	397
FR-55	0	70	0	70	1988-2007	31	51	12	287
FR-32	0	29	56	85	1981-2007	5	48	5	334
FR-33	0	10	54	64	1982-2007	14	6	8	131
FR-34	0	56	15	71	1983-2007	6	13	39	219
FR-35	0	13	23	36	1983-2007	0	58	13	225
FR-13	3	54	15	72	1978-2007	69	22	10	521
FR-14	0	65	59	124	1978-2007	22	7	15	505
FR-15	0	9	32	41	1978-2007	11	22	4	588
FR-16	0	54	39	93	1980-2007	4	50	8	341
FR-50	0	68	0	68	1986-2007	9	40	29	793
FR-53	0	12	24	36	1987-2007	33	6	9	451

FR-60	0	38	3	41	1988-2007	16	35	56	188
FR-65	0	3	38	41	1991-2007	40	14	3	134
FR-40	0	52	0	52	1982-2007	18	6	28	303
FR-41	0	11	51	62	1984-2007	31	13	25	342
FR-56	0	19	0	19	1986/2007	2	5	39	259
FR-57	0	22	27	49	1987-2007	6	17	36	257
FR-62	0	0	8	8	1997-2007	0	80	26	939
FR-70	0	0	81	81	1997-2007	0	100	60	914
FR-72	0	0	0	0	2002-2007	4	16	5	175
FR-73	0	0	29	29	2002-2007	0	6	49	177
FR-42	0	37	20	57	1983-2007	12	14	8	395
FR-43	0	44	0	44	1984-2007	0	5	1	287
FR-44	0	21	21	42	1984-2007	2	11	1	132
FR-45	0	12	48	60	1984-2007	3	7	20	272
FR-22	0	159	42	201	1980-2007	8	39	12	261
FR-29	0	96	23	119	1981-2007	25	12	15	279
FR-30	0	76	0	76	1981-2007	43	4	9	253
FR-31	1	80	11	92	1981-2007	6	5	58	413
FR-11	0	7	5	12	1977-2007	16	29	5	634
FR-12	0	6	29	35	1977-2007	16	16	16	413
FR-46	0	21	34	55	1985-2007	13	39	24	678
FR-47	0	20	2	22	1985-2007	21	19	43	572
FR-61	0	10	0	10	1990-2007	12	5	8	153
FR-68	0	50	0	50	1993-2007	0	42	5	258
FR-20	0	31	20	51	1980-2007	8	8	17	482
FR-21	21	48	58	127	1980-2007	6	7	9	139
FR-27	1	26	65	92	1981-2007	4	9	21	255
FR-28	0	12	35	47	1981-2007	16	56	4	355
FR-51	0	10	0	10	1984-2007	0	13	31	275
FR-52	0	37	2	39	1985-2007	17	18	14	262
FR-58	0	19	0	19	1987-2007	1	64	0	510
FR-59	0	54	0	54	1988-2007	37	24	9	245
FR-36	0	52	0	52	1984-2007	4	54	34	392
FR-37	0	25	0	25	1984-2007	22	108	8	563
FR-38	0	3	21	24	1985-2007	40	86	45	589
FR-39	0	26	1	27	1986-2007	17	15	9	534
FR-63	0	4	0	4	1990-2007	14	9	24	261
FR-64	0	6	0	6	1992-2007	5	26	14	422
FR-48	1	31	1	33	1985-2007	12	21	12	551
FR-49	0	13	29	42	1986-2007	4	64	14	676
FR-17	0	376	16	392	1982-2007	41	40	17	469

FR-23	0	138	0	138	1981-2007	47	20	11	525
FR-18	0	31	0	31	1980-2007	2	4	2	313
FR-19	0	35	43	78	1980-2007	22	42	8	253
FR-25	0	26	0	26	1981-2007	17	40	13	287
FR-26	0	81	10	91	1981-2007	31	17	10	210
DE-12	2	3	0	5	1975-2007	387	20	3	782
DE-18	0	0	0	0	1976-2007	0	2	68	472
DE-32	0	9	3	12	1987-2007	0	0	8	86
DE-13	0	3	0	3	1976-2007	0	3	707	1324
DE-33	0	0	0	0	1988-2007	0	0	0	27
DE-23	0	0	0	0	1983-2007	0	0	0	166
DE-27	0	0	0	0	1985-2007	0	4	0	43
DE-26	0	5	0	5	1984-2007	0	0	0	13
DE-28	0	0	0	0	1985-2007	15	0	0	176
DE-16	8	0	0	8	1977-2007	0	0	0	122
DE-31	0	0	0	0	1988-2007	0	0	0	65
DE-20	0	0	0	0	1984-2007	1	0	0	465
DE-15	0	0	1	1	1976-2007	1	0	0	31
DE-44	0	0	0	0	1989-2007	0	0	0	5
DE-14	0	5	0	5	1981-2007	9	4	2	132
DE-24	0	0	72	72	1985-2007	0	5	0	79
DE-17	0	18	0	18	1978-2007	0	6	22	266
HU-1	0	6	0	6	1983-2007	4	17	0	54
HU-2	0	21	0	21	1984-2007	0	20	0	537
HU-3	0	0	0	0	1987-2007	0	44	0	118
HU-4	0	3	0	3	1988-2007	0	16	0	49
NL-2	0	3	5	8	1973-2007	14	4	4	143
SK-3	0	0	0	0	1980-2007	0	1	14	58
SK-13	0	0	0	0	1985-2007	1	4	5	61
SK-14	0	0	0	0	1985-2007	0	5	0	39
SK-6	0	7	0	7	1998-2007	0	6	0	58
SK-7	0	0	0	0	2000-2007	0	0	8	66
SL-1	0	0	0	0	1981-2007	3	2	0	129
ES-6	0	0	0	0	1982-2007	0	13	35	128
ES-7	0	7	0	7	1983-2007	2	10	4	136
ES-8	0	7	0	7	1983-2007	0	3	0	215
ES-9	15	5	3	23	1985-2007	0	1	0	146
ES-10	0	7	0	7	1985-2007	0	14	4	176
ES-2	6	14	21	41	1971-2007	34	40	10	389
ES-11	0	0	0	0	1989-2007	0	6	0	124
ES-16	0	0	6	6	1988-2007	0	38	157	373

SE-9	0	0	16	16	1981-2007	0	13	6	151
SE-11	0	0	18	18	1981-2007	17	1	2	148
SE-14	0	0	9	9	1985-2007	0	4	0	48
SE-2	0	114	0	114	1971-2007	24	97	14	663
SE-3	0	87	2	89	1975-2007	7	10	0	173
SE-12	0	19	0	19	1985-2007	11	11	1	92
SE-4	0	29	10	39	1974-2007	47	69	9	493
SE-5	0	0	8	8	1974-2007	74	7	0	653
SE-7	0	0	5	5	1981-2007	0	1	0	286
SE-10	0	0	0	0	1982-2007	1	2	3	154
CH-1	0	0	0	0	1971-2007	3	95	2	236
CH-3	0	0	0	0	1971-2007	0	8	1	68
CH-4	0	0	0	0	1979-2007	0	2	0	33
CH-5	3	0	0	3	1985-2007	0	0	0	199
CH-2	0	2	0	2	1971-2007	2	0	0	173
GB-24	0	0	0	0	1995-2007	66	31	4	257

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Abstract

In this report the capability of nuclear power plants to adapt to the demand is examined and several types of regulations needed for this are explained. From design there exists a power fluctuation margin and this is also an important characteristic of the design rules agreed upon by the European Utility Requirements (EUR rules) that should apply to the new builds in Europe. In the last chapter of this report the fluctuation margins as needed from wind farms are estimated from the experience gained in the wind turbines installations from Scandinavia and from the US. This allows an estimation of the compatibility of wind and nuclear generating units in a geographic area.
A central point of this study was to consider to what extent the contribution of NPPs to grid regulation impairs their economical profitability due to possible higher O&M costs. In a liberalised electricity market price components are not communicated. Consequently no precise cost data were available and the study is based on personal communication and on aggregated data from an IAEA database collecting yearly average loss of production of NPPs worldwide. The study shows that the supplementary O&M costs due to load-following like operating mode can be majored by 2% of the theoretical available capacity of a power plant. These supplementary costs allow a power plant to be eligible for regulation which is associated with much higher electricity prices than if the unit is always producing base-load electricity.

The conclusion may need to be reconsidered in case of a larger share of intermittent electricity generation. The decisive factor on this is the price at which reserve capacity is to be sold. This will be the adjustment factor and this last is more dependent on the share of the intermittent energy than of the nature of the backup plants.

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