# Economic Evaluation of Thermal Power Station Investments Considering the Impact of Renewable Energy Sources

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*Abstract* — **With the advent of power system restructuring, there is now competition on the generation activity and the generation mix changed in many countries with the incentives to induce investments in renewables, in many cases, using volatile primary resources. Given this increase of the installed capacity in wind parks and PV stations as well as in hydro stations (as a way to address the mentioned volatility), investments in large thermal stations became more risky. In this scope, this paper describes a long term generation expansion planning model that can be used by generation companies to investigate the profitability of new thermal generation investments considering the increasing presence of renewables. This long term simulation tool uses System Dynamics, a framework particularly suited to mode the long term dependencies between different variables while incorporating delays on some decisions. At a final section this paper includes a Case Study based on a generation system that corresponds to a scaled version of the Portuguese system.**

*Keywords*— generation investments, renewable sources, economical evaluation, uncertainties, electricity markets, long run strategies. Dynamic Systems

## I. Introduction

In the last 25 years power systems in several countries and geographic regions were subjected to a restructuring move. This movement started in Chile in the middle 80's, passed to England & Wales and then progressively spread to other European countries, to several states in the USA, to Australia and New Zealand and to several other Latin American countries. Although with different particular characteristics and implementation paces, there are a number of aspects that are common to all these restructuring moves, as follows:

- traditional vertically integrated utilities were progressively unbundled. In the first place, generation was separated from transmission and distribution, and typically distribution included both the wiring and the retailing businesses. Then, as eligibility was enlarged to include an increased number of consumers, distribution wiring was separated from retailing;
- this means that current restructured power sectors typically include four activities – generation, transmission, distribution and retailing. The activities at the extreme sides of the value chain are typically opened to competition while wiring transmission and distribution are provided by regulated monopolies;
- in current organization schemes, generation and demand (directly from larger consumers or through retailers) relate themselves through electricity markets or via bilateral contracts with different time spans [1];
- as a consequence of this unbundling, the number of agents increased and there is a need for coordination both at the economic, at the technical and at the regulatory levels;
- another crucial consequence of the unbundling is that new tariff schemes had to be conceived, because different activities are provided by different companies having different owners. This means that Regulatory Agencies conceived new tariff schemes identifying activities covering the entire value chain from generation to the consumer, associated tariffs to these activities and, as a result of the application of an additive principle, each end consumer pays a final tariff that results from the addition of a generation component (reflecting generation prices in the markets), access tariffs (including transmission and distribution tariffs) and a retailing tariff.

In the beginning of this process a larger accent was put on shorter term activities, as it is illustrated by the development of day-ahead markets. As the time passed, longer term activities, including generation and transmission expansion studies and models, regained a place in the arena although with a different focusing. Regarding generation, there are now several competing companies, the demand and fuel costs are very much affected by uncertainties and the profitability of the investments of one player has to be evaluated in view of possible behaviours of other competitors. In this new environment, uncertainties [2, 3], risk analysis and the identification of robust plans play an increasing role.

To understand the current power industry and the motivations for this work, it is still important to mention that several countries put in place schemes to subsidize investments in renewable stations, namely using volatile resources as wind and solar radiation. As a result of feed-in tariffs, countries as Portugal, Germany, Denmark and the Netherlands have now an important share of installed capacity in wind farms which creates regulation problems due to the volatility of the primary resource. As an example, by the end of 2011 the Portuguese generation system has an installed capacity of 17.000 MW, about 6.000 MW correspond to Special Regime Generation operating under specific feed in tariffs, from which 4.500 MW correspond to wind parks. In order to adequately deal with this volatility, there are investments in new hydro stations and reinforcements of some older ones, that as a result will contribute to increase the share of renewables in the demand supply to above 60 % in 2020.

An important consequence of this new paradigm, is that in several countries thermal stations are used during fewer hours than in the past and investments in new coal and combined cycle stations are now more risky and have to be carefully evaluated namely estimating their profitability on the long run. In previous publications [4, 5], we described a long term generation expansion planning model that considers a two-step procedure. In one of them, generation agents prepare their own generation expansion plans based on the expected evolution of the demand, of the electricity market price and considering a list of candidate technologies and available capacities. The individual plans are then submitted to a coordination analysis in order to check some global constraints as the maximum value specified for the LOLE reliability index and the margin between the installed capacity and the demand. If some of these constraints are violated, then it is activated a long term model to estimate the evolution of the demand, of the electricity market price and the capacity factor of each of the technologies used in the current generation mix. This long term model is formulated using System Dynamics, that proved to be a very powerful modelling tool able to capture dependencies between several variables as well as incorporating delays for instance associated with the construction time of a new power station. The results in [4, 5] illustrate the application of this approach and the kind of results it outputs.

This model can be used by individual generation companies as well as by regulatory agencies. A generation company can use this approach to build robust expansion plans considering the possible expansion plans of the competitors and evaluating the impact of uncertainties affecting the demand evolution and fuel prices. It can also be used by regulatory agencies to simulate the long term impact on the generation system, on the demand and on the price of changes on the market design, for instance the introduction of a capacity term to remunerate power stations.

In line with this reasoning, in this paper we evaluate on the long run the impact on the system of the increase of the installed capacity in renewable technologies as wind power and hydro stations. In fact, as the capacity in wind power increases, hydro capacity becomes more and more important for several reasons, namely the possibility of having fast generation stations that can cope with the volatility of the wind and also the possibility of using wind power (for instance available in off peak hours) to pump water to upper reservoirs. As the global renewable capacity increases, it is clear that the share of thermal stations will not increase and so existing thermal stations will be less profitable and eventually new investments in thermal technologies will not take place. As a result, it is important to evaluate if investments on traditional thermal power stations are still attractive or not, depending on the share of renewable capacity. Secondly, we will investigate if the introduction of a capacity payment to remunerate power stations can be effective as a way to induce new investments.

In this analysis we used the mentioned Dynamic model conveniently modified namely introducing the capacity payment. The developed approached is illustrated using a scaled system based on the Portuguese generation mix. This analysis is important given that in recent years the installed wind capacity increased to about 4500 MW (close to 25% of the total installed capacity) and there going on investments in pumped hydro stations of 2000 MW that will increase the hydro capacity to a value close to 7000 MW (about 40% of the total installed capacity). As a result of the current generation mix, there are already some combined cycle thermal stations that are typically not dispatched in the day-ahead market, thus strongly compromising the profitability of these investments. These indications suggest that the kind of analysis reported in this paper is relevant for generation systems facing an increasing presence of renewable resources.

## II. Developed Approach

### A. General ideas

More than in the past and as mentioned in Section I, long term generation investment decisions are now influenced by uncertainties that affect the price of fuels, the evolution of the demand, the evolution of the generation mix due to the possible behavior of other generation companies and also certainly by the larger penetration of renewable stations using volatile resources, namely wind and solar radiation.

This means that investment decisions will now have to be taken internalizing these uncertainties, evaluating the risk and investigating how the level of return on these investments can be influenced by several of the above mentioned factors. Given this increased risky environment, it is reasonable to consider that higher return rates are expected or required for instance for investments on new thermal stations. This also means that it is important to characterize as much as possible the impact of these uncertainties on future investments so that more sounded decisions can be taken. As an example, the capacity factor of some thermal plants is in some countries very reduced, as a result of the increased level of wind capacity and of the demand reduction due to the current economic crisis affecting some countries.

As a result of these concerns, in the developed approach we considered that a number of input data can be affected by uncertainties modeled by normal pdf distributions. These include the demand, the coal and fuel costs, the investment and maintenance costs of several types of generation stations and the capacity factor of generation technologies in the mix under analysis, representing the percentage of hours along the year that each technology is used. Regarding the electricity prices, we used non-negative normal probability distribution derived from hourly the prices in the Iberian Electricity Market established since 2007 between Portugal and Spain publicly available in [6].

### B. Economic Evaluation of Investment Projects

The economic evaluation of a possible generation expansion project should be conducted on the long run, namely to get insight on the evolution of some indicators along an extended horizon. Prior to the description of the long term model that was used, we will detail the economic indicators we are looking for. In the first place, admitting that generation stations are only paid according to the energy output, we can estimate its profit along a period S using expression (1). This is a general expression that can be used for instance for thermal stations. In this expression, Pf is the profit obtained along the period S, $Energ_s$ is the energy generated by the power station under analysis in period s in MWh, $Pe_s$ is the electricity price in period s (namely obtained for period s in the electricity market) in €/MWh and $Cost_s$ is the generation cost in period s in €/MWh. Although other discretization steps can be used, in this case we adopted the month, so that S represents the number of months in the planning horizon and all the values in (1) correspond to averages along each period s.

$$Pf = \sum_{s=1}^{S} Energ_s (Pe_s - Cost_s) \quad (1)$$

The generation cost $Cost_s$ can be estimated using (2). This expression includes the average number of hours that each station or the set of stations of the same technology is used measured by the capacity factor $\alpha_s$ in % in each period s, the variable operation and maintenance cost, VOM in €/MWh, the fix operation and maintenance cost, FOM in €/MW, the number of hours, $h_s$, in each period s (of one month in this case), the cost of capital associated with the investment in this station, $C_{cap}$ in € and the installed capacity, $P_{ints}$ in MW. The evaluation of this cost requires a number of elements that have to be estimated on the long run as the capacity factor. This parameter together with the demand evolution and the electricity price will be obtained by the Dynamic Model to be detailed in Section III.

$$Cost_s = VOM.\alpha_s.h_s.P_{inst} + FOM..P_{inst} + C_{cap} \quad (2)$$

Using this information and the evolution of the profit along the horizon under analysis, it is possible to compute the Net Present Value, NPV, to characterize the interest of a particular project. NPV is calculated using (3) in which $Pf_n$ represents the estimate of the profit in year n, N is the number of years in the horizon to analyse, IC is the investment cost, and r is a discount rate adequate for the level of risk of the activity, for instance set by comparison with the discount rates of other economic activities having the same level of risk. It is clear that the profit in year n, $Pf_n$, is obtained using (1) and admitting that S=12.

$$NPV = \sum_{n=1}^{N} \frac{Pf_n}{(1+r)^n} - IC \quad (3)$$

According to this expression, the annual estimates of the profit resulting from the operation of a particular power station are transferred to initial year using the discount rate r, so that they become comparable, and are then added leading to the global profit along the horizon. The investment cost associated with this power station is assumed in year 0 and it is then subtracted from this global profit. This investment cost corresponds to an unique term since it is associated with the construction of the station prior to the start of its operation. The NPV measures the cash-flow created by the project referred to the initial investment year, that is, referring all financial flows to a common time instant. When an investment project is under evaluation, the NPV can be used to give insight on its economic value since if the NPV is positive this means that this investment brings positive value to the company. If it is negative, then the project should be rejected because it is not capable of increasing the value of the company and if it is zero than it is neutral and has no relevant impact on the performance of the company. If a company has a portfolio of investment projects, it should start by estimating their NPV's, eventually subjecting this analysis to the impact of uncertainties that can affect several input data and then select the one or ones having larger NPV.

According to these ideas, it becomes clear that evaluating a number of investment projects just estimating for each of them a deterministic value for the NPV is rather risky. In fact, changing some input data (for instance, admitting that the demand will evolve at a lower rate) will contribute to reduce the market electricity price and reduce the capacity factor of some technologies, namely thermal ones, specially in countries having an important share of hydro's and where feed-in tariffs apply for renewables. This means that the economic analysis should incorporate a risk evaluation under the form of a sensitivity analysis or explicitly representing some uncertain parameters by probability distributions. Then, it is possible to translate the uncertainties in the input data on the NPV, for instance sampling sets of values from these distributions and computing the NPV for each set of input data, according to a Monte Carlo simulation approach [2]. As it is usual in Monte Carlo approaches, the sampling and the NPV computation steps should be done a large number of times in order to be able to translate the input probability distributions to the output NPV probability distribution. In other words, the Monte Carlo procedure should only end when the current estimate is sufficiently stable. This can be measured by monitoring the uncertainty coefficient, $\beta$, as detailed in [7].

A second index that is also used to characterize the economic performance of an investment is the Coefficient of Variation, CV, given by (4) [8]. This index gives insight to the level of risk of the project because a project displaying a large value for CV has a larger NPV standard deviation regarding the estimate of its mean value. This ultimately means that small changes in some input parameters are likely to cause a drift of the NPV to negative values, drastically reducing the interest of such a project. On the contrary, a project displaying a large NPV mean and a small NPV standard deviation is rather immune to changes in the input data in the sense that its final NPV will remain largely positive.

$$CV(NPV) = \frac{StdDeviationNPV}{MeanNPV} \quad (4)$$

Finally, when analysing investment projects it is also common to compute the Internal Rate of Return, IRR. This value corresponds to the rate r for which the NPV given by (3) becomes zero. In other words, the IRR is defined as the discount rate at which the accumulated present value considering all costs becomes equal to the accumulated amount of benefits which means that the *IRR* can be interpreted as the maximum rate of interest (in real terms) that the investment can provide. The IRR is computed turning the expression of NPV (3) equal to zero and letting r be the variable to be calculated by the resulting equation.

## III. Dynamic Model of the Electricity Sector

The economic analysis detailed in Section II requires estimating the profit of the power station along its life time. In this scope, in recent years System Dynamics started to be used to model the long-term behavior of electricity markets. System Dynamics was conceived by J. W. Forrester in the 1960's and [9] summarizes its main concepts. References [10 - 12] illustrate the application of these concepts to the Generation Expansion Planning problem, GEP.

This is a long run estimation determined by a number of variables that are in fact interdependent. For instance, the profit depends on the global economic environment, in the sense that this affects the industrial activity, the demand level and ultimately the capacity factor of each technology, in terms of the number of hours each station is operating. On the other hand, the demand depends on the price of coal and fuels and these prices also have an important impact on the electricity prices, that on its turn also influences to some degree the demand itself. Finally, investment decisions taken by other competitors as well as the evolution of installed capacity in renewable stations, namely wind parks and hydro stations, affect the generation mix. Given the characteristics of this long term evaluation, we developed an approach fully reported in [4, 5] that uses System Dynamics as a way to incorporate all the dependencies and loops and to include delays between the instant in which a project is approved and it starts operation. These dependencies and interactions are illustrated in the casual diagram displayed in Figure 1.

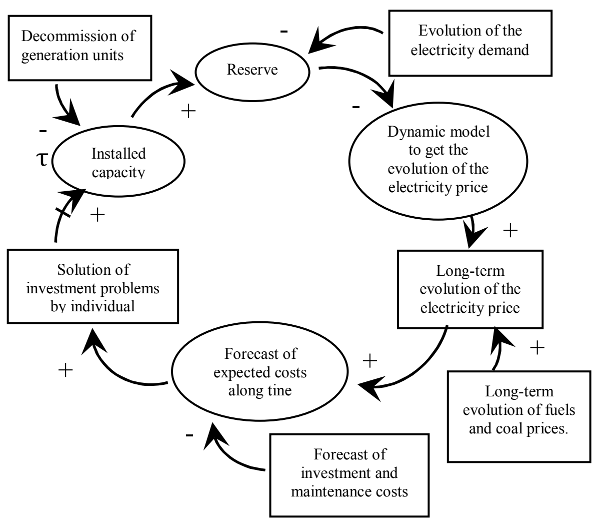


Fig. 1. Diagram representing the market long-term interactions.

According to this diagram, there is a positive cause-effect relation between the installed capacity and the amount of reserves. On the other hand, decommissioning units has a negative effect on the total available power and a demand increase reduces the reserve margin and eventually induces an increase in the electricity price. This diagram also includes a delay, $\tau$, between the decision to build a new unit and its commissioning. This delay is due to the licensing and the building period and it should not be forgotten when modeling the long-term evolution of the electricity price. Finally, there is a feed-back loop between the demand and the electricity price. Departing from an initial set of investment decisions, it is obtained the evolution of the electricity price using an initial demand rate. However, the price level will also impact on the demand depending on its elasticity. If there is a capacity shortage or a very dry year, the electricity price tends to increase which can induce a demand reduction. The evolution of fuel costs and the updated electricity prices can then lead to a change in the investment plans because the profitability of the expansion projects will change.

In brief, this approach admits three sets of power stations – hydro stations (run-of-river and reservoirs), thermal stations (using coal, fuel and natural gas) and renewables, namely wind parks. The model integrates three main sub-models to simulate the annual electricity demand, to simulate the supply of the demand by the different available technologies and to estimate the evolution of the electricity market prices. The annual electricity demand is influenced by the demand rate evolution, by the demand level in the departing year, by the electricity price in the beginning of the horizon and by its evolution and by the elasticity demand/price. The demand rate is modeled by a stochastic variable to incorporate the associated uncertainty.

The generation system is simulated considering the existing stations in the initial year and the ones to be commissioned and decommissioned along the horizon. Regarding wind parks and hydro stations we use historical series that reflect both the installed capacity and its availability and the availability of the natural resource. This means we used fdp's to consider this uncertainty and a stochastic process to extract values from it. For wind parks the mean value of the capacity factor varies from 0.20 to 0.30. For hydro stations we admitted three possible intervals that can be used to model an average hydro year (capacity factor ranging from 0.26 to 0.30), dry year (capacity factor from 0.20 to 0.25) and wet year (capacity factor from 0.31 to 0.37).

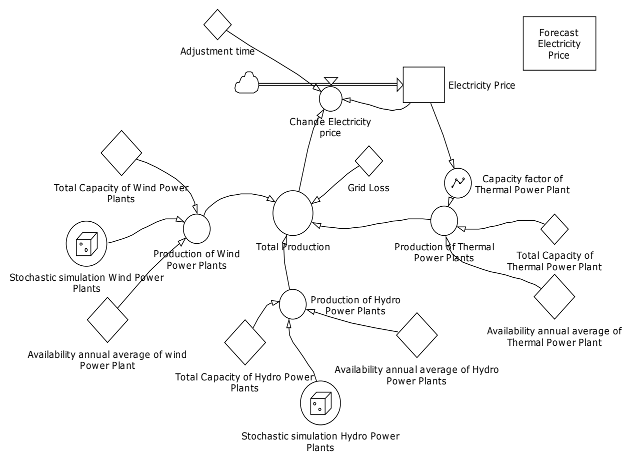


Fig. 2. Dynamic model to simulate the electricity price.

Finally, the electricity price is modeled using values obtained from generation and demand evolution and this model plays a key role because it outputs the evolution of the price as a result of the interaction of different sub models as illustrated in Figure 2. From a mathematical point of view, the electricity price evolution is given by (5) and (6). According to (5), the electricity price in period s is determined by the reference value in the starting period plus a term that is influenced namely by the unbalance between the demand D and the available generation Pg together with an attenuation factor AF that can be used to smooth the impact of these unbalances on the prices.

$$Pe_S = Pe_{S=0} + \int_0^S \Delta Pe_S . ds \quad (5)$$

$$\Delta Pe_S = Pe . \left( \frac{D - Pg}{D} \right) . \frac{1}{AF} \quad (6)$$

As the Dynamic Simulation evolves, the model estimates the demand level at each time step. If there is an unbalance between the demand and the available capacity, there will be a positive impact on the electricity price that can be attenuated by a value of AF larger than 1. When this approach iterates, the increase of the electricity price will correspond to a signal to investors to build and commission new generation stations or to the consumers to reduce the demand level.

## IV. Illustrative Example

### *A. Data*

The approach detailed in Sections II and III is illustrated considering that a generation company is evaluating the possible investment in a new CCGT station. The existing generation system is characterized in Table I in terms of the technologies, the installed capacity and the Forced Outage Rate of each unit, FOR. On the other hand, at the departing stage the distribution of the installed capacity by technologies is as follows: 50.33 % in thermal units; 13.25% in wind parks, 29.80% in hydro stations and 6.62 % in cogeneration units.

TABLE I: Characteristics of the existing technologies.

| no. units | Technology | Inst. Cap. (MW) | FOR |
|---|---|---|---|
| 5 | coal_1 | 1.000 | 0.02 |
| 2 | coal_2 | 600 | 0.02 |
| 3 | gas turbine | 500 | 0.02 |
| 6 | CCGT | 1.500 | 0.02 |
| 2 | oil | 200 | 0.02 |
| 6 | wind parks | 1.000 | - |
| 4 | hydro reservoires | 750 | - |
| 8 | hydro run-of-river | 1.500 | - |
| 20 | cogeneration | 500 | - |

In the initial year, we admitted that the peak power was 4750 MW and the annual demand was 30.64 TWh. We also admitted that the annual load duration curve was discretized in 6 steps as follows: 100% of the peak power during 5 % of the year, 90% for 20 % of the year, 80% for 45 % of the year, 70% for 65 % of the year, 60% for 85% of the year and 50% of the peak power during 100% of the year. Along the planning horizon we admitted that the annual demand increased as determined by the Dynamic Model but these discretization steps remain unchanged.

As mentioned, the objective of this study is to evaluate the economic interest in building a new CCGT thermal station with an installed capacity of 400 MW. Table II details the technical and economic aspects of this project. Finally, along the planning horizon of 25 years (duration of the life time of the new possible station) it was assumed that the distribution of the installed capacity by technologies remains unchanged. This is not a constraint of the developed model, since the model can also be used considering an input schedule of new additions along the horizon.

TABLE II – Input Data for the New CCGT Plant.

| | Mean | Standard desviation |
|---|---|---|
| Capacity (MW) | 400 | |
| Investment cost (€/kWe) | 550 | 50 |
| Economic life time (years) | 25 | |
| Fuel cost (€/MWh) | 22.9 | 3 |
| Variable O&M costs (€/MWh) | 2.8 | 0.5 |
| Fixed O&M costs (€/MW year) | 20 | 5 |
| Thermal efficiency (%) | 50 | 5 |
| Cost of capital (€/MW.year) | 44133.4 | 5000 |
| Rate of fuel cost increase along the life time of the plant (%) | 2 | 0.5 |

### *B. Deterministic Analysis*

In the first place, it was conducted a deterministic analysis considering the mean values in Table II and the capacity factor and electricity price evolution provided by the Dynamic Model, briefly described in Section III. Under these conditions, the average capacity factor obtained for the new thermal station was 73 % and the average electricity price was 52 €/MWh. Then, using these values, we conducted the economic analysis using 7% for the discount rate. Using this deterministic approach, we obtained 92.15 million € for NPV and 10.1% for the IRR. Accordingly, this investment seems attractive but we should have in mind this is a preliminary analysis determined by the average values in Table II, by the generation mix, namely regarding the installed capacity in wind parks and in hydro stations, as detailed in Table I.

### *C. Risk Analysis*

The previous results do not incorporate the impact of the uncertainties affecting several input parameters. In this Section we report the results obtained from the risk analysis that was conducted using Normal FDPs to model the parameters in Table II and adopting a Log-Normal FDP to represent the electricity price with a mean value of 52.0 €/MW.h and a standard deviation of 4.0 €/MW.h. Regarding the capacity factor, we also modelled it using a Normal FDP. For the mean value, we adopted the capacity factor of 73%, that is the value that was estimated by the Dynamic Model as reported in Section IV.B and then we also specified a standard deviation of 5%. This means we didn't actually run the Dynamic Model again, but rather used probability functions built over the results of the deterministic analysis of Section IV.B. Using these FDP's, we sampled a large number of sets of values of the parameters now subjected to uncertainties and then we used expression (3) to obtain the corresponding NPV values. The obtained NPV values are displayed in the histogram in Figure 3 and Figure 4 displays the NPV cumulative distribution curve. These results indicate that the probability of the project displaying a negative NPV value is zero. Finally, Table III presents some financial indicators as the minimum, mean and maximum NPV values, the coefficient of variation computed using (4) and the value of IRR, 10.1% in this case.

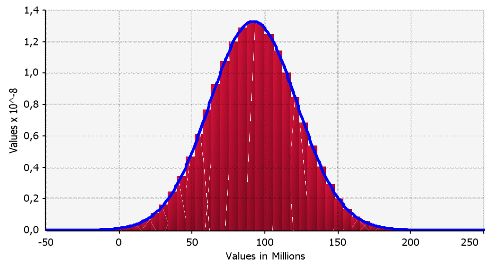


Fig. 3. Histogram and normal distribution function of NPV.

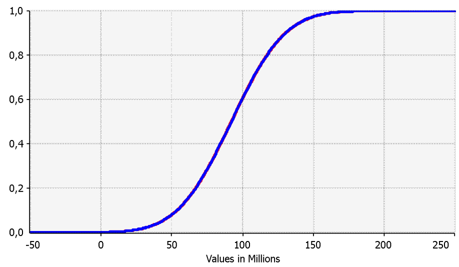


Fig. 4. Ascending cumulative distribution curve of NPV.

TABLE III - FINANCIAL INDICATORS

| Indicators | Value |
|---|---|
| NPVmin ($10^6$ €) | 26.23 |
| NPVmean ($10^6$ €) | 92.15 |
| NPVmáx ($10^6$ €) | 213.46 |
| CV | 0.32 |
| Pr(NPV<0) | 0.00 |
| IRR (%) | 10.1 |

### *D. Sensitivity Analysis – Case 1*

In order to gain more insight on the interest of this project, we established a scenario in which the presence of renewable stations is larger. We admitted that the installed capacity in wind parks and in hydro stations correspond to 20% and to 35% of the total. Using this modified generation mix, we ran again the Dynamic Model described in Section III and, as a result, the capacity factor of the new CCGT was reduced from 73% to 64%. The electricity price was also reduced to 44.0 €/MWh. Using this information, we repeated the economic study of the project using again the inputs in Table II.

The deterministic analysis indicated that the project got degraded given that the NPV reduced to -13.98 million € and the IRR is now 6.1%, which is smaller than the discount rate of 7% admitted for the project. Accordingly, this investment shouldn't be approved because a small increase on the share of renewables (for instance, induced by political measures to increase the presence of wind parks and PV panels) was sufficient to degrade the economic indicators of the project. Finally, Figure 5 displays the cumulative distribution curve for NPV. According to this curve, we can conclude that the probability of the project displaying a negative NPV value is 0.62. This value reinforces the conclusion that under these conditions the project is very risky.

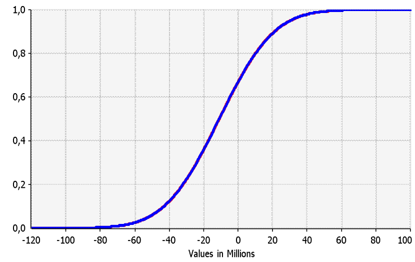


Fig. 5. Ascending cumulative distribution curve of NPV.

### *E. Sensitivity Analysis – Case 2*

At a final step, we conducted a study to estimate the value that should be adopted for an eventual capacity tariff that would turn the investment more attractive. This type of study is relevant, namely for market design activities conducted by Regulatory Agencies, and also for the security of power systems itself namely in cases where there is a large penetration of renewable stations using volatile sources (namely wind and solar radiation). In these systems, thermal plants can play an important role in terms of providing reserves and so adequate remuneration schemes should exist to pay them while creating economic conditions for new investments on thermal stations.

We will now detail the changes introduced in the approach described in Section II in order to include a capacity payment term as a way to turn generation investments more attractive and less risky. In this case, the capacity payment should be enough to compensate the fixed costs, namely for the stations that have a lower capacity factor along the horizon, that is, the ones according to their technology or the price of fuels are less used. In some way, we admitted that less extensively dispatched stations can be more frequently used to provide reserve services thus contributing to increase the security of the system. This extra remuneration would then help turning some investments still attractive even though they can display larger operation costs. Currently, such an approach can be interesting in view of the large penetration of technologies using volatile renewable resources, as wind and solar radiation. Even though the installed capacity in wind parks is large in some countries (about 22% of the total capacity in Portugal, for instance), CCGT or coal thermal stations and if possible hydro stations are still required namely to cope with the volatility of wind. If only paid the market price, some investments in traditional technologies would not be justified and so a capacity payment or the participation in the provision of reserves becomes a way to of inducing such investments.

In order to model this capacity payment, expression (1) was changed introducing a new term in the summation, namely for the periods in which the station was not dispatched so that we obtain (7). In this expression, $P_{cap}$ and $P_{inst}$ represent the capacity payment in €/MW and the installed capacity in MW associated with this station. On the other hand, $\alpha_s$ is the capacity factor expressing the percentage of the number of hours in period s during which the station under analysis is in operation. The value of the capacity factors $\alpha_s$

along the planning horizon are then estimated by the long term Dynamic Model described in Section III.

$$Pf = \sum_{s=1}^{S}\left[Energ_S.(Pe_S - Cost_S) + P_{cap}.(1-\alpha_S).P_{inst}\right] \qquad (7)$$

Considering this expression, it is clear that if the Dynamic Model estimates a large value for the capacity factor $\alpha_s$ of a particular station, then it will not be possible to use it so intensively for reserve purposes, meaning that the amount to be provided by the capacity term will be reduced. On contrary, a station that is more rarely dispatched in the market, has a larger value for $1-\alpha_s$ meaning that it is available to provide reserve services. In any case, and for security reasons we limited the amount of reserve that can be provided by a station to 80% of its installed capacity.

Using the economic and technical data in Table II, we concluded that the capacity payment required to obtain a IIR value equal to the discount rate used in the simulation (7%), was 5 €/MW. Under these conditions, the NPV is 14.73 million €. If, for instance, the Log-Normal FDP representing the electricity price has a mean value of 44.0 €/MW.h and a standard deviation of 4.0 €/MW.h and the Normal FDPs modelling the capacity factor has a mean value of 64% and a standard deviation of 5%, then we obtain the cumulative NPV distribution in Figure 6. This curve indicates that the probability of getting a negative value for NPV gets reduced from 0,62 to 0.3, suggesting that under these conditions this investment has a moderate risk.

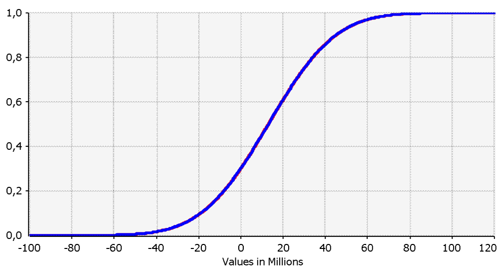


Fig. 6. Ascending cumulative distribution curve of NPV.

Going further on this sensitivity analysis, if the capacity tariff was increased from 5 to 7 €/MW, then the NPV would increase from 14,73 to 26.23 million € and the IRR would rise to 8%. As a result of this change, the probability of getting a negative NPV would be reduced from 0,3 to 0.12 indicating that the project would be less risky.

This interaction between the economic analysis and the Dynamic Model to obtain long term estimates is very relevant, not only for generation agents when deciding if developing or not a possible investment project. This is also important for Regulatory Agencies and market designers to set different values adequately and to investigate if parameters and tariffs provide in the long run the most adequate results not compromising the security of supply.

## V. Conclusions

The increased presence of renewable power stations namely using volatile resources as wind and solar radiation places new challenges to power systems not only from the point of view of their daily operation but also when conducting expansion planning studies and deciding new investment projects. This is the case of new thermal power station projects, since these stations are already facing and will probably face in the next years more reduced capacity factors than in the past, thus reducing their expected profits.

This paper describes an approach designed to evaluate on the long term the economic interest of this type of investments. This evaluation involves the computation of a number of economic indicators to give insight to a specific project. This economic evaluation is linked with a long term power system modeling tool implemented using Dynamic Systems and designed to provide estimates on a number of parameters required by the economic evaluation. These characteristics together with the internalization of uncertainties turn these tools of interest not only for generation agents but also to policy makers helping them investigating the most adequate designs for several aspects of power systems.

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