A robust investment strategy for generation capacity in an uncertain demand and renewable penetration environment

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***Abstract*—With the growing environmental and energetic concern, the issue of adapting our energy systems is paramount. This paper deals with the issue of new optimal energy mixes in a high renewable energy share context, and capacity investment in such a framework. We use the "screening curve" method to determine competitors' investments and deduce the benefit of a conventional generator. This work is carried out using a robust approach i.e. we determine a threshold of benefit we want to reach with a defined probability no matter the actual demand and renewable penetration. To determine this solution, we consider four demand scenarii and levels of installed capacity both for wind and for photovoltaic energy. This work is undertaken for the French case. Some results are shown for a coal power plant with 2030 scenarii for demand, wind and solar capacity.**

***Keywords*—Wind energy, Solar energy, Power generation planning, Power system economics, Profitability.**

I. Introduction

The path towards liberalization in the electricity sector [1] brings forward issues related to investment under uncertainty. In contrast to a monopolistic structure, independent generators have to ensure their investment pay-back based on one or several projects only, being deprived from the possibility to soften errors on demand and production projections, and to have visibility on their competitors' projects.

Moreover, renewable energy's impact is increasing. Renewable generation either sold through feed-in tariffs or sold on electricity markets at zero marginal cost, results into lower demand left for conventional power plants and this increases the uncertainty on the demand forecasts used to make an investment decision.

These are two factors which may prevent new investments, as decision-makers are usually risk-averse. In this view, it is interesting to develop a robust approach i.e. to determine strategies which guarantee a minimum level of benefit with a given probability. This is consistent with the emerging capacity availability issue on liberalized markets. Indeed, in a competitive electricity market, peak means of production seem to have difficulties at being beneficial, or are reluctant to carry out investment in an uncertain legal and economic environment [2].

Another issue is the transformation of the optimal energy mix related to the massive introduction of renewable energy. The existing systems result from investment decisions carried out decades ago. The future investments need to take into account the new environment in which they will produce energy. Based on legal commitments (such as the European Climate and Energy package), this environment will include a large share of renewable energy. We are interested in analyzing how the bigger renewable share will change the optimal energy mix. This issue was dealt with in [3], for the Great Britain case, for scenarii with and without wind energy.

II. Objectives

In this work we are interested in finding opportunities for investment in new power plants. We determine an investment strategy (capacity of a new plant) considering a set of scenarii for demand and renewable penetration levels. Instead of determining such a strategy by maximizing the mean benefit obtained from trading on the electricity market, we are interested in a robust solution i.e. ensuring that the project is profitable (the benefit exceeds a certain threshold) with a defined probability no matter the actual demand and renewable production levels. To our knowledge, this robust approach used to deal with renewable penetration is new in the literature [4].

III. Method

Our work is based on the "screening curve" method which determines the optimal energy mix for a given demand scenario. This enables us to determine the benefit of the considered generator (named i_0 in the following) for each scenario (associated with a probability), according to different investment levels. Finally we select a level of capacity which satisfies our criterion.

A. The screening curve method

The screening curve method determines what the optimal energy mix would be considering a given load duration curve[1] and the costs of the available power plants.

The cost of one megawatt according to the number of hours it is used is given by the following relation:

$$F_i + V_i h \qquad (1)$$

where F_i is the yearly fixed cost, V_i is the variable cost per megawatt hour for generator *i*, and *h* is the number of hours where the considered megawatt is used.

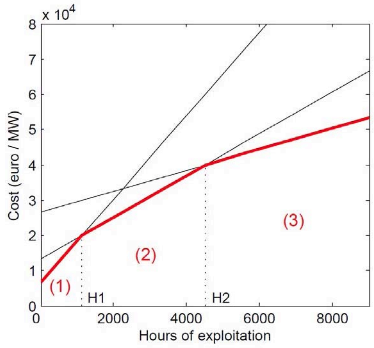

Fig. 1. Example of 3 cost functions

The fixed cost corresponds to the yearly investment cost for one megawatt, and the operational cost corresponds to the costs the generator has to bear to produce one megawatt hour (fuel, maintenance). This way, it is possible to recover the cost of one megawatt according to the number of hours it is used during the year.

Consequently, the energy mix may be determined by using the least expensive production means according to each type of hours. This is illustrated in Fig.1 where the cost per megawatt of three different units according to the number of hours is shown. The red lines correspond to the least expensive costs for each type of hours. This means that producer (3) should be used for base demand (as it is the least expensive per megawatt when it is called H2 hours or more during the year). Producer (2) should be used for intermediate hours (between H1 and H2), and producer (1) should be used for peak hours. Finally, the load duration curve enables us to determine the level of investment for each type of power plant (respectively C1, C2 and C3 in Fig.2) according to hours defined with the cost functions (here H1 and H2). In our work, we will consider a load duration curve representing reduced demand (demand minus renewable energy production) for each scenario.

[1] A load-duration curve orders a chosen year's hours from highest demand to lowest. The hours on the left will correspond to peak hours, the hours in the middle, to intermediate demand and the hours on the right will correspond to off-peak, base hours.

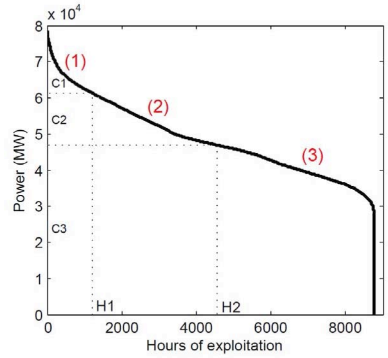

Fig. 2. Example of load duration curve

From here, the market prices may be estimated considering the cost of the most expensive generator called for each hour (assuming all generators are non strategic).

B. Investment assumptions

We consider there is one generator per type of plant.

The "screening curve" method implies we know exactly the fixed and variable costs of all available generators. We assume all generators have this information.

At the investment stage, we assume the considered generator does not have perfect information on the reduced demand level (the actual scenario). On the contrary, we assume the competitors know the scenario and invest accordingly. They will invest as if all generators had perfect information, except for the generator corresponding to the last means called. To fulfill the demand at any time, we consider that this generator (loss of load or demand side management) may adapt and over-invest if necessary.

C. Market price assumptions

We suppose that once the investment has been carried out, the generator will have perfect information on the scenario and adapt its offer price (price required to produce) accordingly.

On the one hand, we consider i_0, a strategic generator, bidding in order to maximize its benefit. On the other hand, we assume other generators have a non-strategic behavior, meaning their bids reflect their true cost (including fixed and variable cost). Formally this means that the offer price π_{ij} for a megawatt *j* sold by producer *i* for one hour is given by $\frac{F_i + V_i h(j)}{h(j)}$ where *h(j)* is the number of working hours for megawatt *j* and is obtained with the load duration curve. This way, π_{ij} does not depend on time. For a megawatt *j* produced by the strategic generator i_0, the offer price is different when its true cost is the smallest among all producers' (when it is price-maker). In this case, i_0 bids an offer price higher than its true cost, but lower than other offer prices in order to ensure it is selected. Therefore, the offer is $\pi_{i_0 j} = \min_{i \neq i_0}(\pi_{ij}) - \varepsilon$ where the gap ε is supposed fixed. Fig. 3 illustrates this with an example of true cost for i_0 (red line) and competitors' offers (blue lines) for the same megawatt j.

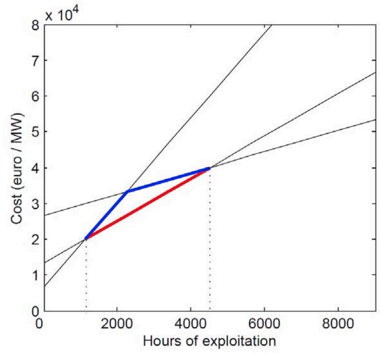

Fig. 3. Minimal (red) and maximal (blue) cost

D. Determination of a robust investment solution

In this framework, once a level of investment in capacity is chosen for our generator, and the scenario is known, its benefit can be directly deduced.

Indeed, the benefit of generator i_0 investing in a capacity of X megawatt is:

$$Benefit(X, i_0, \omega) = (\pi_\omega^m - V_{i_0}) \cdot P_{i_0\omega}(X) - F_{i_0} \cdot X \qquad (2)$$

π_ω^m and $P_{i_0\omega}(X)$ are vectors of length 8760 (number of hours in a year) containing respectively market prices and production sold for a given scenario ω. The market price at a given time is the maximum accepted offer. The production is limited either by the actual capacity X or the maximal amount of accepted offers. On hours where i_0 is price-taker, it is maximal.

We use a Monte Carlo method to estimate the considered generator's benefit for different values of installed capacity. To this end we consider several scenarii for demand occurring with defined probabilities. This means that for each value of installed capacity, we have a range of possible benefit with the associated probability. All that remains is to determine the values of installed capacity which satisfy the criterion (i.e. exceed a defined threshold) with a good probability. Note that this could be extended to continuous density functions with assumptions on the density of the demand.

IV. CASE STUDY

A. The generation cost data

We consider the French energy mix generators: nuclear, gas, coal, oil and a fifth which corresponds to demand-side management (loss of load could also be considered).

The considered costs [5] are given in table I.

TABLE I. ENERGY COSTS

Generation	Nuclear	Coal	Gas	Oil	Demand Side Management (DSM)
Fixed cost (k€/MW/year)	287	174	73	62	5
Variable cost (k€/MWh)	0.007	0.02	0.035	0.045	2

B. The demand data

We fix 2030 to be the year of analysis. To produce demand forecast data, we use 2011 real demand data from the French Transmission System Operator, RTE. As we consider the French energy system (nuclear and thermal), the hydro is subtracted from the demand. In these data, the overall consumption is 476 terawatt hour (432 terawatt hour once the hydraulic generation is subtracted). We resize these data considering the yearly forecasted consumption in 2030, provided by RTE's "Generation adequacy report 2012" [6]. Although the consumption scenarii considered in this report are prospective, i.e. they tend to describe evolutions according to political or social decisions, we consider them as equiprobable scenarii of demand evolution.

For 2030, RTE's generation accuracy report provides four scenarii for demand: an intermediate scenario, a scenario with low and high demand levels, and a scenario where a new energy mix gives more importance to renewable energy.

TABLE II. DEMAND AND RENEWABLE CAPACITY SCENARII

Scenario	High	Intermediate	New Mix	Low
Yearly consumption (TWh)	648	589.4	557.3	468
Wind Capacity (GW)	24.5	24.5	28	18.5
Solar Capacity (GW)	20	20	30	12

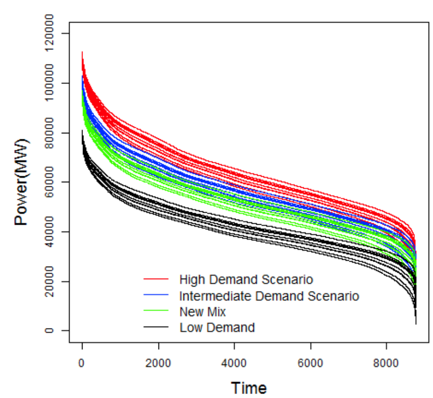

Fig. 4. Load duration curves for each scenario

C. The renewable energy data

We consider hypothesis for installed capacity coming from the same scenarii as for demand (see Table II).

We use normalized wind production data generated in [7] for France for the same year as demand (to keep any correlations due to temperature or weather conditions between the sets of data). They are generated using MERRA (Modern Era Retrospective-Analysis for Research and Applications, from National Aeronautics and Space Administration) reanalysis recalibrated with ECMWF (European Centre for Medium-Range Weather Forecasts) and extrapolated to get 80 meters from ground wind speed data. The power curve (transforming wind speed to power) is then based on a statistical estimation from French regional production data.

The photovoltaic data used are global horizontal irradiation estimations coming from the Helioclim 3 database, converted to electrical power using French production data to calibrate the power conversion.

V. RESULTS

The calculation is carried out using the R software environment.

We have carried out the calculation considering a coal power plant. Fig.5 and Fig.6 show offer prices (we keep the order from peak to base hours) for Demand side management (DSM), Oil, Gas and Coal power plants, on hours where they are price-maker (otherwise the values are put to zero), for six levels of investment (from 0 to 20 GW). Each level of investment corresponds to a group of 4 strips (each strip corresponding to a level of demand and being composed of all scenarii on renewable energy): red strips corresponds to the high demand, blue to the intermediate, green to the new energy mix and black to the low demand scenario. The nuclear offer price is zero up till the last 69 hours of the year.

DSM is called more hours when investment is insufficient. Afterwards, the number of hours when it is called remains the same as considered investment has reached the required level (fourth level in Fig.5 left) and as surplus investment is lost (those megawat cannot compete with megawatt from other generators as their cost are higher). In the same way, oil or gas stations hours are posponed (corresponding in reality to calling them earlier, for lower levels of demand) when the investment in coal is insufficient. The coal station is called according to its investment (zero offer price with zero investment and smaller number of hours when under-investing). Finally, in our work, nuclear is price-maker a few hours (69), and having the highest priority in the merit order, it is not impacted by the investment in other means of production. We also find that with lower demand levels (black strip), or higher renewable penetration (green strip) which also decreases demand, DSM production is called for more hours (and shifts others means consecutively).

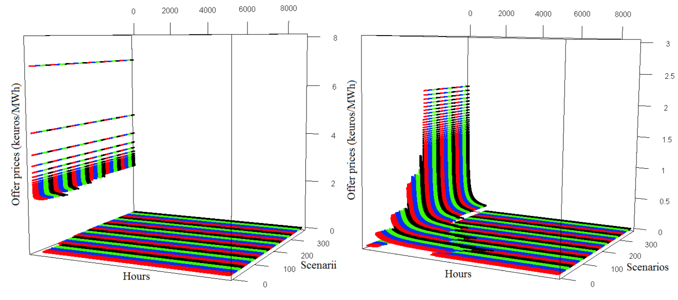

Fig. 5. Offer price for DSM and Oil for all scenarii

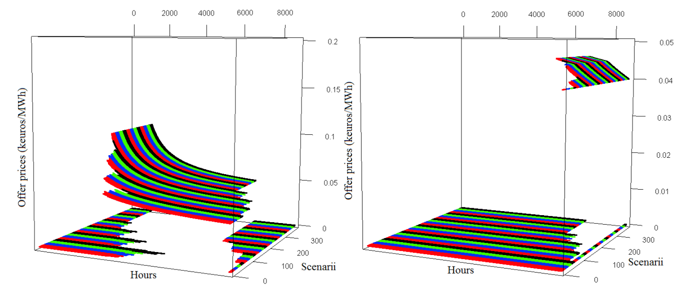

Fig. 6. Offer price for Gas and Coal for all scenarii

Fig.7 displays the market price and the level of investment which would be optimal for each scenario. The market price is showed for all the yearly hours (we keep the order from peak to base hours), according to the 64 scenarii and 6 levels of investment. The average of optimal investment according to each scenario is 14.9 gigawatt. We also find that optimal investments increase when the demand or the renewable share increase (see Fig.7 right where up peaks correspond to higher renewable capacity installed).

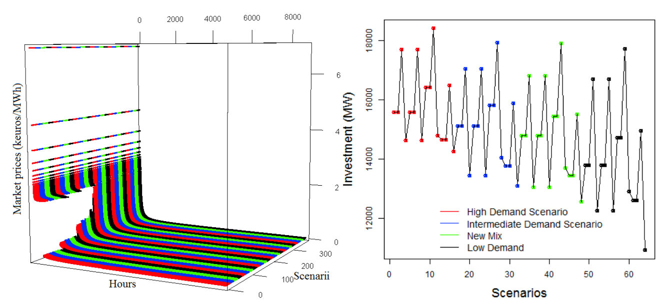

Fig. 7. Market Price and recommended investment per scenario

The benefit threshold is fixed to 4 billion euros, and the probability requirement to 0.8. The highest benefit investment changes according to scenarii. Fig.8 shows the limit where the actual investment is smaller than the optimal investments for the considered scenarii. After this limit, the benefit becomes linear and decreasing. Indeed, the amount of sales does not change (the volume of power used and offer prices do not change anymore), and only the investment cost wears down the benefits. We find that the surest investment is between 10.5 and 14 gigawatts (Fig. 9), lower than the average value of optimal investment according to each scenario.

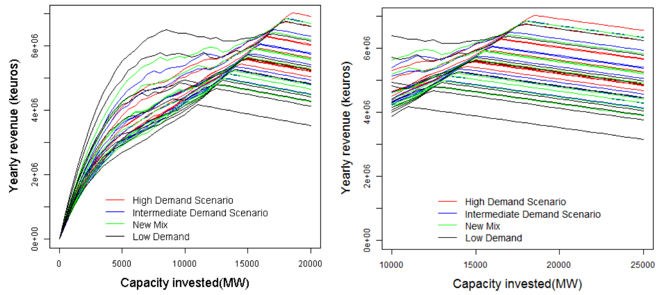

Fig. 8. Benefit according to investment levels for all scenarii

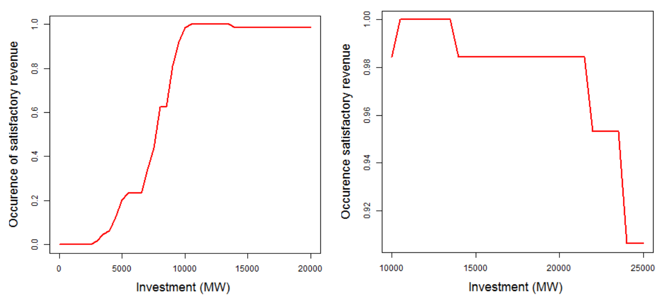

Fig. 9. Probability of satisfying the criterion according to investment levels

Indeed,the robust solution depends on the level of benefit required. In Fig.8 we see that the required level is met for most scenarios for investments between 10 and 14 Gigawatt.

Analysing this issue for several benefit requirements, we find that they are no investment guaranteed for a threshold of more than 5.1 billion euros (Fig.10). The most robust investment remains under the average optimal investment according to scenarios to ensure enough scenarios will satisfy the required benefit.

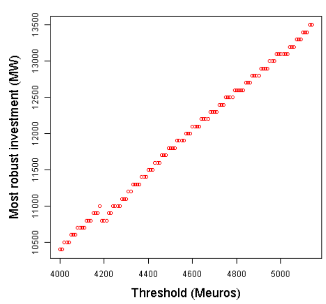

Fig. 10. Investment with highest probability of satisfying the criterion according to different tresholds

VI. Conclusions and Perspectives

This work's purpose was to introduce a new method to determine a robust investment decision. We show that a simple approach using the optimal investment for one scenario, or the average on several scenarios may differ strongly from the robust solution, as it is highly dependent on the criterion used.

Further work could focus on improving demand and renewable production scenarii considered (with their respective probability), and more scenarii could be described. This method could also benefit from modeling a Gaussian noise around the considered scenarii to analyze the impact of deviations from the projected demand and renewable levels.

We have considered the scenario known to the decision-maker once the investment was carried out. A development of this work could also be to consider scenarii on the offer price determination process, to model the imperfect information of the generator. This could also be done for generator costs assumption. Detailed analysis on power plants costs would also be a perspective to improve the results of our model.

Finally, this work was undertaken for conventional plants but it could also apply to investment in renewable energy.

Acknowledgment

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