46755 – Assignment 2

Deadline: May 8, 2023 (23:59pm)

April 17, 2023

Step 1

In lectures 8 and 9, you learn the offering strategy of price-taker renewables. Please consider a wind farm with the nominal (installed) capacity of 150 MW. We are interested to formulate and solve an offering strategy problem for this farm. This problem determines her participation strategy in the day-ahead market (in terms of her hourly production quantities). Note that her offer price is zero. We consider a time framework of 24 hours. Please also note that we discard reserve and intra-day markets, and consider day-ahead and balancing markets only.

Sources of uncertainty: Please consider three sources of uncertainty, namely:

1. Hourly wind power production in the next day
2. Hourly day-ahead market prices in the next day
3. The power system need in the balancing stage in every hour, i.e., the system has either a power supply deficit or excess.

We will generate scenarios to model these three sources of uncertainty. For simplicity, we assume there is no correlation among these three sources of of uncertainty.

Scenario generation for wind power production forecast: Potential references are as following:
Reference 1: You can get wind data from the FINGRID website (Finnish TSO) or the ELIA website (Belgian TSO), and normalize them for a 150-MW wind farm. Although they report "aggregate" wind data, you can assume they are data for an individual farm. The wind profile during a day can be seen as a scenario. For example, wind profile on March 1 can be seen as scenario 1. This profile on March 2 can be seen as the second scenario, and so on.
Reference 2: `https://sites.google.com/site/datasmopf/wind-scenarios`
Reference 3: `https://www.renewables.ninja`

Scenario generation for day-ahead price forecast: Using a similar strategy, you can generate price scenarios for 24 hours from the Nord Pool website. For example, you can assume the wind farm is located in DK1, and use the corresponding hourly day-ahead market prices.

Scenario generation for the power system need (excess or deficit): You can generate a series of 24 random binary (two-state) variables, e.g., using a bernoulli distribution, indicating in every hour of the next day, whether the system in the balancing stage will have a deficit in power supply or an excess.

Final scenarios: To model three sources of uncertainty, please consider at least 600 scenarios. Discarding the potential correlation between these three sources of uncertainty, the total number of scenarios is equal to the number of scenarios for uncertain source 1 times the number of scenarios for uncertain source 2 times the number of scenarios for uncertain source 3. For example, if we consider 10 wind power scenarios, 20 day-ahead price scenarios, and 3 power system need scenarios, this results in 10*20*3 = 600 scenarios.

Out of these scenarios, we will arbitrarily select at least 200 scenarios (the so-called *in-sample* or *seen* scenarios) and will use them in Steps 1.1 to 1.4 for decision-making, i.e., the determination of the optimal quantity offer in the day-ahead stage. The rest of scenarios (the so-called *out-of-sample* or *unseen* scenarios) will be used later in Steps 1.5 and 1.6 for an ex-post analysis. We can assume all scenarios are equiprobable. In other words, in case we consider 200 in-sample scenarios, the probability of each scenario is 0.005.

Note 1: Under a **one-price** balancing scheme, we can generate corresponding balancing price forecasts, based on scenarios generated for day-ahead prices and for the power system need. Recall that Energinet has switched to this scheme since November 2021. The balancing price is higher (lower) than the day-ahead price if the power system has a power supply deficit (excess) in the balancing stage. Similar to the lecture, let's assume *balancing price = coefficient * day-ahead price*, and use coefficients 0.9 and 1.2 to generate balancing prices.

Note 2: Unlike Note 1, we cannot generate balancing price scenarios *a priori* if the balancing stage uses a **two-price** scheme. Recall that the balancing price will be equal to the day-ahead price if the underlying wind farm provides a positive imbalance, i.e., helps the system to cope with the system imbalances. Before determining the optimal quantity offer in the day-ahead stage, we will not be able to quantify the imbalance (whether it will be positive or negative) and therefore cannot identify whether the wind farm provides a positive imbalance or not.

The following are the guidelines for this step.

1.1 **Offering strategy under a one-price balancing scheme:** Formulate and solve the stochastic offering strategy problem accounting for a one-price balancing scheme and in-sample scenarios. Determine the optimal hourly production quantities that the wind farm should offer in the day-ahead market. Report the expected profit. Please also illustrate the profit distribution over scenarios.

1.2 **Offering strategy under a two-price balancing scheme:** This step is similar to Step 1.1, but reformulate it for a two-price balancing scheme. Please note that we should modify the model in a way that it endogenously identifies in every hour whether the wind farm provides a positive imbalance, and if so, then the corresponding hourly balancing price should be equal to the day-ahead price in that hour. Any remarkable difference between results of Steps 1.1 and 1.2?

1.3 **Sensitivity analysis:** Please conduct a sensitivity analysis by varying the coefficients (one coefficient at a time). For example, first vary coefficient 0.9 from 0.85 to 0.95. Similarly, vary coefficient 1.2 between 1.1 and 1.3. Any interesting observation under one- and two-price schemes?

1.4 **Risk analysis:** For fixed coefficients of 0.9 and 1.2 and given value of α = 0.90, formulate and solve the risk-averse offering strategy problem of wind farm under both one- and two-price balancing schemes. Recall that the objective function is in the form of [(expected profit) + (β * CVaR)]. Gradually increase the value of β, starting from zero. For each value of β, save the values obtained for the expected profit and for the CVaR, and plot a 2-dimension figure (expected profit versus CVaR). Note that the CVaR value does not include β. Please interpret this figure. In addition, please explain how the offering strategy of wind farm and her profit volatility over scenarios are changing by increasing β. Finally, for different values of confidence level (i.e., α=0.80 and α=0.95), repeat this step and report your observations.

1.5 **Out-of-sample simulation:** Given in-sample (seen) scenarios, in Step 1.1, we have obtained optimal hourly quantity offer of the wind farm in the day-ahead stage. Let's indicate it by $p_t^{\mathrm{DA}\star}$ for every hour t. Now imagine the wind farm has already submitted hourly offers $p_t^{\mathrm{DA}\star}$ in the day-ahead stage and earned x euro and we are now in the balancing stage, where uncertainties are being realized. Suppose the realization is based on the first out-of-sample (unseen) scenario. Calculate how much the wind farm should be paid or pay under this realization — let's call it y_1. Note that we do not need any optimization for this stage. Calculate the same for all unseen scenarios, i.e., y_1 to y_{400}, assuming we have 400 out-of-sample scenarios. Now, calculate the *average out-of-sample profit*, i.e., x plus average of y over 400 unseen scenarios. Please report it and check how different it is with respect to the in-sample expected profit we have already achieved in Step 1.1 (i.e., the optimal value of the objective function). How different are the probability distributions of profit in in-sample and out-of-sample analyses? If in-sample and out-of-sample profits (in expectation and their distribution) are significantly different (or indifferent), what does it imply? Now, please repeat the same out-of-sample simulation analysis for Steps 1.2 and 1.4 (under both schemes).

1.6 **Cross validation:** Are the results of Step 1.5 very sensitive to the selection of in-sample and out-of-sample scenarios (the same number of scenarios but different scenarios)? For example, arbitrarily choose another 200 in-sample scenarios out of original 600 scenarios. Please try to find a "good" number of arbitrarily selected in-sample scenarios (which might be different than 200), under which we get similar in-sample and out-of-sample profits. Any recommendation for scenario generation, decision-making, ex-post analyses, etc?

Step 2

In lectures 10 and 11, you learn how to develop an offering strategy problem for a strategic (price-maker) producer, who may own one or multiple generation assets across the network. Please consider a 6-node power grid as illustrated in Figure 1.

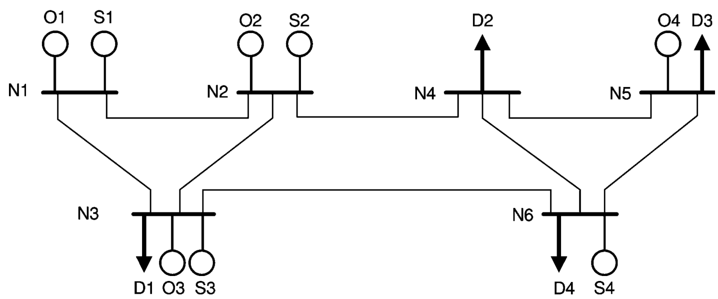

Figure 1: Six-node test system. This figure is adopted from [link].

Generation units "S" belong to the strategic producer, whereas generation units "O" are non-strategic belonging to other producers who are price-takers. Therefore, there is one strategic player only. Note that "D" are price-elastic demands. According to Figure 1, generation prevails in the western area, while demands are mostly located in the eastern side. The operational details of generation units are as follows:

Table 1: Operational details of generation units

Unit	S1	S2	S3	S4	O1	O2	O3	O4
Technology	Coal	Gas	Coal	Gas	Wind	Hydro	Gas	Gas
Capacity [MW]	155	100	155	197	450	350	210	80
Cost [€/MWh]	15.2	23.4	15.2	19.1	0	5	20.1	24.7
Ramp up/down limit [MW/h]	90	85	90	120	-	350	170	80

In the given hour, consider the wind farm O1 produces at 75% of its capacity. The demand profile and bidding prices in the given hour are as follows:

Table 2: Bidding details of demands

Demand	D1	D2	D3	D4
Quantity [MW]	200	400	300	250
Bid price [€/MWh]	26.5	24.7	23.1	22.5

Assumption: The strategic producer has perfect foresight about operational details of other non-strategic producers, bidding details of demands, and network details. This assumption will be relaxed later.

The following are the guidelines for this step.

2.1 **Perfect (non-strategic) competition:** Consider a single hour (no ramp limit for generation units). Consider large enough capacity for transmission lines, such that no line will be congested. Assume for all lines, the susceptance is 50. Consider all producers owning S1-S4 and O1-O4 offer their true cost as reported in Table 1. Formulate the market-clearing optimization problem, and report outcomes, including schedules, the market-clearing prices (one per node), and the value of social welfare.

2.2 **Strategic offering:** Similar to Step 2.1, consider a 1-hour time horizon and transmission lines with large enough capacity to not have any congestion. However, consider that the producer owning S1-S4 offers strategically. Formulate the bi-level model and solve it as a mixed-integer linear program. Please consider large enough values for Big-M (e.g., 10^4). After solving the problem, numerically check whether every single original complementarity constraint is hold — if there is a complementarity constraint violated, reduce the corresponding Big-M value, and solve the problem again. Once they all are fulfilled, please report strategic offer prices (for S1-S4) and interpret them. Is there any strategic offer price which is identical to the bid price of a demand? or is there any which is identical to an offer price of a non-strategic unit? Compare market-clearing outcomes (nodal prices, schedules, and social welfare) with respect to those in Step 2.1, and explain whether they are logical.

2.3 **Network effect** Built upon the model developed in Step 2.2, please fix the capacity of transmission lines N2-N4 and N3-N6 to the power flow across those lines obtained in

Step 2.2. Does this result in congestion (different nodal prices)? Is this congestion in favor of the strategic producer or not? Does congestion change the strategic offer prices? Can we *generalize* our findings, or are they case-dependent?

2.4 **Uncertainty modeling:** Similar to Step 2.2, let's assume there is no congestion. While still considering a single hour, let's now relax the assumption on the prefect foresight of the strategic producer. We model uncertainties on (i) the offer price of non-strategic units O1-O4, (ii) the bid price of demands D1-D4, (iii) the quantity bid of demands D1-D4, and finally (iv) the production of wind producer O1. Similar to the process in Step 1, please generate at least 1000 scenarios, and use at least 20 of them (arbitrarily selected) for in-sample decision-making. In case it is still computationally tractable, please increase the number of in-sample scenarios as convenient as possible. Please consider identical probabilities for in-sample scenarios. The rest of scenarios will be used for an out-of-sample analysis. To generate scenarios, as a simple solution, you may consider coefficients $x1$, $x2$, $x3$, and $x4$ for four sources of uncertainty, such that (1,1,1,1) refers to the single scenario in Step 2.2. For example, the set of coefficients (1.1, 1.0, 1.0, 0.9) could be the second scenario. The scenarios should be reasonable though, for example make sure the total demand under every scenario is less that total available generation capacity. Please note that the strategic offer prices for S1-S4 should not take an index for scenario, as they are first-stage variables. In the out-of-sample analysis, the strategic offer prices are fixed to the values obtained in-sample, so then the market should be cleared for every out-of-sample realization of uncertainties. Please report in-sample outcomes (strategic offer prices, expected profit of the strategic producer, expected social welfare) and out-of-sample outcomes (average profit of the strategic producer and average value obtained for social welfare). Is is straightforward to interpret strategic offer prices?

2.5 **From one to 24 hours with ramping constraints (*this step is optional. In case you complete this step, you will get up to 10% extra*):** Built upon step 2.2 (deterministic, no congestion), please consider 24 hours, where ramping (up and down) constraint of conventional generation units is enforced. For simplicity and avoid the need for initial schedules, enforce ramping limits from hour 2 onward. Consider arbitrary values for the production factor of wind unit O1 across hours. For demands D1-D4, consider different values for their quantity bid and bid price over 24 hours, such that total demand is always less than total available generation capacity. Please repeat the same analysis as those in Steps 2.1 and 2.2. In particular, what are the hourly strategic offer prices? Can we interpret how they are formed?

Remark: Please recall this slide from course introduction on January 30. For any extra page beyond 14, there will be a grade reduction of 1% (for the first 5 pages), and then 2%. In case you go for Step 2.5, it can be reported in page 15. Please note that this additional page should only be used for the results of Step 2.5.

Report template and content

DTU

- ❑ Each report includes the pdf file of your project report, programming code(s), and other files, if necessary. We will check your codes, so please make sure we will be able to run them.
- ❑ Single column
- ❑ Length: as short and efficient as possible, **14 pages** maximum (each report), but we encourage you to not go beyond **10 pages**. Please recall that efficient writing is part of the assessment criteria! An appendix can be included (outside the page limit) for less important information, e.g., input data, etc.
- ❑ A short introduction can be included.
- ❑ Formulation should be included in a complete way. If relevant, you can use a compact representation of your formulation. The notation needs to be defined precisely.
- ❑ There will be a case study. It is recommended to provide the most important numerical results in the form of figures or tables. Please avoid reporting trivial results. It is highly important to interpret and analyze the results obtained.
- ❑ Please include additional relevant information such as number of variables and constraints in the optimization problem, computation aspects (machinery used, time, etc).