MULTI-CRITERIA SHORT-TERM MAINTENANCE OUTAGE SCHEDULING IN SMART DISTRIBUTION SYSTEMS

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ABSTRACT

Effective legislation and standards for the coordination procedures between consumers, producers and the system operator supports the advances in the technologies that lead to smart distribution systems. In short-term (ST) maintenance scheduling procedure, the energy producers in a distribution system access to the long-term (LT) outage plan that is released by the distribution system operator (DSO). The impact of this additional information on the decision-making procedure of producers in ST maintenance scheduling is studied in this paper. The final ST maintenance plan requires the approval of the DSO that has the responsibility to secure the network reliability and quality, and other players have to follow the finalized schedule. Maintenance scheduling in the producers' layer and the coordination procedure between them and the DSO is modelled in this paper. The proposed method is applied to a 33-bus distribution system.

INTRODUCTION

LT generation maintenance plans for the time horizon of a year or more are developed through an iterative coordination procedure between producers and the system operator. ST planning for maintenance decisions is necessary due to changes in operation conditions. In this paper, ST maintenance scheduling is studied in a smart distribution system and a single step procedure between the virtual power players (VPP) and the DSO is introduced. A VPP is a group of interconnected DG units, including renewable and non-renewable units and energy storage systems (ESS) located in different nodes of the distribution system, but managed as a single entity. In ST scheduling, the time horizon and increment differ from LT scheduling. In this model, the DSO provides the opportunity of resubmitting the maintenance outage plans for the following ST time horizon to those units that were previously considered for maintenance during this interval in LT plans.

In comparison to LT maintenance scheduling, planning in the ST time horizon provides the VPPs with an efficient means to reach their outage decisions. They conservatively estimate the time periods that other VPPs choose for the maintenance outage, based on the information released after LT scheduling and the higher access to system conditions that they normally have in a smart grid. In this model, the decisions of VPPs are made simultaneously and each VPP can submit several plans to the DSO with different levels of priority and payments in case of deterioration in the reliability and security indices of the system.

Game theory is applied to model maintenance scheduling in oligopolistic electricity markets, and the VPPs are considered as market players competing in a Cournot model. The Nash equilibrium of each VPP is obtained by maximizing its ST profit in a pool market.

Operational decisions need the approval of the DSO, which is responsible for planning, operating, and managing the distribution system. Maintenance outages naturally deteriorate the grid reliability and increase the operation cost; therefore, the DSO should check the VPPs' proposals from the viewpoint of security and reliability constraints and probably modify them.

This work develops the coordination procedure proposed in [1] by introducing a model for maintenance outage scheduling in the level of producers. In [1] the reaction of the DSO to suggested maintenance outage plans of producers is modelled. A stochastic model for optimal risk-based outage scheduling based on hourly price-based unit commitment is suggested in [2]. The scenarios reflect the randomness in hourly prices of energy, ancillary services and fuel. In this model, maintenance scheduling of generation companies is not affected by the loads' behaviour during the scheduling time interval. In [3], line maintenance is included as constraint for unit maintenance scheduling problem. However, the generating units do not consider the load forecasts or the generation patterns of rival units. Supply function equilibrium is used in [4] to represent the strategic behaviour of each electricity supplier.

ST maintenance scheduling is studied in a 33-bus distribution test system, which has high penetration of DGs and ESSs, from the viewpoint of each individual VPP and considering the regulating authority of the DSO over proposed outage plans.

SMART DISTRIBUTION SYSTEMS

The technologies that support bidirectional communication infrastructure in distribution systems enable them to experience effective coordination procedures between the participants and consequently function smarter [1].

The main responsibility of the DSO in a smart grid is regional grid stability and load balancing. In the EU commission task force for smart grids, DSO is introduced as an independent entity in charge of distribution system operation, maintenance, development in the given area, and interconnection with other systems [5].

Due to the time limitation, an iterative coordination procedure between the producers and the DSO appears impossible and consequently a single step procedure is used in the proposed ST maintenance outage scheduling.

PROBLEM OF THE VPP

The expected payoff of VPPi during the following time horizon is shown in (1). Each VPP seeks the maximum payoff during the scheduling horizon of T periods. Two markedly different functions are considered to model the revenue function of an individual VPP at time period t and for scenario s. The index of each generating unit or ESS is j in (1), and Δ_i is the set of generating units owned and managed by VPPi. The sign P^s shows the probability of occurrence for each expected scenario.

$$\Pi_i = \sum_{j\in\Delta_i}\sum_{s=1}^{S}\sum_{t=1}^{T} P^s.\left[\mathrm{Rev}_j^s(t) - \mathrm{Cost}_j^s(t)\right] \quad \forall i \qquad (1)$$

The underlying distinction between the two revenue functions is the inclusion of rival's decisions in the decision-making procedure of VPPi. In the first revenue function (2), the price of electricity λ for each time period of the following ST time horizon is considered as a stochastic input data (2). The uncertainty in forecasted price scenarios is considered in the model by the assigned probability.

$$\mathrm{Rev}\,1_j^s(t) = \lambda^s(t)\cdot P_j^s(t) \quad \forall j \qquad (2)$$

Inverse demand function is used in the second revenue function (3), to model the reaction of loads to the changes in price. Implementing the second revenue function depends on an uncertain estimation of other VPPs probable generation pattern during the following ST time interval. Various sources are used to build the proper assessment of an individual VPP of what others can produce during the following time horizon. The LT plans that are publicly announced by the DSO for all the participants in the market are implemented as a reliable means to help each VPP make an acceptable realization of what other competitors in the market might produce during the following ST time horizon. Maintenance outage decisions are the main elements in LT plans that are trusted by the target VPP in this form of the revenue functions. This interconnection between the decisions of the market players takes place in oligopolistic electricity markets, where few players compete with each other to maximize their profits. When the decision variables are the generation quantities, the Cournot model, a game theory-based approach, is used to calculate the Nash equilibrium.

$$\mathrm{Rev}\,2_j^s(t) = \left[a^s(t) - b^s(t)\cdot D^s(t)\right]\cdot P_j^s(t) \quad \forall j \qquad (3)$$

One of the main sources that cause uncertainty in future planning is the forecasted demand curve. It is not possible to consider the uncertainty of demand in the objective function that is based on the first revenue function, due to the reason that the target VPP needs an estimation of other units' generation to be able to include the forecasted demand curve in the ST maintenance scheduling.

In [2], the income derived from bilateral contracts, spinning and non-spinning reserves is also considered to show the income of each producer that owns several generating units and participate in the pool market. However, the scope of this paper is to study the inclusion of rivals' strategies on decision-making procedure of an individual VPP and demonstrating the coordination procedure between LT plans and ST maintenance scheduling and between DSO and VPPs in ST outage scheduling.

In LT scheduling it is possible to have several data exchange between the VPPs and the DSO to accomplish generation and maintenance plans. Nevertheless, due to the time limitations in ST scheduling it would be more efficient and applicable to define a single step coordination procedure between the VPPs and the DSO.

It is necessary to add the reserve constraints when the second form of revenue function is used.

The ST period might be a week or more. In the case study performed in this paper, time increments are considered as one hour in a weekly time interval.

VPPs need to include several operational constraints in their decision-making. The reserve constraint that is required when the VPPs are considering the rivals' generation strategies (3), ensures a prespecified amount of power as reserve in each time period. The rest of constraints ensure the continuity of maintenance periods of each generating unit, crew availability limitations by defining the maximum number of units that a VPP can handle for maintenance at each time period and the commitment logic.

The source of uncertainty for the first revenue function is the uncertainty in forecasted price. In the second revenue function, the load demand, parameters of the inverse linear demand function that are affected by the price elasticity of demand at each period, and the VPP's expectation of other rivals' generation and maintenance plan during the following time interval are the main sources that impose uncertainty on the decision-making procedure of each individual VPP.

The scenarios and their assigned probabilities are generated by the sequential Monte Carlo simulation. The VPPs need to reduce the number of scenarios either after optimization or before applying the proposed method, because the DSO only accepts limited number of proposals for the maintenance outage during the following horizon. However, the main purpose of scenario reduction techniques is helping the planners to achieve a reasonably good compromise between computation time and solution accuracy in stochastic optimization problems. In this paper, SCENRED, an efficient tool in GAMS that implements backward and fast forward reduction methods is used for scenario reduction [6].

PROBLEM OF THE DSO

The objective of the generating units and the transmission lines, which is generally profit maximization, conflicts with the objective of the DSO for the generation and transmission scheduling.

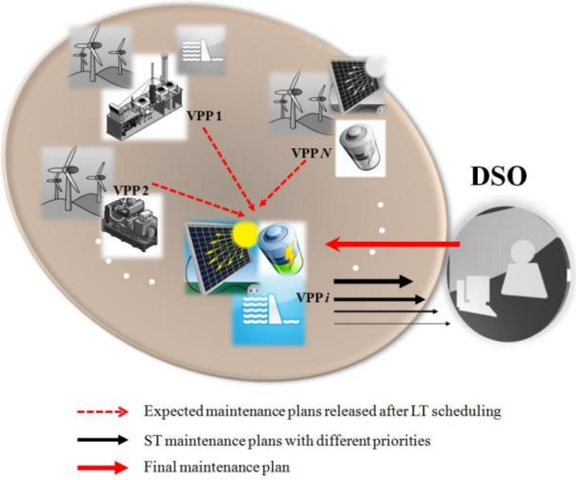

Figure 1. Interaction between VPP *i*, its rivals and the DSO

Maximizing the social welfare is the principal objective of the governing authority in a distribution system. In the absence of demand side bidding this objective can be equally explained as the consumer payment minimization [4]. This is also true in a smart grid where a DSO is the regulatory authority in charge of maintaining the security and reliability of the system at an acceptable level [3].
In the proposed model, the VPPs submit their suggested plans for maintenance to the DSO (figure 1). The DSO is responsible for planning, operating and managing the distribution system and operates a monopoly business for its regional network [1].
The social welfare is theoretically the area between the aggregate bid curve and the aggregate offer curve [7]. If the demand is inelastic, maximizing the above function will be equivalent to minimizing the production cost.
In the DSO's objective function (1) the index p shows the priority of the maintenance scheduling plans for generating unit j and line y. The two binary decision variables α and β are 1 if the suggested plan for that unit or line is accepted. The payments that act as penalty in the case that the preferred plans deteriorate the reliability and security constraints of the system is shown by Φ and Ψ in the objective function. The function OC represents the system aggregate operation cost for all the scheduling horizon.

$$\text{Min}\left[\begin{array}{l} \text{OC-}\sum_{j=1}^{NG}\sum_{t=1}^{T}\sum_{p\in\Pi_j}\alpha_j(p)\cdot\phi_j^t(p)\cdot(1-x_j^t) \\ -\sum_{y=1}^{NY}\sum_{p\in\Pi_y}\beta_y(p)\cdot\Psi_y^t(p)\cdot(1-x_y^t) \end{array}\right] \qquad (4)$$

CASE STUDY

Figure 2 shows the one-line diagram of a 25-kV 33-bus distribution test system with weekly peak load of 8060 kW and installed capacity of 9855 kW comprised of 32 distributed generating units which are managed by 4 VPPs. The VPPs submit their preferred maintenance outage plans for the following 168 hours of a weekly time horizon. The DSO checks the proposed plans, considering the payments that VPPs have proposed to the DSO to increase the chance of acceptance for their preferred plans. A stochastic mixed-integer linear problem is solved by each VPP, considering both proposed revenue functions. The DSO needs to run a mixed-integer nonlinear problem. The reason for non-linearity in the problem of the DSO is the inclusion of reliability and security constraints.
Maintenance scheduling from the viewpoint of an individual VPP is carried out based on the two aforementioned revenue functions for each generating unit. In the first proposed function, stochastic electricity prices with their assigned probabilities for all the periods are required. In the second revenue function, the VPPs need the parameters of the inverse linear demand function to model the relationship between the electricity price and the consumers' willing to purchase at that price. After reducing the 22 initial scenarios generated by considering the uncertainties in demand function and the estimated generation pattern of other VPPs to two scenarios with the SCENRED tool in GAMS; the probabilities of occurrence for the price elasticity of 0.4 and 0.5 at price 85 €/MWh are respectively calculated as 0.3 and 0.7. The maximum number of maintenance plans that the DSO accepts for the following weekly ST period is two distinct proposals. The priority outage plans of VPPs for each unit might have overlap for some periods; however, the penalties are just paid in the case that the target unit is considered for maintenance by the DSO just during the specified suggested periods [1].
In figure 3 the available generation capacity is shown, considering the LT maintenance plans and the offline units for maintenance. In the LT maintenance plan, 13 generating units were considered for maintenance outage during the following week.
Table I shows the maintenance periods that VPPs will suggest to the DSO categorized by their priority and preference. It is obvious that it would be more desirable for VPPs to gain approval over their suggested plans with higher priority.

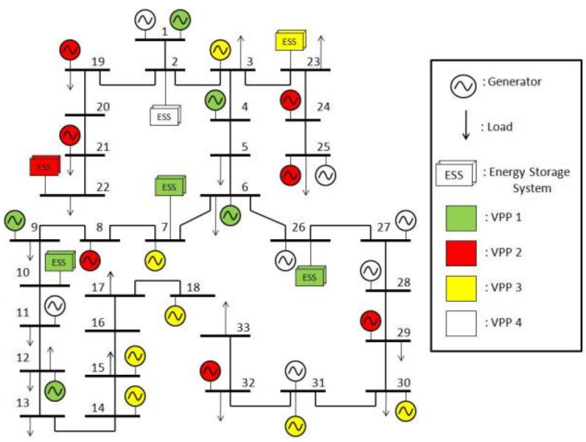

Figure 2. 33 bus test system

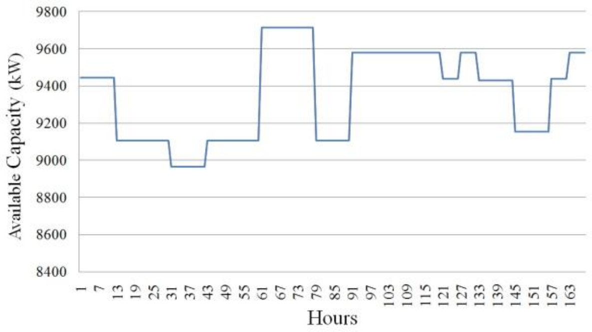

Figure 3. Available capacity in LT maintenance plan

In figure 4 the reliability index, which is calculated by dividing the net reserve by the gross reserve at each time period, is shown for the 168 hours of the following week. First priority of all VPPs is considered for analysis. When the VPPs determine their maintenance outage periods without considering the probable strategies of the rival VPPs, the reliability index deteriorates in several periods and the DSO will certainly reject the first priority plans of some VPPs.

Table I – Maintenenace plans submitted to the DSO

	Unit No	Priority 1 Rev1	Priority 2 Rev1	Priority 1 Rev2	Priority 2 Rev2
VPP1	1	32-48	32-48	14-30	14-30
	4	9-14	22-27	70-75	103-108
	5	156-168	153-165	155-167	154-166
	8	1-5	1-5	100-104	1-5
VPP2	7	156-165	114-123	95-104	95-104
	16	1-33	1-33	54-86	59-91
	22	80-100	79-99	137-157	146-166
VPP4	2	1-15	54-68	139-153	3-17
	9	94-98	47-51	1-5	164-168
	18	10-46	10-46	33-69	31-67
	19	71-74	64-67	54-57	56-59
	20	134-144	42-52	10-20	81-91
	25	23-41	1-19	120-138	12-30

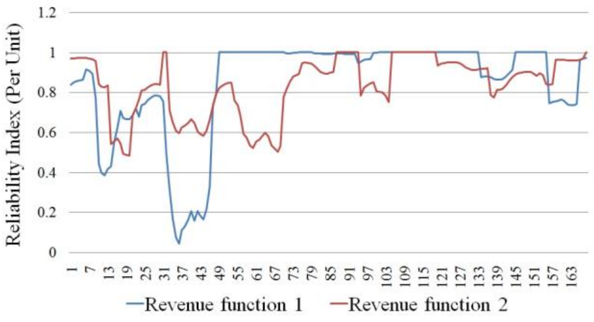

Figure 4. Reliability index for the 168 hours

CONCLUSIONS

In the proposed model, the impact of LT maintenance plans on ST decision-making of generating units is studied. The merit of this work is featured by considering the strategic interaction between the VPPs and including the uncertainty of estimations. Although the generating units are not obligated to meet the demand of customers, including the most probable generation pattern of rival generating units in addition to the demand behaviour in the following ST time interval gives more realistic assessment of the system. The results show that including the estimation of the rivals' generation pattern and trying to satisfy the reserve constraints, VPPs can increase the chance of acceptance for their preferred outage plans.

Acknowledgments

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