Long-Term Generation Maintenance Scheduling with Integration of Pumped Storage Units

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Abstract- In a power system, the reliable performance of generation units for the supply of demand has the great importance. The execution of maintenance in a timely manner has a great impact on forced outage rate of generation units and so has impacts on mitigation of generation costs. In restructured power systems, regard to the independence of generation companies, the procedure of maintenance planning has become more complicated compared with traditional power systems. This study presents an optimization problem, which seeks for a long-term maintenance scheduling method for power generation units subject to the reduction of maintenance and operation costs, retaining the system's reliability and satisfaction of prevailing constraints. A mathematical method based on Benders decomposition technique is proposed to arrange a maintenance schedule for generation units. A penalty factor corresponding to the peak load curve is defined and the lost profits of the units at the time of maintenance are also added to the objective function, to schedule maintenance proportional to the consumption patterns. In addition, by integrating the hydro pumped storage unit into the power system, the reliability of the system has been improved. IEEE-RTS 24-bus test system and GAMS software are used to show the effectiveness of the proposed method. The obtained results imply the accuracy, simplicity and great performance of the model.

Keywords- Maintenance, generation units, reliability, pumped storage, Benders decomposition, GAMS.

Nomenclatures

b	Bus index
BG_{ib}	Bus-Generator matrix
BL_{bk}	Node-Branch matrix
D_w	Weekly demand peak in week w
D_{bw}	Weekly demand peak at bus b in week w
D_{max}	Maximum of weekly demand peak in year
D_{min}	Minimum of weekly demand peak in year
FOR_i	Forced outage rate for unit i
g_i^{max}	Maximum generation capacity of unit i
g_i^{min}	Minimum generation capacity of unit i
g_i	Power generation of unit i at peak load
g_{iw}	Power generation of unit i at peak load in week w
i	Generation unit index
k	Branch index
M_{iw}	Unit maintenance status in week w
MC_i	Maintenance cost of unit i
MCP_w	Market clearing price in week w
N_k	Number of line for branch k
OC_i	Operation cost of unit i
PF_w	Penalty factor in week w
PL_k^{max}	Maximum capacity of line k
PL_{kw}	Power flow at peak load of line k in week w
r_{bw}	Real power interruption at bus b in week w
s_i	Maintenance time variable of unit i
TC	Total operation cost
t_i^m	The duration of the maintenance process for unit i
t_i^{max}	The latest possible time for execution of maintenance of unit i
t_i^{min}	The soonest possible time for execution of maintenance of unit i
TMC	Total maintenance cost
w	Week index

1- Introduction

In traditional power systems with a vertically integrated structure, the maintenance scheduling program for generation units, transmission lines and the coordination between these units are performed by the system operator in a centralized way [1]. In restructured power systems, the independent system operator (ISO) is responsible for the provision of security and reliability. The generation units share their desired time-oriented maintenance schedule with ISO with the aim of maximization of their profit and regardless of reliability and security of the entire system. ISO must modify and manage the received offers from the generation companies (GENCOs) in a coordinated manner. ISO assesses the offered maintenance schedules in compliance with the reliability restrictions in order to confirm or decline the offer. Then ISO sends the rejected offers back to the corresponding GENCOs for reconsideration of required modifications [2], so the maintenance scheduling problem in a restructured environment is a multi-level process, where each level deals with a multi-objective, discrete, stochastic, and non-linear optimization problem. Some important constraints should be considered in this optimization problem such as the permissible time of maintenance, the adequacy of the workforce, resource availability, seasonal restrictions, power equality, transmission flow capacity, forced outage rate of units, and real power interruption at every bus. Besides, any equipment, which affects the generation or consumption of electricity can alter reliability and consequently has profound implications on maintenance schedules. The solution methods can be classified into two models of mathematical and analytical solutions and metaheuristic approaches [3].

A wide range of studies has been done on the subject of maintenance scheduling for power systems and different approaches with various constraints are proposed to solve these problems [4]. In [5], maintenance scheduling of a virtual power plant is proposed for scheduling the planned outage of DGs. The virtual power plant Including DGs, photovoltaic and wind turbines, energy storage systems, and curtailable loads. In [6] the generator maintenance scheduling problem in hydropower systems is studied. the proposed method is a mixed-integer optimizing model that includes the maintenance time windows, as well as the nonlinearity and disjunction of the hydroelectric generation functions. In [7], a new criterion based on the generators' outage risk is defined. The occurrence of a fault in a generation unit can be estimated by reliability-oriented methods based on reliability theory and risk assessment fundamentals. In these concepts, the final goal is to calculate the probability of the proper functioning of a system within a specific interval. The schedule is based on the number of generation units and their corresponding capacity, and the grid's structure and transmission limitations have been ignored. In [8], a maintenance scheduling model for generation and transmission section is proposed, in which the N-1 contingency condition is incorporated. In this model, the objective is to maximize the considered items of the utility owners and to observe N-1 restrictions. The Benders decomposition technique is used to solve this problem, and the problem is divided into a master problem and some subproblems. In [9], the Ant Lion optimization algorithm (ALO) is employed as an effective tool for the preparation of a maintenance schedule. However, the system's constraints are restricted to the capacity of lines. In [10], a closed-loop model for coordination between maintenance schedule and the long-term security-constrained unit commitment is proposed in order to improve the security and optimal economic dispatch. Regard to the complexity of the calculations, in this study, the constraint transformation techniques have been employed, and they work in accordance with mixed-integer programming. In [11], the uncertainties corresponded with the generation cost and load forecasting are modeled by fuzzy logic, and the maintenance scheduling problem is solved using a dynamic non-cooperative fuzzy game. Nevertheless, the problem is solved only by consideration of maintenance costs and the reliability indices are not taken into consideration. In [12], the maintenance scheduling for power plants is regarded as a key part of generation expansion planning, and the multi-objective binary gravitational search algorithm is employed to search the solution space of the maintenance scheduling problem. There are three objectives in the objective function of this problem. The first one incorporates the lost capacity into the model while the unit is under maintenance. The second and third objectives include the minimization of operation and maintenance costs together with the expected energy not supplied (*EENS*) reliability index. In [13], the genetic algorithm is used to establish a maintenance schedule while the power flow model is included. In this research, the requirements of restructured power systems are not observed. In [14], the role of microgrids in maintenance scheduling of generation units is investigated. In this research, in order to make the load curve smoother, a large number of microgrids are included in the model so that the 30% of the whole demand of each bus must be met by the corresponding microgrids. In [15], a bi-level optimization method is used to deal with maintenance schedules. At the first stage, the optimization must be conducted subject to minimize the total cost of maintenance. Afterward, it is strived to maximize the profit of GENCOs on the second level. In [16], an optimization model with respect to the integration of wind power potential and forced outage rate of equipment is used for maintenance scheduling. A set of uncertainties is used to describe the wind intermittency, and an innovative approach is proposed to control the model optimally. In [17], the arrangement of a maintenance schedule is made while the presence of a photovoltaic unit is evaluated. Since the problem features as a non-linear, non-smooth, and non-convex problem, the electro search optimization algorithm (ESOA) is used while the operation and maintenance costs are only included in the model. In [18], the maintenance scheduling for hydroelectric power plants is proposed. In this work, the objective of maximization of profit using MILP approach is pursued. The final profit is defined as the subtraction of the final cost of maintenance from the economic value of generated power within the time horizon of the study added by the residual water in the dam's reservoir. In [19], the maintenance scheduling procedure is conducted by the employment of biography-based optimization. However, the *FOR* index of units is ignored, and the proposed method is only tested on a power system encompassing three generators. In [20] the impact of general system constraints on generation unit maintenance scheduling has been studied to a limited extent and only the maintenance cost has been taken into account and the cost of operating and reliability of the system is examined. Also, the FOR of units, spinning reserve and *EENS* are not considered. In [21-23] the role of modern technologies in the improvement of maintenance scheduling and attaining a more smart system is proposed.

Regard to this fact that the modeling of an optimization problem by a non-mathematical approach is remarkably simpler, most of the conducted researches are done using non-mathematical and metaheuristic methods. However, in these methods, the accuracy of results is less to some extent in comparison with mathematical methods. In the studies mentioned in the literature, some of the constraints or indices are ignored in order to simplify the solution. For instance, the FOR index of units is not considered in some of the described works. Just the same, in some works, the *EENS* index is ignored too. Besides, in some studies, the simulation is just performed with consideration of the number and capacity of units as well as the demand peak value, and the power system structure and the transmission lines' restrictions are not taken into consideration. In some studies, the number of involved generation units in the maintenance schedule is restrained and the targeted time horizon of study is limited to some weeks in order to simplify the model. Therefore, most of the previously conducted works are not suitable to be applied for large-scale power systems and long-term applications.

In this study, a long-term model for generation maintenance scheduling of large-scale power system is presented. Regard to this fact that the multi-year load forecasts and price forecasts are not accurate, it is recommended that a yearly time horizon should be considered. Regard to the impact of a weekly demand peak on the maintenance schedules and reliability of the grid, the new concept proposed in study deals with the implication of the presence of pumped-storage unit on the maintenance schedule along with the reliability of the system. Another feature, which is added to the model, is that the lost profit is also integrated into the maintenance schedule and maintenance costs. When a generation unit is under maintenance, this unit does not earn revenue, so the GENCO's profit will be diminished. This amount of revenue reduction is defined as the lost profit and should be added to the maintenance cost. In addition, by definition of coefficient proportional to the weekly demand peak, known as a penalty factor, it is tried to maintain a maintenance schedule in alignment with the reliability of the grid.

In this study, the maintenance schedule is optimized using a mathematical approach to the Benders decomposition technique, and the formulation of the problem is described. In order to evaluate the effectiveness and performance of the proposed model, the suggested methodology is tested on an IEEE-RTS 24-bus system. The simulation is carried out in six scenarios, in which the impacts of FOR, *EENS*, required spinning reserve, and pumped storage units on the maintenance schedule are investigated. Furthermore, the obtained results are compared with a metaheuristic method.

2- The proposed method

In the maintenance scheduling problem, *M* is an integer decision-making variable, and the amount of generation of each unit is a positive number. Thus, the maintenance scheduling of generators is counted as a mixed-integer linear programming model, which consists of maintenance constraints and system restrictions. The main goal is to minimize the maintenance and operation cost during the targeted time interval. This interval is usually set to be one or two years. It is because, in longer intervals, the uncertainty of load forecasting methods lead to drastically increase of forecasting error. *TMC* stands for total maintenance cost, and *TC* denotes the total cost of operation. These parameters are shown by Eqs. (1) and (2). In Eq. (1), M_i is a binary variable so that it takes the value of 1 if the unit is in service and out of maintenance schedule, and it takes the value of 0 if the unit is under maintenance and out of service.

$$TMC = \sum_i MC_i (1 - M_i) \tag{1}$$

$$TC = \sum_i OC_i g_i \tag{2}$$

In the approach proposed in this paper, a weekly coefficient according to Eq. (3) is defined as a penalty factor to further coordinate maintenance scheduling with the weekly peak curve. The value of this coefficient per each week corresponds to a peak load of that week is a number between 1 and 2. If the value of this factor equals to 1 in a week, it means that the weekly peak load is at its lowest during the year, and if it equals to 2, it means that the week's peak load is at its highest value throughout the year. By adding this coefficient to Eq. (1), the generating units maintenance program is redirected to the lower peak load weeks. Because the value of this coefficient in a week corresponds to the difference in peak load of that week with the minimum weekly peak load and it can increase the cost of maintenance in the high peak load weeks.

$$PF_w = 1 + \frac{D_w - D_{\min}}{D_{\max} - D_{\min}} \tag{3}$$

If a generating unit is not undergoing maintenance and the network allows it, it will be able to use all of its generation capacity. In other words, it can potentially work with all of its generation capacity and makes money. In the proposed method, this income is considered as the maximum income that the generating unit could have earned and is named as lost income. The total maintenance cost is explained as the summation of maintenance costs and the lost income. Eq. (4) represents the total maintenance cost.

$$TMC = \sum_i PF.MC_i (1 - M_i) + \sum_i MCP (1 - M_i) g_i^{\max} \tag{4}$$

By consideration of a yearly interval for the maintenance schedule and weekly intervals for maintenance execution, the final maintenance cost can be achieved through Eq. (5):

$$TMC = \sum_w \sum_i (PF_w.MC_i (1 - M_{iw}) + MCP_w (1 - M_{iw}) g_i^{\max}) \tag{5}$$

The overall objective function of the schedule within various intervals as defined as the summation of maintenance and operation costs that are expressed as Eq. (6) as below:

$$\begin{cases} \min \sum_w (TMC_w + TC_w) \\ \text{s.t. ; maintenance constraints; network constraints} \end{cases} \tag{6}$$

The optimization problem consists of two sets of constraints. The maintenance constraints are dealt with GENCOs. The maintenance scheduling practice will be done by utilization of these constraints subject to minimize the costs and maximize their own profit. The other set of constraints is the network constraints, which are imposed by ISO to assess the reliability and security criteria. If the provided schedule plan by the GENCOs does not meet the reliability and security constraints, the schedule will be rejected by the ISO, and it will be sent back to the GENCOs along with the required reconsideration of the network in order to implement some modifications. In Eq. (6), the maintenance constraints indicate the temporal restrictions of maintenance implementation of each unit that can be described by Eq. (7) [24]:

$$\begin{cases} M_{iw} = 1 & ; w \le t_i^{\min} \quad or \quad w \ge t_i^{\max} + t_i^m \\ M_{iw} = 0 & ; s_i \le w \le s_i + t_i^m \\ M_{iw} = 0 \quad or \quad 1; & t_i^{\min} \le w \le t_i^{\max} \end{cases} \tag{7}$$

Where M_{iw} shows the state of maintenance of the i^{th} unit in the w^{th} week. This value is 0 when the unit is under maintenance and out of service, whereas 1 represents the unit is in service. t_i^{min} indicates the soonest time for execution of maintenance of the i^{th} unit, and similarly t_i^{max} delineates the latest possible time for execution of maintenance of this unit. t_i^m shows the duration of the maintenance process for unit i. In addition, s_i shows the time of implementation of maintenances. The values of t_i^{max} and t_i^{min} will be determined based on the hours of operation and seasonal restrictions. The constraints of availability of workforce and accessibility to the resources can be also included in the model. In other word, this constraint conveys that how many units can be under maintenance simultaneously with respect to the availability of workforce and accessibility to the resources. The required maintenance for each unit have to be carried out within the specified maintenance window. This limitation is expressed by Eq. (8).

$$\sum_w s_{iw} \ge 1 \qquad w \le t_i^{\max} \tag{8}$$

The power system constraints are issued and controlled by ISO. Equations (9) to (13) describe these restrictions.

$$\sum_k BL_{bk}.PL_{kw} + \sum_i BG_{iw}.g_{iw} + r_{bw} = D_{bw} \tag{9}$$

$$g_i^{\min} \le g_i \le g_i^{\max} \tag{10}$$

$$r_{bw} \le D_{bw} \tag{11}$$

$$PL_{kw} \le PL_k^{\max}.N_k \tag{12}$$

$$\sum_b r_{bw} \le \varepsilon \tag{13}$$

In above equations, r_{bw} shows the active power interruption of bus b at the weekly peak, which shows the difference between generated and consumed active power at each bus in each week. The summations of r_b in each week delineates the *EENS* in that week. Eq. (9) represents the load balance at each bus of the system. Eq. (10) exhibits the maximum and minimum generation capability of each unit. Eq. (11) shows that the active power interruption at each bus has to be lower than the peak of load at that bus. Eq. (13) shows that the *EENS* must be capped with a preassigned value by ISO presented by ε to assure the reliability and protect the security of the system [24].

M_i is a binary integer variable that describes the state of being under maintenance or being in service. g_i is a continuous variable that demonstrates the amount of generation of unit i. Hence, the maintenance scheduling problem is regarded as a mixed-integer non-linear problem. Fig.1 displays an illustrative view of the proposed model for the maintenance scheduling problem.

3- Solution procedure

The proposed solution method is based on the Bands decomposition algorithm. In this algorithm, the scheduling problem is divided into two parts of a master problem and one or more subproblems. The maintenance master problem is integer programming. Solving this problem creates a preliminary answer for generating unit maintenance schedules so that it only minimizes the cost of maintenance. For considering network constraints the subproblems must also be resolved. If the answer is infeasible, then an infeasibility cut will be generated and added to the main problem. In the next repeat, the main maintenance problem, along with the infeasibility cut added to it, is solved by the GENCO. these process of resolving the problem is repeated until the feasible answer is achieved.

In order to minimize TMC in Eq. (4) by the Benders decomposition algorithm, it is divided into two parts of a master problem and subproblems. So Eq. (6) is upgraded as Eq. (14).

$$\sum_w TMC_w + \sum_w \min\{TC_w \mid \text{network constraints}\} \tag{14}$$

Eq. (15) represents the Lagrangian function of Eq. (14). In this method, the violations of inequality constraints are penalized with respect to the Lagrangian multipliers.

$$\begin{aligned} & L_w(\kappa,\pi,\gamma,\zeta,\mu) = \\ & \min\left\{ TC_w + \sum_b \kappa_{bw}\left(\left(\sum_k Bl_{bk} PL_{kw}\right) + \right.\right. \\ & \left.\left(\sum_i BG_{ib} g_{iw}\right) + r_{bw} - D_{bw}\right) + \\ & \sum_i \pi_{iw}\left(g_{iw} - g_i^{\max} M_{iw}\right) + \sum_b \gamma_{bw}\left(r_{bw} - D_{bw}\right) + \\ & \sum_k \zeta_{kw}\left(\left|PL_{kw}\right| - PL_k^{\max}\right) + \mu_w\left(\left(\sum_b r_{bw}\right) - \varepsilon\right) \end{aligned} \tag{15}$$

Thus, the maintenance scheduling problem can be expressed by Eq. (16).

$$\begin{cases} \min \sum_w TMC_w + L_w \\ \text{s.t ; maintenance constraints} \end{cases} \tag{16}$$

The solution derived from Eq. (16) minimizes the operation and maintenance cost. In order to ensure and guarantee the reliability of the grid, Eq. (17) has to have a minimum value.

$$\begin{cases} \min \sum_b r_{bw} \\ \text{s.t. ; network constraints} \end{cases} \tag{17}$$

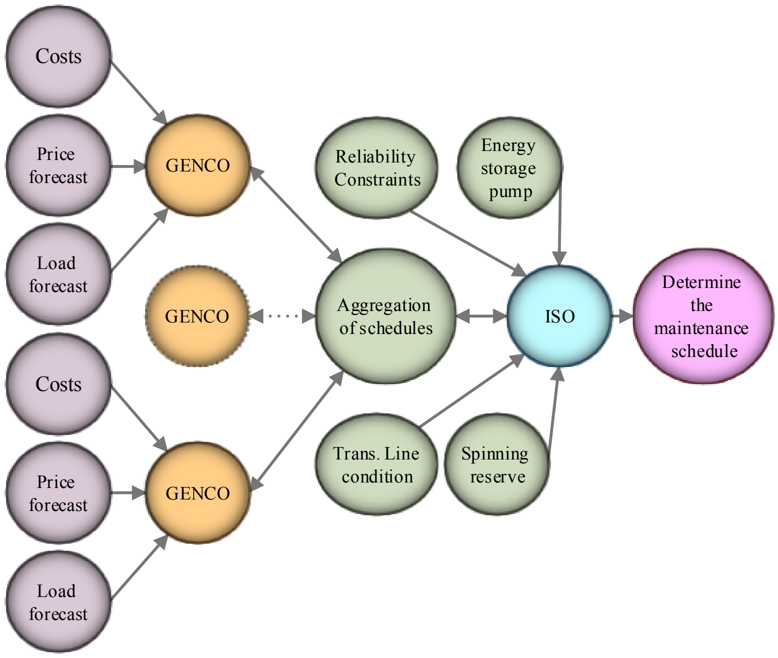

Figure 1. The schematic of the proposed maintenance schedule

Eq. (18) represents the Lagrangian function of Eq. (17).

$$U_w(\nu,\lambda,\tau,\eta) = \min\left\{\sum_b r_{bw} + \sum_b \nu_{bw}\left(\left(\sum_k BL_{bk} PL_{kw}\right) + \left(\sum_i BG_{ib} g_{iw}\right) + r_{bw} - D_{bw}\right) + \sum_i \lambda_{iw}\left(g_{iw} - g_i^{\max} M_{iw}\right) + \sum_b \tau_{bw}\left(r_{bw} - D_{bw}\right) + \sum_k \eta_{kw}\left(\left|PL_{kw}\right| - PL_k^{\max}\right)\right. \tag{18}$$

The problem of the maintenance schedule will be obtained by minimizing C in Eq. (19).

$$\begin{cases} \sum_w TMC_w + \sum_w L_w \le C \\ \text{s.t.} \\ \sum_w U_w\left(\nu,\lambda,\tau,\eta\right) \\ \text{maintenance constraints} \end{cases} \tag{19}$$

The master problem, which must be solved by the GENCOs, expressed by Eq. (20):

$$\begin{cases} \min \sum_w \sum_i \left(PF_w.MC_{iw}(1 - M_{iw}) + MCP_w(1 - M_{iw}) g_i^{\max}\right) \\ \text{s.t. ; maintenance constraints} \end{cases} \tag{20}$$

ISO compares the obtained results with the solution of Eq. (17). If the obtained result is not viable, an infeasibility cut will be sent to the GENCO as in Eq. (21):

$$\sum_b r_{bw} + \sum_i \lambda_{iw}\left(M_{iw}^{old} - M_{iw}\right) \le \varepsilon \tag{21}$$

The GENCO solves the master problem again by adding the infeasibility cut as a constraint. Then the GENCO send the solution back to ISO. This process will be repeated until the feasibility condition is materialized. Regard to this fact that this procedure is time-consuming and sophisticated, the iterative loop between GENCO and ISO should not be a lot. The number of these iterations are defined by ISO, and hereby the GENCO is obliged to accept a mandatory maintenance window if the feasibility is not reached after the dedicated amount of iterations [18].

The spinning reserve is defined as the difference between the maximum generation capacity of a unit and the real amount of generation at a specific interval, and it is usually described as a certain percentage of the weekly peak (β). If the spinning reserve is included in the operation schedule, Eq. (22) must be added to the system's constraints.

$$\sum_i g_i^{\max}.(1 - FOR_i) - \sum_i g_{iw} \ge \%\beta.D_w \tag{22}$$

A pumped storage unit exploits the potential energy of water in an elevated reservoir. Once the electrical demand level is low, water is pumped from a lower reservoir into an upper reservoir in order to store energy and charge the storage. When the demand is mounted, the water is let to flow toward the lower reservoir. Meanwhile, the water drives a set of hydro-turbines to generate electrical power. In general, the most prominent application of pumped storage units is to shift the low-priced energy of off-peak to the expensive electrical energy at peak [25-29].

A pumped storage unit has three operational modes: pumping state, idle state, and generation state. During off-peak hours, it functions as a consumer and uses electricity to store energy in pumping mode. During mid-peak hours, the plant is in idle mode, and it is often stated in generation mode at peak hours [30]. These units are connected to the bus that has high demand, and connected with high operation cost units. So in addition to considering the geographic conditions, the connection point of the pumped storage unit is determined according to the type of generation units and consumers connected to each bus. The load balance equation in the presence of a pumped storage unit connected to the bus b in the week w can be explained by Eq. (23). In this equation, SP represents the weakly consumed or generated power by the pumped storage unit.

$$\sum_k BL_{bk}.PL_{kw}+\sum_i BG_{iw}.g_{iw}.M_{iw}+r_{bw}+PS_{bw}=D_{bw} \quad (23)$$

In Fig.2, the solving procedure of the problem with integration of pumped storage unit into the power system is proposed.

4- Simulation results

The proposed methodology for generation maintenance scheduling is implemented on IEEE-RTS 24-bus standard test system. This power system contains 32 generators, 24 buses, and 38 transmission lines. In this power system, the maximum forecasted peak of the yearly duration curve is equal with 2850 MW [31]. Fig.3 shows the schematic of this power system. In this power system the buses are numbered from 101 through 124. Table 1 shows the specifications of generating units.

Table 1: Specifications of generating units

Unit	Bus	P_{max}	FOR	Maintenance duration (week/year)	Type
G_1	115	2	2	12	Oil/Steam
G_2	115	2	2	12	Oil/Steam
G_3	115	2	2	12	Oil/Steam
G_4	115	2	2	12	Oil/Steam
G_5	115	2	2	12	Oil/Steam
G_6	101	2	10	20	Oil/C. Turbine
G_7	101	2	10	20	Oil/C. Turbine
G_8	102	2	10	20	Oil/C. Turbine
G_9	102	2	10	20	Oil/C. Turbine
G_{10}	122	2	1	50	Hydro
G_{11}	122	2	1	50	Hydro
G_{12}	122	2	1	50	Hydro
G_{13}	122	2	1	50	Hydro
G_{14}	122	2	1	50	Hydro
G_{15}	122	2	1	50	Hydro
G_{16}	101	3	2	76	Coal/Steam
G_{17}	101	3	2	76	Coal/Steam
G_{18}	102	3	2	76	Coal/Steam
G_{19}	102	3	2	76	Coal/Steam
G_{20}	107	3	4	100	Oil/Steam
G_{21}	107	3	4	100	Oil/Steam
G_{22}	107	3	4	100	Oil/Steam
G_{23}	115	4	4	155	Coal/Steam
G_{24}	116	4	4	155	Coal/Steam
G_{25}	123	4	4	155	Coal/Steam
G_{26}	123	4	4	155	Coal/Steam
G_{27}	113	4	4	197	Oil/Steam
G_{28}	113	4	4	197	Oil/Steam
G_{29}	113	4	4	197	Oil/Steam
G_{30}	123	5	8	350	Coal/Steam
G_{31}	118	6	12	400	Nuclear
G_{32}	121	6	12	400	Nuclear

The time horizon of the study is targeted to be a year, and the duration of maintenance windows are assigned to be a week. It is assumed that the concurrent maintenance of two units at the same interval is possible. The data corresponded with the weekly *MCP* predictions refer to [32-33]. These references address the weekly electricity price of Nordpool deregulated and restructured power system. The six scenarios are developed as follows:

- Scenario 1: The basic scenario, without consideration of FOR_i and penalty factor and with consideration of *EENS* equal with 0%.
- Scenario 2: Scenario 1 plus the inclusion of FOR_i
- Scenario 3: Scenario 2 plus the consideration of maximum *EENS* equal with 1% of weekly peak.
- Scenario 4: Scenario 3 plus the inclusion of penalty factor.
- Scenario 5: Scenario 4 plus the assigning spinning reserve required by 10% of weekly peak.
- Scenario 6: Scenario 5 plus the integration of a pumped storage unit into the system.

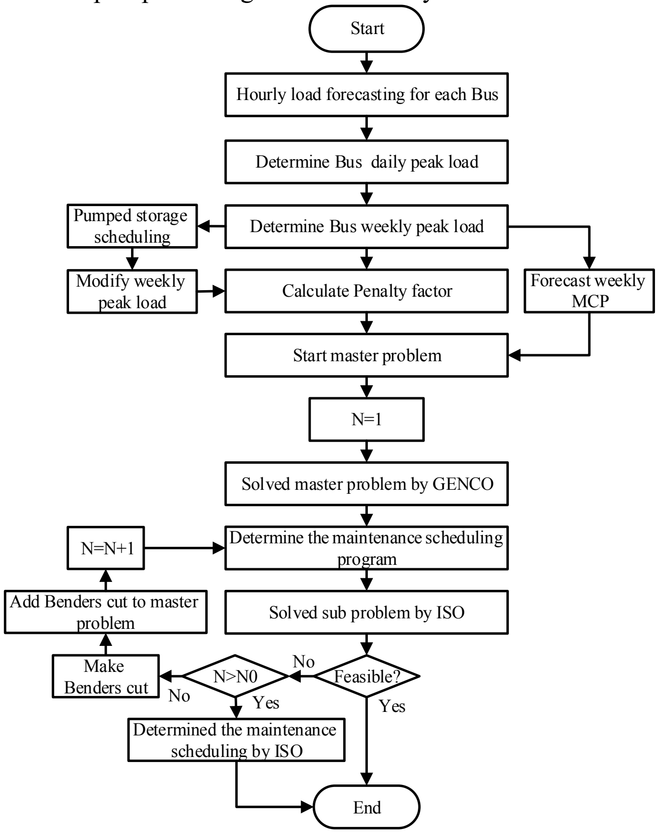

Figure 2. The paradigm of maintenance scheduling with integration of pumped storage

In Fig.4, with respect to the loss of load expectation (*LOLE*) index, a comparison is made between two cases regardless of maintenance scheduling and scenario 1. Due to the outage of some units for maintenance, the *LOLE* index is changed from 0.58 to 1.3 (day per year) in a year in the first scenario. By executing the maintenance program and specifying the number and types of units available in each week, the value of the *LOLE* index can be calculated by forming the Table of capacity outage probability. According to the IEEE network data, the maximum weekly peak load is at week 51, so although in the first scenario no maintenance is programmed at this week and *EENS* is assumed to be zero in the calculations, it is due to the forced outage rate (*FOR*) of generating units and the peak load carve, *LOLE* index is increased.

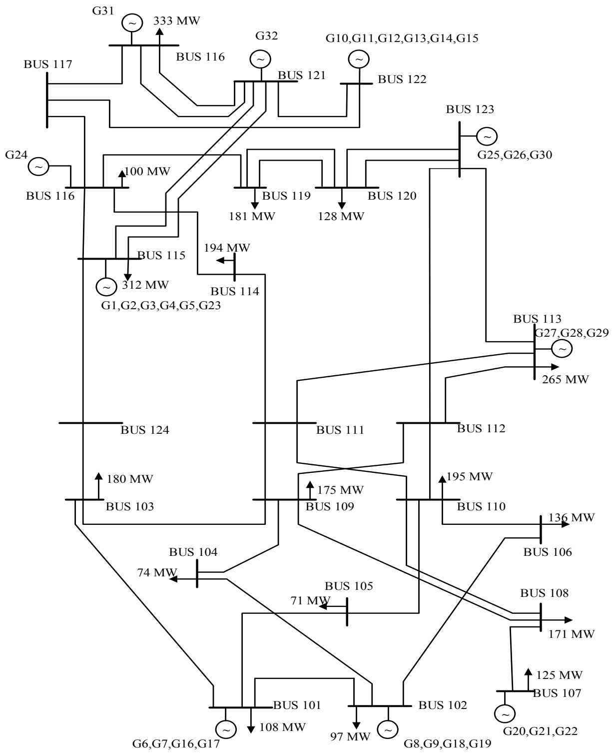

Figure 3. The Schematic of IEEE-RTS 24-Bus

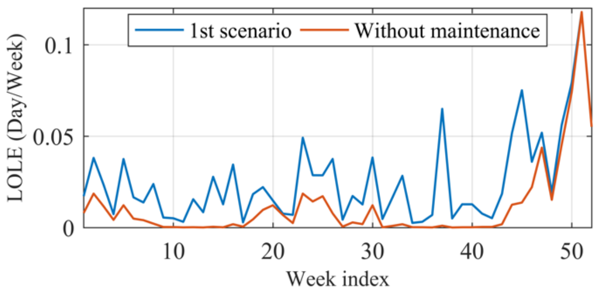

Figure 4. The *LOLE* index in scenario 1

In the second scenario, the maximum output of each unit in each week corresponds with the maximum rated power, availability, and FOR of each unit [18]. The *LOLE* index has risen and reached the value of 2.08 day per year.

EENS is one of the important indices of reliability of power systems. If this index takes a value larger than zero, it conveys that the system may sometimes be unable to serve the loads. In the third scenario, the maximum *EENS* is assigned to be equal with 1% of the weekly peak of demand. As it was expected, by the increase of *EENS*, the *LOLE* index has been highly mounted from 2.08 to 3.5 day per year.

The penalty factor specifies the weekly priority of execution of maintenance for generation units corresponded with the maximum peak of that week. By calculation of this factor, in accordance with Eq. (3), a value between 1 and 2 is obtained for each week. As this value is closer to 2, it represents that the amount of demand has been high. Thus, if a unit is forced or required to perform maintenance in that week, its maintenance cost goes up because a penalty is charged to the unit. In Fig.5, the weekly demand peak and the corresponding penalty factors within 52 consecutive weeks of a year is displayed. This factor is equal with 1 in the minimum peak of the year, and it is equal with 2 at the maximum peak of the year. In the fourth scenario, the penalty factor is included in the scheduling presented in the last scenario.

By taking penalty factor into consideration, with respect to the increase of maintenance cost due to the rise of demand peak in some weeks, the units are less prone to perform maintenance measures within these weeks. Hence, it is predicted that reliability will be enhanced. The comparison of *LOLE* index in this scenario and the previous scenario obviously implies that the value of this index has been reduced from 3.5 to 2.02 day per year.

In the fifth scenario, the spinning reserve of the grid is considered to be 10% of the weekly demand peak. The investigation of obtained results indicates that the reliability of the grid has been improved and the *LOLE* index is diminished and reached to the value of 1.41 day per year.

Regard to the location of generators (the corresponding bus), the type of generator connected to each bus, and the demand of each bus, the bus 115 is chosen for the installation of a storage unit which is considered to have the type of pumped storage. The pumped storage units resemble hydroelectric power plants. In IEEE-RTS test system, there are hydroelectric power plants with a capacity of 50 MW.

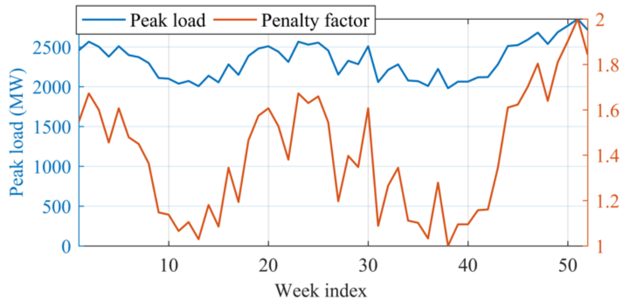

Figure 5. The weekly demand peak and the corresponding penalty factor

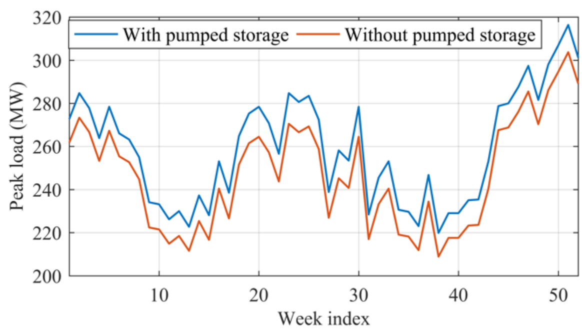

Figure 6. The weekly demand peak of bus 115

Hence, in the sixth scenario, a pumped storage unit with a capacity of 50 MW is supposed. In Fig.6, the weekly peak of bus 115 in two cases of with and without the integration of pumped storage unit is presented. In scenario 6, the results of maintenance scheduling problem with the inclusion of a pumped storage unit imply that the reliability has been vastly improved so that the *LOLE* index has been reached the value of 0.81 day per year. In Fig.7, the weekly *LOLE* indices for all scenarios are depicted. In Table 2 a comparison of total *LOLE* index in a year and the maintenance and operation cost between all scenarios is made.

Scenario sequencing is done in such a way that each scenario completes the previous one and optimizes the maintenance schedule. For example, in the third scenario, because only the *EENS* is set to oppose zero, the maintenance schedule for units 30 and 32 are planned for week 25. These units are the high capacity units in the network and their simultaneous maintenance has increased the *LOLE* of week 25. In the fourth scenario, the *LOLE* value is modified by taking into account the penalty factor and decreased from 3.5 days per year to 2.03 days per year.

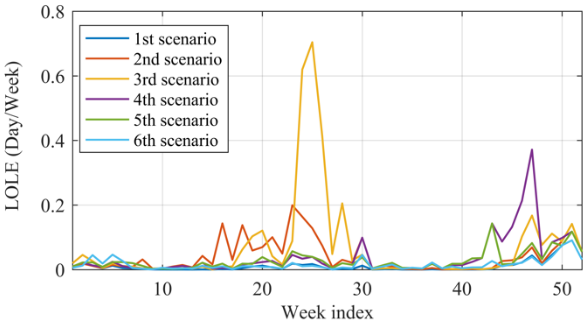

Figure 7. The *LOLE* index in all scenarios

Table 2: The LOLE index and costs for all scenarios

	LOLE (day/year)	Maintenance cost (millions $)	Operation cost (millions $)
Without maintenance	0.59	-	-
1st scenario	1.31	79.49	76.61
2nd scenario	2.09	79.51	76.8
3rd scenario	3.5	79.53	75.62
4th scenario	2.03	102.65	75.54
5th scenario	1.42	99.2	75.46
6th scenario	0.82	97.88	74.96

The first scenario, which is the most fundamental form of a maintenance schedule, has the lowest maintenance cost. By consideration of *FOR* index, the maintenance cost and operation cost is fairly enhanced. By the increase of *EENS* in the 3rd scenario, the maintenance cost has increased slightly, but the operation cost and total cost are reduced.

As it was expected, whereas the consideration of penalty factor leads to a remarkable increase in the reliability of the grid, it brings about a steep rise in operation cost. The reason is that some units must perform their maintenance at some specific intervals when the peak price is extremely high. Hereby, the given penalty by ISO to these units has increased their maintenance cost.

Even though the inclusion of spinning reserve improves the reliability of the grid, it results in a slight reduction in maintenance cost. The consideration of the impact of the pumped storage unit has provided a visible improvement in the reliability of the system, and it has reduced the maintenance and total cost. The use of pumped storage unit has not a notable impact on the maintenance cost, although it provides a considerable reduction in operation cost due to its influence on the change of consumption curve. Table 3 shows the maintenance schedule in all scenarios.

In order to evaluate the effectiveness of the proposed approach, the obtained results are compared with a similar work, which has employed a modified PSO algorithm to solve the optimization problem. In [32], by applying the MPSO algorithm, the maintenance scheduling problem is tested on a 24-bus power system while the simultaneous maintenance of 5 units is contemplated and the time horizon is targeted to be a year. To assure the effectiveness, accuracy, and good performance of the proposed method using the MPSO algorithm, the maintenance scheduling the 6th scenario is performed with the assumption of maximum concurrent maintenance of 5 units. In Fig.8, the *LOLE* index and in Fig.9 the maintenance schedule in both methods are pointed out.

By comparison of these two methods, it can be obviously perceived that the proposed method in this paper provides more optimal results in shorter time for computation so that the *LOLE* index in the proposed method has been taken the value of 2.18 day per year, which is better than the results of MPSO approach with the value of 3.55 day per year.

Table 3: The week number of maintenance schedule in all scenarios

Unit	1st scenario	2nd scenario	3rd scenario	4th scenario	5th scenario	6th scenario
G1	46-47	9-10	8-9	25-26	1-2	1-2
G2	20-21	6-7	4-5	1-2	1-2	19-20
G3	19-20	4-5	50-51	1-2	3-4	25-26
G4	49-50	4-5	15-16	3-4	25-26	1-2
G5	47-48	50-51	3-4	19-20	5-6	20-21
G6	3-4	50-51	50-51	5-6	44-45	46-47
G7	24-25	48-49	1-2	7-8	44-45	24-25
G8	1-2	48-49	39-40	7-8	7-8	23-24
G9	48-49	46-47	42-43	23-24	9-10	48-49
G10	22-23	46-47	5-6	9-10	48-49	50-51
G11	45-46	44-45	6-7	47-48	46-47	44-45
G12	34-35	44-45	33-34	45-46	11-12	49-50
G13	25-26	42-43	4-8	48-49	46-47	45-46
G14	4-5	19-20	32-33	49-50	23-24	47-48
G15	6-7	42-43	10-11	15-16	48-49	26-27
G16	22-24	39-41	21-23	4-6	20-22	17-19
G17	27-29	6-8	46-48	14-19	17-19	28-30
G18	1-3	39-41	41-43	16-18	3-5	21-23
G19	16-18	36-38	29-31	20-22	20-22	3-5
G20	17-19	36-38	12-14	21-23	27-29	16-18
G21	41-43	33-35	30-32	27-29	23-25	27-29
G22	5-7	33-35	1-3	24-26	16-18	6-8
G23	8-11	29-32	20-23	31-34	26-29	40-43
G24	26-29	29-32	35-38	27-30	35-38	31-34
G25	8-11	25-28	46-49	30-33	30-33	9-12
G26	30-33	25-28	16-19	35-38	31-34	34-37
G27	42-45	21-24	38-41	34-37	34-37	30-33
G28	12-15	21-24	17-20	11-14	6-9	3-6
G29	31-34	17-20	34-37	38-41	13-16	13-16
G30	12-16	14-18	24-28	39-43	39-43	35-39
G31	36-41	11-16	9-14	42-47	38-43	10-15
G32	35-40	8-13	24-29	10-15	10-15	38-43

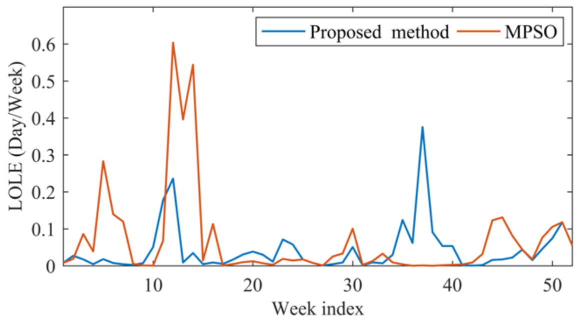

Figure 8. The comparison of *LOLE* between the proposed method and MPSO

5- Conclusions and discussion

In this study, the long-term maintenance scheduling problem for the generation units in the restructured power systems with the evaluation of the impacts of pumped storage units was investigated. This optimization problem is solved by the Benders decomposition technique. The objectives of mitigation of maintenance and operation costs and the improvement of reliability level are assigned for the objective function in order to use this proposed method for dealing with applications in large-scale power systems.

The proposed method is implemented on an IEEE-RTS 24-bus standard test system in order to measure its effectiveness and accuracy. The scenarios are designed to improve the results of the previous scenario. In the first scenario, regardless of the specific circumstances, the scheduling is based on cost reduction and increased profits and maintaining network reliability. In the second scenario, the effect of the forced outage rate on the maintenance program is investigated. It is observed that considering *FOR* will reduce network reliability, while also increasing annual operating costs. In the third scenario, scheduling is carried out by setting the maximum amount of *EENS* equal to 1% of the weekly peak load. As expected, network reliability drops sharply, but costs do not change significantly. In the fourth scenario, to further control the reliability of the network, ISO directs the fine-tuning of unit scheduling to lower peak load weeks by setting a penalty factor. It can be seen that by applying the penalty factor and coordinating the unit maintenance schedule with the peak load consumption curve, the reliability of the network has improved significantly, but it has dramatically increased maintenance costs and slightly reduced annual operating costs. In the fifth scenario, ISO sets the spinning reserved to 10% of the weekly peak load. Spinning reserved compensates to some extent the loss of reliability caused by the forced outage of units. In the sixth scenario, the maintenance schedule is planned with the use of an energy storage pump. The energy storage pump smoothes the daily consumption curve. The result of the maintenance scheduled indicates that the existence of an energy storage pump in the test network will greatly increase the reliability of the network and reduce maintenance and operating costs. of units, and determination of a non-zero value for energy not supplied index will result in the deterioration of the reliability of the grid and mitigation of operation cost in contrast.

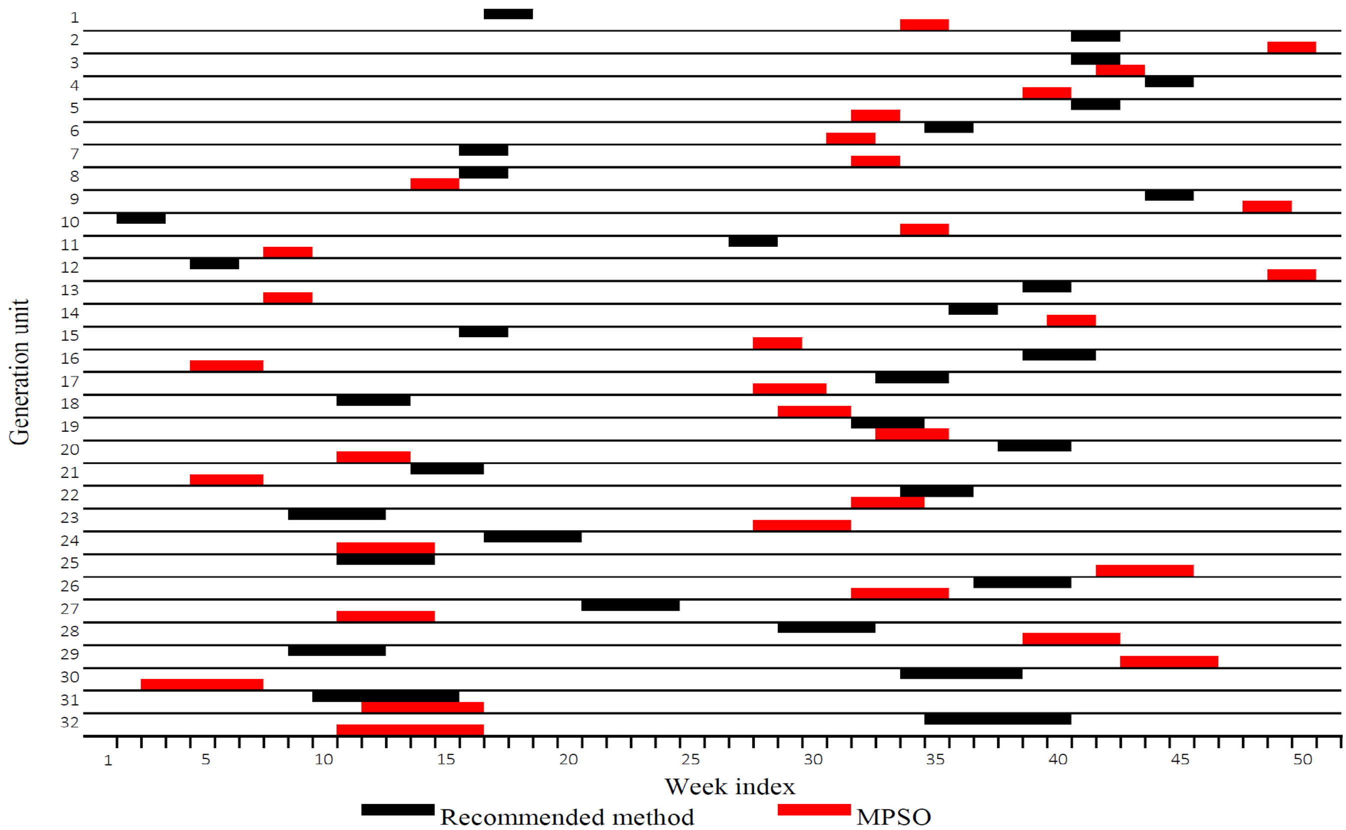

Figure 9. The comparison of maintenance schedule between the proposed method and MPSO approach

By incorporation of penalty factor into the objective function, the maintenance cost was mounted, whereas the reliability indices were improved tremendously. In addition, the incorporation of the spinning reserve requirement in the model has resulted in the improvement of the reliability. Ultimately, the integration of a pumped storage facility into the targeted power system has resulted in a significant increase in the reliability levels because it has made the demand curve smoother and it has alleviated the weekly peaks. Hereby, the maintenance cost and operation cost were cut down. By adding a comparison between the proposed method and a published work, which has employed modified PSO (MPSO) algorithm, it can distinctly be perceived that the proposed method has inspired performance in terms of speed and accuracy and can be applicable for preparing maintenance schedules in large-scale power systems.

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