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Reliability-based maintenance scheduling of generating units in restructured power systems

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Abstract: Maintenance scheduling of generating units in restructured power systems is a collaborative and interactive process between independent system operators (ISOs) and generating companies (GENCOs). The ISO should comply with GENCO maintenance preferences subject to targeted system reliability levels. This process might be multistage since the admission of all initial unit outage requests may threaten system reliability. Hence, the ISO accepts some proposals and determines alternatives for the remaining units. The GENCOs are then allowed to confirm the alternatives or revise them. In this paper the ISO problem of generating unit maintenance scheduling is tackled. The objective function is to minimize the deviation of awarded schedule from the requested schedule, as measured in MW weeks. A novel and effective optimization technique is developed to solve the problem at hand. In the proposed methodology, risk leveling and dynamic programming optimization algorithms are concurrently utilized to lessen the computation burden and enhance the solution process. The effectiveness of the proposed method and its applicability to real-life systems are verified by examining the generation section of the IEEE reliability test system (IEEE-RTS). The performance of the new method is also compared with that of the individual risk leveling approach.

Key words: Dynamic programming, maintenance scheduling, optimization algorithms, reliability assessment, risk leveling

1. Introduction

Generating units in a power system require periodic maintenance during which the unit under maintenance is detached from the grid and can no longer produce electricity. The maintenance of generating units would probably influence the system in 2 ways: increasing the production costs and eroding reliability. In vertically integrated power utilities that own all properties of generation, transmission, and distribution the process of maintenance scheduling is organized by the system administrator while keeping in mind that the aforementioned impacts should be limited as much as possible. In these conventional systems, maintenance scheduling is performed in a single course of action; afterward, the resultant maintenance timetable is announced to unit managers.

In restructured power systems, independent system operators (ISOs), which are responsible for ensuring the reliability of power systems, cannot determine the unit outage schedule alone since unit owners are inde-

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pendent entities with specific economic perspectives. Instead, generating companies (GENCOs) compute their preferred maintenance schedules and submit them to the ISO. Acquisition, refining, and coordinating GENCO proposals are then conducted by the ISO. Due to the security/reliability boundaries, the ISO either accepts the schedules or proposes the best alternatives to GENCOs. They can also confirm the alternatives or revise them. As a result, in a restructured environment the problem of maintenance scheduling is resolved through a multistage procedure in which each stage is perceived as an optimization problem.

After compilation of the maintenance proposals by GENCOs at the first stage, the ISO executes the second stage to refine the proposals. In the literature, various objective functions have been defined for the ISO optimization problem. In [1], setting unit maintenance time as early as possible and reserve leveling were considered the objectives of the ISO. Reference [2] proposed minimizing operating costs as the optimization criterion. In [3] and [4], the objective of the optimization algorithm was leveling the designated risk measure. In addition to reserve adjustment, reference [5] included the deviation of the final solution from the GENCO timetable in the objective function. Indeed, it was assumed that any deviation from the GENCO-proposed schedule results in a loss in their revenue. The amount of financial loss was supposed to be proportional to the extent of deviation regardless of unit capacities. To be fair, the method proposed in [5] was devised such that the losses associated with all GENCOs are at approximately the same level.

In this paper, the objective function of the ISO optimization problem is defined as minimizing the sum of deviations from the scheduled requests of GENCOs in the final solution. The optimization problem is subjected to the system reliability constraint. Therefore, the privileges of GENCOs will be respected by minimizing rejected requests, and system reliability will be preserved within an appropriate range. An innovative hybrid algorithm of risk leveling and dynamic programming techniques was designed to tackle the complicated optimization problem. Numerical case studies are conducted on the IEEE reliability test system (IEEE-RTS).

The rest of this paper is organized as follows. In section 2, the mathematical representation of the maintenance scheduling problem is expressed. Then, in sections 3 and 4 the risk leveling method and dynamic programming algorithm are described, respectively. Section 5 presents details of the proposed hybrid optimization method. Numerical studies are conducted in section 6. A comparison between the proposed method and the risk leveling approach is given in section 7. The concluding remarks are drawn in section 8.

2. Mathematical representation of the maintenance scheduling problem

As mentioned earlier, the first step in maintenance scheduling in a restructured power system is submission of outage requests by GENCOs. Then the ISO evaluates the proposals to see whether all the GENCO requests can be accepted without any alteration. Otherwise, some unit outage times should be awarded and the remaining modified accordingly. In such a case, the ISO attempts to keep the changes imposed on the remaining units minimal. In this paper the deviation from the requested time schedule associated with each unit is measured in MW weeks. This quantity is calculated by multiplication of unit capacity (in MW) as a weighting coefficient and absolute value of the difference between demanded and appointed outage times (in weeks). As an example, if the outage time of a 400 MW unit is postponed for 3 weeks by the ISO, the respective deviation would be 1200 MW weeks. The philosophy behind consideration of weighting coefficients is that any deviation associated with a large unit would bring a greater loss of revenue than deviation associated with a low-rated generating unit.

The set of equations (1)–(3) formulate the designated optimization problem, where t_k denotes the decision variable. The objective function, (1), is to minimize the sum deviations (in MW weeks) associated with all units. Vector-form–represented inequalities of (2) guarantee the satisfaction of weekly reliability constraints. Constraints (3) express a technical limitation referring to the fact that the maintenance outage cannot be too soon or too late with respect to the last maintenance course.

$$\min Z = \sum_{k=1}^{n} c_k \times |t_k - rt_k| \tag{1}$$

subject to:

$$\mathbf{R}_n \leq \mathbf{R}_{max} \tag{2}$$

$$e_k \leq t_k \leq l_k \tag{3}$$

3. Risk leveling method

In the risk leveling method that was first introduced in [3] and [4], generating units are sorted according to their capacities; in addition, the applicable maintenance times associated with each unit are sorted according to the reliability index. Then the largest unit is selected to go on outage in the most reliable time interval. The procedure is repeated for the remaining units until the outage times of all units are appointed. A more detailed description of this algorithm is as follows:

1. Select the largest remaining unit.
2. Compute the reliability measure for all weeks of the year.
3. Assign the most reliable time interval to detach the unit under consideration.
4. If all units are scheduled, stop and publish the results. Otherwise, restart the algorithm from **Step 1.**

It should be noted that adaptation of the most reliable time interval is subject to constraint (3). For instance, consider a unit detached from the grid for maintenance at the 40th week of the last year, when the time gap between 2 consecutive maintenance periods of this unit is 52 $\pm$ 5 weeks. Here, it is technically justifiable to approve any week from the 35th to 45th as the beginning of maintenance procedures. The reliability index of loss of load probability (LOLP) associated with weeks 35–48 in this hypothetical power system is given in Table 1. If maintenance of this unit lasts 4 weeks, the safest 4-week–long period will be the one with the lowest maximum risk within the period. In this example the best period is the one beginning from week 38 and ending in week 41, which is bolded in Table 1.

Table 1. LOLP associated with weeks 35 to 48 in the hypothetical power system.

Week	LOLP (%)	Week	LOLP (%)
35	0.0082	42	0.0142
36	0.0039	43	0.0678
37	0.3762	44	0.4525
38	**0.0027**	45	0.4641
39	**0.0078**	46	0.7611
40	**0.0078**	47	0.7611
41	**0.0140**	48	0.5102

The risk leveling method, although it is very simple and fast, would lead to a nonoptimal solution, particularly from the viewpoint of GENCO economical objectives. The reason is that this algorithm emphasizes the selection of most reliable time intervals, i.e. the system reliability criterion is explicitly considered; the GENCO beneficiary preferences are not accounted for at all. Therefore, the risk leveling method is not a suitable solution for scheduling outage times in restructured systems.

On the other hand, the solution would very likely be suboptimal even from the system reliability aspect because the straightforward and unintelligent risk leveling method is not strong enough for the maintenance scheduling, which is, mathematically, a nonconvex, large-scale, mixed-integer, and nonlinear optimization problem with a series of intertemporal constraints. It is often possible to attain better results by using other optimization methods at the expense of longer computation time.

4. Dynamic programming

A dynamic programming solution to the maintenance scheduling problem can be formulated in various forms. The form presented here is the one suitable for merger with the risk leveling algorithm above.

In order to solve the maintenance scheduling problem using a dynamic programming method, the reliability measure of the system is considered the system state. There is one decision to make associated with each unit which specifies the week for starting the maintenance process. Having influenced system reliability, that decision at the current stage determines the system state at the next stage. Since there is one decision per unit, the number of required stages in dynamic programming is equal to the number of generating units. To update the system state after every stage, the effect on the system LOLP of the maintenance outage of unit k at time interval t_k is calculated as $\mathbf{\Delta R}(t_k)$. This value is then added to the last stage LOLP value to form the LOLP index at the present stage. That is,

$$\mathbf{R}_k = \mathbf{R}_{k-1} + \mathbf{\Delta R}\left(t_k\right) = \mathbf{R}_0 + \sum_{i=1}^{k} \mathbf{\Delta R}(t_i) \tag{4}$$

To avert schedules violating the system reliability constraints, a penalty function is defined as (5):

$$pf\left(\mathbf{R}_k\right) = \begin{cases} 0, & \mathbf{R}_k \leq \mathbf{R}_{max} \\ \infty, & \textbf{otherwise} \end{cases} \tag{5}$$

If the system generating units are arranged based on their capacities, the largest unit has index 1, whereas the smallest unit corresponds to index n. Then the dynamic programming method can be used to solve the optimization problem by applying the following recursive formula:

$$f_k\left(\mathbf{R}_{k-1}\right) = \min_{e_k \leq t_k \leq l_k} \left[c_k \times |t_k - rt_k| + pf\left(\mathbf{R}_{k-1} + \Delta\mathbf{R}(t_k)\right)\left(\mathbf{R}_{k-1} + \Delta\mathbf{R}(t_k)\right)\right] \tag{6}$$

where $f_1(\mathbf{R}_0)$ gives the minimum deviation in the optimal solution. The inherent pitfall in the dynamic programming method is that the computation burden dramatically increases as a function of the number of state variables. Owing to the many imaginable states of system reliability in 52 weeks of a year, the volume of computation would be cumbersome; this leads to the inapplicability of the dynamic programming method to practical implementation.

5. The proposed method

In this section a novel method for the maintenance scheduling of generating units is proposed. This technique is indeed a hybrid version of both risk leveling and dynamic programming approaches. As discussed in section 2, the main idea behind the new model refers to the role of unit capacity in the evaluation of scheduling deviation. This issue also forms the basis for the optimization methodology, which will be discussed following of this section.

Reliability constraints, (3), prevent the ISO from accepting all maintenance outage requests with no alteration. After acceptance of 1 or a few unit proposals, it may become impossible to confirm other requests because of the affected system reliability. Therefore, the ISO has to choose among units. Evidently, minimizing the deviation of larger units corresponds to lower GENCO losses. It makes sense that larger units are thus given higher priority for the requested maintenance times. For the sake of illustration, suppose that a 20 MW unit requires 1 week for maintenance while a 400 MW unit requires a 4-week maintenance outage. Both units have submitted week 35 as the requested time for the maintenance commencement. However, because of reliability constraints, the ISO can only approve one of these requests. Therefore, one unit must necessarily go through the maintenance operation after the other. If the request of the 20 MW unit for maintenance at week 35 is granted, maintenance of the 400 MW unit is put off until week 36, i.e. just after the small unit reconnection. In this case, the total deviation would be 400 MW weeks. The reverse allocation of outage times, i.e. maintenance of the 400 MW unit at week 35 and outage of the 20 MW unit at week 39, brings about only a 80 MW week deviation. This observation might not generally be the case, particularly when units do not have such different capacities. For instance, instead of the 20 MW unit above, consider a 350 MW unit that requires 3 weeks for the maintenance. Rejecting the outage request of the 350 MW unit in favor of the 400 MW unit imposes $4 \times 350 = 1400$ MW week deviation, while accepting the outage request of the 350 MW unit results in $3 \times 400 = 1200$ MW week deviation.

Considering other factors such as the effect of unit maintenance on system reliability, which in turn depends on the capacity of the unit under maintenance, forced outage rate (FOR) of the unit, and duration of maintenance, among other things, it is obvious that determination of the optimum sequence of GENCO maintenance requests is not an easy task. Either a large number of combinations must be analyzed and compared, or a heuristic intelligent search method or classical optimization programming technique should be employed. The comprehensive search method is not commonly employable, as the number of combinations is intractable even in small-scale systems. The classical mathematical programming methods are not directly applicable either, because the reliability measure cannot be explicitly expressed in terms of problem variables, and a postprocessing computation should be followed.

Accordingly, in this paper a heuristic and hybrid optimization method is developed. The new method is an iterative process, and the system generating units are classified into 3 categories associated with each iteration phase:

1. **Scheduled units:** Units whose outage times have been decided in earlier iterations. This set is empty at the first iteration and is expanded as the algorithm goes forward.

2. **Dynamic units:** Units whose optimum outage time is being determined by the dynamic programming technique. In fact, various combinations of these units are examined in order to find the optimum combination. The number of units in this group is adjusted based on computational capability and should not lead to an intractable computation burden. At a minimum, the 2 largest units in the unscheduled units should be accounted for. After each iteration some of the dynamic units are transferred to the

category of scheduled units and replaced by some directed units on top of the list.

3. **Directed units:** Units that do not belong to the above categories. The risk leveling method determines the outage times of directed units merely to discoverer whether there is an acceptable combination of outage times for these units. Upon completion of each iteration and movement of some dynamic units to the scheduled group, some of the direct units are transferred to the dynamic unit category.

As a general rule, the algorithm moves some units from one category to another after each iteration. Units of the same size should be moved together between categories. The proposed procedure is as follows:

1. Sort units according to their capacities in descending order so that the largest generating unit is labeled unit 1 and the smallest generating unit is called unit n.
2. Let the units whose outage times have been determined earlier lie in the category of scheduled units.
3. From the remaining unscheduled units, choose 2 or more of the largest as dynamic units. The remaining units belong to the category of directed units.
4. Compute $f_k(\mathbf{R}_{k-1})$ as follows:
   (a) If unit k belongs to the category of scheduled units, calculate f_k using (7). Note that t_k is known for this type of unit.
   $$f_k\left(R_{k-1}\right) = c_k \times |t_k - rt_k| + f_{k+1}\left(R_{k-1} + \Delta R(t_k)\right) \tag{7}$$
   (b) If unit k belongs to the category of dynamic units, calculate f_k using (6).
   (c) If unit k belongs to the category of directed units, find the maintenance outage time, t_k, using the risk leveling algorithm; thereafter, calculate f_k by:
   $$f_k\left(\mathbf{R}_{k-1}\right) = c_k \times |t_k - rt_k| + f_{k+1}\left(\mathbf{R}_{k-1} + \mathbf{\Delta R}(t_k)\right) + pf\left(\mathbf{R}_{k-1} + \mathbf{\Delta R}\left(t_k\right)\right) \tag{8}$$
   where $pf(\mathbf{R}_{k-1}+\mathbf{\Delta R}\left(t_k\right))$ and t_k are computed by (5) and the risk leveling algorithm, respectively.
5. Transfer the largest unit(s) in the category of dynamic units to the category of scheduled units. Additionally, the time specified in this iteration is considered the outage time for the transferred units.
6. Repeat the algorithm from Step 3 until all units lie in the category of scheduled units.

The point deserving special emphasis is that by limiting the number of units in the category of dynamic units and reducing the number of possible combinations, a remarkable saving in CPU time is achieved. The rational reason behind the proposed algorithm is that there is no need to deal with all combinations of units at a single stage. It is more efficient to make decisions about larger units without engaging in the details associated with smaller ones. Another benefit of the newly devised methodology is that, depending on the computational power and allowable execution time, the analyst is able to govern the calculation burden through the number of units being handled in the category of dynamic units.

At the same time, the production of unsatisfactory combinations can be avoided by examining whether or not any feasible solution exists for smaller units (Step 4.c). To this end, one can deduce that using (8) and owing to the system reliability constraints, it is verified that the intended combination of the dynamic units does not deprive smaller units in the category of directed unit from maintenance outages. In other words, unfeasible combinations would be omitted automatically and in an intelligent manner.

6. Case study

In this section the IEEE-RTS [6] is examined to demonstrate the efficiency of the proposed algorithm. The implementation and simulations have been carried out in the MATLAB environment [7].

The set of generating units in the IEEE-RTS includes various nuclear, fossil-fueled, and hydro units ranging from 12 MW to 400 MW capacities. The units are partitioned and under the ownership of 3 GENCOs: A, B, and C. Table 2 outlines the GENCO units and the maintenance outage requests submitted to the ISO. The technically allowable time interval for the maintenance outage commencement is 52 $\pm$ 5 weeks of the previous year's outage. The generation system LOLP is adopted as the monitored reliability constraint, and it is supposed to be held below 1% for all weeks save the last 5 weeks of the year.

Table 2. GENCO units and their associated outage requests submitted to the ISO.

GENCO A			GENCO B			GENCO C		
Unit	Cap	Week	Unit	Cap	Week	Unit	Cap	Week
1	12	35	1	50	14	1	12	35
2	12	40	2	50	35	2	12	27
3	12	35	3	76	11	3	20	16
4	20	12	4	100	31	4	50	35
5	20	40	5	100	38	5	76	8
6	20	38	6	155	13	6	197	10
7	50	16	7	155	31	7	197	10
8	50	38	8	155	9	8	350	38
9	50	16	9	197	36	9	400	35
10	76	34	10	400	10	-	-	-
11	76	11	-	-	-	-	-	-
12	100	34	-	-	-	-	-	-
13	135	38	-	-	-	-	-	-

Cap = capacity [MW].

In order to solve the maintenance scheduling problem, as shown in Table 3, the units are first sorted with respect to their capacities.

In the first iteration the set of scheduled units is empty. Thus, units associated with the 3 largest capacities (400 MW, 350 MW, and 197 MW units) are assumed as the set of dynamic units, and the remaining group is labeled directed units. Thus, the category of scheduled units is empty, the category of dynamic units consists of 6 units, and the direct category encompasses 26 generating units.

Technically speaking and owing to the minimum and maximum time distance of the maintenance operation with the last course, if 10 different possibilities are examined for each dynamic unit, a maximum of 1,000,000 combinations have to be examined. By applying the risk leveling method, a schedule for the 26 remaining units is determined for each of these 1,000,000 combinations. Unacceptable schedules, namely those leading to the violation of reliability constraints, are rejected; acceptable ones are kept as candidates for the optimal schedule. The result of the first iteration is outlined in Table 4.

In the next iteration, two 400 MW units are moved to the category of scheduled units, and their associated outage times are fixed on the obtained solution at the first iteration. Accordingly, weeks 10 and 34 are adopted for units 1 and 2, respectively. Additionally, the 155 MW units are placed in the dynamic unit category. Hence, the numbers of generating units in the categories of scheduled, dynamic, and directed units are, respectively,

Table 3. Generating units listed in order of capacity.

Unit	Cap	LYO	RW
1	400	9	10
2	400	34	35
3	350	38	38
4	197	31	36
5	197	10	10
6	197	14	10
7	155	40	38
8	155	6	9
9	155	26	31
10	155	15	13
11	100	31	34
12	100	35	38
13	100	27	31
14	76	11	11
15	76	34	34
16	76	7	11
17	76	3	8
18	50	21	16
19	50	35	38
20	50	21	16
21	50	31	35
22	50	19	14
23	50	30	35
24	20	43	38
25	20	43	40
26	20	17	12
27	20	21	16
28	12	31	35
29	12	43	40
30	12	21	35
31	12	24	27
32	12	35	35

Cap = capacity [MW], LYO = last year outage,
RW = requested week.

Table 4. First iteration results of the proposed method: 400 MW, 350 MW, and 197 MW units in the category of dynamic units.

Total deviation: 7754 MW weeks					
Unit	Cap	Dev	RW	Acc	AW
1	400	0	10	YES	-
2	400	–1	35	NO	34
3	350	0	38	YES	-
4	197	–3	36	NO	33
5	197	0	10	YES	-
6	197	4	10	NO	14
7	155	2	38	NO	40
8	155	–3	9	NO	6
9	155	–5	31	NO	26
10	155	–3	13	NO	16

Cap = capacity [MW], Dev = deviation, RW = requested week, Acc = accepted or not,
AW = alternative week.

2, 8, and 22 associated with the second iteration. The results obtained in the second iteration are presented in Table 5.

Table 5. Second iteration results of the proposed method: 350 MW, 197 MW, and 155 MW units in the category of dynamic units.

Total deviation: 7754 MW weeks					
Unit	Cap	Dev	RW	Acc	AW
3	350	0	38	YES	-
4	197	–3	36	NO	33
5	197	0	10	YES	-
6	197	4	10	NO	14
7	155	2	38	|NO	40
8	155	–3	9	NO	6
9	155	–5	31	NO	26
10	155	3	13	NO	16
11	100	–3	34	NO	31
12	100	–2	38	NO	36

Cap = capacity [MW], Dev = deviation, RW = requested week, Acc = accepted, AW = alternative week.

Since the outage time of the 350 MW unit is established at the third iteration, this unit leaves the dynamic unit category, and three 100 MW units enter. At this iteration, various combinations of 197 MW, 155 MW, and 100 MW are examined for determination of the maintenance schedule. This procedure goes forward until, at the last iteration, various combinations of 50 MW, 20 MW, and 12 MW units are inspected in the category of dynamic units, and the algorithm is terminated. In this last iteration the directed unit category is empty since all units are processed, and their maintenance times are determined. At this stage the algorithm turns into ordinary dynamic programming. The reliability index for 52 weeks of the year is updated incorporating the maintenance outages of 17 larger units; thereafter, various combinations of the 15 smaller units are examined to find the optimum schedule.

The final solution is given in Table 6. As observed, the scheduled maintenance outage times of all units lie within the declared allowable interval, i.e. 52 $\pm$ 5 weeks from the previous year's outage.

7. Comparing the proposed method with other techniques

In the literature a variety of methods have been used or devised to solve the maintenance scheduling problem [8]. They differ both in unit maintenance scheduling procedure and in the algorithm utilized to find the optimum solution. A few other algorithms are briefly introduced in this section, and a comparison between the proposed algorithm and these alternative algorithms is given.

Employing the proposed algorithm, the CPU execution time on a 1.5 GHz Intel Celeron processor is about 2 h for the maintenance scheduling of the IEEE-RTS generation system. The proposed method generates a schedule with 5801 MW week total deviation from the requested outage times. The system average LOLP, incorporating the effect of maintenance outages, is about 0.75%.

For the sake of comparison, the problem is solved using the individual risk leveling method as well. The computation time elapsed is negligible against that of the hybrid algorithm; however, the introduced deviation equals 8007 MW weeks, which is much greater than the 5801 MW weeks of the hybrid method. Considering the scheduled outages, the system average LOLP was about 0.72%. Based on the aforementioned explanations, it can

Table 6. The final solution: maintenance outage schedule of all generating units.

Total deviation: 5801 MW weeks						
Unit	GENCO	Cap	Dev	RW	Acc	AW
1	B	400	0	10	YES	-
2	C	400	–1	35	NO	34
3	C	350	0	38	YES	-
4	B	197	–4	36	NO	32
5	C	197	0	10	YES	-
6	C	197	4	10	NO	14
7	A	155	2	38	NO	40
8	B	155	–3	9	NO	6
9	B	155	–5	31	NO	26
10	B	155	3	13	NO	16
11	A	100	0	34	YES	-
12	B	100	–2	38	NO	36
13	B	100	0	31	YES	-
14	A	76	0	11	YES	-
15	A	76	–4	34	NO	30
16	B	76	–3	11	NO	8
17	C	76	–1	8	NO	7
18	A	50	1	16	NO	17
19	A	50	2	38	NO	40
20	A	50	4	16	NO	20
21	B	50	1	35	NO	36
22	B	50	6	14	NO	20
23	C	50	–3	35	NO	32
24	A	20	0	38	YES	-
25	A	20	0	40	YES	-
26	A	20	1	12	YES	-
27	C	20	1	16	NO	17
28	A	12	0	35	YES	-
29	A	12	2	40	NO	42
30	A	12	–5	35	NO	30
31	C	12	0	27	YES	-
32	C	12	4	35	NO	39

Cap = capacity [MW], Dev = deviation, RW = requested week, Acc = accepted, AW = alternative week.

be deduced that the risk leveling method cannot solely be an effective solution for the maintenance scheduling in multiagent restructured electric power systems. Although it is very fast and has a trivial computational load, this method does not consider GENCO preferences and results in very large deviations from the requested maintenance schedules.

Some research has utilized mixed integer linear programming (MILP) to solve the maintenance scheduling problem. In order to apply this powerful optimization programming, it is a prerequisite to express the objective function and all constraints in a linear fashion. To this end, a simple reliability index was used. In [9], the ratio of the net reserve to the gross reserve is used as an index to measure system reliability. Since the proposed method in this paper exploits dynamic programming as the core algorithm, no specific limitations regarding the objective function or constraint form are imposed. Hence, LOLP, which accurately reflects system reliability, is used as the reliability index.

Nonlinear constraints and objective functions in the maintenance scheduling problem have led to increasing implementation of artificial intelligence methods to solve the problem in [5] and [10]–[12]. Among these methods, genetic algorithm is the most popular. Genetic algorithm mainly relies on random mutations and crossovers between best candidates in every generation, hoping that the offspring will be better than the parents, and that an evolution will occur after several stages. Random mutations are a means to explore more possible solutions and avoid a suboptimal outcome. When the number of units increases, either larger populations or more mutations must be used to sufficiently cover the search space, and this requirement dramatically increases the computation time. Therefore, the main issue impeding the application of genetic algorithm in the maintenance scheduling problem is that it is a very time consuming process, particularly when the problem dimension is rather large, which is the case here.

In contrast to the genetic algorithm, in the proposed method the search space is limited, and a large number of possible solutions are enumerated in a systematic manner. Along with some hybrid methods devised to improve the genetic algorithm performance such as [11] and [12], an idea similar to what we have applied here to dynamic programming could be utilized to accelerate the evolution process of genetic algorithms. That is, at the beginning stages of optimization the focus should be on genes associated with larger units. After achieving a set of best combinations for these units, the optimization of other genes representing smaller units is initiated. This approach might result in convergence in a shorter time; however, further research should be devoted to this subject.

Another method applied to the maintenance scheduling problem is dynamic programming [13]. The major drawback associated with this technique is the excessive computation burden, particularly in large-scale systems. For the numerical example investigated in this paper any attempt to solve the problem solely with the dynamic programming method failed due to the cumbersome computational effort. The proposed method is an effort to improve dynamic programming by limiting the search space.

8. Conclusions

A novel methodology for coordinating GENCO outage requests by ISOs was introduced in this paper. Using this technique, in addition to maintaining the system weekly reliability indices below prespecified thresholds, the deviation of the final solution from GENCO proposals was minimized in order to lessen GENCO profit losses. The new algorithm is a hybrid optimization technique based on concurrent utilization of dynamic programming and risk leveling methods.

The proposed method is applicable in restructured environments as it takes the reliability criteria into consideration while respecting the interests of GENCOs. Classifying generating units into scheduled, dynamic, and directed units restricts the dimension of dynamic programming to just a few units. This attribute, as shown in the numerical studies, makes the developed model tractable within a reasonable execution time. Furthermore, by adjusting the number of dynamic units, the overall execution time can be governed.

Nomenclature

c_k	capacity of unit k
d_k	duration of maintenance outage of unit k
e_k	earliest applicable time to begin maintenance outage of unit k
ik	generating unit indices
l_k	latest applicable time to begin maintenance outage of unit k
n	number of units requesting maintenance outages
rt_k	outage time of unit k requested by the relevant GENCO

$\mathbf{R}_0$ vector of weekly LOLP index before maintenance scheduling
$\mathbf{R}_k$ vector of weekly LOLP index considering maintenance outage of units $1, 2, \ldots, k$ in various weeks
$\mathbf{R}_{max}$ vector of maximum acceptable weekly LOLP
t_k outage time of unit k assigned by ISO
$\mathbf{\Delta R}\,(t_k)$ vector representing the effect on weekly LOLP of maintenance outage associated with unit k from weeks t_k to $t_k + d_k$

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