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A Comparative Study of Maintenance Scheduling Methods for Small Utilities

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Abstract. This paper presents a comparative study of a few commonly used maintenance scheduling methods for small utilities that consists solely of thermal generating plants. Two deterministic methods and a stochastic method are examined. The deterministic methods employ the leveling of reserve capacity criterion, of which one uses a heuristic rule to level the deterministic equivalent load obtained by using the product of the unit capacity and its corresponding forced outage rate. The stochastic method simulates the leveling of risk criterion by using the peak load carry capacity of available units. The results indicate that for the size and type of the maintenance scheduling problem described in this study, the stochastic method does not produce a schedule which is significantly better than the deterministic methods.

Key Words : *maintenance scheduling, heuristic, implicit enumeration, peak load carry capacity, reserve capacity, forced outage.*

1. INTRODUCTION

The main function of any electric utility industry is to cater for the need of customers, both large and small users, for a reasonably priced and reliable electrical energy source. The increasing need to achieve higher system reliability, lower operating cost and faster response to changes in the power system leads the system planners to involve in various planning activities. In board term, it entails the application of system planning to cater for anticipated future load requirements, and to ensure that additions to the capacity of generation, transmission and distribution systems are always timed accurately. The necessity of this long range planning lies with the capital-intensive nature of the electric utility. In addition, there is also the necessity for short range planning to cater for fluctuating load situations, regular maintenance requirements of installed plants and random breakdowns of the operating equipment.

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In Singapore, the lack of natural resources limits the type of electric generating facilities to fossil-fueled thermal plants. Other types of plants such as geothermal, hydro-power or pumped hydro-power are not available here. In addition, the absence of widely ranging weather conditions means that the peak demand does not vary dramatically throughout the year. However, as illustrated in Figure 1, the load pattern tends to have substantial variations over a 24-hour cycle with a peak load at around normal working hours and changing over to a low load towards the night and early hours of the morning. Therefore, to meet this continuously fluctuating load pattern, it is not economical to use large base-load units alone. In order to supply for load requirements during the peak periods, the utilities in Singapore have to rely on mid-range units and fast reserve units such as gas turbines as well. These different types of generating units coupled with their different service conditions have different nature of maintenance requirements in addition to the constraints from statutory legislation governing high pressure components.

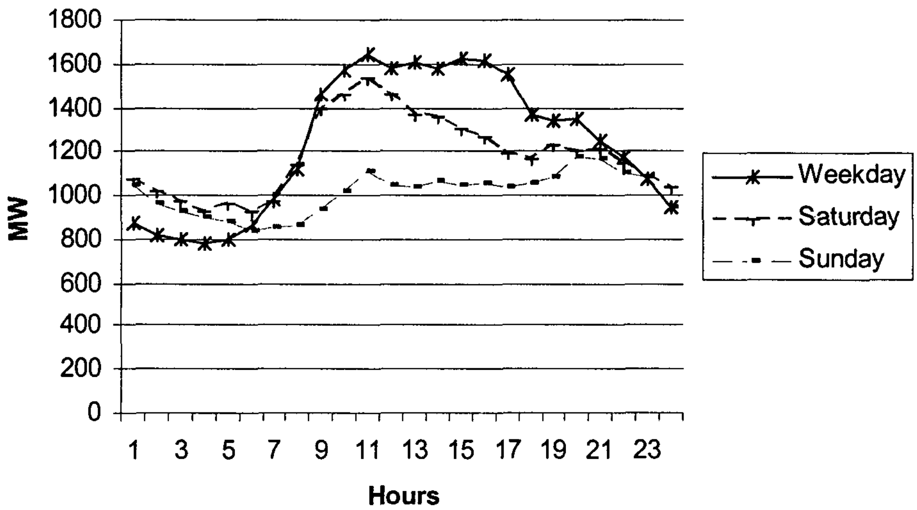

Figure 1. Typical daily load pattern for a week.

In this paper, we focus on the issue of maintenance scheduling problem (henceforth referred as MS problem) for short range planning. In practice, preventive maintenance is always required for all generating equipment in order to reduce the chance of forced outage or random failures, and to improve the overall availability of such units. The forced outage is a condition which requires a generating unit to be taken out of service at once or as soon as possible. This may due to random failure of any auxiliary equipment or any sub-system in boiler, turbine or generator.

The MS problem is normally formulated as a constrained optimization problem (Yamayee, 1982). It involves, after having considered a desired objective function, available resources, and other constraints, specifying the dates on which manpower is to be allocated to designated generating units in various locations for a certain amount of planned preventive maintenance to be executed. Generally, there are two major objective functions pursued by most utilities in the operation of electric power systems: minimize operating cost (Dopazo and Merrill, 1975; Hara et al., 1966; Zurn and Quintana 1975) and maximize reliability or minimize risk of loss generating capacity (Allan and Takieddine, 1977; Christiaanse and Palmer, 1972; El-Sheikhi and Billinton, 1984; Egan et al., 1976; Garver, 1972; Khatib, 1979; Stremel and Jenkins, 1981).

The most well known and commonly used method for the MS problem is the deterministic approach of leveling the reserve capacity over all periods of the scheduling horizon (Christiaanse and Palmer, 1972). The advocates of this method argue that for practical purposes, leveling the reserve capacity may be approximately equivalent to achieving a schedule that closely matches the equal risk criterion. It is even simpler for utilities in Singapore to apply this method since the peak loads of the systems hardly change due to the absence of seasonal changes in a year. The main drawback is that it does not reflect the stochastic characteristics of a power system. For example, a 100 MW reserve capacity at a period when load is at 1000 MW would not have the same level of reliability as another period when the reserve is still 100 MW, but with the load at 500 MW. But this drawback is not evident on systems with fairly stable load levels throughout the year similar to that of Singapore. The method also does not differentiate units with different availabilities so that it might lead to schedule a relatively large but reliable unit for maintenance during the low load periods. The level of system reliability after the withdrawal of a high reliable unit is different from that of a less reliable one even though the reserve capacity may be the same.

In contrast, stochastic methods are introduced to take into account of factors such as uncertainties in load forecasts, fuel supply and price, forced outage rate of generating units (the ratio of forced outage time to the time the unit is in operation), and other constraints. The main effort is to level the risk of loss of generating capacity across the scheduling horizon. The risk or reliability index used is very often the loss of load probability (LOLP) which is defined as the probability that generating capacity becomes deficient. A variation of the method is to use the concept of effective load carrying capacity (ELCC) or the peak load carrying capacity (PLCC) for each configuration of available units during the time intervals, and then leveling the equivalent reserve capacity is given by the difference between the ELCC or PLCC and the peak load forecasted for the periods. Details of these methods can be found in Allan and Takieddine (1977), Billinton and Allan (1996), Garver (1972), Khatib (1979), Stremel and Jenkins (1981).

The MS problem has also been modelled and solved by mathematical programming techniques such as integer programming (Dopazo and Merrill, 1975; Egan et al., 1976) and dynamic programming (Zurn and Quintana 1975). However, most of the formulations require excessive computer resources in terms of storage and computation times. For small scale problems, such as those in Singapore, it is not justifiable to use sophisticated methods when simpler methods are available, and can serve the same purpose.

As there are no comparative results on the performance of various methodologies on a small size problem, we present in this paper a comparative study carried out based on the small utilities in Singapore to evaluate the relative performance of both deterministic and stochastic methods. Based on the results of this study, we suggest some suitable and practical methods for the small utility users. The rest of the paper is organized as follows: Section 2 gives a brief description of the MS problem. Section 3 presents the three methods compared in this study. In Section 4, an implicit enumeration for solving the MS problem is given. The comparative results for the three methods are analyzed in Section 5. Finally, some concluding remarks are given in Section 6.

2. DESCRIPTION OF THE MAINTENANCE SCHEDULING PROBLEM

Most of the methodologies proposed in the literature are not devoted to power systems of a particular size or with certain specific features and conditions. It is often assumed that if a methodology can cope with larger systems, it should work for smaller systems as well. Although this may be true in general, however, for smaller utilities like that of Singapore's where the number of feasible schedules is small, there is no real advantage in applying sophisticated techniques such as the branch and bound technique. For small power systems, there is an advantage to identify some stringent constraints that can be incorporated into the model of the MS problem. These constraints limit the number of feasible solutions and hence lead to the development of some efficient procedures for the solution of the MS problem. The constraints taken into account in this study are as follows:

1) Technological constraint
The cyclical maintenance recommended by the manufacturer is enforced with relatively strict rigidity as the underlying assumption is that the manufacturer, with experience over many similar units of equipment installed, is more competent to establish the maintenance requirements that will maximize the equipment's availability and efficiency. Also, the manufacturer's knowledge of the design criteria will enable them to identify the critical components to concentrate on.

2) Statutory legislation
The local legal requirements affect mainly the boilers units, which in turn affect the operation of the entire generating unit since the plants are of unitized configuration, that is, each turbine can only receive steam from its respective boiler. The other rules governing pressure vessels, such as air receiver or fuel oil heaters, do not affect an entire generating unit as these auxiliary equipment are usually installed in a parallel configuration. For the boiler units, a major inspection by an approved person must be carried out every two years. In addition, a minor inspection which includes floating of safety valves and burner throat inspection, must be completed every year. For convenience of reference, the latter requirement is called minor inspection which is usually completed within two weeks. The former requirement is termed major overhaul which may require an outage period varying from 4 to 8 weeks.

3) System reserve requirement
To ensure that a system has a certain minimum level of reliability, a minimum amount of generating capacity is kept on standby. This operating requirement restricts the number of units to be scheduled for maintenance outage concurrently.

4) Manpower constraints
The size of a maintenance crew at each power station is normally limited to what is sufficient to execute major preventative maintenance work on a unit with the largest capacity. This implies that unit outage can be scheduled only one at a time. However, in the local context, contracting out of major works, such as reblading of turbine rotor or boiler retubing, occur occasionally when need arises. In such case, it is permissible for more than one unit to be scheduled at the same particular station, provided other constraints such as the reserve capacity requirement are not violated.

5) Time horizon
The span of time considered in the solution of a MS problem is usually one year.

6) Time increment
Maintenance scheduling of generating units is done for discrete time units. Most utilities use a typical time period of one week.

Based on these constraints, the current practice of the Power Supply Authority of Singapore is to schedule a major overhaul once every 18 months with a minor inspection scheduled in between, 12 months from the time since previous maintenance.

3. COMPARATIVE FEAMEWORK

3.1. Methods Compared

The deterministic method selected in this study is the widely used leveling of reserve capacity technique, and for the stochastic method, the leveling of the risk using the relatively well known peak load carry capacity (PLCC) technique is chosen. Since the main disadvantage accrued to the leveling of reserve method is that of vastly differing levels of reliability in the various periods, it is proposed to study the effect of adding a heuristic rule to this deterministic method to circumvent this inherent weakness. The method proposed is to use the deterministic equivalent load, obtained by using the product of the unit capacity and its corresponding forced outage rate (FOR), to compute the reserve capacity instead of the usual reserve capacity derived from using the rate capacity of generating units. The implication of the equivalent load is that the unit is not subject to any chance of random failure, but is merely derated by a certain amount of capacity that corresponds to those lost as a result of random outage during its operation. This, the equivalent load as defined has no probabilistic characteristics. Nevertheless, the idea of this heuristic technique is to differentiate the relative reliability level, if any, among the feasible combinations of units scheduled for various periods. The expected effect is to spread out the scheduled outage of the less reliable units from occurring at the same time. In other words, it also tends to avoid the other extreme situation where the more reliable units are withdrawn for outage all together.

For convenience, the original and revised deterministic methods are referred to as Method 1 and Method 2, respectively. The stochastic method is referred to be Method 3.

The main data input for the MS problem are listed below:

1) Pertinent data of each generating unit – Unit name and rated capacity
2) Forced outage rate of unit
3) Last major overhaul dates of each unit
4) Time interval to next major overhaul
5) Time interval to next minor inspection
6) Fixed dates for next inspection or overhaul if any. This can be termed as planned firm maintenance.
7) Durations for the next minor inspection and the next major overhaul
8) Permissible delay of next inspection and next major overhaul.

Some of the data input are basic requirements of the MS problem while others are additional variables that can be used to represent special conditions of specific units or to make adjustments such as relaxing of constraint for specific units.

3.2. The Reliability Index for Assessment Methods

There are a number of reliability indices currently used in power system engineering, and can be generally classified under the categories of probability indices, frequency indices, duration indices and expectation indices. For the purpose of this study, the widely used approach of loss of load expectation (LOLE) is chosen (Billinton and Allan, 1996).

The LOLE method is considered suitable because it provides a single index which expresses the expected number of days in a given period of time (normally a year) in which the daily peak load exceeds the available capacity. The index is sometimes called the loss of load probability (LOLP). It is proposed to use the 2-state generating unit representation of the method so that the worst case of static inadequacy of the generating capacity is modelled. The basic steps to obtain this index can be summarized as follows:

Step 1: Develop a capacity outage model from the parameters of the individual generating units.
Step 2: Develop a load model from the forecast peak loads over the period of study.
Step 3: Combine the capacity model with the load model to obtain a probabilistic model of system capacity adequacy.

The power system in Singapore consists of generating units with capacities of 60 MW, 120 MW and 250 MW. However, in developing the capacity outage model, the capacities used need to be multiples of the smallest unit size (i.e. 60 MW, 120 MW and 240 MW). If the 250 MW units are introduced into the capacity model as its actual capacity size, then a non-representative and improbable capacity probability curve will result. Hence, a modified capacity size of 240 MW will be used, but an offsetting technique will be introduced to overcome this capacity reduction discrepancy. The offset required is to reduce the forecasted peak load for an interval by 10 MW whenever a 250 MW unit is scheduled to be available for that interval. The errors introduced by this adjustment should be very small compared to that if the actual capacity size is used for the capacity model.

For the load model, an assumption is made that the peak load forecasted for weekly intervals occurs daily during the weekdays, but not during Saturday and Sunday. Since the worst case is taken into consideration, it can be assumed that if the planned outages scheduled for a specific weekly interval do not affect system adequacy requirement, then with the off-peak period during the weekend, it should be possible to schedule some short-term corrective maintenance outage for the available generating units should the need arises.

With the use of LOLP, the relative performance of the proposed MS methods can be assessed easily. The technique to achieve this is to compare the LOLPs of the power system for all the 52 weekly intervals based on the schedule obtained by each method. A plot of the LOLP versus time for each method is made for comparison. The best method is indicated by the most level plot which implies that the risk of loss-of-load is `equalized' over the scheduling horizon.

Note that in using LOLP as a reliability index, some assumptions have been made which must be realized so as to understand the conditions which make the model valid.

The assumptions made for each generating unit are:

a) Times between forced outages are independent and exponentially distributed.
b) Durations of forced outages are independent and exponentially distributed.
c) A forced outage results in loss of the total capacity.

While the assumption of exponentially distributed times are plausible in practice, the assumption of independence for forced outages of generating units and forced outage durations may not always be true. There is always a small likelihood on a power grid with interconnected generating units that a sudden failure of a certain unit may affect other operating units. It is also quite certain that failure of more than a small number of units during a short period could overtax the repair capabilities of most utilities. But other than these peculiar situations mentioned, it is reasonable to assume that the assumptions are valid for the MS problem concerned.

4. AN IMPLICIT ENUMERATION ALGORITHM FOR THE MS PROBLEM

As mentioned in Section 2, stringent constraints have effect of limiting the number of feasible solutions, and this is true in the case of Singapore. For example, the number of possible time intervals to schedule the overhaul of a specific unit is not 52 weeks, but equal to (allowable delay in weeks + 1) ways of scheduling the maintenance requirement. A typical value of the maximum allowable delay is usually from 2 to 4 weeks. As a result, the number of possible combinations for 17 generating units with allowable delay of 3 weeks to be considered for each schedule is approximately 7 x 109 which is till quite tremendous. However, not all units will have a major overhaul within the same scheduling horizon. Since the cyclical maintenance interval is about 18 months, thus, it is not necessary to consider all the possible combinations that cover 52 time intervals. A 'blocking' technique can be applied to reduce the number of combinations. This can be illustrated this by an example below.

As shown in Table 1, the '1' and '0' represent the available and possible outage states of five generating units, respectively, each having a maintenance duration of 4 weeks with the maximum allowable delay of 3 weeks. As the '0' states imply, Unit 1 can have its overhaul scheduled from weeks 4 to 7, 5 to 8, 6 to 9, or 7 to 10. Over the time frame of 27 weeks used for the illustration, the number of combinations of unit outage is 768 (i.e. 45). However, there are a large portion of redundant and repetitive combinations. This is because only outage states of Units 1, 3 and 4 intersect with each other, but not with Units 2 and 5. There is a 'break' between weeks 14 and 15 which subdivides the problem into 2 smaller blocks. Hence, there are actually only 80 (i.e. 43 + 42) unique combinations.

Table 1. Possible combinations of unit outage (Block method)

Unit No.	Week													
	1			4				8				12		
1	1	1	1	0	0	0	0	0	0	0	1	1	1	1
2	1	1	1	1	1	1	1	1	1	1	1	1	1	1
3	1	1	1	1	1	1	1	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	1	1	1	1	1	1	1
5	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Unit No.	Week													
		16				20				24				
1	1	1	1	1	1	1	1	1	1	1	1	1	1	
2	1	1	1	1	1	0	0	0	0	0	0	0	1	
3	1	1	1	1	1	1	1	1	1	1	1	1	1	
4	1	1	1	1	1	1	1	1	1	1	1	1	1	
5	0	0	0	0	0	0	0	1	1	1	1	1	1	

Even if the possible outage states of Units 2 and 5 occur earlier by one week (see Table 2) so that there is no 'break', the resulting number of combinations to be considered is not as high as the original number of 768. The data structure can be considered to be consisting of 2 intersecting blocks (first from intervals 1 to 14, second from 14 to 27) which can be separated into 4 possible blocks. Let the '2' state be used to represent firm scheduled outage for the unit for that specific period. For the first part of the intersecting blocks as represented in Tables 3 and 4, the state of Unit 5 in week 14 must either be either '2' or '1' (see the states highlighted in bold in Tables 3 and 4) in the final schedule. Similarly, for the second part of the intersecting block, the state of Unit 3 in week 14 must be either '2' or '1'. This implies that all possible schedule combinations of the original block can be accounted for by the intersecting blocks. In the worst case when all 4 alternatives need to be enumerated, their is a total of 160 unique combinations (i.e. 2 x 43 + 2 x 42). During the computation stage, the optimal solution may be found without enumerating up to this limit. This happens when the search through both alternatives 1 and 2 of the first part results in the state of Unit 3 in week 14 to be identical, say state `1'. Then only alternative 4 of the second part will need to be enumerated to obtain the optimal solution. The intersecting block method only caters for the case where there are 2 units with possible outage intervals overlapping at one time interval period.

Table 2. Possible combinations of unit outage (Intersecting Block method)

Unit No.	Week													
	1			4				8				12		
1	1	1	1	0	0	0	0	0	0	0	1	1	1	1
2	1	1	1	1	1	1	1	1	1	1	1	1	1	1
3	1	1	1	1	1	1	1	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	1	1	1	1	1	1	1
5	1	1	1	1	1	1	1	1	1	1	1	1	1	0

Unit No.	Week												
		16				20				24			
1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	1	1	1	1	0	0	0	0	0	0	0	1	1
3	1	1	1	1	1	1	1	1	1	1	1	1	1
4	1	1	1	1	1	1	1	1	1	1	1	1	1
5	0	0	0	0	0	0	1	1	1	1	1	1	1

Table 3. Alternative 1 of Intersecting Block 1
(firm scheduled outage of Unit 5 in week 14)

Unit No.	Week													
	1			4				8				12		14
1	1	1	1	0	0	0	0	0	0	0	1	1	1	1
2	1	1	1	1	1	1	1	1	1	1	1	1	1	1
3	1	1	1	1	1	1	1	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	1	1	1	1	1	1	1
5	1	1	1	1	1	1	1	1	1	1	1	1	1	2

Table 4. Alternative 2 of Intersecting Block 1
(do not schedule outage of Unit 5 in week 14)

Unit No.	Week													
	1			4				8				12		14
1	1	1	1	0	0	0	0	0	0	0	1	1	1	1
2	1	1	1	1	1	1	1	1	1	1	1	1	1	1
3	1	1	1	1	1	1	1	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	1	1	1	1	1	1	1
5	1	1	1	1	1	1	1	1	1	1	1	1	1	1

The two blocking techniques described above form the basis of the implicit enumeration algorithm, and the existence of data structure to facilitate this depends mainly on the size of the problem. In Singapore, this method is applicable as the problem size is small (20 units or less). The main advantage of the implicit enumeration algorithm is that the optimal solution can be obtained with relatively small amount of computer storage as compared to other methods such as the branch-and-bound technique. At any one time, only the current best solution is stored while the search continues on new combinations.

5. ANALYSIS OF RESULTS

The three MS methods described in Section 3 were tested on some sample data sets that are representatives of a MS problem for a small power system. The setup of the local power system was used as the background for the problem. The forced outage rates, overhaul lengths and intervals between overhauls or inspections were varied to achieve the desired effects. Several sets of data were run to test the performance of the scheduling methods. The results of the test are discussed in this section.

The data sets can generally be divided into two groups representing the two main categories of results obtained. The first group of data sets, referred to as Group A, represents those cases that the scheduling methods can find some maintenance schedules that differ. The second group of data sets, referred to as Group B, represents those cases that the scheduling methods consistently find schedules that are identical to one another. In fact, it was found that for data representing actual local conditions, the results for Group B data sets are most frequently encountered. The factors that influence this trend will be discussed in details in Section 4.1. In both groups of data sets, some parameters such as the forced outage rates are exaggerated in some cases so as to ascertain effects for the purpose of study and comparison.

The results indicate that the leveling of reserve method (Method 1) is the most efficient method in terms of CPU time. The next efficient method is the leveling of risk using equivalent load method (Method 2) which utilizes approximately 10% more CPU time than the first one. The leveling of risk using PLCC method (Method 3) requires the most of the computing resources, and the CPU time used can be 50 to 70 times more than that of Methods 1 and 2.

From the comparative study, we observe that although there are instances when all three methods result in different schedules. However, this occurs only at certain time intervals and not over the entire scheduling horizon. It was found that these schedules still have many identical outages scheduled for many of the units at various time intervals.

5.1. Factors Affecting Performance and Sensitivity

There are several factors which may affect the performance and sensitivity of the MS methods. These can be summarized as follows:

a) The forced outage rates (FOR) of the generating units.
b) The forecasted peak load pattern.
c) The interacting effect of more than one generating unit on outage in the same vicinity of time intervals.

It is usually not just one fact alone, but a combination of two or more factors that can cause a difference in the outcome of the maintenance schedules obtained by the various methods.

The FORs of the generating units can affect the outcome of the schedule if the magnitude of the FORs are significantly different between related units, in terms of scheduled outages. However, only Methods 2 and 3 are sensitive to this factor. When the magnitude of the FOR or its difference between units is small, then even Methods 2 and 3 may not be able to find a schedule that is different from that obtained by Method 1 unless some other factors are exist. Although Method 1 is not sensitive at all to the FOR of the generating units, it is sensitive to peak load pattern forecasted. When the load pattern is fluctuating (i.e. not level over a span of time intervals), Method 1 will search for a schedule such that the minimum reserve capacity is maximized, and it can do this just as efficiently as the other two methods. But when the load is level, and if the difference in the FORs among the units is significant, then Method 1 may not perform as well as the other two methods. It should be noted that the condition of a fluctuating load pattern and a significant FOR effect may counteract each other. The third factor mentioned requires the existence of either a significant FOR effect or fluctuating load pattern, or both. It was found that in general, if the number of generating units on possible outage in the same vicinity of time intervals is less, it is more likely for the final schedule determined by the three methods to be the same. In the simulation of more generating units to be on outage at the same time by means of dummy power stations, different schedules were obtained by the various methods.

To study the performance of three MS methods when different schedules are obtained, the LOLP for each time interval of the schedules was computed. The results seem to show that Methods 2 and 3 can give better solutions in certain cases. In worst case, a similar solution is obtained for all the three methods. There is no indication for the cases encountered in the study to show that Method 3 is significantly better than Method 2.

5.2. Special Conditions of the Local Problem

As mentioned earlier, with data sets using conditions similar to the local power system, the schedules obtained by the three methods were usually identical. There are a few reasons for this peculiarity of the local MS problem which can be summarized as follows:

1) The small number of power stations and generating units together with the constraints of one unit per station on maintenance outage limit the number of possible combinations of units on outage at any one time. The configuration of units on outage cannot deviate from the pattern of 60-60-120, 60-60-250, 60-120-120, and 60-120-250, where the number represents the capacity size.

2) The typical FORs of the generating units are structured in such a way that the older and smaller capacity units have the highest FOR while the newer and higher capacity units have the lowerest FOR. The magnitudes are also relatively low and can be grouped according to their capacities, 2% to 4% for 60 MW units, 0.2% to 2% for 120 MW units, and 0.1% to 1.2% for the 250 MW units.

3) The lack of seasonal demand in electricity and drastic weather change allows the maintenance to be spread equally throughout the year. In the study, the data sets were adjusted in an attempt to determine how much the outcome of the schedule by the various methods can be changed, and it was found that it is difficult to obtain different schedules unless the FORs or the load effects are `exaggerated'.

6. CONCLUSION

A comparative study has been carried out to examine the relative performance of three MS methods for small utilities. The results indicate that for the size and type of the MS problem described in this study, the PLCC method does not produce a schedule which is significantly better than the deterministic methods. Although the results have not revealed much of the inherent strengths and weakness reported in the literature, it should be noted that these were found when dealing with MS problems on large and much more complex power systems.

The study further conforms the feasibility of implementing the MS process on a microcomputer. In view of the CPU time requirement and the lack of significant advantage in terms of better schedules, it is recommended that the stochastic method should not be used at the initial stage of the MS process. It is proposed that both the deterministic methods be used to solve the MS problem sequentially so that any difference, if any, in the schedules can be noted and analyzed further. It may be necessary to make a few runs to obtain a feasible schedule so that none of the generating units requiring maintenance are omitted. Once an optimal schedule is obtained, there are two approaches to check on the reliability level of the power system over the scheduling horizon. The simpler approach is to compute the LOLP for all time intervals and plot it graphically. The other is to make a final run with the stochastic method and check if a different schedule can be obtained.

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