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Preventive Generation Maintenance Scheduling Considering System Reliability and Energy Purchase in Restructured Power Systems

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ABSTRACT

The completely Electric Power System encompasses three parts: Generation, Transmission, and Distribution that all require maintenance to enhance system security and reliability. Most generation maintenance scheduling (GMS) packages consider preventive maintenance scheduling for generating units over one or two years time horizon to lessen the total operation costs while fulfilling system energy requirements. In advanced power systems, inclusion of network constraints and demand for electricity has resulted in higher number of generators and lower reserve, making GMS problem more complex. This paper proposes a security constrained model for preventive GMS problem. For more realistic study, system reliability indices such as power system reserve and unit forced outage rates are taken into account. Impact of load curve on GMS problem is investigated by a novel proposed penalty factor. Unlike some previous studies that consider a fixed period for all unit maintenance windows, here various maintenance windows are considered for the units that are more realistic. In addition, a heuristic model is proposed to show the impact of energy purchase while implementing GMS in a case of unit fuel shortage. Considering the problem that contains integer variables for unit maintenance scheduling and taking into account the proposed model that is based on optimal generation and maintenance costs, mixed integer programming (MIP) is employed as to obtain the most accurate results. Branch and bound algorithm is employed as the most general algorithm to solve the problem and find the optimal solution. An IEEE 24-bus Reliability Test System is employed for simulation and show the accuracy of results.

As demonstrated system security and reliability constraints like, transmission capacity limits, unit force outage rates, and power system reserve may affect unit maintenance scheduling and altering system maintenance and operation costs. These strategies may lead to increases in unit operation or maintenance costs while varying unit maintenance scheduling. By this strategy, ISO will have more effect on unit maintenance schedules.

KEYWORDS: Generation maintenance scheduling, Network constraint, System reliability, System reserve, Energy purchase, Forced outage rate.

NOMENCLATURE

- x_{it} Unit maintenance status, 0 if unit is off for maintenance, 1 otherwise
- S_i Period in which maintenance of unit *i* starts
- e_i Earliest period for the beginning of unit *i* maintenance
- l_i Latest period for the beginning of unit *i* maintenance
- ρ_t Cost of energy purchased from outside at time *t*
- $\varphi_{i,t}$ Allocated fuel to unit *i* at time *t*
- ω_i Maximum fuel allocation for unit *i*
- $sv_{i,t}$ Maintenance start-up variable of unit *i* at time *t*
- C_{it} Maintenance cost of unit *i* at time *t*
- c_{it} Generation cost of unit *i* at time *t*
- γ_t Weekly penalty factor
- d_i Duration of maintenance for unit *i*
- $g_{max,i}$ Maximum power generation for unit *i*
- $g_{min,i}$ Minimum power generation for unit *i*
- g_{it} Vector of power generation for unit *i* at time *t*
- D_t Vector of the demand at time *t*
- D_{max} Maximum demand at time *t*
- D_{min} Minimum demand at time *t*
- z Node-branch incidence matrix
- α Percentage of load for system reserve
- F_t Expected energy purchased from outside

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β_t Maximum number of maintenance at time *t*
f_{max} Maximum line flow capacity
f Active line flow
N Maximum number of transmission line
$M_{i,t}$ Maximum number of maintenance crew in area for maintenance of unit *i* at time *t*
for_i Forced outage rate of the unit *i*

1. INTRODUCTION

As of 1980, many countries have made improvements in forming electric power markets. The main aim was breaking the monopoly operation pattern of tradition electric power industry and building a competitive power industry. Therefore, it can decrease the electric power production cost and electricity price. Besides, it can improve the power supply quality and promote the healthy development of electric power industry. Additional competition and increasing complexity in power generating systems as well as a necessity for high service reliability and low production costs triggered additional interests in automatic scheduling techniques for maintenance of generators, transmission, and pertinent equipment. Several optimization methods were applied to solve the problem, which could be sorted into three categories called, heuristic methods, artificial intelligent methods and mathematical programming methods. Heuristic methods supply the most primitive solution based on trial-and error principles. Artificial Intelligent methods contain expert system, simulated annealing [1,2], fuzzy theory, neural network, evolutionary optimization comprising evolutionary programming, evolutionary strategy, and genetic algorithm, simulated evolution, Tabu search and various combinations of artificial intelligent methods [3,4]. Finally, mathematical programming methods contains MIP, mixed integer linear programming (MILP), decomposition [5], branch-and-bound, dynamic programming, and various combinations of mathematical programming methods.

Although in the past decades, several procedures were recommended for the solution of unit maintenance scheduling, there was no consensus on the most appropriate approach to this problem. Earlier, much emphasis was given to heuristic methods that could not meet the multi-objective requirements of the problem and could not assure a feasible solution.

Most artificial intelligent techniques have the ability of referring to multi-objective requirements. Since an inference engine must be organized according to the particular characteristics of a designed problem, it is hard to generalize the expert system approach. The membership function in fuzzy sets are to be configured under the specific requirements of the designated power system, therefore fuzzy sets are usually used as an auxiliary of tool in maintenance optimization methods. However, the literature shows that, of all the possible intelligence techniques, genetic algorithms are the most suitable artificial intelligent technique for maintenance scheduling. There is no doubt that mathematical programming methods supply more reliable and versatile solution to maintenance scheduling [6].

Generally, maintenance scheduling in a raw system may falls into two stages from time horizon perspective, entitled, long-term and short-term scheduling [7]. Long-Term Generation Maintenance Scheduling (LTGMS) considers the schedule of generating units on a horizon of one or two years in order to minimize the total system operation costs. The long-term scheduling problem tackles fuel allocation, emission, budgeting, production, and maintenance costing. The solutions obtained from LTGMS can then be used as guidelines and bases for addressing unit commitment and optimal power flow problems [8-11]. The objective of Short-Term Maintenance Scheduling (STMS) is to minimize the cost of operation over hourly, daily, or weekly periods. Because dynamic economic dispatch is fundamental for real time control of power systems, the STMS causes a commitment strategy for real-time economic dispatch to meet system requirements in an on-line operation. The dynamic economic dispatch is solved for short periods of time in which the system load conditions can be assumed constant.

In deregulated power markets, Independent System Operator (ISO) is in charge of unit maintenance scheduling as well as maintaining instantaneous balance of the system. The ISO carries out its function by controlling the dispatch of flexible power plants. Furthermore, ISO is the sole responsible for system security and reliability. Most of researches deal with GMS problem in both long term and short term scheduling regardless of system security indices. In our previous paper [12] unit maintenance scheduling with network constraints and energy not supplied (ENS) as reliability index are taken into account.

M.K.C. Marwali and S.M. Shahidehpour [4,5],[13] have implemented a long term maintenance scheduling study considering energy not supplied (ENS) and transmission constraints. However, in [12] index of ENS as well as transmission constraints were considered in long term generation maintenance scheduling. Unlike [13], impacts of consumers loading and penalty factor are taken into account. Note that the results provided in our previous paper [12] represent generators operation and maintenance costs considering ENS with and without transmission constraints that are comparable with results obtained in [13]. As expected there are some differences in costs in [12] in comparison with [13] that are due to considering consumers loading.

In some papers a number of indices are introduced for power system reliability [14,15]. Impact of unit outages on maximum system loading is presented in [16]. A model for security constrained unit commitment is proposed in [17] that may be interpreted maintenance dual problem. Eventually, an economic load dispatch problem is presented in [18] that considers system security

This paper proposes a security constrained model for preventive long term unit maintenance scheduling problem in which system security and reliability indices such as transmission line limits, system reserve and unit forced outage rates are taken into account. In order to get more realistic results a novel penalty factor is introduced to study the impact of customers load curve on proposed GMS problem. Unlike some previous studies that consider a fixed period for all unit maintenance windows, here various maintenance windows are considered for the units that are more realistic. In addition a heuristic model is proposed to show the impact of energy purchase while implementing GMS in a case of unit fuel shortage. Considering the problem that contains integer variables for unit maintenance scheduling and taking into account the proposed model that is based on optimal generation and maintenance costs, MIP is employed to obtain the most accurate results. Among different algorithms provided for solving mixed integer problems, branch and bound algorithm is employed as the most general algorithm to solve the problem and find the optimal solution. The paper is organized as follow: sections 2 and 3 represent the formulation of proposed maintenance scheduling model and solution in methodology. In section 4, a case study is presented to show the accuracy of proposed model and section 5 provides the conclusion. Finally section 6 gives suggestions for further research.

2. PROBLEM DESCRIPTION

While transmission and reliability limitations are taken into account, the proposed LTGMS problem is determining the period for which generating units should be off, over one or two years planning horizon to lessen the total operation cost. Leave out the network in maintenance scheduling may end in loss of information on scheduling limitations. When network and fuel constraints are included, the problem becomes a lot more realistic and complex that could be referred as a security constrained maintenance scheduling. The long-term generation maintenance scheduling in the power market environment is a large-scale optimization problem. Mathematically, it can formulate as follow:

2.1 Objective Function

The objective function of the proposed model is to minimize the total maintenance and production costs over the operational planning period. Equation (1) corresponds to a MIP problem since x_{it} is integer variables and g_{it} is continuous. The first term of the objective function is the maintenance cost of generators and the second is the energy production cost.

$$Min \sum_{t} \left\{ \sum_{i} C_{it}\, \gamma_t (1 - x_{it}) \right\} + \sum_{t} \sum_{i} c_{it} g_{it} + \sum_{t} \rho_t F_t \tag{1}$$

2.1.1 Penalty Factor

In order to consider the impact of the load curve demand on generation maintenance scheduling problem a novel penalty factor is represented as Equation (2). In fact, penalty factor shows importance of loading points on proposed LTGMS based on amount of consumptions. ISO could employ penalty factor to patronize unit not to have maintenance in peak loads. Here, the total unit maintenance cost is the maintenance cost of unit multiply by penalty factor. By this strategy, ISO could have more effect on unit maintenance schedules.

$$\forall\ t \qquad \gamma_t = 2 - \frac{D_{max} - D_t}{D_{max} - D_{min}} \tag{2}$$

2.2 Maintenance Constraints

In order to make the maintenance schedule feasible, certain constraints should be fulfilled. Some of basic constraints which should be set up are continuousness maintenance of some units, maintenance manpower, maintenance window, maintenance duration, and so on .Maintenance constraints in the current research could be categorized as follow:

2.2.1 Maintenance Window

Equations (3-5) show the maintenance timetable stated in terms of maintenance variables (S_i). The unit maintenance may not be scheduled before their earliest period (e_i), or after latest period allowed for maintenance ($li+di$).

$$for \quad t \le e_i \quad or \quad t \ge l_i + d_i \Rightarrow x_{it} = 1 \tag{3}$$

$$for \quad S_i \le t \le S_i + d_i \Rightarrow x_{it} = 0 \tag{4}$$

$$for \quad e_i \le t \le l_i \Rightarrow x_{it} = 0 \quad or \quad 1 \tag{5}$$

2.2.2 Maintenance Duration

The maintenance of the unit i lasts a given number of periods d_i.

$$\sum_{t \in T} \left(1 - x_{i,t}\right) = d_i \qquad \forall i \in I \tag{6}$$

2.2.3 Maintenance Period

A maximum number of maintenance is imposed in the period t.

$$\sum_{i \in I} \left(1 - x_{i,t}\right) \le \beta_t \qquad \forall t \in T \tag{7}$$

2.2.4 Non-Stop Maintenance

The maintenance of a unit is carried out in consecutive periods.

$$(1 - x_{i,t}) - (1 - x_{i,t-1}) \le sv_{i,t} \quad , \ \forall i \in I \ \& \ \forall t \in T$$
$$for \ \ t = 1 \ \ select, \ x_{i,0} = 1 \tag{8}$$

2.2.5 Exclusion Constraint

Units i and j cannot be in maintenance at the same time.

$$(1 - x_{i,t}) + (1 - x_{j,t}) \le 1 \qquad \forall t \in T \tag{9}$$

2.2.6 One-Time Maintenance

Each unit has an outage for maintenance just once along the time horizon considered.

$$\sum_{t \in T} sv_{i,t} = 1 \qquad \forall i \in I \tag{10}$$

2.2.7 Manpower Availability

If one considers that in each maintenance area, there is limited available manpower. The constraints will be stated as follows:

$$\sum_{i \in I} \left(1 - \mathrm{x}_{\mathrm{i,t}}\right) \le \mathrm{M}_{\mathrm{i,t}} \qquad \forall t \in T \tag{11}$$

Here, $M_{i,t}$ would be the number of manpower in area for maintenance of unit i at time t.

2.3 Network Constraints

The network can be modeled as either the transportation model or a linearized power flow model.

2.3.1 Power System Load Balance

We apply transportation model to exhibit system operation limits such as load balance equation, unit capacities, and power flow limits as below:

$$\forall \ t \qquad zf + g = D \tag{12}$$

2.3.2 Unit Capacity Limit

Each unit is designed to work between minimum and maximum power capacity (MW). The following constraint in equation (13) ensures that unit is within its respective rated minimum and maximum capacities.

$$\forall \ t \qquad g_{min,i} \le g_{it} \le g_{max,i} \tag{13}$$

2.3.3 Transmission Flow Limit

The power flows on transmission lines are constrained by line capacity. The constraint (14) represents power transmission capacity.

$$\forall \ t \qquad |f| \le f_{\max} \tag{14}$$

2.3.4 Spinning Reserve

Actually ISO is in charge of system reserve in all periods of time. It is a safety margin that usually is given as a demand proportion. Equation (15) represents spinning reserve constraint. This indicates that the total capacity of the units running at each interval should not be less than the specified spinning reserve for that interval.

$$\forall \ t \qquad \sum_i g_{max,i} - \sum_{\mathrm{i}} g_{it} \ge \%\alpha \times D_t \tag{15}$$

2.3.5 Reliability Indices

For the sake of the simplicity, most of the time, no uncertainty is considered which means that appropriate units are provided. Nevertheless, unit forced outage rates can be approximately taken into account derating their corresponding capacities [19-21]. Here we should replace equation (16) instead of maximum level of power generation in equation (13).

$$g^{+}_{max,i} = (1 - for_i) \times x_{it} \times g_{max,i} \tag{16}$$

$$\forall t \quad \sum_i g_{Max,i} \times (1 - for_i) - \sum_i g_i(t) \geq \% \alpha \times D_t \tag{17}$$

Accordingly, one can replace equation (17) instead of equation (15) in order to model forced outage rates in spinning reserve.

2.4 Fuel Constraint

In some cases thermal units may face fuel shortages. In this case required energy should be purchased from outside. Eq. (18) models fuel shortage constraint for each unit.

$$\sum_t \varphi_{i,t} \leq \omega_i \times x_{i,t} \tag{18}$$

3. SOLUTION METHODOLOGY

Any determination problem with a purpose to be maximized or minimized in which the determination variables must assume non fractional or discrete values may be sorted as an integer optimization problem. An integer problem is sorted as linear if, by relaxing the integer limitation on the variables, the resulting functions are completely linear. If all the determination variables are limited to integer values, the problem is called a (pure) integer problem, otherwise a MIP [22,23].

In the context of linear and mixed-integer programming problems, the function that appraises the quality of the solution, named the objective function, should be a linear function of the determination variables. A linear programming will either maximize or minimize the value of the objective function. Eventually, the determinations that must be made are subject to certain requirements and limitations of a problem. Each constraint that is a linear function needs to be either equal to, not more than, or not less than, a scalar value. A common condition simply states that each determination variable must be nonnegative. Actually, all LP problems can be transformed into an equivalent minimization problem with nonnegative variables and equality constraints.

Therefore, suppose that here, $x_1, \ldots, x_n$ are our set of determination variables. LP problems are as follow:

Maximize or minimize $\quad f(x) = c_1 x_1 + c_2 x_2 + \ldots + c_n x_n \quad (20)$

Subject to:

$$a_{11} x_1 + a_{12} x_2 + \ldots + a_{1n} x_n \ (\leq, =, or \geq)\ b1 \tag{21}$$

$$a_{21} x_1 + a_{22} x_2 + \ldots + a_{2n} x_n \ (\leq, =, or \geq)\ b_2 \tag{22}$$

$$\ldots$$

$$a_{m1} x_1 + a_{m2} x_2 + \ldots + a_{mn} x_n \ (\leq, =, or \geq)\ b_m \tag{23}$$

$$x_i \geq 0 \ \forall i = 1, \ldots, n. \tag{24}$$

Here, the values c_i , $\forall i = 1, \ldots, n$, are indicated as objective coefficients, and are often connected to the costs associated with their corresponding determinations in minimization problems, or the income generated from the corresponding determinations in maximization problems.

The values $b_1, \ldots, b_m$ are the right-hand-side values of the constraints, and often depict amounts of available resources (especially for $\leq$ constraints) or requirements (especially for $\geq$ constraints). The a_{ij}-values thus typically indicate how much of requirement or resource j is satisfied or consumed by decision i.

In this paper in order to find the optimal solution, Branch and Bound [24] is used as the most general algorithm. Branch and bound consists of a systematic enumeration of all candidate solutions, by using upper and lower estimated bounds of the quantity being optimized. Considering above problem assume the goal is to find the *minimum* value of a function $f(x)$ where x ranges over some set S of admissible or candidate solutions. A branch-and-bound procedure requires two tools. The first one is a splitting procedure that, given a set S of candidates, returns two or more smaller sets S_1, S_2,... whose union covers S. Note that the minimum of $f(x)$ over S is $Min\ (v_1, v_2,\ldots)$, where each v_i is the minimum of $f(x)$ within S_i. This step is called branching, since its recursive application defines a tree structure whose nodes are the subsets of S. The second tool is a procedure that computes upper and lower bounds for the minimum value of $f(x)$ within a given subset of S. This step is called bounding. The key idea of the branch and bound algorithm is: if the lower bound for some tree node (set of candidates) A is greater than the upper bound for some other node B, then A may be safely discarded from the search. This step is called pruning, and is usually implemented by maintaining a global variable m that records the minimum upper bound seen among all sub regions examined so far. Any node whose lower bound is greater than m can be discarded. The recursion stops when the current candidate set S is reduced to a single element, or when the upper bound for set S matches the lower bound. Either way, any element of S will be a minimum of the function within S.

Problems of the form (20-24) are called linear programming since the objective function and constraint functions are all linear. A MIP is a linear program with the added limitation that some, but not necessarily all, of the variables must be integer-valued. Several studies also replace the term integer with binary (0-1 variables) when variables are limited to take on either 0 or 1 values.

A solution that fulfills all constraints is called a feasible solution. Feasible solutions that obtain the best objective function value (according to whether one is maximizing or minimizing) are called optimal solutions. Sometimes no answer exists to an MIP, and the MIP itself is named infeasible. On the other hand, some feasible MIPs have no optimal solution, because it is possible to obtain limitlessly good objective function values with feasible solutions. These problems are called unbounded.

4. CASE STUDY

In this paper, the proposed method is applied to the IEEE 24-bus Reliability Test System. The system has 32 units, 20 consumers, 24 buses and 38 transmission lines (See Appendix). A three month study period of summer, weeks 18-29 are taken into account. Some unit facilities in a special area require maintenance within the study period. The maintenance area coverage is from buses 1 through 10. Table 1 gives unit placements and capacities. Operating and maintenance characteristics of the units are given in Table 2. Fig. 1 depicts weekly peak loads as the percent of the annual peak load. As shown the maximum peak load are in weeks 20, 23-25. Subsequently, weekly penalty factors are provided in Fig. 2. As indicated the highest penalty factors are applied in peak loaded weeks to avoid unit maintenance during peak periods, hence shifting maintenance periods towards off peak times. It is assumed that during three months, manpower constraint is up to three groups for generation maintenance. Detailed system data for transmission lines, generators and loads can be seen in Appendix.

Table 1: Unit data

Unit	10, 11	12, 13	14	15, 16	6, 7
Capacity (MW)	2×76	2×76	1×100	2×100	2×20
Bus	1	2	7	7	1

Table 2: Unit operating & maintenance data

Size (MW)	**Fuel**	**Fuel Price (US$/MBtu)**	**Maintenance cost ($/kW/Yr)**	**Heat rate (Btu/KWh)**	**Maintenance**	
					Window (Week)	**Duration (Week)**
20	Oil #2	3.00	0.3	14500	18-29	2
76	Coal	1.20	10	12000	18-29	3
100	Oil #6	2.30	8.5	10000	18-29	4

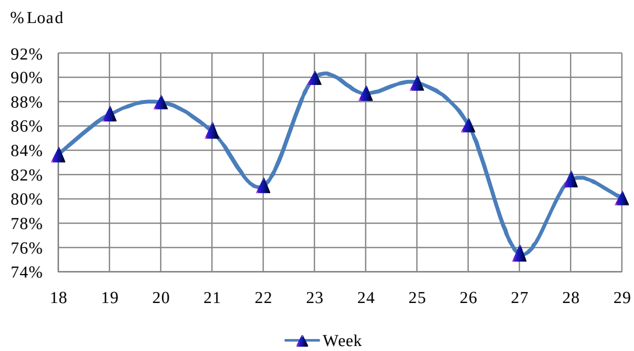

Fig. 1: Weekly peak load in percent of annual peak

Three scenarios are studied for maintenance scheduling problem as follow:

Scenario 1: Study on unit maintenance scheduling problem considering network constraints excluding system reserve and unit forced outage rates;

Scenario 2: Study on unit maintenance scheduling problem considering network constraints including system reserve and unit forced outage rates;

Scenario 3: Study on unit maintenance scheduling problem considering network constraints, unit fuel shortage and energy purchase option, excluding system reserve and unit forced outage rates;

Scenario 1 shows the effect of penalty factor and transmission security constraints on unit maintenance scheduling problem. Three cases are considered for this scenario. In the first case, it is assumed that there is no limit on transmission capacity constraints while in the second case, the effect of the penalty factor on LTGMS is considered. In the latter one, it is assumed that transmissions capacity of the lines, between buses (15 to 21), is reduced to quarter while penalty factor is considered as well. Table 3 represents corresponding operation and maintenance costs in all above cases. Subsequently, Tables 4-6 show corresponding unit maintenance scheduling during specified 12 weeks.

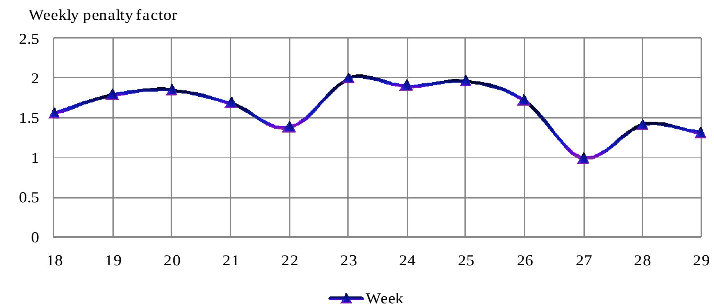

Fig. 2: Penalty factor for generator unit maintenance cost

Table 3: Total operation & maintenance cost for generating unit (Scenario 1)

State	Total Operation & Maintenance cost	Maintenance cost	Operation cost
Maintenance scheduling with network constraints	6.307648×10^{7} \$	0.5607998×10^{7} \$	5.7468482×10^{7} \$
Maintenance scheduling with network constraints and penalty factor	6.616396×10^{7} \$	0.8695478×10^{7} \$	5.7468482×10^{7} \$
Maintenance scheduling with network constraints, penalty factor, and limit on transmission capacity	6.629995×10^{7} \$	0.8695478×10^{7} \$	5.7604472×10^{7} \$

Table 4: Maintenance scheduling with network constraints (Scenario 1)

Unit	T18	T19	T20	T21	T22	T23	T24	T25	T26	T27	T28	T29
6												
7												
10												
11												
12												
13												
14												
15												
16												

Table 5: Maintenance scheduling with network constraints and penalty factor (Scenario 1)

Unit	T18	T19	T20	T21	T22	T23	T24	T25	T26	T27	T28	T29
6												
7												
10												
11												
12												
13												
14												
15												
16												

Table 6: Maintenance scheduling with limit on transmission capacity (Scenario 1)

Unit	T18	T19	T20	T21	T22	T23	T24	T25	T26	T27	T28	T29
6												
7												
10												
11												
12												
13												
14												
15												
16												

The results illustrated in Table 3 are comparable with those provided in [12, 13] unless, here impact of energy not supplied (ENS) index is not taken into account.

As shown in Table 3, penalty factor and transmission security constraints may have profound effects on maintenance and operation costs, respectively. Here, the operation costs in first and second cases are the same but their maintenance costs are different due to considering load levels by means of penalty factor. ISO may employ penalty factor to patronize unit not to have maintenance in peak loads. By this strategy, ISO will have more effect on unit maintenance schedules. Table 4 illustrates unit maintenance scheduling regardless of penalty factors. Comparing Tables 4, 5 one can conclude that applying penalty factor results in some shifting in unit maintenance periods toward off peak periods. In fact due to more request for energy in peak periods (weeks 20, 23-25) all units, especially cheaper ones (i.e. 12 and 13) must be available within these periods. This in turn improves system reliability. However, due to penalty factor coefficients that are normally more than unity, aggregated maintenance cost will increase. Considering penalty factor units 15, 16 urged to have their own maintenance in peak load periods despite their relative expensive maintenance costs. It should be noted that although there is no regulation on maintenance periods in Table 4 in order to lessen the operation costs almost all efficient and cheap units are available in peak periods.

Table 6 shows unit maintenance scheduling when transmission line limit is applied. As seen the maintenance costs are unchanged in comparison with Table 5 while the operation costs are increased. This is due to the fact that, applying limits on transmission line capacities may result in contributions by more expensive units that leads to higher operation costs. As shown, penalty factor and transmission limits bring about some increases in system-aggregated costs.

In order to investigate the impact of reliability indices on LTGMS, in the second scenario system reserve and unit forced outage rates are taken into account as the significant factors from system operator perspective. For the sake of clarity, in the first case LTGMS problem is investigated considering system reserve. It is assumed that system reserve in each week is limited to the minimum of 6% of the total weekly load and no uncertainty is considered for generation units. However, in the second and third cases, the impact of unit forced outage rates is considered, regardless of system reserve in which in the former case unit forces outage rates are normal values (See Appendix) while in the latter one forced outage rates of cheap units (10,11,12,13) are increased to 0.1. In all above studies network constraints and penalty factor are considered as well. Table 7 represents corresponding unit operation and maintenance costs. Subsequently, Table 8 and 9 show corresponding unit maintenance scheduling during specified 12 weeks in above mentioned cases, respectively.

By comparing the result represented in Table 7-9, taking into account system reserve and unit forced outage rate, one can deduce that units with more capacity and more efficiency have arranged their maintenance timetable in minimum weekly load to satisfy requirment of the ISO. Furthermore, comparing Tables 3, 7 shows that system reserve and unit forced outage rates may increase unit operation costs. It is due to contribution of more expensive units. Nevertheless, unit forced outage rates have more profound effects on unit aggregated costs. Note that in all above mentioned studies, unit maintenance costs are the same although there are some changes in unit maintenance scheduling. That is due to considering constant maintenance cost coefficients and also fixed maintenance durations; however, unit maintenance scheduling may vary depending specified conditions.

Table 7: Total operation & maintenance cost for generating unit (Scenario 2)

State	Total Operation & Maintenance cost	Maintenance cost	Operation cost
Maintenance scheduling with network constraints, penalty factor, and system reserve	6.616783×10^{7} \$	0.8695478×10^{7} \$	5.747235×10^{7} \$
Maintenance scheduling with network constraints, penalty factor and forced outage rates	7.0471458×10^{7} \$	0.8695478×10^{7} \$	6.177598×10^{7} \$
Maintenance scheduling with network constraints, penalty factor and, increased forced outage rates	7.075386×10^{7} \$	0.8695478×10^{7} \$	6.205838×10^{7}\$

Table 8: Maintenance scheduling considering system reserve (Scenario 2)

Unit	T18	T19	T20	T21	T22	T23	T24	T25	T26	T27	T28	T29
6								■	■			
7								■	■			
10	■	■	■									
11	■	■	■									
12										■	■	■
13										■	■	■
14									■	■	■	■
15				■	■	■	■					
16				■	■	■	■					

Table 9: Maintenance scheduling units considering forced outage rates (Scenario 2)

Unit	T18	T19	T20	T21	T22	T23	T24	T25	T26	T27	T28	T29
6												
7												
10												
11												
12												
13												
14												
15												
16												

Fig 3 illustrates variation of system reserve within all maintenance periods in proposed LTGMS with and without considering units forced outage rates. As shown considering forced outage rate has significantly increased system reserve in all periods. Forced outage rate somehow may be interpreted as derate in unit capacities. Consequently, taking into account unit actual capacities the system aggregated reserve may increase.

Table 10: Fuel Price for Units

Fuel	Unit Size (MW)	Total Weekly Fuel Limit (MBtu)	Fuel Price ($/MBtu)
Oil #2	20	69400	3.0
Oil #6	197,100,12	1311255	2.3
Coal	350,155,76	1390857.6	1.2

Finally, in third scenario, the impact of fuel shortage is studied on proposed unit maintenance scheduling problem. Here, it is assumed that units may purchase fuel from outside in case they face any shortage in their fuels. To get more realistic results network constraints and penalty factor are considered as well. Unit average fuel prices as well as their corresponding fuel limits are provided in Table 10. Also price of energy purchased from outside is considered to be 49.00 $/MWh. Table 11 represents units operation and maintenance costs with and without unit fuel shortages.

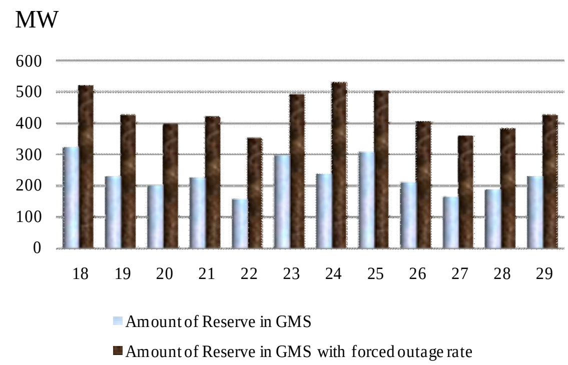

Fig 3: Weekly spinning reserve considering unit force outage rate

Table 11: Total operation & maintenance cost for generating unit (Scenario 3)

State	Total cost ($)	Maintenance cost ($)	Operation cost ($)	Purchased cost ($)	MW purchased from outside	MW generated
Maintenance scheduling with network constraint, penalty factor, without fuel shortage	**6.616396×10^7**	**0.8695478×10^7**	**5.7468482×10^7**	**---**	**---**	**28984.8**
Maintenance scheduling with network constraint, penalty factor, with fuel shortage	**7.918261×10^7**	**0.8695478×10^7**	**6.3912356×10^7**	**0.6574776×107**	**798.7**	**28186.1**

As shown, system total cost increases to $ 79.18261 million when fuel shortage constraint is taken into account. This is because of lower contribution of more efficient units (due to corresponding fuel limits) that leads to more generation of other inefficient units. Although there is another imposed cost for energy purchased from outside. As seen unit maintenance scheduling and scheduling are the same as illustrated in Table 12.

Table 12: Maintenance scheduling of generating unit (Scenario 3)

Unit	T18	T19	T20	T21	T22	T23	T24	T25	T26	T27	T28	T29
6								■	■			
7								■	■			
10	■	■	■									
11	■	■	■									
12										■	■	■
13										■	■	■
14									■	■	■	■
15				■	■	■	■					
16				■	■	■	■					

For more clarification impact of different energy purchase prices on proposed LTGMS problem is provided in Table 13. It is assumed that prices vary from 40% to 120% of above mentioned price.

As shown increasing in purchase prices brings about decreases in imported power, consequently increases in generation output powers. Note that when purchase prices are 40% or 80% of original price oil unit contributions may not be efficient, thus a larger portion of required load is provided from outside. Note that unit maintenance costs are unchanged in all above mentioned cases. In prices above 49 $/MWh the purchase costs will increase despite reduced imported power. This is due to raised purchase prices.

Table 13: Total operation & maintenance cost for different energy purchase prices

Price Percent	Unit outputs (Mw)	Imported power (Mw)	Operation cost ($) ($\times 10^7$)	Purchase cost ($)
40%	18997.3	9987.5	2.788439	32886295.3
80%	27646.2	1338.6	5.996603	8816044.7
100%	28186.1	798.7	6.391235	6574775.9
110%	28189.4	795.4	6.393581	7203191.2
120%	28192.7	792.1	6.396266	7824840.7

Finally, Fig. 4 illustrates system aggregated costs considering different energy purchase prices. As it is appear power system aggregated costs will increase by escalating energy purchase prices. It may be interpreted as the result of increasing unit operation costs and system purchase costs as well.

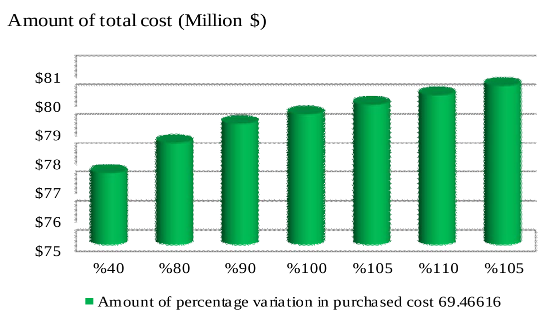

Fig 4: Variation of system aggregated costs for different energy puchase prices

5. CONCLUSIONS

This paper presents a model for long term generation maintenance scheduling in which network constraints, as well as system reliability indices are taken into account. As demonstrated system security and reliability constraints like transmission capacity limits and power system reserve may affect unit maintenance scheduling and altering system maintenance and operation costs. On the other hand unit force outage rates may impose limitations on available generation capacity that leads to increases in unit operation costs while varying unit maintenance scheduling. In order to consider effect of system loading on proposed LTGMS problem, a heuristic penalty factor coefficient was introduced. In fact ISO may employ penalty factor to patronize unit not to have maintenance in peak loads. By this strategy, ISO will have more effect on unit maintenance schedules. Finally impact of energy purchase on LTGMS was represented in case of unit fuel shortage. As shown decreasing energy purchase prices may encourage the system operator to buy from outside while minimizing corresponding operation and maintenance cost. On the other hand, increasing energy purchase prices may increase system aggregated costs by increasing unit operation costs and system purchase cost as well.

6. Suggestions for Further Research

In a universal maintenance scheduling problem, transmission maintenance should be taken into account as well. Incorporating generation and transmission maintenance scheduling is more realistic model that improves the output results. The authors are currently working on generation and transmission maintenance scheduling problem considering system reliability and security indices. Furthermore, air pollution constraints and among another effective parameters that may affect the problem. Therefore, considering environmental factors would be other important issue that may be considered in further studies.

APPENDIX

The main criterion in select of the test system configuration was the desire to achieve a useful reference for testing and comparison of reliability evaluation methods. In this paper, we apply the proposed method to the IEEE 24-bus Reliability Test System [25].

I. IEEE 24-Bus Reliability Test System Data

The Transmission network consists of 24 bus locations connected by 38 transmission lines. Impedance and rating data for transmission lines is given in Tables 1 and 2. The place of Generating units is shown in Table 3. From these Generating stations we have decided to do maintenance for only 3 Generating stations at buses 1, 2 and 7 (see Table 6). The unit operating cost data can be seen in Table 4. Table 5 gives data on weekly peak loads in percent of the annual peak load. The annual peak load for the test system is 2850 MW. The data in Table 5 shows a typical pattern, with two seasonal peaks.

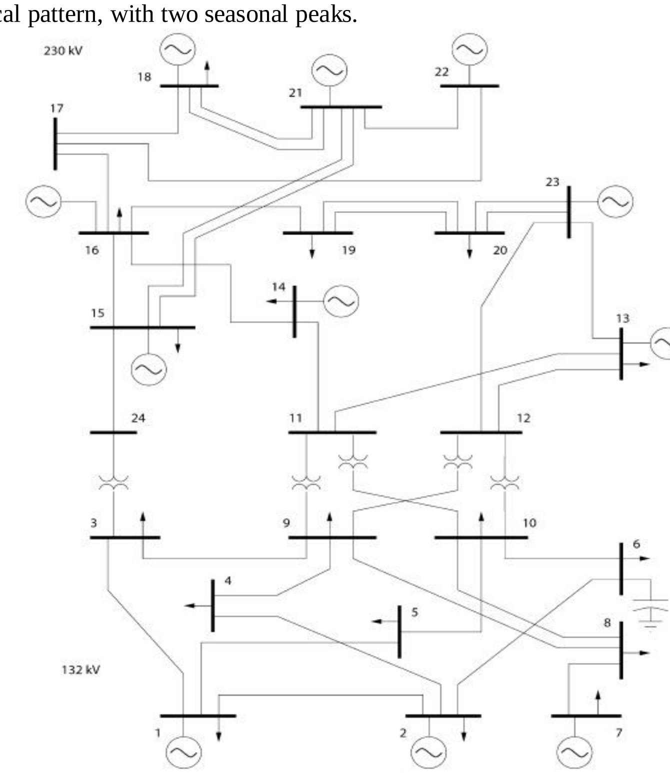

Fig 5: IEEE 24-bus reliability test system

Table A.1: Transmission line impedance and rating data

From bus	To bus	Impedance (p.u /100 MVA base)			No. of lines	Rating (MVA)
		R	X	B		
1	2	0.0026	0.0139	0.4611	1	193
1	3	0.0546	0.0211	0.0572	1	208
1	5	0.0218	0.0845	0.0229	1	208
2	4	0.0328	0.1267	0.0343	1	208
2	6	0.0497	0.1920	0.0520	1	208
3	9	0.0308	0.1190	0.0322	1	208
3	24	0.0023	0.0839	0.0322	1	510
4	9	0.0268	0.1037	0.0281	1	208
5	10	0.0228	0.0883	0.0239	1	208

6	10	0.0139	0.0605	0.0204	1	193
7	8	0.0159	0.0614	0.0166	1	208
8	9	0.0427	0.1651	0.0447	1	208
8	10	0.0427	0.1651	0.0447	1	208
9	11	0.0023	0.0839	0.0322	1	510
9	12	0.0023	0.0839	0.0447	1	510
10	11	0.0023	0.0839	0.0447	1	510
10	12	0.0023	0.0839	0.0322	1	510
11	13	0.0061	0.0476	0.0999	1	600
11	14	0.0054	0.0418	0.0879	1	600
12	13	0.0061	0.04736	0.0999	1	600
12	23	0.0124	0.0966	0.2030	1	600
13	23	0.0111	0.0865	0.1818	1	600
14	16	0.0050	0.0389	0.0818	1	600
15	16	0.0022	0.0173	0.0364	1	600
15	21	0.0063	0.0490	0.1030	2	600
15	24	0.0067	0.0519	0.1091	1	600
16	17	0.0033	0.0259	0.0545	1	600
16	19	0.0030	0.0231	0.0485	1	600
17	22	0.0135	0.1053	0.2212	1	600
18	21	0.0033	0.0259	0.0545	2	600
19	20	0.0051	0.0396	0.0833	2	600
20	23	0.0028	0.0216	0.0455	2	600
21	22	0.0087	0.0678	0.1424	1	600

Table A.2: Transmission line length

From bus	To	Length (miles)	From bus	To	Length (miles)
1	2	3	11	13	33
1	3	55	11	14	29
1	5	22	12	13	33
2	4	33	12	23	67
2	6	50	13	23	60
3	9	31	14	16	27
3	24	0	15	16	12
4	9	27	15	21	34
5	10	23	15	24	36
6	10	16	16	17	18
7	8	16	16	19	16
8	9	43	17	22	73
8	10	43	18	21	18
9	11	0	19	20	27
9	12	0	20	23	15
10	11	0	21	22	47
10	12	0			

Table A.3: Generating units locations

Unit	Capacity (MW)	Bus	Unit	Capacity (MW)	Bus
1	2*76	1	8	1*155	15
2	2*76	2	9	1*155	16
3	1*100	7	10	1*400	18
4	2*100	7	11	1*400	21
5	2*20	1	12	6*50	22
6	3*197	13	13	2*155	13
7	5*12	15	14	1*350	14

Table A.4: units operating cost data

Size (MW)	Fuel	Fuel Cost (US$/MBtu)	Heat Rate (Btu/kWh)	Forced Outage Reate
12	Oil #6	2.30	12000	0.02
20	Oil #2	3.00	14500	0.10
50	Hydro	---	---	0.01
76	Coal	1.20	12000	0.02
100	Oil #6	2.30	10000	0.04
155	Coal	1.20	9700	0.04
197	Oil #6	2.30	9600	0.05
350	Coal	1.20	9500	0.08
400	Nuclear	0.60	10000	0.12

Table A.5: Weekly peak load in percent of annual peak

Week	Peak load	Week	Peak load
1	86.2	27	75.5
2	90.0	28	81.6
3	87.8	29	80.1
4	83.4	30	88.0
5	88.0	31	72.2
6	84.1	32	77.6

7	83.2	33	80.0
8	80.6	34	72.9
9	74.0	35	72.6
10	73.7	36	70.5
11	71.5	37	78.0
12	72.5	38	69.5
13	70.4	39	72.4
14	75.0	40	72.4
15	72.1	41	74.3
16	80.0	42	74.4
17	75.4	43	80.0
18	83.7	44	88.1
19	87.0	45	88.5
20	88.0	46	90.9
21	85.6	47	94.0
22	81.1	48	89.0
23	90.0	49	94.2
24	88.7	50	97.0
25	89.6	51	100
26	86.1	52	95.2

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