Hybrid NSGA III/Dual Simplex Approach to Generation and Transmission Maintenance Scheduling

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***Abstract*-- The generation and transmission maintenance scheduling (GTMS) problem presents generation (GENCOs) and transmission (TRANSCO) companies scheduling their facilities for maintenance to maximize their profits, while the independent system operator (ISO) pushes for maintenance schedules (MS) that guarantees system reliability and minimizes operation cost. Inherently, GTMS is a high-dimensional, non-linear, non-convex, multi-objective optimization problem that contains conflicting objectives related to different participants in the market. This paper develops a hybrid model to tackle the GTMS problem in a deregulated market environment by combining in a novel way the non-dominated sorting genetic algorithm III (NSGA III) and the Dual-Simplex (DS) techniques. The model manages to minimize the total system operational cost and keep high system adequacy, both aspects of interest for independent system operator (ISO) while increasing the profits of GENCOs. The approach used matches accepted industry maintenance practices with cutting-edge optimization techniques developed in academia. The model, tested in the IEEE-RTS 24 bus test network, delivers a set of feasible MS solutions that address the conflicting relationships between the GENCOs and the ISO in the market, displays a degree of coordination among generation and transmission MS and their impact on electricity prices. Finally, it allows the ISO to use this set to identify the best using the technique for ordering preferences according to the similarity to an ideal solution (TOPSIS) decision-making tool.**

***Index Terms*-- Generation and transmission maintenance scheduling, Deregulated electricity market, multi-objective optimization, multi-objective evolutionary algorithms, Non-dominated Sorting Genetic Algorithm, Dual-Simplex optimization technique.**

I. Introduction

Preventive generation and transmission maintenance scheduling (GTMS) is an important part in today's power systems planning and operation due to the increasing complexity of today's power grid. It is vital to extend the life cycle of generators and transmission lines, keep system reliability above certain levels and preserve operational costs, incurred to run generation units to meet the demand, as low as possible. GTMS is a non-convex, high-dimensional, non-linear and mixed-integer optimization problem. Careful planning and coordination of generators and transmission lines maintenance among self-interested parties in a deregulated market environment are critical to achieve an optimal trade-off among GENCOs profits, system reliability, and operational cost [1].

In a deregulated electricity market, many GENCOs compete among themselves and keep a conflicting relationship with the ISO because of their different interests. From the perspective of a GENCO, MS is defined considering technical and financial criteria so that maintenance works are carried out in periods when electricity prices are low. In this way, companies can keep generation units available when prices are high to maximize their profits. On the other hand, from the ISO point of view, as many units and lines as possible should be available at any time, to provide end-users with a reliable electricity supply at a minimum cost. The GENCOs and the ISO objectives clearly conflict with each other, making the GTMS a challenging multi-objective optimization problem.

A. Literature Review

Several classical optimization techniques and Multi-objective Evolutionary Algorithms (MOEA) have been used to tackle the GTMS problem.

For instance, the coordination mechanism proposed in [2] requires GENCOs to submit their generation MS and their willingness-to-pay for keeping them without being adjusted by the ISO. In case of need, the ISO can modify the MS of the GENCO with less willingness to pay informed, to keep acceptable the system reliability. The mechanism is tested in a system with few units, emphasizing in reliability and without considering GENCO's profits.

The Generation Maintenance Scheduling (GMS) problem is solved in [3] using the criteria of maximizing GENCOs profits. In this approach, the objective function includes a penalty component for violation of contractual terms for under-suppling electrical power to the market. The optimal periods of maintenances are determined based on seasonal, operative, and reliability constraints. Similarly, [4] uses a dynamic programming approach that maximizes the profits of the GENCOs considering forecasted electricity prices and constraints related to the operation and reliability of the system and the availability of maintenance resources. A new formulation for solving the GMS problem is proposed in [5], considering electricity prices and demand forecasts, generation capacity, and maintenance resources constraints. It minimizes and maximizes GENCOs costs and profits respectively, to identify the best MS of units of a GENCO. All these approaches work well with few units, without considering system operation costs.

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The GMS problem is solved by using Bender Decomposition method in [6]. First, a master problem is solved to find the MS that minimizes the maintenance cost of a GENCO subject to constraints related to maintenance duration and resources. The results are sent to the ISO, which solves a sub-problem related to the minimization of the system operation, subject to network constraints and the unit's availability. If the MS violates any of these constraints, Bender's cuts or constraints are generated and introduced to the master problem to improve the solution. The iterative procedure continues until a unique optimal solution is found. A coordinating mechanism is added to Benders Decomposition method in [7] and [8] to consider the transmission lines MS. In these approaches, after solving the generation MS, a second master problem is solved related to the Transmission Company (TRANSCO) objective of minimizing maintenance costs subject to time and crew constraints. The process of creating cuts and adding them to the new master problem is repeated until an optimal solution is found. Bear in mind that these decomposition mechanisms tackle the GTMS problem as a single objective optimization problem.

An application of Genetic Algorithms (GA), Simulated Annealing (SA), and their hybrid is proposed in [9] to solve the GMS problem using a reliability criterion. A binary gravitational search algorithm is proposed in [10] to solve the GMS as a multi-objective problem and as a part of a bigger problem related to the expansion of the network. The proposal considers criteria related to maximizing the reserve, minimizing the operation and maintenance costs, and the energy not supplied in the system. Even though the results of these meta-heuristic techniques are promising; their methodologies do not consider the interests of the GENCOs in the market.

A new approach for solving the GMS problem is presented in [11]. It uses a hybrid combination of LIM and differential evolution algorithm (MADE) to find an optimal starting period for maintenance of generating units, provides a feasible MS for the generating units by considering the minimization of system operation cost while satisfying system and operational constraints. Still, the approach only tackles the GMS as a single-objective optimization problem and levels the reserve ensuring that available generation is equal or greater than the demand.

Two mechanisms of coordination between GENCOs and ISO, based on GA, are used in [12] and [13] to find the optimal generation MS. They involve the ISO and GENCOs solving the GMS problem to maximize the reserve and profits respectively. The solutions obtained are collected by the ISO, which compares them in terms of a reliability index. If these indexes are close enough the MS is accepted, otherwise, the ISO modifies them or sets up incentives so that the GENCOs can modify their MS. These mechanisms keep the system reliability, without addressing the system's operation cost.

Two approaches based on Non-dominated Sorting Genetic Algorithm (NSGA) II and Group Search Optimizer are used in [14] and [15] respectively to solve the GMS problem, with the difference that [15] considers network constraints in the problem too. The GENCOs profits, the system reliability, and total operation cost are optimized simultaneously. A new variable encoding technique is used to represent the maintenance, online, and start-up status of generators. The Pareto-optimal solutions generated by both approaches present a set of unit's MS and show the conflicting nature of the objective functions considered. Each MS generated is associated with a single reliability index but to more than one system operation cost, increasing unnecessarily the number of optimal solutions. Thus, many solutions must be processed when identifying the best generation MS while transmission MS is not considered.at all.

The electricity industry in many parts of the world tackles the GTMS problem using classical optimization techniques combined with complex coordination mechanisms among GENCOs, TRANSCOs, and the ISO, to find a unique MS that minimizes the operational cost of the system and maximizes the reliability and security of the network. For example, the regulation in the electricity sector of Bolivia [16] and Ecuador [17], requires GENCOs and TRANSCOs to send their MS proposals to the ISO, who analyzes them and produce a unique MS, making sure that the reliability of the system is above a certain margin. If it is not, then the ISO requires the GENCOs and TRANSCOs to modify their MS accordingly until a final MS is agreed on. In Brazil [18] [19], the coordination process described earlier happens as well but for each of the four subsystems defined inside the national interconnected network. At the same time, the ISO determines programmed unavailability factors for each unit according to the proposed MS which have a direct impact on the capacity electricity prices and the remuneration of GENCOs. If there is a problem with the reliability, the ISO coordinates with the GENCOs involved in the problem a new MS using the programmed unavailability factors as a negotiation tool. In Chile [20], the GTMS problem is defined considering the cost of faults in the system as well, that may occur while certain facilities are on maintenance. In the UK [21], National Grid Electricity Transmission (NGET) receives the MS proposals of TRANSCOs and GENCOs to draw up a GTMS draft plan and notify them about it, highlighting the reasons why certain electricity facilities outages have been modified. If any utility is unhappy with the outcome, it can contact NGET, explain its concerns and discuss a new solution. All these industry practices result in a unique MS that may not render the minimum operation cost or maximum reliability of the system.

B. Proposed Model and Contributions

To address the issues discussed above, this paper takes the advantage of classical and MOEA optimization techniques combining them in a novel way to develop a singular approach to the multi-objective GTMS problem in a market environment. This approach presents a hybrid NSGA III/Dual Simplex model that solves the GTMS problem, handling the maintenance and operational variables separately and sequentially to find a set of feasible MS solutions among which the ISO can choose the most convenient for the system. GENCO's profits, system adequacy, and operation costs are used as objective functions to obtain the set of MS and their relationship is analyzed. The model is evaluated in the IEEE-RTS 24 bus test system with conventional generation units, considering transmission constraints and an electricity market operating under marginal pricing. Finally, TOPSIS is used to find the best MS in the set of feasible solutions.

C. Paper Structure

The article is organized as follows: Section II describes the variables and formulates the problem in mathematical terms. Section III shows the proposed model structure and the strategy used to solve the problem. Section IV describes the case study and the parameters used during the analysis. Section V present the results obtained from the proposed model when solving the GTMS problem. Finally, conclusions are drawn in Section VI.

II. GTMS Problem

A. Variable Representation

The GTMS problem deals with mixed integer-real variables correspondent to the maintenance status of generators and transmission lines and the output of generation units. To solve it, the following variable representation techniques are used:

1) Maintenance Variables

Every generator j and transmission line l are assigned maintenance starting time variables x_j and y_l respectively, as follows:

$$x_j = \begin{cases} s_j + round\left[u\left(l_j - d_j + 1 - s_j\right)\right]; if\ d_j > 0 \\ 0 \qquad\qquad\qquad\qquad\qquad\qquad ; if\ d_j = 0 \end{cases} \tag{1.1}$$

$$y_l = \begin{cases} s_l + round[u(l_l - d_l + 1 - s_l)]; if\ d_l > 0 \\ 0 \qquad\qquad\qquad\qquad\qquad\qquad ; if\ d_l = 0 \end{cases} \tag{1.2}$$

where:

x_j Starting time of maintenance of unit j.
s_j Earliest start of maintenance of unit j.
l_j Latest start of maintenance of unit j.
d_j Duration of maintenance of unit j.
y_l Starting time of maintenance of line l.
s_l Earliest start of maintenance of line l.
l_l Latest start of maintenance of line l.
d_l Duration of maintenance of line l.
u Random Number between [0, 1].

If the maintenance duration of any facility is greater than zero, a random integer number u is generated and the maintenance starting time is found; otherwise, the implication is that the facility is not scheduled for maintenance at any time during the whole period of analysis.

With this representation, the outage duration and continuity of maintenance period constraints are both automatically satisfied, reducing the number of effective constraints and the complexity of the problem.

2) Availability Variables

The intermediate binary availability variables $X_{j,t}$ and $Y_{l,t}$ represents the maintenance status of generator j and transmission line l at any time t and depend on the value of the maintenance variables, as shown in equations (2):

$$X_{j,t} = \begin{cases} 1\ ; & if\ s_j < x_j\ or\ x_j > l_j \\ 0\ ; & if\ s_j \le x_j \le s_j + d_j - 1 \end{cases} \tag{2.1}$$

$$Y_{l,t} = \begin{cases} 1\ ; & if\ s_l < y_l\ or\ y_l > l_j \\ 0\ ; & if\ s_l \le y_l \le s_l + d_l - 1 \end{cases} \tag{2.2}$$

The availability variables limit the generators' output and lines transmission capacity in the system at any time t and eliminate the presence of binary variables directly involved in the model.

3) Generation Variables

Power generation output variables $P^g_{j,b,t}$ are expressed as real numbers, whose values lay between generators' capacity limits and in accordance with the values of their correspondent availability during subperiod b at any time t.

B. Problem Formulation

Several GENCOs, a few TRANSCOs, and the ISO, all try to achieve their own goals in the electricity market, which are represented as objective functions related to constraints that define the GTMS problem.

1) Objective Functions

The conflicting goals or objective functions considered in the model proposed are the following:

System Adequacy: An ISO aims to maximize the system reliability which is represented by an adequacy index F_1 or average relation between the net and the gross reserve in the system [14]:

$$F_1 = \frac{1}{T}\sum_{t=1}^{T}\left[\frac{\sum_{j=1}^{Nt} P_j^{g,max} X_{j,t} - \sum_{n=1}^{N} P_{n,t}^{d,max}}{\sum_{j=1}^{Nt} P_j^{g,max} - \sum_{n=1}^{N} P_{n,t}^{d,max}}\right] \tag{3}$$

where:

F_1 System Adequacy Index (%).
$P_j^{g,max}$ Maximum capacity of unit j (MW).
$P_{n,t}^{d,max}$ Maximum demand in node n at time t (MW).
Nt Number of generation units.
N Number of nodes in the system.
T Duration of period under analysis.

The net reserve is the difference between the available capacity and the maximum demand at time t, while the gross reserve corresponds to the difference between the total installed generation capacity and the demand already mentioned.

System Total Operational Cost: The ISO tries to minimize the system total operation cost F_2, composed of fuel and maintenance costs incurred by GENCOs to operate their units:

$$F_2 = \sum_{t=1}^{T}\sum_{b=1}^{Nb}\left\{\sum_{j=1}^{Nt}\left[c_j P_{j,b,t}^g T(t,b) + C_{j,t}^{mg}\left(1 - X_{j,t}\right)\right] + \sum_{l=1}^{Nl} C_{l,t}^{mt}\left(1 - Y_{l,t}\right)\right\} \tag{4}$$

where:

F_2 System Total Operation Cost (US$).
$P_{j,b,t}^g$ Generation of unit j during subperiod b at time t (MW).
c_j Marginal Generation Cost of unit j (US$/MWh)
$C_{j,t}^{mg}$ Maintenance Cost of unit j at time t (US$).
$C_{l,t}^{mt}$ Maintenance Cost of line l at time t (US$).
Nb Number of subperiods considered.
Nl Number of transmission lines.
$T(t,b)$ Duration of subperiod b at time t (hrs.).

GENCO's Profits: In a deregulated electricity market, each GENCO tries to maximize its profits F_G by producing electricity and taking advantage of electricity prices:

$$F_G = \sum_{t=1}^{T} \sum_{\substack{j=1 \\ j\in\Phi_G \\ j\in\Phi_n}}^{Nt} \left\{ \sum_{b=1}^{Nb} \left[\lambda_{n,t,b} P_{j,b,t}^{g} - \left(C_{0\,j} + C_{1j} P_{j,b,t}^{g} + C_{2j} P_{j,b,t}^{g\;2} \right) \right] T(t,b) - C_{j,t}^{m} \left(1 - X_{j,t}\right) \right\} \quad (5)$$

where:

F_G Profit of generation company G (US$).

$C_{0\,j}, C_{1j}, C_{2j}$ Generation cost curve coefficients of unit j given in (MBtu/h), (MBtu/MWh) and (MBtu/MW^2h), respectively.

$\lambda_{n,b,t}$ Nodal electricity price at node n during subperiod b at time t (US$/MWh)

Φ_G Set of generation units owned by GENCO G.

Φ_n Set of generation units connected to node n.

This expression is formulated for each GENCO G and depends on the unit's generation output, its operation and maintenance costs, and the nodal electricity prices. These prices are determined using the dual variables obtained after solving the economic dispatch (ED) problem, considering transmission congestion and losses effects, using the DS approach:

$$[\lambda]_{b,t} = [\pi]_{b,t}[NF]_{b,t} + [\mu]_{b,t}^{T}[\beta]_{t} \quad (6)$$

where:

$[\lambda]_{b,t}$ Vector of Nodal Energy Prices during subperiod b at time t (US$/MWh)

$[\pi]_{b,t}$ Vector of System Marginal Cost during subperiod b at time t (US$/MWh)

$[NF]_{b,t}$ Vector of Nodal Penalty Factors during subperiod b at time t (US$/MWh)

$[\mu]_{b,t}$ Vector of transmission lines congestion cost during subperiod b at time t (US$/MWh)

$[\beta]_{t}$ Sensibility Matrix at time t

The penalty loss factor in the first term of expression (6) reflects the marginal increase of power losses in all the system due to an increase in the demand in node n. It is determined in terms of the following equation [22]:

$$NF_{n,b,t} = 1 + \frac{\partial P_{loss}}{\partial Pd_n} = 1 + 2\sum_{l=1}^{Nl} r_l f_{l,t,b}\, \beta_{nl} \quad \forall b, \forall t \quad (7)$$

where:

$NF_{n,b,t}$ Penaly factor of node n in subperiod b at time t.

r_l Resistance of transmission line l (pu)

$f_{l,t,b}$ Line l power flow in subperiod b at time t (MW).

β_{nl} Sensibility Matrix row correspondent to node n.

With nodal prices defined in this way, consumers payments and GENCOs revenues are found, and the market is settled. Since transmission is a natural monopoly, a unique TRANSCO is considered, and its revenues are calculated too.

2) Constraints

The constraints consider electricity facilities capacities, the system generation reserve, and the supply of the electricity demand at any moment:

Minimum Reserve: Equation (8) ensures the net reserve of the system remains above a specified minimum reserve limit R^{min} at any time t:

$$\sum_{j=1}^{Nt} P_j^{g,max} X_{j,t} - \sum_{n=1}^{N} P_{n,t}^{d,max} \geq R^{min} \quad ; \quad \forall t \quad (8)$$

Minimum number of available units: Due to system reserve requirements or to GENCOs limited resources, at any given time t certain number of units $Nmin$ must be available for generation. This situation is addressed by using equation (9):

$$\sum_{j=1}^{Nt} X_{j,t} \geq N^{min} \quad ; \quad \forall t \quad (9)$$

Generators' capacity: The power output of generators must be kept within certain capacity limits and in accordance with their correspondent availability status. Thus, this constrain is formulated as follows:

$$P_j^{g,min} X_{j,t} \leq Pt_{j,b,t} \leq P_j^{g,max} X_{j,t} \quad ; \quad \forall t, \forall b \quad (10)$$

where $P_j^{g,min}$ is the minimum capacity of unit j (MW).

Transmission lines capacity: The capacity of transmission lines and transformers must also be kept within certain capacity limits and in accordance with their correspondent availability status. Thus, this constrain is formulated as follows:

$$f_l^{min} Y_{l,t} \leq f_{l,b,t} \leq f_l^{max} Y_{l,t} \quad ; \quad \forall t, \forall b \quad (11)$$

where f_l^{max} and f_l^{min} are the maximum and minimum capacity of transmission line l (MW) respectively.

Power Balance: To ensure that the energy demand $P_{n,b,t}^{d}$ and the respective power losses $f_{l,b,t}^{loss}$ during subperiod b at time t is meet by the power output of the most efficient units available, the following constraint in (12) is formulated:

$$\sum_{j=1}^{Nt} Pt_{j,t,b} = \sum_{n=1}^{N} Pd_{n,b,t} + \sum_{l=1}^{Nl} f_{l,b,t}^{loss} \quad ; \forall t, \forall b \quad (12)$$

where:

$f_{l,b,t}^{loss}$ Line l losses in subperiod b at time t (MW).

$Pd_{n.b,t}$ System electricity demand at time t for high block demand (MW).

Power losses are determined for each line according to equation (13) [23]:

$$f_{l,b,t}^{loss} = r_l f_{l,b,t}^{2} \quad ; \forall t, \forall b \quad (13)$$

III. Solving the GTMS Problem in a Deregulated Market Environment

The proposed hybrid NSGA III/Dual Simplex model involves an iterative algorithm that tackles the multi-objective GTMS problem in a sequential manner, simulating the rational behavior of GENCOs and of the ISO in a single marginal cost pool-based electricity market, to obtain a set of non-dominated MS solutions, from which the best can be chosen. The proposed model works as follows.

First, an initial population of Np individuals or MS

scenarios is created randomly. The codification of individuals is done by generating random numbers u between 0 and 1 to determine the maintenance starting time variables x_j and y_l, corresponding to generators and transmission lines respectively, by using equations (1.1-2). The length of every individual is equal to the number of generators and transmission lines analyzed as shown in Fig. 1.

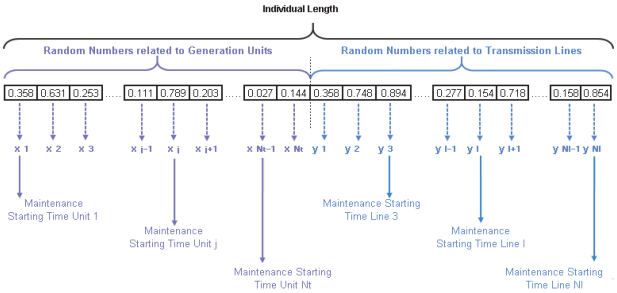

Fig.1. Codification of every component inside a potential solution

Second, the reference points needed by NSGA III to achieve diversity in the obtained solutions are generated according to [24]. Since there is no information about the possible shape of the solution front, reference points are generated uniformly distributed across the search space.

Then, a fitness value corresponding to each objective function in the problem is found so that the performance of every individual is evaluated. To do so, intermediate availability variables $X_{j,t}^{g}$ and $Y_{l,t}$ using equations (2.1-2), so that every individual is examined in terms of the system adequacy index objective function F_1 and the minimum reserve and maximum number of units on maintenance constraints. On the other hand, generators input-output curves and marginal theory are used to determine generation marginal costs (bidding prices) in the market for each unit [25]. With these costs, the demand of electricity, the availability variables, and the network characteristics, a unit commitment (UC) problem is solved. The results obtained are used as inputs to tackle an ED problem using the DS method to find the generators' outputs $P_{j,b,t}^{g}$ that minimize the system operation cost F_2 to meet the demand, an aspect of importance for the ISO. To calculate the transmission losses $f_{l,b,t}^{loss}$, a DC lossy-load flow is used where every line power loss is halved, and each half is added up as extra load to the nodes of each line [22] [23].

Next, power flows $f_{l,b,t}$, transmission losses penalty factors, congestion surpluses, and nodal electricity prices $\lambda_{n,b,t}$ are determined using DS' dual multipliers. With this information, consumer payments, GENCOS and TRANSCOs revenues are calculated, the economic transactions in the market are settled. These results in turn are used to find GENCO's profit objective function F_G. Notice that generation outputs and power flows depend on the values of generators and transmission lines availability variables.

While evaluating the fitness values related to the objective functions, feasible and infeasible individuals are identified using the Adaptive Tradeoff Model (ATM) constraint handling technique [26]. ATM tackles the evaluation of solutions when the population is full and partially composed of infeasible individuals by privileging infeasible individuals with fewer constraint violations and by defining a feasibility proportion that has a direct impact on the fitness function calculation. In that way, the technique drives infeasible individuals slowly towards a feasible search space after each iteration. Then, a normalization process takes place by identifying the hyperplane's extreme points in each objective function axis using an adaptive achievement scalarization function (ASF) adjusted to handle solutions' constraint violations values [27] [28] [29].

Later, individuals in the population are sorted based on the fitness of their objective functions using the non-domination criteria for feasible and infeasible individuals and the concepts stated in [30] and [31]. A fast non-dominated algorithm is applied, so that every individual is assigned a rank equal to its non-dominated front, starting with front 1 as the best, front 2 as the second-best, and so on.

After that, individuals inside the sorted population are selected randomly according to their rank as parents using a binary tournament selection mechanism [32]. Genetic operators are applied to the selected individuals to generate children individuals in a new population. The operators used are the Self Adaptive Simulated Binary Crossover (SBX) and Polynomial Mutation operators [33] [34]. In the first case, a self-adaptive mechanism [35] complements SBX to achieve an "explore first and exploit later" capability during the evolutionary process of solutions, to dynamically adjust the distribution index η_c through a diversity running performance metric defined in [36] and [37]. With respect to the latter, the self-adaptive property described in [38] and [39] is introduced in the mutation operator to allows the update of the probability of mutation p_m and the distribution index η_m values as iteration progress.

Thereafter, the parent and child populations are combined into a single population of size $2Np$. This combined population is again evaluated and sorted using non-dominated concepts already mentioned [40]. Since parent and children individuals are combined in a single set, elitism is ensured in the model. From this, a new population is constructed by selecting individuals of different non-dominated fronts one at a time, starting from the first front until the size of the new population is equal or for the first time becomes larger than Np.

Subsequently, the associate operator is applied by defining a reference line to each reference point in the normalized hyperplane by joining the reference point with the origin [40]. Perpendicular distances from every individual to each reference line are calculated and the reference point whose reference line is closest to an individual is considered associated with that individual. In the same manner, the niching preservation operator is used by NSGA III that highlights iteratively solutions nearest to the reference line of each reference point by updating a niche count repeatedly until all vacant population slots of the new population are filled and its size reaches a value of Np [41].

Finally, TOPSIS is used to assist the decision-maker (ISO) to identify the best individual in the population [42]. The process is repeated until a stopping criterion, based on the maximum number of iterations, is meet. The chart flow of the model is shown in Fig. 2.

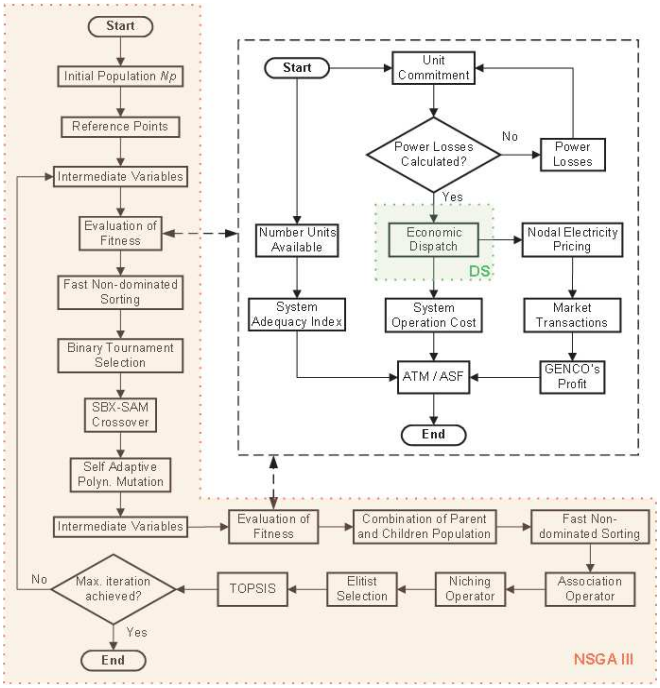

Fig. 2. Flowchart of the hybrid NSGA III/Dual Simplex model

IV. Case Study

The hybrid NSGA III/Dual Simplex model proposed is applied on the IEEE-RTS 24 bus test network with 32 generators and 38 connections [43].

Table I shows generators' technical characteristics, the GENCO they belong to, annual operation and maintenance costs, and the periods and duration of their maintenance.

Three GENCOs are defined in the analysis so that three profit maximization objective functions are considered in the problem. The period under analysis is of 52 weeks. The maximum annual demand considered is 2,850 MW. Table II shows the percentage of the peak demand used to find the demand in each week.

TABLE II
Annual demand percentage for each week

Week	Annual Demand Percen. (%)	Week	Annual Demand Percen. (%)	Week	Annual Demand Percen. (%)	Week	Annual Demand Percen. (%)
1	90.5%	14	76.5%	27	88.4%	40	81.8%
2	90.0%	15	78.5%	28	86.4%	41	83.6%
3	88.5%	16	81.7%	29	84.3%	42	86.5%
4	87.5%	17	84.1%	30	82.5%	43	89.1%
5	86.1%	18	85.8%	31	80.9%	44	91.5%
6	84.3%	19	87.6%	32	79.7%	45	93.4%
7	83.2%	20	88.9%	33	78.9%	46	95.1%
8	80.8%	21	90.9%	34	78.7%	47	96.5%
9	78.4%	22	91.4%	35	78.4%	48	97.6%
10	77.5%	23	91.5%	36	79.0%	49	98.5%
11	76.1%	24	91.4%	37	79.5%	50	99.5%
12	75.5%	25	90.6%	38	80.1%	51	100.0%
13	75.1%	26	89.6%	39	81.1%	52	99.2%

The daily load curves of each day of a week have been divided into three subperiods or demand blocks corresponding to high, medium, and low demand levels. The duration and the percentage of the weekly demand on each subperiod are shown in Table III and the correspondent weekly energy demand is shown in Fig. 3.

TABLE I
Technical characteristics of generation units

Name	Node	Size (MW)		Fuel	Biding Price (US$/MWh)	Output Curve (US$/h)			Maintenance Cost		Maintenance (weeks)			GENCO
		Min	Max	Type		a (US$/ MW^2h)	b (US$/ MWh)	c (US$/ h)	Fixed $/kW/Yr	Variable $/MWh	Window Earliest	Window Latest	Duration	
1	15	2.4	12.0	Gas Natural	30.40	0.02433	28.9700	15.1935	10.0	5.0	1	52	2	2
2	15	2.4	12.0	Gas Natural	30.40	0.02433	28.9700	15.1935	10.0	5.0	1	52	2	2
3	15	2.4	12.0	Gas Natural	30.40	0.02433	28.9700	15.1935	10.0	5.0	1	52	2	2
4	15	2.4	12.0	Gas Natural	30.40	0.02433	28.9700	15.1935	10.0	5.00	1	52	2	2
5	15	2.4	12.0	Gas Natural	30.40	0.02433	28.9700	15.1935	10.0	5.00	1	52	2	2
6	1	4.0	20.0	Diesel	29.58	0.06966	26.2440	28.7003	0.3	5.00	1	52	3	2
7	1	4.0	20.0	Diesel	29.58	0.06966	26.2440	28.7003	0.3	5.00	1	52	3	2
8	2	4.0	20.0	Diesel	29.58	0.06966	26.2440	28.7003	0.3	5.00	1	52	3	2
9	2	4.0	20.0	Diesel	29.58	0.06966	26.2440	28.7003	0.3	5.00	1	52	3	2
10	1	15.2	76.0	Carbon	20.53	0.01280	17.8200	87.5000	10.0	0.90	1	52	4	2
11	1	15.2	76.0	Carbon	20.53	0.01280	17.8200	87.5000	10.0	0.90	1	52	4	2
12	2	15.2	76.0	Carbon	20.53	0.01280	17.8200	80.5000	10.0	0.90	1	52	4	3
13	2	15.2	76.0	Carbon	20.53	0.01280	17.8200	80.5000	10.0	0.90	1	52	4	3
14	7	25.0	100.0	Natural Gas	18.60	0.00960	16.1900	91.5000	8.5	0.80	1	52	5	3
15	7	25.0	100.0	Natural Gas	18.60	0.00960	16.1900	91.5000	8.5	0.80	1	52	5	3
16	7	25.0	100.0	Natural Gas	18.60	0.00960	16.1900	91.5000	8.5	0.80	1	52	5	3
17	22	10.0	50.0	Natural Gas	20.24	0.00658	17.4000	59.3650	8.0	0.75	1	52	4	1
18	22	10.0	50.0	Natural Gas	20.24	0.00658	17.4000	59.3650	8.0	0.75	1	52	4	1
19	22	10.0	50.0	Natural Gas	20.24	0.00658	17.4000	59.3650	8.0	0.75	1	52	4	1
20	22	10.0	50.0	Natural Gas	20.24	0.00658	17.4000	59.3650	8.0	0.75	1	52	4	1
21	22	10.0	50.0	Natural Gas	20.24	0.00658	17.4000	59.3650	8.0	0.75	1	52	4	1
22	22	10.0	50.0	Natural Gas	20.24	0.00658	17.4000	59.3650	8.0	0.75	1	52	4	1
23	15	54.3	155.0	Carbon	12.60	0.00481	10.7300	135.0000	7.0	0.80	1	52	6	1
24	16	54.3	155.0	Carbon	12.60	0.00481	10.75000	135.0000	7.0	0.80	1	52	6	1
25	23	54.3	155.0	Carbon	12.60	0.00481	10.75000	135.0000	7.0	0.80	1	52	6	2
26	23	54.3	155.0	Carbon	12.60	0.00481	10.75000	135.0000	7.0	0.80	1	52	6	2
27	13	69.0	197.0	Natural Gas	19.20	0.01610	14.8500	162.7500	5.0	0.70	1	52	7	1
28	13	69.0	197.0	Natural Gas	19.20	0.01610	14.8500	162.7500	5.0	0.70	1	52	7	1
29	13	69.0	197.0	Natural Gas	19.20	0.01610	14.8500	162.7500	5.0	0.70	1	52	7	1
30	23	140.0	350.0	Carbon	12.24	0.00300	10.7600	194.2500	4.5	0.70	1	52	8	1
31	21	100.0	400.0	Nuclear	7.65	0.00106	8.3390	200.5016	5.0	0.30	1	52	9	2
32	18	100.0	400.0	Nuclear	7.65	0.00106	8.3390	200.5016	5.0	0.30	1	52	9	3
TOTAL		**987.7**	**3,405.0**											**3**

TABLE III
Demand subperiod duration and percentage for weekly demand

Demand Block	Duration (hrs.)	Weekly Demand Percen. (%)
High	5.0	100.0%
Medium	12.0	92.0%
Low	7.0	85.0%

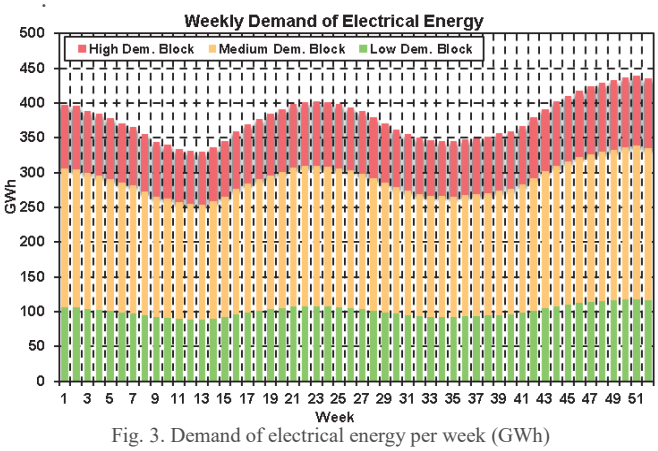

Fig. 3. Demand of electrical energy per week (GWh)

On the other side, the weekly electricity prices for each demand subperiod are determined by simulating a marginal price-based electricity market using the dual multipliers obtained after solving an ED problem. The system marginal price is found, and a marginal unit and node are identified using the following rules:

- The marginal unit correspond to the last dispatched unit in an unconstrained power dispatch.
- A unit forced to generate energy at its minimum capacity cannot be the marginal unit.

The test network technical characteristics are shown in Table IV. Their maintenance cost considered are 2,500 US$/miles.week for transmission lines and 40.5 US$/MVA.week for power transformers [44].

With respect to the constraints, a minimum reserve margin of 12% of the annual peak demand was assumed [45]. Furthermore, the minimum number of available generators during the whole year of analysis was set to 14 units.

The parameter values related to the hybrid model proposed, used to solve the GMS problem are shown in Table V. The number of objective functions has a huge effect on the proportion of non-dominated solutions present in an initial population. In that sense, the population size is chosen so that a third of the individuals created in the initial population belong to the first non-dominated front, as recommended in [46]. Furthermore, the number of iterations used ensures convergence of the NSGA III avoiding any unnecessary computational effort [47]. Following the reference points creation technique, the number of partitions defined is a little bit greater than the number of objective functions in the problem. In this way, it is expected that every solution found will be associated with a particular reference point created [40,24]. The crossover and mutation probability distribution indexes defined correspond to initial values and is expected that, with the self-adaptive capabilities introduced to these operators, they will change according to the necessities of the evolutionary process. The number of grids defined for the diversity metric (DM) of the self-adaptive simulated binary crossover (SBX) operator value is equal to the number of partitions used to generate reference points. In such a manner, it was possible to couple the self-adaptive SBX operator with the NSGA III algorithm more effectively. On the other side, the crossover probability is defined so that most individuals in a parent population undergo a crossover process to produce child individuals with better fitness function values [48]. The mutation probability value is defined as a number equal or greater than the inverse of the number of variables or the length of the individuals in the problem [34].

TABLE IV
Technical characteristics of transmission facilities

No	Name	Node Conection i	Node Conection j	Impedance r (pu/line)	Impedance x (pu/line)	Length (miles)	Capacity (MW)	Maintenance Window (week) Earliest	Maintenance Window (week) Latest	Maintenance Duration (weeks)	TRANSCO
1	LIN 1-2	1	2	0.0026	0.0139	3	193.00	1	52	2	1
2	LIN 1-3	1	3	0.0546	0.2112	55	208.00	1	52	3	1
3	LIN 1-5	1	5	0.0218	0.0845	22	208.00	1	52	0	1
4	LIIN 2-4	2	4	0.0328	0.1267	33	208.00	1	52	2	1
5	LIN 2-6	2	6	0.0497	0.192	50	208.00	1	52	0	1
6	LIN 3-9	3	9	0.0308	0.119	31	208.00	1	52	2	1
7	TRA 3-24	3	24	0.0023	0.0839	0	510.00	1	52	1	1
8	LIN 4-9	4	9	0.0268	0.1037	27	208.00	1	52	0	1
9	LIN 5-10	5	10	0.0228	0.0883	23	208.00	1	52	2	1
10	LIN 6-10	6	10	0.0139	0.0605	16	193.00	1	52	0	1
11	LIN 7-8	7	8	0.0159	0.0614	16	208.00	1	52	0	1
12	LIN 8-9	8	9	0.0427	0.1651	43	208.00	1	52	3	1
13	LIN8-10	8	10	0.0427	0.1651	43	208.00	1	52	3	1
14	TRA 9-11	9	11	0.0023	0.0839	0	510.00	1	52	1	1
15	TRA 9-12	9	12	0.0023	0.0839	0	510.00	1	52	1	1
16	TRA 10-11	10	11	0.0023	0.0839	0	510.00	1	52	1	1
17	TRA 10-12	10	12	0.0023	0.0839	0	510.00	1	52	1	1
18	LIN 11-13	11	13	0.0061	0.0476	33	600.00	1	52	2	1
19	LIN 11-14	11	14	0.0054	0.0418	29	600.00	1	52	2	1
20	LIN 12-13	12	13	0.0061	0.0476	33	600.00	1	52	2	1
21	LIN 12-23	12	23	0.0124	0.0966	67	600.00	1	52	0	1
22	LIN 13-23	13	23	0.0111	0.0865	60	600.00	1	52	0	1
23	LIN 14-16	14	16	0.005	0.0389	27	600.00	1	52	0	1
24	LIN 15-16	15	16	0.0022	0.0173	12	600.00	1	52	2	1
25	LIN 15-21 A	15	21	0.0063	0.0490	34	600.00	1	52	2	1
26	LIN 15-21 B	15	21	0.0063	0.0490	34	600.00	1	52	2	1
27	LIN 15-24	15	24	0.0067	0.0519	36	600.00	1	52	0	1
28	LIN 16-17	16	17	0.0033	0.0259	18	600.00	1	52	0	1
29	LIN 16-19	16	19	0.003	0.0231	16	600.00	1	52	0	1
30	LIN 17-22	17	22	0.0135	0.1053	73	600.00	1	52	3	1
31	LIN 18-21 A	18	21	0.0033	0.0259	18	600.00	1	52	2	1
32	LIN 18-21 B	18	21	0.0033	0.0259	18	600.00	1	52	2	1
33	LIN 19-20 A	19	20	0.0051	0.0396	27.5	600.00	1	52	2	1
34	LIN 19-20 B	19	20	0.0051	0.0396	27.5	600.00	1	52	2	1
35	LIN 20-23 A	20	23	0.0028	0.0216	15	600.00	1	52	2	1
36	LIN 20-23 B	20	23	0.0028	0.0216	15	600.00	1	52	2	1
37	LIN 21-22	21	22	0.0087	0.0678	47	600.00	1	52	3	1
38	LIN 17-18	17	18	0.0018	0.0144	10	600.00	1	52	0	1

TABLE V
Parameters of the hybrid NSGA III-Dual Simplex model proposed

No	Concept		Value	Concept		Value
1	**NSGA III**					
	Size of Population:	Np =	200	Number of Partitions:	p =	6
	Maximum Iteration:	Imax =	500	Number of Obj. Functions:	M =	5
	Number Ref. Points:	H =	210			
2	**SBX-SAM Crossover Operator**					
	Crossover Probability:	pc =	80.0%	Number of Grids:	G =	6
	Initial Distribution Index:	ηc =	10			
3	**Self Adaptive Polynomial Mutation Operator**					
	Mutation Probability:	pm =	5.0%			
	Initial Distribution Index:	ηm =	0.6			

Finally, to use TOPSIS, the weighting factors shown in Table VI were assigned to each objective function of the problem. These weights factors were defined in terms of any Electricity Regulation Agency (ERA) attitude towards the interests of the system. From the ERA perspective, the priority is to guarantee a reliable supply of electricity to consumers. The next priority is to deliver this electricity at the minimum cost

possible. Finally, it is important to allow that each GENCO has an equal chance of making profits. With these weights defined and regulated in this way, the ISO can apply the hybrid model to find the best generation MS.

TABLE VI
TOPSIS weights factors assigned to the objective functions

No	Objective Function			Weigth
	Type	Concept	Interested Party	
1	Maximization	System Realiability	ISO	23.0%
2	Minimization	Operation Cost	ISO	20.0%
3	Maximization	Company Profits	GENCO 1	19.0%
4	Maximization	Company Profits	GENCO 2	19.0%
5	Maximization	Company Profits	GENCO 3	19.0%
Total				**100.0%**

V. Results and Analysis

The simulation of the proposed hybrid NSGA III/DS model used to determine an optimum GTMS in a competitive electricity market was done in MATLAB R2019b in an Intel® Core™ i7-8700 CPU 3.20GHz processor and lasted 93 hours with 24 minutes.

A. Feasibility of MS Solutions

The NSGA III/DS model returned a total of 231 different MS solutions (individuals) at the end of the iteration process. The model allowed the initial population to evolve after each iteration towards a feasible and non-dominated set of solutions, as shown in Fig. 4. From iteration 80 onwards, the number of feasible individuals in the population increases dramatically and reaches at the end of the simulation a proportion of 100%.

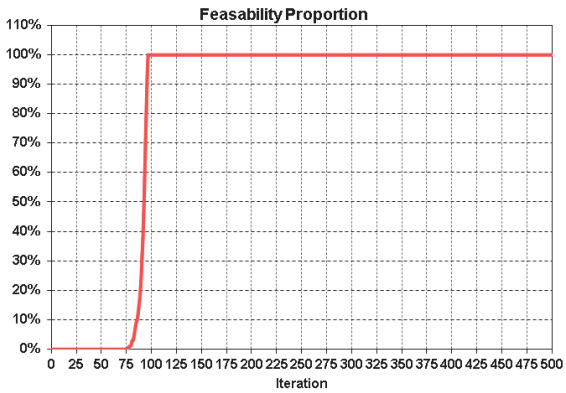

Fig. 4. Percentage of feasible MS (individuals) in the population

B. Objective Function's Relationship

The feasible non-dominated MS results are spread across a five-dimensional (5D) space whose axis corresponds to the systems adequacy index and total operation cost and the profits of three GENCOs. To have a better picture of the results, a set of two-dimensional (2D) plots with their non-dominated solutions identified are shown in Figs. 5-7.

The non-dominated fronts of the three objective functions related to profit maximization of the GENCOs are shown in Fig. 5. It reflects the competitive relationship between the GENCOs. This relation is weak between GENCO 1 and the other two companies. This is because units of GENCO 1 are usually the marginal units of the system and end up defining the electricity marginal cost of the system. The strong correlation between this cost and the demand has a huge impact on electricity prices and revenues of all companies. This puts this GENCO in a strong position in the market, allowing it to make considerable profits and set prices. However, the competitive relation between GENCO 3 and 2 is stronger because both utilities own units with similar generation costs. Then, when any of the units of one of these companies are on maintenance, the units of the other company are dispatched by the ISO immediately to cope with the loss of capacity in the system and supply the demand. Fig. 5 also shows the 3D shape of the non-dominated front of profits of the three GENCOs when plotted together.

Fig. 6 presents the non-dominated fronts related to the profits of each GENCO and the system total operation cost. It shows that when the profits of GENCO 3 increase, the system total operation cost increases as well, and vice versa. The same is true for the relationship between total generation costs with GENCO 2 profits and, to a lesser extent, with GENCO 1 profits too. GENCO 2 and GENCO 3 own the most efficient units of the system, which when on maintenance causes the system operation cost to increase. This situation represents a loss of profits for these GENCOs, which is compensated by the revenues made from selling the energy generated with less efficient units at a higher price. On the other side, GENCO 1 owns much of the less efficient units in the system. When these are available, they get dispatched, and some become marginal units and fix the electricity prices in the system. As a result, the total operation cost of the system varies according to the demand fluctuations. Furthermore, Fig. 6 also shows the shape of a non-dominated front in a 3D-space when the non-dominated profits of GENCO 2 and 3 and the total operation cost of the system are plotted together.

Fig. 7 shows the non-dominated fronts related to the profits of each GENCO and the system total operation cost and the system adequacy index. In the case of GENCO 1, its cheapest carbon unit is the most profitable and has a big capacity. When this unit is unavailable other less expensive and bigger units get dispatched, so that the system adequacy index increases while the company profits decrease. This conflicting relationship is a little bit more notorious between GENCO's 2 and 3 profits with the adequacy index. When efficient units of any of these utilities are on maintenance, the available units of the other company are dispatched, increasing the adequacy of the system, and reducing the profits of the utility with its units unavailable. This situation is stressed for GENCO 2 since it owns the less efficient units in the system that hardly ever get dispatched. Thus, when its most efficient high-capacity unit is on maintenance, a great loss of profits is experienced by GENCO 2, the ISO compensates for the loss of capacity by keeping available GENCO 2 less efficient units to improve the adequacy index. Fig. 7 shows that the system's total operation cost decreases as the adequacy index of the system decrease too. This strongly depends on the fluctuations of the demand of the system. The system's total operation cost is higher at periods of high demand when more available units are needed to keep the system reserve margin above the minimum defined. On the other side, this cost is lower for periods of low demand, when fewer units are needed to keep the reserve margin and the adequacy index consequently.

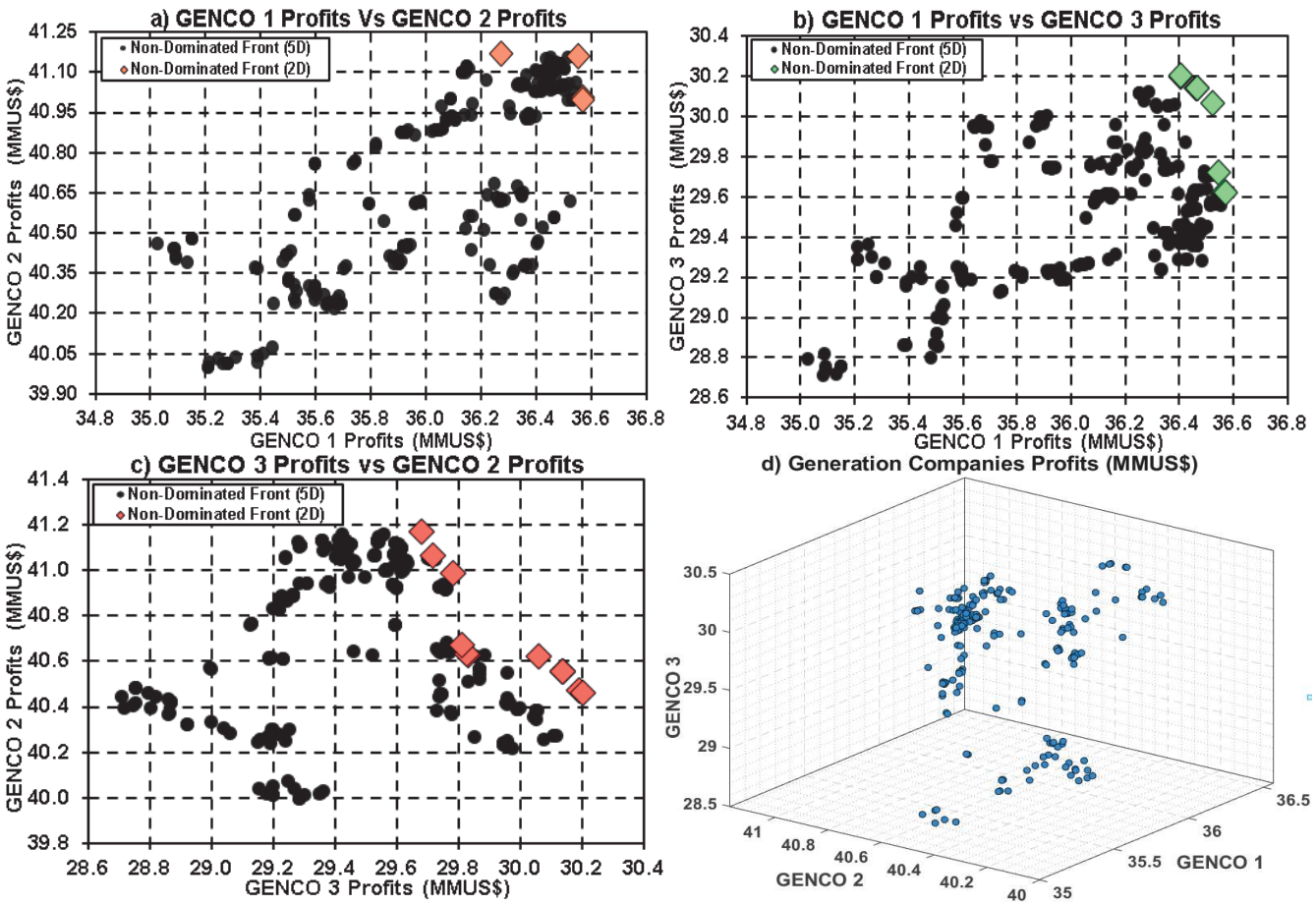

Fig. 5. Non-dominated fronts for GENCOs profits objective functions (MMUS $)

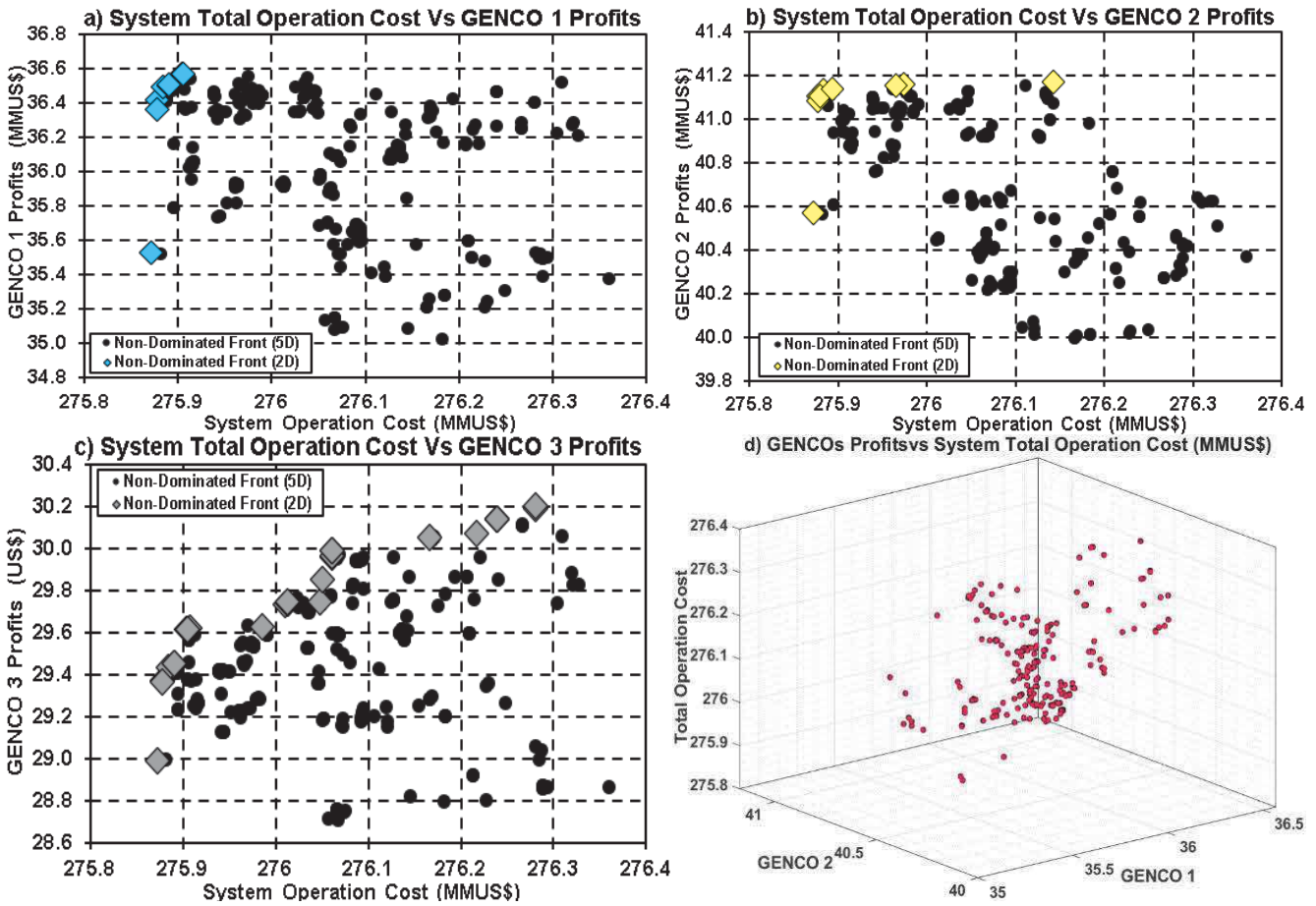

Fig. 6. Non-dominated front for GENCO's profit and system total operation cost (MMUS $)

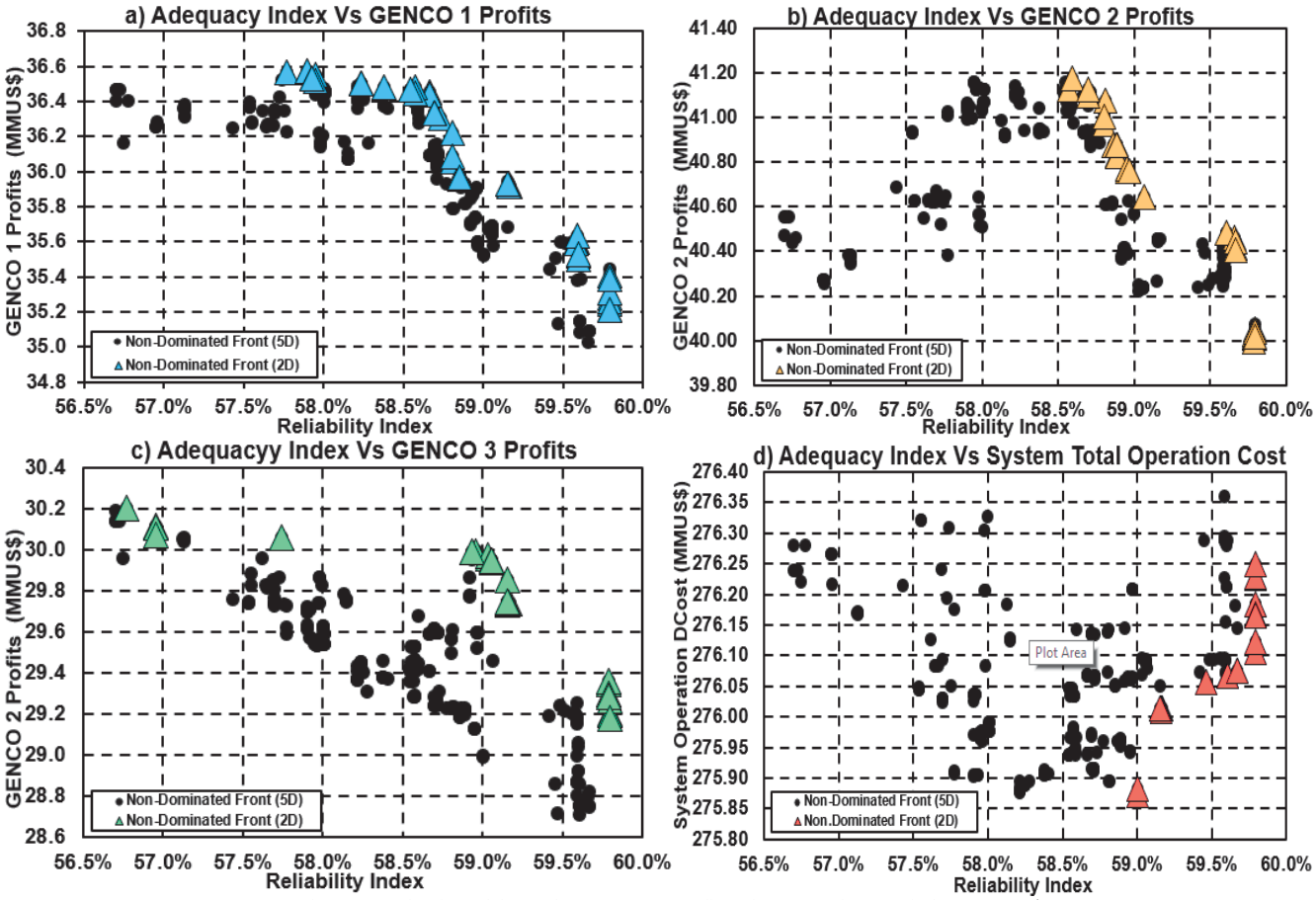

Fig. 7. Non-dominated fronts for GENCO's profit and system adequacy index (MMUS$)

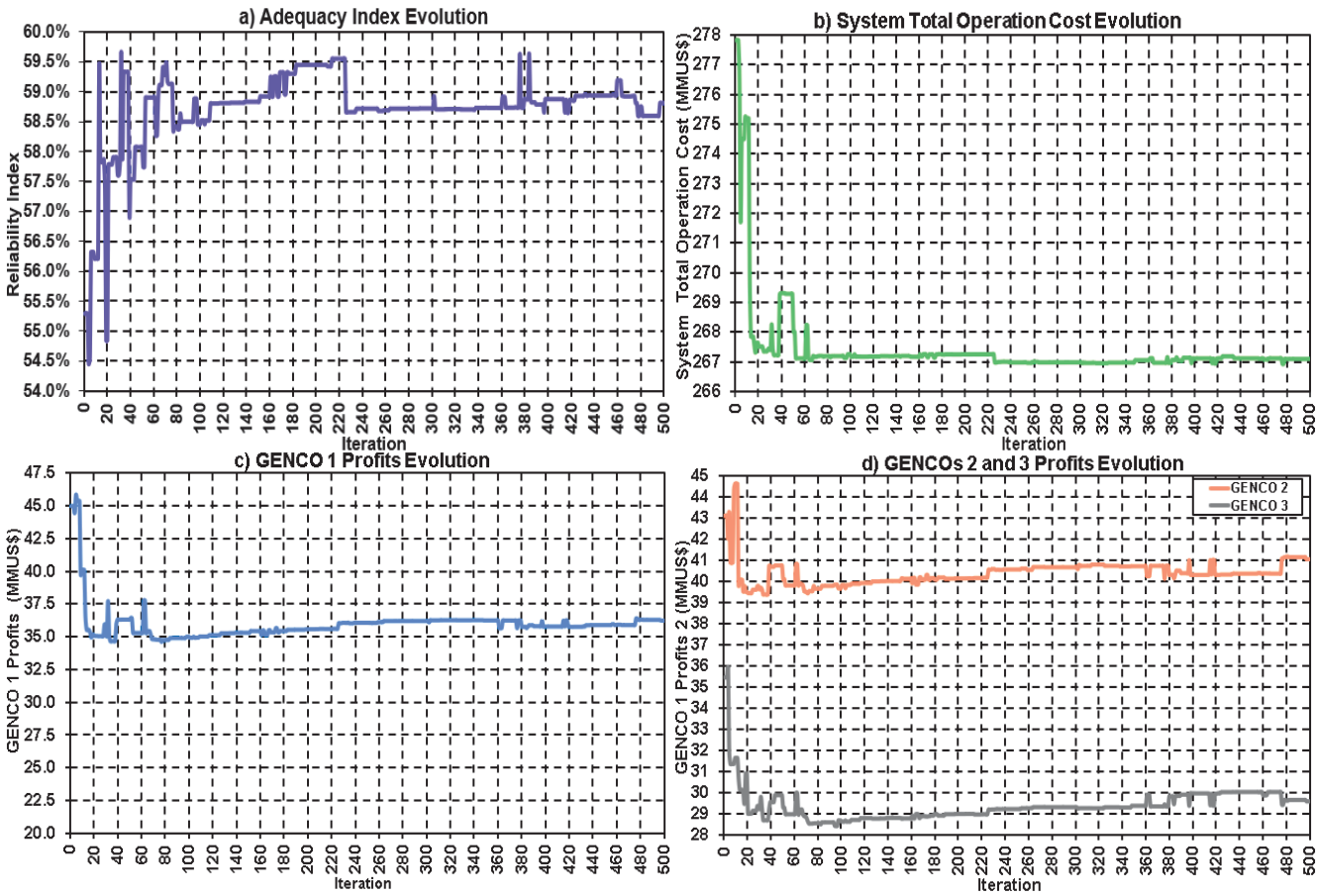

Fig. 8. Evolution of the objective functions of the best MS solution in each iteration

C. Evolution of the Best MS during simulation

Every individual inside the non-dominated set of feasible solutions represents a possible MS scenario. Using the proposed hybrid model, MS solutions are developed so that each scenario has its own single minimum system total operation cost, which does not happen in [14] and [15], related to an adequacy index.

This aspect works in accordance with the maintenance scheduling philosophy of the electricity industry, with the difference that the model allows the ISO not to have one but a set of feasible non-dominated MS at disposal, among which it can choose the best considering the weight factors assigned to the objective functions by the ERA. Since TOPSIS decision-making tool has been applied after each iteration, the evolution of the objective functions related to the best GTMS scenario was tracked during the simulation and is shown in Fig. 8.

After every iteration, the hybrid NSGA III/Dual Simplex model tries to increase the system adequacy and reduce the system total operation cost because these two objective functions have a great weight factor assigned. In the case of GENCO's profits, the model attempts to increase them, when possible, without compromising the system adequacy index.

D. Best Generation and Transmission MS Solution

The best generation and transmission MS scenario generated by the proposed model is shown in Fig. 9. Moreover, Fig. 10 shows the energy generated by each unit in the system, per GENCO and per technology used. The figure shows that from weeks 13 to 21, GENCO 3 is not generating energy at all since its most profitable and efficient unit, powered by nuclear fuel and connected to the system through node 18, is on maintenance. At the same time, line LIN 18-21B goes into maintenance at week 35, while its parallel counterpart, line LIN 18-21A, becomes unavailable due to maintenance from week 16, when the demand has low values. In the same way, the two parallel lines LIN 15-21 A and LIN 15-21 B go into maintenance at weeks when the demand of the system is decreasing or starting to increase, respectively. Furthermore, maintenance of transformers takes place at different weeks with low demand levels, making it possible the transfer of energy from different parts of the system. All these results suggest that the hybrid model manages to develop a certain degree of coordination among generators and transmission MS and between them with the system energy demand.

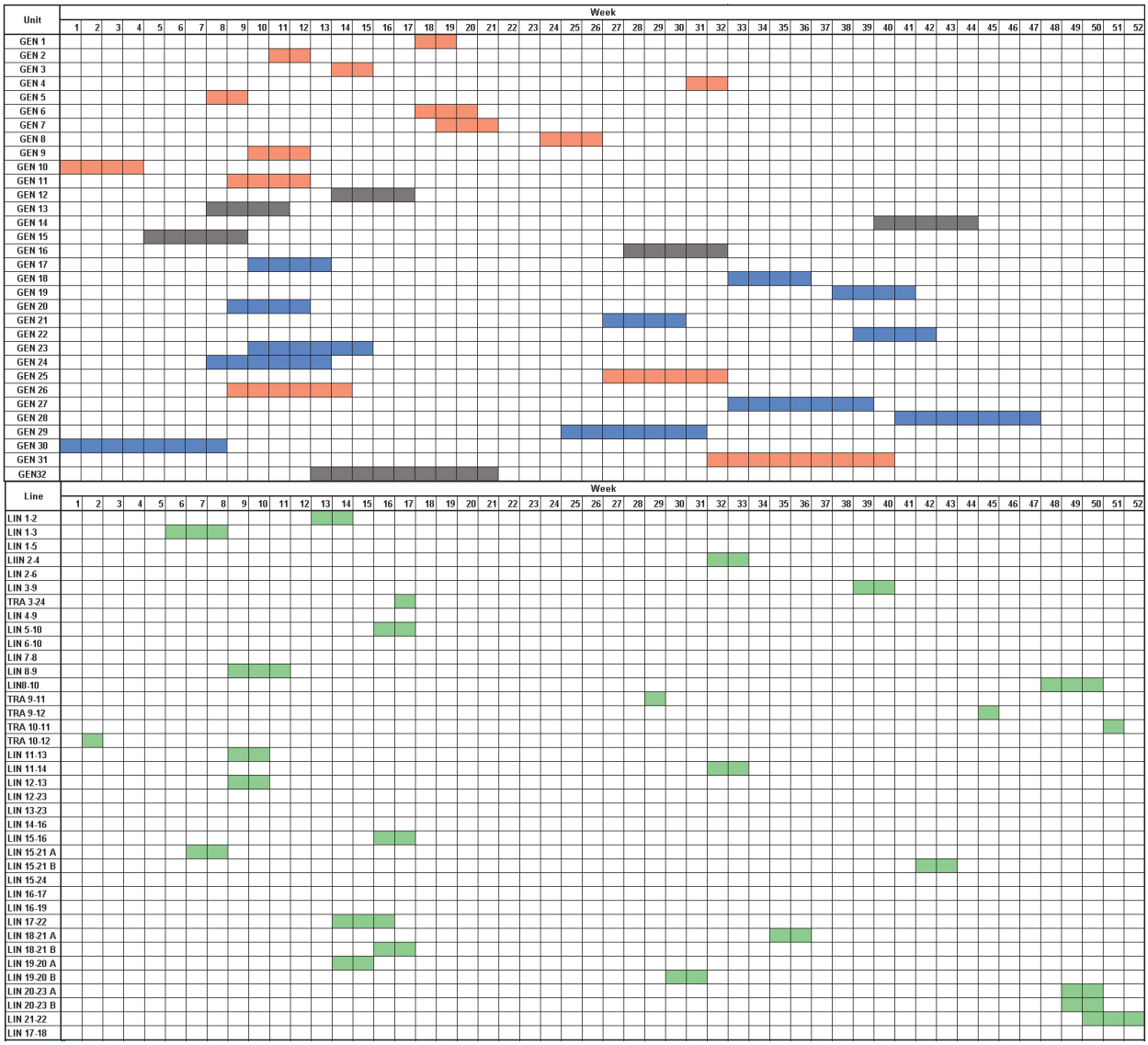

Fig. 9 Best Generation and Transmission Maintenance Schedule Solution

Fig. 11 shows the reserve margin of the system and the number of units available corresponding to the best MS scenario found by the model. At any time at least one of the efficient units belonging to GENCOs 2 and 3 is available for generating electricity. These units are scheduled for maintenance at periods of low electricity demand, so that it can be available when the demand is high, contributing to an acceptable adequacy index.

On the other hand, Fig. 11 also shows that at the beginning and at the end of the period of analysis there is a greater number of generation units available. This is because during these periods the demand for electricity is high, and the model ensures that all the necessary units remain available to keep a high adequacy index. Notice that a minimum of 23 units is available at week 11 and that the reserve margin reaches a minimum of 349.7 MW at week 13, values that comply with the constraints stated for the GTMS problem.

Fig. 12 shows the average system marginal cost, and nodal energy prices, economic transactions on the electricity market, and GENCOs weekly profits for the best MS scenario. The average system marginal cost is not only affected by the demand fluctuation, but also by the MS of generation units. When efficient units are on maintenance, more inefficient units are required to supply the demand, which increases the system marginal cost. The average nodal energy prices have a strong correlation with the system marginal cost.

Few congestion cases during the medium and low block demand have been detected, especially in line LIN 7-8 which injects energy generated by efficient gas-fired units directly into the system. On the other hand, in terms of the economic transactions, most of the money end consumers pay is allocated to GENCOs as revenues in accordance with the amount of energy produced. A small proportion represents the merchandising surplus that arises due to losses in the system and is allocated to the TRANSCO as revenue. Notice that a very small amount of congestion surplus arises due to constraints in the network, which is not allocated to any company at all.

Finally, it should be mentioned that the best MS scenario resulted in an adequacy index of 58.81%, a total system operational cost of MMUS$ 276.14, and profits of MMUS$ 36.22, MMUS$ 41.07, and MMUS$ 29.61 for GENCOs 1, 2, and 3 respectively.

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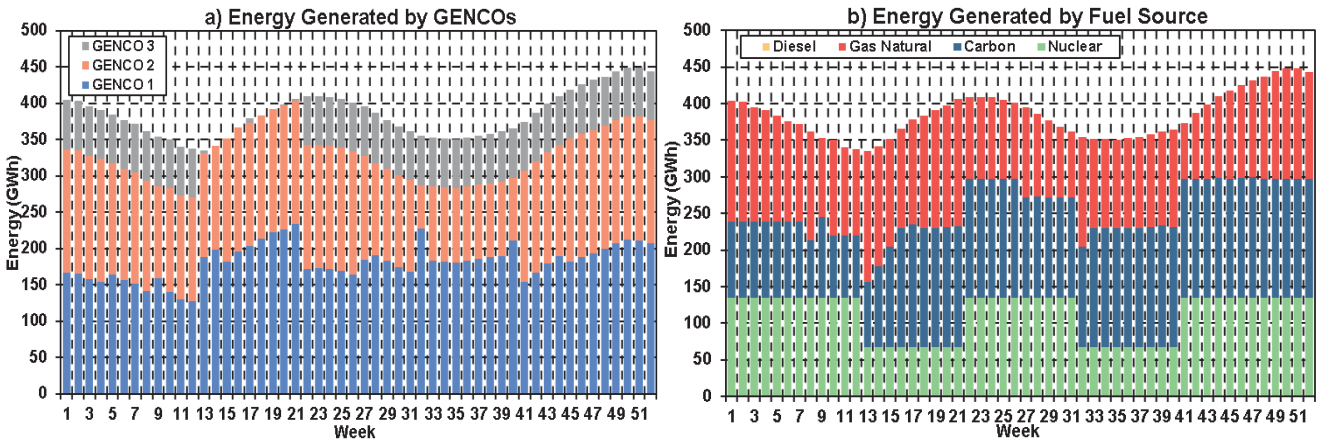

Fig. 10. Energy generated by GENCOs and by fuel source and Transmission lines load profile

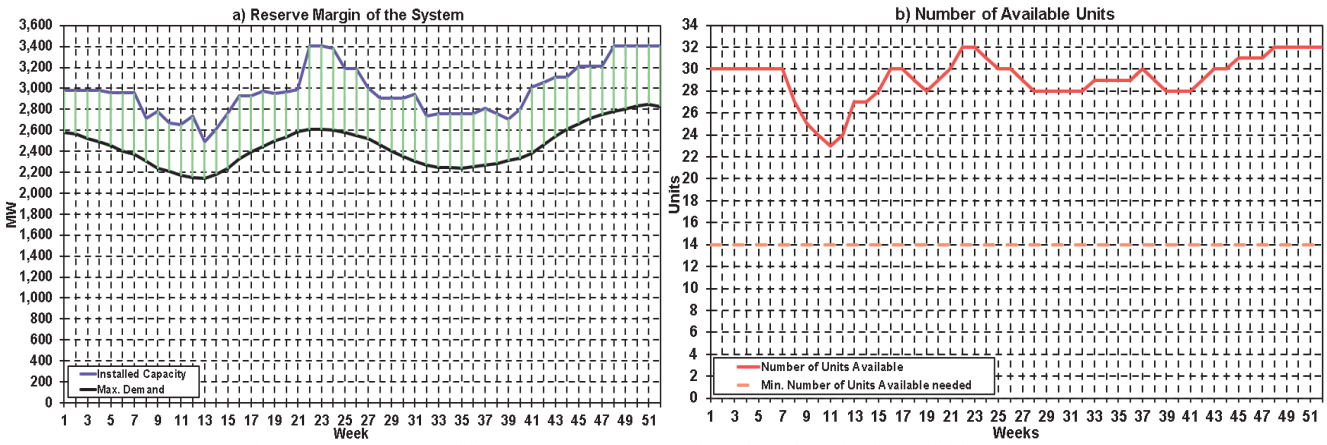

Fig. 11. Energy generated by GENCOs, reserve margin and number of units available in the system

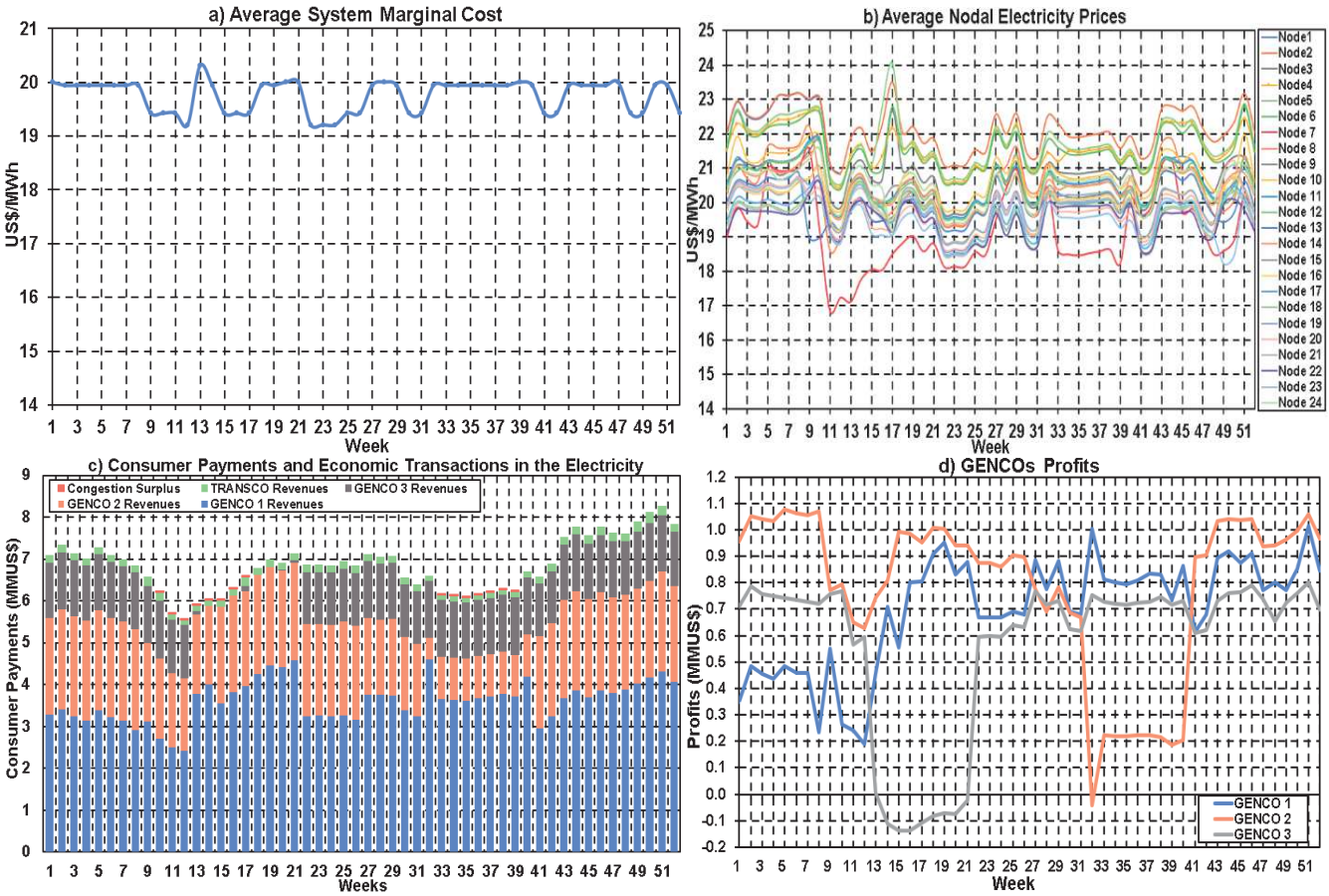

Fig. 12. Average System Marginal Cost and Nodal Energy Price of the system

VI. Conclusions

A hybrid approach has been developed, combining in a novel way NSGA III and the Dual Simplex optimization techniques, to solve the GTMS problem in a market environment, considering the nature of the variables involved, their interdependence, the effect of the MS solutions found in the market electricity prices and the relationship among the objectives of the parties involved.

The results show that the model produces a well-spread set of feasible and non-dominated MS solutions whose characteristics comply with the reasonable behavior of GENCOs and the ISO in an electricity pool market. The competitive relationships among GENCOs and the conflicting relationships between GENCOs and the ISO in the market are clearly visible in the results.

Furthermore, in contrast with previous models proposed to solve the GTMS problem, for each MS solution generated by the model, an adequacy index and a single system total operation cost are found. This reduces the size of the set of feasible solutions and comes at hand with the maintenance practices of today electricity industry.

At the same time, the results display a degree of coordination between transmission and generation MS and their effect on the electricity prices, which affect the GENCOs profits and the system operation cost in the market.

Finally, the model makes available to the ISO (decision maker) not one but a set of feasible generators and transmission lines MS, from which it can choose the best using TOPSIS. Alternatively, the ISO can use it as a MS portfolio during any negotiation process with the GENCOs in the market to agree on a final MS.

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