Multiyear Transmission Expansion Planning Under Hydrological Uncertainty

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***Abstract*— Hydrothermal systems should be characterized by a transmission-intensive nature in order to deal with climatic phenomena which, for example, can determine dry conditions in one region while there are large rainfalls in another one. Thus, the grid must be robust to deal with the different export/import patterns among regions and accommodate several economic dispatches. This paper describes a multiyear probabilistic Transmission Expansion Planning, TEP, model that uses Evolutionary Particle Swarm Optimization (EPSO) to deal with the uncertainties present in hydrothermal systems. The numerical simulations were conducted using the IEEE 24 bus reliability test system in which the planning horizon is 10 years and the load growth is 2,5% per year. The results highlight the importance of adopting expansion strategies to reduce the risk and consider the inflow variations in this type of systems.**

***Index Terms*-- Transmission Expansion Planning, Probabilistic Approach, Uncertainties, Evolutionary Particle Swarm Optimization.**

I. Introduction

The restructuring of the electricity sector which occurred especially in the last two decades led to the separation of the generation, transmission, distribution and retailing of electricity activities in several countries [1]. In this context, the activities of generation and retailing are now provided in free competition while network services, namely transmission, are provided in term of regulated monopolies. This separation introduces a higher degree of complexity in long-term planning. To further complicate the planning activities, hydrothermal systems should have a transmission-intensive nature in order to deal with the climatic phenomena which, for example, can determine dry conditions in one region while there are increasing rainfalls in another one. Thus, the grid must be robust enough to deal with the different export/import patterns among regions and be able to accommodate several economic dispatches [2]. These reasons combined with the importance of the electric sector in the economy and sovereignty of a country turn the Transmission Expansion Planning (TEP) one of the biggest challenges faced by researchers in the power systems area.

TEP is a problem that has non-linear and non-convex characteristics. It is also characterized by a combinatorial explosion phenomenon, that is, a huge number of expansion possibilities which leads to an enormous computational burden. These aforementioned difficulties lead to a diffusion of relaxed models such TEP approaches based on DC Model [3]. This model does not consider the reactive power, the branch losses and the voltage limits on the bars, and so its computational effort is lighter. However, it does not represent the real behavior of an AC grid and therefore can lead to solutions that corresponds to undervalued investments while also leading to serious violations of network constraints in their solutions when are checked against pure AC TEP models as reported in [4], [5]. In order to overcome these problems, the TEP problem was solved using the AC model in [6], [7].

Apart from DC based models, the TEP literature also includes several models in which the holistic planning view is discarded (static models) in order to reduce the computational burden. In these static approaches each planning period is analysed at a time and an equipment (transmission lines, transformer, cables) is selected in a given period and it is considered as available on the next one [8]. However, the multiyear (or dynamic) nature is very important in TEP problems once it preserves the holistic view on the planning exercise. In dynamic approaches the entire planning horizon is taken at the same run [9], which is essential to adequately select investment alternatives in long term problems.

This paper describes a probabilistic multiyear TEP model that uses EPSO to address its particular characteristics. It also considers different hydro inflows as well as a risk index to measure the annual deficit of the system in supplying the demand. The main contributions of this paper are as follows:

i) TEP is performed considering several hydro shares generation scenarios in a multiyear approach and it incorporates the AC Optimal Power Flow (AC-OPF) to adequately model the operation of the network. Therefore, this TEP approach is more realistic since it uses a probabilistic approach, it preserves the holistic planning view and uses the AC model that truly represents the network behavior;
ii) The EPSO algorithm is implemented using the concept of parallel computing. Due the huge computational burden required to solve the TEP problem considering several hydro scenarios, this approach can save time and enable analyzing realistic systems in the future.

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Regarding the structure of the paper, following this Introduction, Section II addresses the uncertainties intrinsic to hydrothermal systems and Section III describes the mathematical formulation of the dynamic TEP problem. Then, Section IV details the main blocks of the EPSO algorithm, Section V presents the simulation results and finally Section VI draws the main conclusions of this research.

II. Hydrological Uncertainties

Hydrothermal systems must have a strong transmission grid because transferring huge energy blocks from wetter to drier regions is frequently required. Therefore, when the TEP problem is solved it must consider several and different dispatch patterns in order to reduce the risk of having Power Not Supplied (PNS). Thus, hydrological uncertainties must be taken into account when addressing the TEP problem.

In this paper, the hydrological uncertainties were addressed through scenarios over the planning horizon. The hydrological scenarios are generated considering the initial hydro share (ε_0), the number of scenarios (*Nscen*) and the maximum annual variation for the hydro shares ($\Delta\varepsilon_M$). The hydro shares for a scenario in period p (ε_p) are calculated using (1) and this process is illustrated in Fig. 1 considering 20 hydro inflows.

$$\varepsilon_p = \varepsilon_{p-1} + randb(-\Delta\varepsilon_M : +\Delta\varepsilon_M) \tag{1}$$

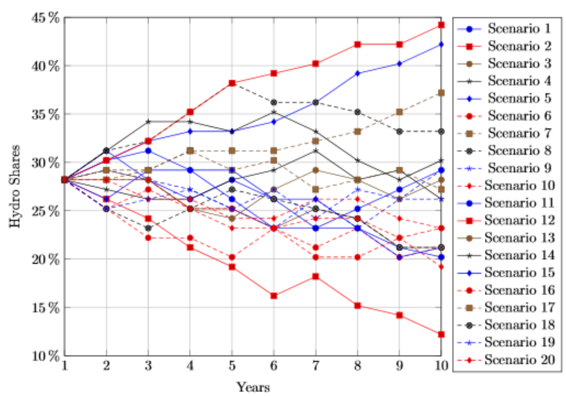

Figure 1. Hydro share generation scenarios.

Besides the hydro shares scenarios for the annual system mix, it is also important to consider different scenarios for the hydro generators of the system, that is, the participation factor for each hydro generator as illustrated in Fig. 2 for a power system having hydro generators in buses 15, 16, 22 and 23.

According to Fig. 2, considering scenario 1 for instance, the generators in buses 15, 16, 22 and 23 contribute to the total hydro share in that scenario and along the planning horizon according to the following percentages: 3.48%, 6.83%, 20.38% and 69.31%.

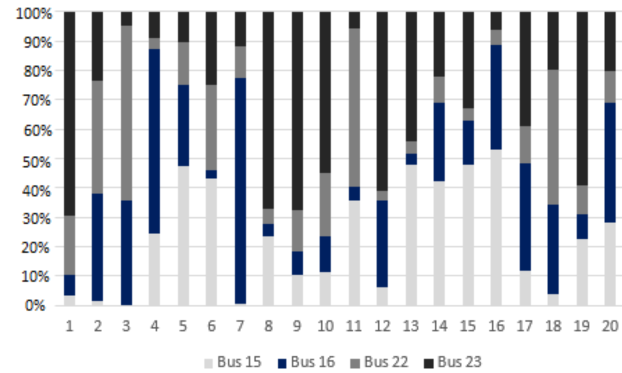

Figure 2. Bus participation factor for each generation scenario.

Apart from that, the minimum and maximum limits of the reservoirs must be respected and so the model ensures that the hydro generation capacity lies between zero and 1,5 times the initial capacity. This means that if in a scenario and in a bus the available hydro share and the bus participation factor indicate that the reservoir level is outside these limits, then that level is set at the violated extreme value.

Additionally, the developed approach incorporates an annual deficit risk index of the system (χ) not being able to supply the demand. This index is defined as the percentage of scenarios for which a particular expansion plan is not able to supply the demand, that is, it originates power not supplied. In order to be considered as a feasible solution for the TEP problem, any expansion plan should have a value of this risk index below a specified threshold.

III. TEP Mathematical Formulation

The mathematical formulation discussed in this paper takes into account the investment ($C_{inv,p}$) and the expected load-shedding costs ($C_{ELS,p}$). Furthermore, the physical (branches and generator capacity limits), financial (capital available in the period) and quality of supply constraints (reliability indices) are also considered. The associated TEP problem can be formulated by (2) to (5).

$$\text{Minimize } \sum_{p=1}^{np} \kappa_p.(C_{inv,p} + C_{ELS,p}) \tag{2}$$

Subject to:

Physical Constraints (3)

Financial Constraints (4)

Quality of service Constraints (5)

In this formulation κ_p is the present-worth value coefficient given by (6) and d is the discount rate.

$$\kappa_p = \frac{1}{(1+d)^p} \tag{6}$$

In order to compute the $C_{ELS,p}$ for the topology of the system in each planning year considering also the new equipments included in the expansion plan under analysis we used an AC-OPF based model. This model represents the true behavior of the AC network once it considers the reactive power, the voltage limits on the bars and the branch losses. In this paper we used the MATPOWER tool [10] to assist the solution of the mentioned AC-OPF problem in a very efficient way because this routine is called a large number of times.

The AC-OPF used in this paper is formulated by (7) to (15) and it considers the new equipments on the grid proposed by the expansion planning in study. In this problem, we used the operation cost as the generator dispatch merit order.

$$\text{Min } C_{OP} = \sum \alpha_{i1}.P_i^2 + \alpha_{i2}.P_i + \alpha_{i3} \tag{7}$$

subject to

$$P(V,\theta,n) - P_G + P_D = 0 \tag{8}$$

$$Q(V,\theta,n) - Q_G + Q_D = 0 \tag{9}$$

$$P_{G\min} \le P_G \le P_{G\max} \tag{10}$$

$$Q_{G\min} \le Q_G \le Q_{G\max} \tag{11}$$

$$V_{\min} \le V \le V_{\max} \tag{12}$$

$$(N+\overset{o}{N})S^{from} \le (N+\overset{o}{N})S_{\max} \tag{13}$$

$$(N+\overset{o}{N})S^{to} \le (N+\overset{o}{N})S_{\max} \tag{14}$$

$$0 \le n \le n_{\max} \tag{15}$$

In this formulation $P(V,\theta,n)$ and $Q(V,\theta,n)$ are calculated by (16) and (17), and the bus conductance G and susceptance B are given by (18) and (19).

$$P(V,\theta,n) = V_i \sum V_j [G_{ij}(n).\cos\theta_{ij} + B_{ij}(n).\sin\theta_{ij}] \tag{16}$$

$$Q(V,\theta,n) = V_i \sum V_j [G_{ij}(n).\sin\theta_{ij} - B_{ij}(n).\cos\theta_{ij}] \tag{17}$$

$$G = \begin{Bmatrix} G_{ij}(n) = -(n_{ij}.g_{ij} + \overset{o}{n}_{ij}.\overset{o}{g}_{ij}) \\ G_{ii}(n) = \sum_{j\in\Omega_i} (n_{ij}.g_{ij} + \overset{o}{n}_{ij}.\overset{o}{g}_{ij}) \end{Bmatrix} \tag{18}$$

$$B = \begin{Bmatrix} B_{ij}(n) = -(n_{ij}.b_{ij} + \overset{o}{n}_{ij}.\overset{o}{b}_{ij}) \\ B_{ii}(n) = b_{ij}^{sh} + \sum_{j\in\Omega_i} [n_{ij}(b_{ij} + b_{ij}^{sh}) + \overset{o}{n}_{ij}(\overset{o}{b}_{ij} + \overset{o}{b}_{ij}^{sh})] \end{Bmatrix} \tag{19}$$

The apparent flows S_{ij}^{from} and S_{ij}^{to} in branch ij are calculated by (20) and (21) where P_{ij}^{from}, Q_{ij}^{from}, P_{ij}^{to} and Q_{ij}^{to} are given by (22) to (25).

$$S_{ij}^{from} = \sqrt{(P_{ij}^{from})^2 + (Q_{ij}^{from})^2} \tag{20}$$

$$S_{ij}^{to} = \sqrt{(P_{ij}^{to})^2 + (Q_{ij}^{to})^2} \tag{21}$$

$$P_{ij}^{from} = V_i^2.g_{ij} - V_i.V_j(g_{ij}.\cos\theta_{ij} + b_{ij}.\sin\theta_{ij}) \tag{22}$$

$$Q_{ij}^{from} = -V_i^2.(b_{ij}^{sh} + b_{ij}) - V_i.V_j(g_{ij}.\sin\theta_{ij} - b_{ij}.\cos\theta_{ij}) \tag{23}$$

$$P_{ij}^{to} = V_j^2.g_{ij} - V_i.V_j(g_{ij}.\cos\theta_{ij} - b_{ij}.\sin\theta_{ij}) \tag{24}$$

$$Q_{ij}^{to} = -V_j^2.(b_{ij}^{sh} + b_{ij}) + V_i.V_j(g_{ij}.\sin\theta_{ij} + b_{ij}.\cos\theta_{ij}) \tag{25}$$

In this formulation, the objective function (2) corresponds to the operation cost of a hydrothermal system where α_{i1}, α_{i2} and α_{i3} are coefficients of the quadratic generator cost functions of each hydro/thermal generation unit *i* dispatching a real power P_i (hydro generator have null coefficients). P_G is the real power generation, Q_G is the reactive power generation, P_D is the real power demand, Q_D is the reactive power demand, V is the voltage magnitude, S_{ij}^{from} and S_{ij}^{to} are the branch apparent flows in terminals, and g_{ij} and b_{ij} are the conductance and the susceptance of branch i-j.

IV. Evolutionary Particle Swarm Optimization

EPSO is a powerful tool that combines concepts of evolutionary computation and multi agent population taking advantage of the standard blocks that are typical in Genetic Algorithms and Particle Swarm Optimization. This tool is able to combine the best features of these two groups of techniques and so it typically shows an excellent performance in solving complex problems such as the one addressed in this paper.

The EPSO algorithm is based on the evolution of a set of particles, each of them representing possible solutions for the problem. Along the process the particles evolve according to a fitness function and continue to improve in each iteration until the process reaches a pre-established stopping criterium. At that point, the best solution of the last population is provided to the user. Fig. 3 details the main blocks of the EPSO algorithm that will also be described in the next paragraphs.

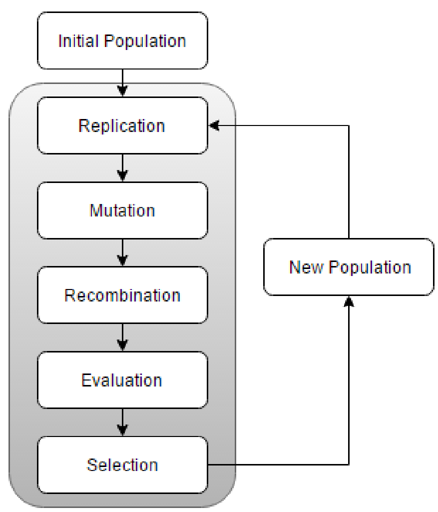

Figure 3. Main blocks of the EPSO Algorithm.

<u>Initial Population</u>

The initial population is created randomly and the developed approach uses a tabu list to prevent repeating the same particle in the population, that is, to increase the diversity of the particles in the initial population.

Replication

Each population is cloned r times in order to create new populations to be mutated in the next block.

Mutation

The weights and the best particle found until now (gbest) for the populations are mutated using (26) and (27) in which the symbol * denotes the mutation operator. This process increases the diversity of the individuals under analysis.

$$\overset{*}{w}_{ij}^{it+1} = 0,5 + rand() - \frac{1}{1+\exp(-\overset{*}{w}_{ij}^{it})} \tag{26}$$

$$\overset{*}{gbest} = gbest + round(2.\overset{*}{w}_{i4}^{it+1} - 1) \tag{27}$$

Recombination

New populations (offsprings) are created based on the PSO movement rule. According to (28) the position of a particle i in iteration it+1 is the result of its position in iteration i plus the velocity vector given by (29). This procedure is repeated for all particles in the cloned population.

$$x_i^{it+1} = x_i^{it} + v_i^{it+1} \tag{28}$$

$$v_i^{it+1} = \overset{*}{w}_{i1}^{it+1}.v_i^{it} + \overset{*}{w}_{i2}^{it+1}.(pbest_i - x_i^{it}) + \overset{*}{w}_{i3}^{it+1}.(gbest - x_i^{it}).P \tag{29}$$

The first term in (29) represents the inertia of the particle, the second term represents its individual knowledge and the last term represents the collective knowledge of the swarm. P is the communication factor described in [11]. It typically takes values 0 or 1 so that if 0 is used for a position of the particle vector then the collective knowledge is not passed to this particle in the next iteration.

Evaluation

The investment and the expected load shedding costs are calculated for all scenarios. If a candidate plan can ensure a safe operation (without PNS) respecting the annual deficit risk of the system, then the load shedding cost is zero, otherwise the average PNS is calculated and multiplied by a penalty factor (in $/MW). The evaluation flowchart for this procedure is shown in Fig. 4.

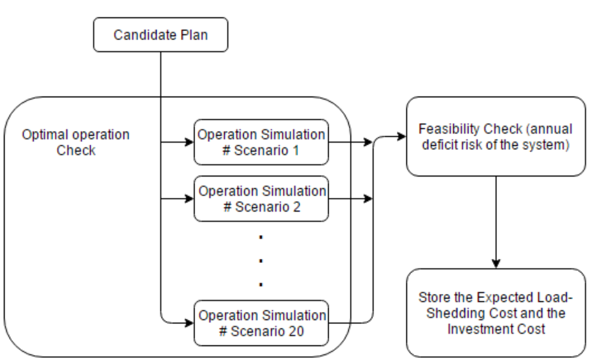

Figure 4. EPSO evaluation block.

Selection

After all the particles are characterized by their investment and expected load shedding costs, a tournament selection is done to build the new population having the same size of the initial one. The iterative process continues until best solution remains unchanged along a pre-defined number of iterations.

In a population with *ps* individuals or particles and considering r clones, *Nsc* hydrologic scenarios and *np* years of planning horizon then the AC-OPF problem is run r x *ps* x *Nsc* x *np* times in iteration. These calculations require a huge computational burden and that was the motivation to implement the EPSO algorithm using parallel computing.

V. Simulation Results

This section presents the results obtained by the proposed TEP approach when applied to a modified version of the IEEE RTS 24 bus system [12]. The used system has some differences regarding the original, as described below:

i. the loads are modeled as negative real power injections with associated negative costs as described in [12]. This modeling is done using negative output generators, ranging from a minimum injection equal to the negative total load to a maximum injection of zero. This means that the AC OPF problem has enough flexibility to reduce the demand if that is required to maintain feasibility. Additionally, if a particular nodal real load is not entirely supplied then the reactive demand is also reduced in the same proportion to keep the power factor of the original load unchanged;

ii. the values of all loads were duplicated and the installed capacity of all generators were tripled (real and reactive) regarding the values in [12] in order to turn the transmission network more stressed;

iii. the modified system has 9 hydro generators that have initial maximum capacity of 2880 MW (28,2% of the total capacity of the system) as follows:
    - 6 hydro generators of 150 MW in bus 22;
    - 1 hydro generator of 1050 MW in bus 23;
    - 1 hydro generator of 465 MW in bus 15;
    - 1 hydro generator of 465 MW in bus 16;

The load growth was set at 2,5% per year and the peak forecasted demand is shown in Table 1. When solving the TEP problem, we also admitted that all transmission equipments in the initial topology could be considered for expansion in terms of installing in parallel a maximum of 2 additional equipments equal to each existing one.

In the performed simulations we used 30 particles in the swarm (ps=30), 20 hydrological scenarios (Nsc=20) as illustrated in Fig. 1 and Fig. 2, 10 years of planning horizon, an annual deficit risk of the system of 5%, which means that an expansion solution is considered as feasible when it ensures a safe operation (without PNS) in at least 95% of the scenarios that is in 19 scenarios out of the 20 analysed scenarios.

TABLE I
Peak demand forecast used along the planning horizon for the modified IEEE RTS 24 bus system.

Year	1	2	3	4	5	6	7	8	9	10
Peak Load (MW)	5700,00	5842,5	5988,56	6138,27	6291,73	6449,02	6610,25	6775,51	6944,89	7118,52

On the other hand, the PNS cost was set at 10^9 $/MW, and a maximum annual variation for hydro shares equal to 3%. Using these parameters and input data, the process converges in 138 iterations in about 22 hours. Fig. 5 shows the behavior of the best solution in the swarm over the iterative process.

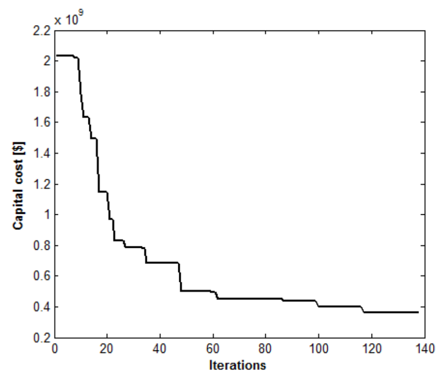

Figure 5. Evolution of the best particle.

Regarding the best solution found over the 10-year planning horizon, the following equipments will be commissioned:

- Year 1 - 138 kV line connecting the buses 1 to 3, 2 to 6 and 8 to 10, one 138 kV cable connecting bus 6 to 10, one 230 kV line connecting buses 12 to 13 and 14 to 16, and one transformer between buses 3 and 24;
- Year 7 - one 138 kV line connecting buses 7 to 8;
- Year 10 - one transformer between buses 9 and 12.

This solution ensures a safe operation in all scenarios except in scenario 16 where this topology does not guarantee the supply of 2 MW. However, the solution is considered feasible as it meets 19 hydrological scenarios thus respecting the annual deficit risk of the system of being below 5%.

Still on the above solution, it is important to notice that most of the equipment is commissioned in the first period because the network is very stressed in the beginning of the planning horison The new equipment gives the system enough flexibility to operate safely until the seventh year. The investment cost for this solution is 0.36 .10^9 $.

In order to check the quality of the solution obtained using the developed probabilistic approach, the planning exercise was also done in a deterministic way considering that the uncertainties affecting the generation inflows are not addressed, that is, the generation pattern remains unchanged over the planning horizon. In this case, the solution requires the inclusion of the following equipments:

- Year 1 - one 138 kV line connecting buses 2 and 6 and another one connecting buses 7 to 8, one 138 kV cable in branch 6-10 and one transformer from bus 9 to 11;
- Year 2 - one 230 kV line connecting buses 11 to 13 and one transformer between buses 3 and 24;
- Year 4 - one 138 kV line connecting buses 5 to 10;
- Year 8 - one 138 kV line connecting bus 1 to 5;
- Year 9 - one 138 kV line connecting buses 3 and 9.

This solution ensures a safe operation, that is, a zero value for PNS, only if the generation pattern does not change over the planning horizon. Fig. 6 shows the behavior of the best solution in the swarm over the iterations for this deterministic approach. In this case the investment cost is $0,28.10^9$ $.

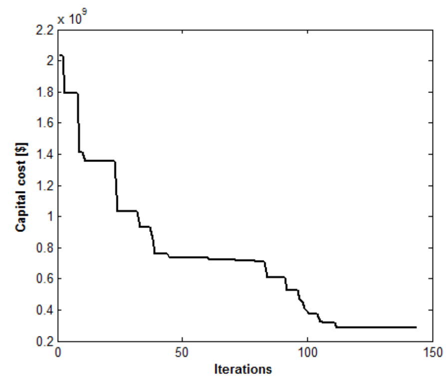

Figure 6. Evolution of the best particle – Deterministic approach.

In order to turn this comparison meaningful, the above deterministic solution was checked against the 20 scenarios considered before in order to calculate the expected PNS for each hydro inflow pattern. Fig. 7 shows the expected PNS for each of these scenarios considering the transmission expansion solution provided by the deterministic approach.

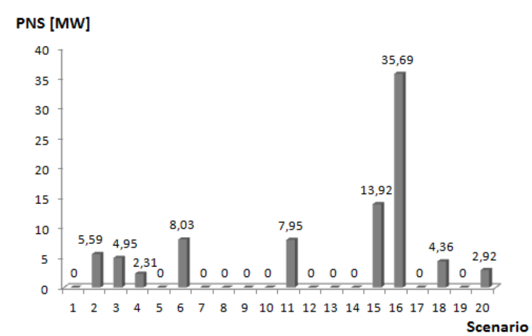

Figure 7. Expected PNS for the deterministic solution in each scenario.

Although the investment cost of the deterministic solution is lower than the obtained with the probabilistic approach, the annual deficit risk of the system is 45% against 5% of the probabilistic approach. This means if we consider the expected load shedding cost as used in (2), the average total cost for the deterministic solution considering the 20 hydro inflows is $4,56.10^9$ $.

Regarding the parallel computing technique used to implement the EPSO algorithm, we use eight cores of an Intel i7, 3.4GHz, 8 GB RAM. Fig. 8 shows the gain in seconds for each iteration when EPSO is implemented using parallel computing (EPSO-PC). As mentioned before, the probabilistic TEP using parallel computing runs 138 iterations in about 22 hours. Not using parallel computing requires a total of 74 hours, which means that the parallel implementation is able to reduce the computation time by about 70%.

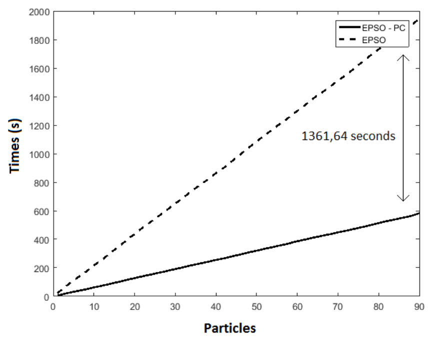

Figure 8. Gain time when using parallel computing to implement EPSO.

VI. Discussion and Conclusions

This paper describes a probabilistic multiyear transmission expansion planning that uses evolutionary particle swarm optimization to solve it via a parallel computing approach as a way to reduce the convergence time. The develop approach models hydro uncertainties using inflow scenarios and it incorporates a risk index determining that a transmission expansion solution is considered as feasible if, and only if, it ensures the safe operation in at least a percentage of these scenarios. For instance, if 20 scenarios are used, and the annual deficit risk index is set at 5% then the solution should ensure a safe operation, that is, zero PNS in 19 scenarios.

The main motivation to develop this probabilistic TEP approach comes from the need to deal with generation uncertainties affecting hydrothermal systems mainly from the climatic phenomena which can determine dry conditions in one region while there is increasing rainfall in another one. This type of systems usually requires a large amount of investments in transmission equipments in order to being able to accommodate different types of generation patterns.

The simulations performed using a system based on the IEEE 24 bus RTS network and the comparisons done in terms of the solution obtained by the probabilistic model and by a deterministic approach highlight the robust nature of the probabilistic based solution in terms of ensuring a safe operation in the lager majority of hydro scenarios although having larger investment costs. As a result, the authors are confident that TEP models based in these concepts can become a contribution to achieve large security of supply levels over the long run in power systems subjected to relevant uncertainties, namely affecting the generation patterns.

Acknowledgments

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Biographies

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