

A Probabilistic Approach to Manage Security Levels through the Unit Commitment

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Abstract—This work expands the traditional unit commitment (UC) problem to account for the effect of UC schedules on security issues. Specifically, this paper focuses on the identification of operational high-risk scenarios that can be mitigated by modifying UC schedules. Furthermore, it also addresses a strategy for risk mitigation that consists of imposing adequate constraints into a long-term UC problem formulation. The proposed work involves using the concept of risk-based long-term sequential simulation to develop methods of strengthening security monitoring and decision-making capability for overload, low voltage, voltage instability, and cascading overload problems. The achievement of a good balance between security level and costs is the ultimate objective of the complete procedure. A case study is presented to highlight the proposed methodology.

Keywords—Unit commitment, security risk assessment.

I. INTRODUCTION

THE unit commitment (UC) problem – scheduling generator start-ups and shut-downs over a period of time to minimize the cost of serving expected loads – has been applied by the power industry and studied by researchers for decades. UC solutions have traditionally been obtained for relatively short-term time frames (daily to weekly). This is because, in solving the UC problem of a realistic size system and for a long time period, one of the main causes of difficulty is the involvement of a large number of variables, causing significant computational challenges. The other reason to use short-term time frames is that the uncertainty of operating conditions, particularly load forecast, becomes great when UC is solved for a longer time period ahead.

On the other hand, secure operation is an enduring concern to electric utilities. The available techniques that deal with this issue can be generally grouped into two broad categories: deterministic and probabilistic approaches. Deterministic methods do not specifically recognize the probability of component failure, i.e. generating units, transmission lines, etc., in their formulation. But a probabilistic approach can be used to incorporate these phenomena in a consistent evaluation of the reliability of an electric power system. Usually, UC solutions do not account for risk as an overall index that reflects the security level of the system. Yet, UC schedules can have significant effect on security levels. Some methods that do incorporate security constraints directly into

the UC formulation have already been developed [1], [2]. These include formulations that integrate the security constrained optimal power flow or the risk constrained optimal power flow within the UC. However, these approaches model security as constraints that impose rigid limits rather than an objective to be achieved. In addition, for long-term scheduling, these approaches are not viable due to their very computationally intensive characteristic.

This paper provides a method for identifying adjustments in long-term UC solutions to reduce risk associated with overload, low voltage, voltage instability, and cascading overload problems. In section II we present some of the methods used to solve the UC and their characteristics. The risk-based assessment concepts are described in section III. Section IV addresses the reformulation of the UC problem discussed in section II, in order to incorporate the adjustments that result from the risk evaluation. To highlight the methodology, section V provides some simulation results obtained with the IEEE Reliability Test System'96. Finally, section VI summarizes the work.

II. UNIT COMMITMENT

For many years, the electric power industry has been using optimization methods to help solve the UC problem [3]. The time horizon for UC-related decisions is usually daily to weekly. However, we desire to develop a tool for investigating longer-term UC schedules with the objective being to identify operational high-risk scenarios that can be mitigated by modifying those schedules. This tool can be used to probe possible future scenarios and identify various strategies for risk mitigation that can be communicated to the operator when the scenarios are encountered. In pursuing this line of thought, the work reported herein is applied to one-year UC schedules, recognizing at the same time that the approach is also very well suited to the daily to weekly schedules that are common in the industry today.

Because of the UC problem's size and complexity and because of the large economic benefits that could result from its improved solution, considerable attention has been devoted to algorithm development. Many approaches have been proposed to solve the UC problem of hydro, thermal, and combined hydrothermal systems [4], [5]. The priority list [6] is the simplest UC solution method, but an important weakness of this approach is the enormous dimensionality that is easily reached due to the exhaustive enumeration of all

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possible unit combinations at each load level. Branch and bound method [7] and dynamic programming [8] enable the problem to be solved satisfactorily from the mathematical viewpoint, but they become impractical due to computational cost and memory size requirement when the system involves some tens of units [9]. Also, additional constraints may not be added into the dynamic programming framework without major software changes. Furthermore, due to the fact that each combination of units will retain only one predecessor path, necessary links back to early start options may be eliminated before it is obvious they are essential to the solution [10]. The Lagrangian relaxation method has gained the most research interest among other proposed approaches mainly because of its internal ability to provide fast, unit-wise decentralized solution and its flexibility to incorporate the majority of constraints [11], [12]. However, this algorithm can cycle resulting in unstable convergence at the end, meaning that some units are being switched in and out, and the algorithm never terminates. Furthermore, there is no guarantee that when the duality gap is small and satisfies the stopping criterion that the solution will be feasible. Also, the optimal solution may not be unique, as shown in [13]. In the security constrained optimal power flow (SC-OPF) [14], or the closely related risk-constrained optimal power flow (RC-OPF) [15], security-related constraints are explicitly represented within the optimization routine. Then again, these techniques are short-term oriented algorithms.

As mentioned before, we aim to develop an approach that will enable study of longer-term UC solutions as well as provide the engineer with the ability to probe possible future scenarios and identify various strategies for risk mitigation that can be communicated to the operator when the scenarios are encountered. UC solutions for longer time periods are more computationally intense, and as a consequence, a very efficient, but approximate, UC approach is used to determine a full year's solution [16]. Two important design requirements must be satisfied: it must be computationally tractable and it must be able to easily handle the incorporation of new constraints. The first requirement is related to the long-term characteristic itself and the inherent dimension of the problem. The second requirement reflects the objective of proposing some adjustments to the UC solution in order to mitigate the risk incurred by the system. To do that, new constraints will systematically be introduced into the UC problem formulation. The long-term UC problem is described below.

Notations:

- N : number of units;
- T : number of hours for one year;
- n_t : number of thermal units, at time t , that are not in maintenance;
- n_n : number of nuclear units, at time t , that are not in maintenance;
- n_h : number of hydro units, at time t , that are not in maintenance;
- P_{ii}^t : generation of thermal unit i at hour t ;

- P_{ni}^t : generation of nuclear unit i at hour t ;
- P_{hi}^t : generation of hydro unit i at hour t ;
- P_D^t : total load at hour t ;
- P_{loss}^t : power loss factor at hour t ;
- U_i^t : unit state of thermal unit i at hour t ;
- S_i^t : start-up cost unit i at hour t ;
- $F(.,.)$: operational cost for thermal unit i (it is a function of P_{ii}^t and U_i^t);
- E_1 : total available hydro energy for spring season;
- E_2 : total available hydro energy for summer season;
- E_3 : total available hydro energy for fall season;
- E_4 : total available hydro energy for winter season.

Objective Function:

The objective function of the long-term UC problem is the total fuel cost of thermal units, and it is expressed as follows:

$$\text{Min} \quad \sum_{i=1}^{n_t} \sum_{t=1}^T (F(P_{ii}^t, U_i^t) + S_i^t) \quad (1)$$

Loading Constraints:

$$\sum_{i=1}^{n_t} P_{ii}^t + \sum_{i=1}^{n_n} P_{ni}^t + \sum_{i=1}^{n_h} P_{hi}^t = P_D^t (1 + P_{loss}^t) \quad t = 1 \dots T \quad (2)$$

Hydro Energy Constraints:

$$\sum_{t=1}^{0.25T} \sum_{i=1}^{n_h} P_{hi}^t = E_1 \quad (3)$$

$$\sum_{t=0.25T+1}^{0.5T} \sum_{i=1}^{n_h} P_{hi}^t = E_2 \quad (4)$$

$$\sum_{t=0.5T+1}^{0.75T} \sum_{i=1}^{n_h} P_{hi}^t = E_3 \quad (5)$$

$$\sum_{t=0.75T+1}^T \sum_{i=1}^{n_h} P_{hi}^t = E_4 \quad (6)$$

Unit Limits:

$$U_i^t P_i^{\min} \leq P_i^t \leq U_i^t P_i^{\max} \quad t = 1 \dots T, i = 1 \dots N \quad (7)$$

Minimum Up and Down Time Constraints:

The minimum up and down time constraints are imposed upon only thermal units to prevent the thermal stress and high maintenance costs due to excessive unit cycling.

The UC solution method adopted is a heuristic approach based on Lagrangian relaxation techniques and also on priority list schemes [17]. The nuclear units are dispatched at full capacity, when they are not in maintenance. This assumption is reasonable since typically, nuclear units present the minimum average production cost among all the thermal units. The hydro units are dispatched to meet the seasonal hydro energy constraints (eqs. 3-6), and the cost for using

hydropower is assumed to be zero. Finally, the thermal units are scheduled according to their incremental heat (cost) rate curves by solving an economic dispatch sub-problem using the lambda-iteration method. The solution obtained with this procedure is suboptimal, however, it is a good one for the purposes of long-term UC.

III. RISK ASSESSMENT

Risk-based security assessment computes a quantitative risk index to reflect the system's exposure to failure [18], [19]. The system risk associated with a forecasted loading condition $X_{t,f}$ is given as a function of the various contingencies E_i , according to:

$$Risk(Sev | X_{t,f}) = \sum_i \sum_j \Pr(E_i) \Pr(X_{t,j} | X_{t,f}) Sev(E_i, X_{t,j}) \quad (8)$$

where $\Pr(E_i)$ is the outage probability of contingency E_i , $X_{t,j}$ is the j^{th} possible loading condition, $\Pr(X_{t,j} | X_{t,f})$ provides the probability of this condition and is obtained from a probability distribution for the possible loading conditions, and finally $Sev(E_i, X_{t,j})$ is the system severity of contingency E_i under the j^{th} possible operating condition X_t .

Transmission line or transformer overload, bus low voltage, voltage instability, and cascading overload are possible impacts that can result from a given contingency E_i and operating condition X_t , each resulting in a different kind of risk, called the overload risk, low voltage risk, voltage instability risk, and cascading overload risk, respectively. The system composite risk can be calculated as the sum of these four kinds of risk, as follows:

$$\begin{aligned} CompositeRisk(Sev | E_i, X_t) = & OverloadRisk(Sev | E_i, X_t) + \\ & LowVoltRisk(Sev | E_i, X_t) + \\ & VoltInstRisk(Sev | E_i, X_t) + \\ & CascadingRisk(Sev | E_i, X_t) \end{aligned} \quad (9)$$

This means that different types of risk associated with different types of security problems can be added up together and used as a comprehensive indicator for system security.

A. Severity Functions

The most difficult part of the modeling is to define the severity functions [20]. In order to do this, we have established the following criteria:

- they should accurately reflect severity between the various events that can occur, to enable the calculation of a composite index;
- they should be physically meaningful;
- they should be simple, easy to understand and use, and should not require large data collection effort and computation;
- they should increase continuously as the performance index (e.g., flow, voltage, loading margin, cascaded lines) gets worse.

More details about these functions can be found in [21].

B. Modeling of Uncertainties

From equation (8) we can see that there are two kinds of

uncertainties that are considered: one is related to the operating conditions ($\Pr(X_{t,j} | X_{t,f})$) and the other is associated to the contingencies ($\Pr(E_i)$). The events E_i are assumed to be Poisson distributed. The probability distribution of $X_{t,j}$ (the probability of the j^{th} possible loading condition at a future time t) given $X_{t,f}$ (the forecasted operating condition of the future time t) is assumed to follow a normal distribution having a mean equal to the forecast [21], [22].

IV. UNIT COMMITMENT ADJUSTMENTS

The problem we are dealing with is to find a UC solution that not only results in the minimal operation cost (equation 1), but also in the minimal cumulative risk. Mathematically, this means that we have a second objective function:

$$\text{Min} \quad \sum_{t=1}^T \left[\sum_{i=1}^C \Pr(E_i) \left(\sum_{j=1}^L \Pr(X_{t,j} | X_{t,f}) \times Sev(E_i, X_{t,j}) \right) \right] \quad (10)$$

where L is the number of possible loading conditions, C is the number of contingencies considered, and other notation is as described before.

Also a new constraint is now incorporated in the problem formulated in section II. For $t = 1 \dots T$, we want the composite risk to be below a specified threshold:

$$\sum_{i=1}^C \Pr(E_i) \left(\sum_{j=1}^L \Pr(X_{t,j} | X_{t,f}) \times Sev(E_i, X_{t,j}) \right) \leq \text{threshold} \quad (11)$$

As a result, our optimization problem has two objectives expressed by equations 1 and 10 and is subject to the constraints described in equations 2-7, 11, and the minimum up and down times.

One possible way to solve this very complex multi-objective optimization problem is to put the two objective functions together with corresponding weights. However, there is no single optimal solution, as it depends on the amount of risk that the decision-maker is willing to take, in relation to the amount of money the decision-maker is able to save or to make. Therefore, our approach does not aim to identify the optimal solution, but rather to illuminate the differences between the risk levels and operating costs of various alternatives. To do this, one UC change is performed at a time, followed by the evaluation of the corresponding modifications. So, our method is to decouple the optimization problem into the following three subproblems:

1. Unit commitment: The UC is first solved using the approach presented in section II.
2. Risk assessment: The risk is evaluated for each hour of the year, using the procedure described in section III.
3. Unit commitment adjustments: For each hour that has risk higher than the *threshold*, the UC adjustments module solves the following optimization problem (for example, let hour h be one of such hours):

Objective functions:

$$\text{Max}_{T_{ij}} \quad \text{cumuRiskDecrease}(T_{ij}) \quad (12)$$

$$\text{Min}_{T_{ij}} \quad \text{cumuCostIncrease}(T_{ij}) \quad (13)$$

Subject to:

$$Risk(h) < Threshold \quad (14)$$

where T_{ij} represents the transition in the thermal unit i during the time interval j if j is composed by more than one time interval then T_{ij} denotes a transition set.

To solve this multi-objective optimization problem, we combine the two objectives (eqs. 12, 13) by defining the following single objective:

$$Max_{T_{ij}} \frac{cumuRiskDecrease(T_{ij})}{cumuCostIncrease(T_{ij})} \quad (15)$$

A. Assumptions

Our solution algorithm to solve the UC adjustments problem is based on the following assumptions:

- The unconstrained UC solution we begin with is an economically optimal one, and therefore any constraint imposed can only result in cost increase.
- A risk decrease may occur only as a result of constraining a unit to be “on” that is “off” in the original solution.
- The risk at any time interval is most effectively decreased by constraints that directly cause one or more UC reversals during at least a part of that time interval. One implication of this assumption is that, in identifying UC changes to reduce risk in a particular time interval, the constraints introduced will certainly include part or the entire high-risk time period, together with other possible time intervals. Although previous changes could affect subsequent UC changes during the time interval of interest, it is highly unlikely that such UC changes by itself would be the most effective ones in reducing the risk during this interval. However, we do consider UC changes in previous time periods, as long as these time periods are combined with the one that includes the interval of interest.
- We assume that the transition, or transition set, T_{ij} that maximizes the risk-cost ratio for unit i is found when $ratio(j+1) < ratio(j)$, where $j+1$ comprises all the time intervals included in j plus the previous time interval where unit i was “off”.

B. Algorithm

Assuming that we have the solution for the basic UC (problem presented in section II) and the risk values for all hours, the following procedure is used to identify risk-based updates in the UC solution:

1. Identify the hours where the risk exceeds the 1.5 value.
2. Check the sensitivities of the high-risk situation with respect to the bus voltage and the real power injected for all the buses connected to generators, and with respect to the reactive power injection for all buses. This is done to account for the possibility that the high-risk problem can be fixed by another less expensive means, such as generator terminal voltage control or re-dispatch. But if any of the sensitivities computed is high for a decommitted unit, then this suggests that a UC modification should be made.

3. Identify the UC transitions that occurred before the high-risk hour.
4. Eliminate the nonreversible transitions. Under the assumptions used in this study, the nonreversible transitions are all the start up transitions and all the transitions that occur in nuclear and hydro units.
5. Select the candidate transitions. These are the shut down transitions occurring in thermal units previous to the high-risk hour for units having full-load average production cost (FLAPC) within $x\%$ of the FLAPC for the next least costly unit. Here, x is chosen to be 20%.
6. Reverse the candidate transitions, one at a time.
7. Evaluate the risk decrease for the high-risk hour.
8. Compute the changes in risk and the changes in cost.
9. Identify the effective transition. This will be the one with a corresponding maximum value of the cumulative risk-cost ratio (equation 15).

V. SIMULATION RESULTS

In order to highlight the methodology described, this section presents the results of a case study. The network used is the IEEE Reliability Test System’96 [23], shown in Fig. 1. It has 24 buses, 38 lines, 24 thermal units, 2 nuclear units, and 6 hydro units.

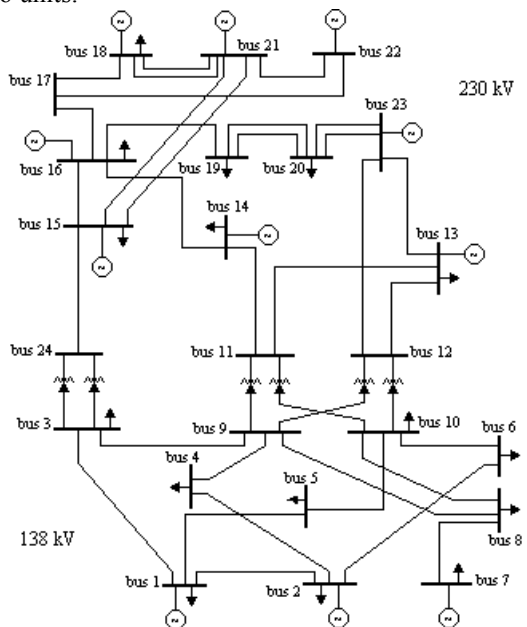


Fig. 1. The IEEE RTS’96

The expected load profile of the next year is shown in Fig. 2, and was obtained from the data provided in [23].

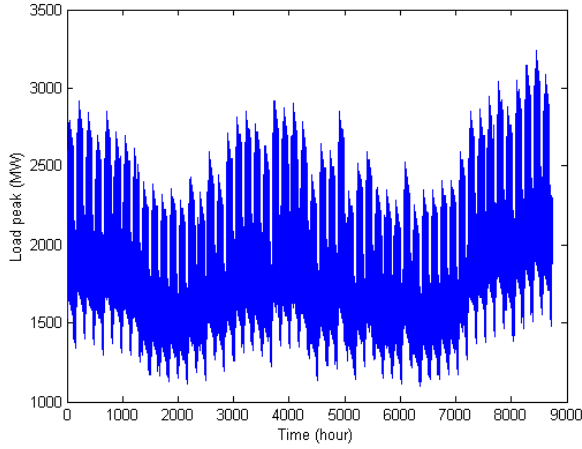


Fig. 2. Expected system load curve over one year

After solving the basic UC we performed the annual risk assessment. The composite risk (overload risk + low voltage risk + voltage instability risk + cascading risk) that the system incurs in each hour, taking into account all the contingencies considered and their probabilities, is depicted in Fig. 3. Here, the contingency list used includes all N-1 contingencies of circuits and units (except the outage of line between buses 7 and 8, as it will cause the islanding of bus 7), and some N-2 contingencies, consisting of parallel lines.

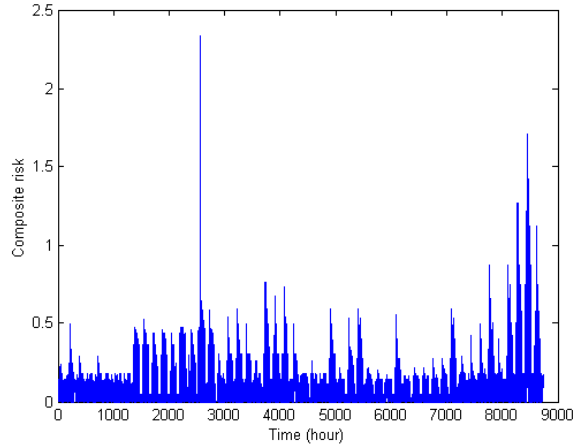


Fig. 3. Composite risk, over all contingencies, for the basic UC

The peak risk occurs at hour 2555 and assumes the value 2.34. The cumulative composite risk (summed over the whole year) is 893.80. The thermal units that experience UC transitions before this hour are listed in Table 1, along with their corresponding FLAPC values.

Table 1 – Thermal generators with UC transitions before hour 2555

| Bus | Unit Size (MW) | Number of Units | FLAPC (\$/MWh) |
|-----|----------------|-----------------|----------------|
| 13 | 197 | 3 | 28.860 |
| 7 | 100 | 3 | 29.631 |
| 15 | 12 | 5 | 39.657 |
| 1 | 20 | 2 | 43.281 |
| 2 | 20 | 2 | 43.281 |

According to step 5 of the algorithm presented in section IV, the candidate transitions are all the shut down transitions occurring in units with capacity 100 MW and 197 MW that happen before hour 2555. Table 2 presents the UC transitions that occur in these machines, from hour 2470 to hour 2570, where “1” indicates that the generators are “on” and “0” indicates that they are “off”.

Table 2 – Unit commitment transitions

| Unit Size (MW) | Time Range (hour) | | | | |
|----------------|-------------------|-----------|-----------|-----------|-----------|
| | 2470-2527 | 2528-2542 | 2543-2551 | 2552-2567 | 2568-2570 |
| 100 | 1 | 0 | 1 | 0 | 1 |
| 197 | 1 | 0 | 1 | 0 | 1 |

Let us concentrate now on the thermal units with capacity 197 MW. They are turned “off” between hour 2552 and hour 2567, which includes the high risk situation. Thus, UC transition should be reversed, according to step 6 of the algorithm presented in section IV. After performing this change, i.e., after imposing these units to be “on” during this time interval and rerunning the UC program, the composite risk curve obtained is the one presented in Fig. 4.

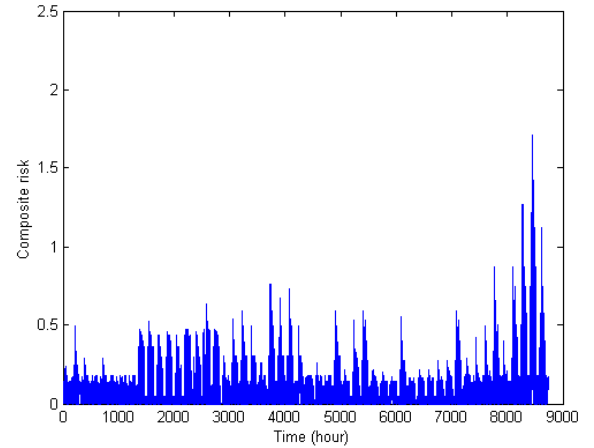


Fig. 4. Composite risk, over all contingencies, for the adjusted UC

At hour 2555, the composite risk is now 0.29, against the initial value of 2.34. Since 0.29 is less than 1.5, this constraint satisfies the acceptable level defined in step 1. The cumulative composite risk decreases from 893.80 to 884.13. On the other hand, the total production cost increases \$1,228.4. So, for this solution the cumulative risk-cost ratio is as follows:

$$\frac{\text{Cumulative Risk Decrease}}{\text{Cumulative Cost Increase}} = \frac{893.80 - 884.13}{1,228.4} = 0.0079 \quad (16)$$

The simulation proceeds evaluating the next candidate transitions. Table 3 summarizes the results obtained while performing the first iteration of the UC adjustments and highlights the selected solution.

Table 3 – Results obtained for the first iteration

| | Changes in the 197 MW Units | | Changes in the 100 MW units | | |
|--|--------------------------------|------------------------|--------------------------------|------------------------|------------------------|
| | 2552-2567 | 2552-2567 2528-2542 | 2552-2567 | 2552-2567 2528-2542 | 2552-2567 2466-2469 |
| Time Period Constrained “On” | | | | | |
| Decrease in Risk for the High-Risk Hour | 2.05 | 2.05 | 1.39 | 1.39 | 1.39 |
| Decrease in Cumulative Risk | 9.67 | 10.02 | 1.19 | 3.12 | 3.45 |
| Increase in Cost | 1,228.4 | 2,381.5 | 1,209.3 | 2,342.9 | 2,645.3 |
| Cumulative Risk-Cost Ratio | 0.0079 | 0.0042 | 0.0009 | 0.00133 | 0.00130 |

According to step 9 of the algorithm, the best UC adjustment in this first iteration consists in constraining the thermal units with capacity 197 MW to be “on” between hour 2552 and hour 2567.

VI. CONCLUSIONS

This paper presents a method for identifying adjustments in long-term UC solutions to reduce the risk associated with overload, low voltage, voltage instability, and cascading problems. A heuristic approach is adopted to solve the referred problem. Besides overcoming the limitations of other methods related to the considered time frame, one very important advantage of this procedure lies in its ability to handle new constraints. This is a crucial issue, because the main idea of this work is the incorporation of new constraints into the UC, as a result of the evaluation of the composite risk incurred by the system. These adjustments will most likely result in an increase of the generation cost. However, they will also translate an improvement on the annual risk. The validity of the solution methodology proposed has been verified through the simulation results presented in the previous section.

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VIII. BIOGRAPHIES

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