Short-term Operating Strategy with Consideration of Load Forecast and Generating Unit Uncertainty

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Keywords: operating strategy, uncertainty, unit commitment, spinning reserve, mixed integer linear programming, decision analysis, deterministic method

One of the common problems faced by many electric utilities concerns with the uncertainty from both load forecast error and generating unit unavailability. This uncertainty might lead to uneconomic operation if it is not managed properly in the planning stage. This paper explicitly demonstrates how to include the uncertainties to obtain the best operating strategy for any power systems. The uncertainty of the load forecast is handled using decision analysis method, meanwhile the uncertainty of the generating unit is approached by inclusion of risk cost to the total cost. In addition, three spinning reserve strategies based on deterministic criteria are incorporated in the development of scenario. Meanwhile, Mixed Integer Linear Programming method is utilized to generate unit commitment decision in each created scenario. The best strategy which gives the minimum total cost is selected among the developed scenarios. The flowchart of the proposed method is shown in Fig. 1.

The proposed method has been implemented to solve a modified IEEE 24-bus system comprising 26 generating units. Three spinning reserve strategies based on deterministic criteria are set for each hour at 8%, 10%, and 12% of the load demand, representing low, medium and high spinning reserve strategy respectively. Meanwhile, the demand uncertainty is modeled by low, medium, and high load level with its associated probability. The load forecast uncertainty is represented by the standard deviation (SD), i.e. x% of the expected values. Sensitivity analysis with respect to the number of unit, expected unserved energy (EUE) price, standard deviation of load forecast, and probability of load level is reported.

In the sensitivity analysis of number of unit, the IEEE test system is duplicated to be 26-unit, 78-unit and 130-unit system representing small, medium, and large-scale system. The load forecast error represented by SD is assumed to be 1% of the forecast value in the first hour and linearly increased to 4% in the last hour. The EUE is priced at 2000 $/MWh. The results shows that the generation cost for each scenario is a little bit different whereas the risk cost is rather different from each other.

The impact of the load forecast error is analyzed through the variation of standard deviation (SD) values. In this analysis, it is supposed that the SD is assumed to be 1% of the forecasted value in the first hour, and is treated as either a constant value for the whole lead time of 24 hours or linearly increased to 2–4% in the last hour. The results show that with higher forecast error, i.e. higher SD, the total cost obtained from the best strategy tends to decrease. However, as the system becomes larger, lower reserve strategy tends to be more appropriated, since the risk cost contribution to the total cost is relatively small.

EUE price is varied to verify its impact on the operating strategy. It can be noticed that if the risk cost is neglected from our consideration, i.e. EUE price is set at zero, the lower spinning reserve strategy will be preferred. However, if the higher EUE price is employed, the higher spinning reserve strategy will be more appropriate in the UC decision.

In other sensitivity analysis, the probability of the future demand is varied meanwhile other parameters such as standard deviation in the first and last hour is fixed at 1% and 4% respectively, and EUE price is defined as 2000 $/MWh. It can be found from the results that the accuracy of the load forecast has the impact on the expected total cost. The better load forecast accuracy will result in the lower expected total cost.

The sensitivity analysis has been conducted, which shows that the degree of sensitivity to the evaluated parameter is different among the investigated system sizes, hence the determination of the best strategy should be suited correspondingly. The results prove that the proposed method has a capability to solve a realistic short-term planning problem taking into account system uncertainties. Utilities may simulate in the same way as presented in this paper to define the best spinning reserve strategy for their systems, according to their specified conditions, e.g. system size, load forecast error in the past, EUE price.
Short-term Operating Strategy with Consideration of Load Forecast and Generating Unit Uncertainty

Sarjinya∗, Bundhit Eua-arporn†, Akihiko Yokoyama∗∗

One of the common problems faced by many electric utilities concerns with the uncertainty from both load forecast error and generating unit unavailability. This uncertainty might lead to uneconomic operation if it is not managed properly in the planning stage. Utilities may have many operational tools, e.g. unit commitment, economic dispatch. However, they require a proper operating strategy, taking into account uncertainties. This paper explicitly demonstrates how to include the uncertainties to obtain the best operating strategy for any power systems. The uncertainty of the load forecast is handled using decision analysis method, meanwhile the uncertainty of the generating unit is approached by inclusion of risk cost to the total cost. In addition, three spinning reserve strategies based on deterministic criteria are incorporated in the development of scenario. Meanwhile, Mixed Integer Linear Programming method is utilized to generate unit commitment decision in each created scenario. The best strategy which gives the minimum total cost is selected among the developed scenarios. The proposed method has been tested using a modified of IEEE 24-bus system. Sensitivity analysis with respect to the number of unit, expected unserved energy price, standard deviation of load forecast, and probability of load level is reported.

Keywords: operating strategy, uncertainty, unit commitment, spinning reserve, mixed integer linear programming, decision analysis, deterministic method

1. Introduction

One of the objectives in the short-term operation of vertically integrated utilities is how to schedule generation to meet all of the forecasted demand over the considered time horizon with minimum operating cost. The system operator has responsibility to seek the best operating strategy which satisfies the prevailing constraints, e.g. power and spinning reserve balance, minimum and maximum generation unit constraints, transmission limit, ramp-rate constraint, fuel constraint, and minimum up and down time limits. The problem becomes much more complicated since, in the actual planning problem, the operator also faces the system uncertainty caused by demand forecast error and generating unit unavailability.

Several approaches have been used to solve the unit commitment (UC) optimization problem, e.g. priority ordering (5), dynamic programming (9), Lagrange Relaxation (LR) (4)(5), mixed-integer linear programming (MILP) (6)(7), evolutionary programming (10), combination of LR and evolutionary programming (11) and simulated annealing (12). Detailed survey on unit commitment problems can be found in Ref. (12). Among the developed unit commitment methods, one of the most popular methods is based on LR technique, which has many advantages on others, e.g. the ability to solve large scale UC problem, ease of incorporating various constraints, and fast computation time (13). However, LR method has main disadvantage due to the nonconvexity of the UC problem hence it needs heuristic procedure to find the feasible solution which may be supoptimal. Meanwhile, the MILP has ability to guarantee the optimal convergence solution of the problem. The most successful method to solve MILP problem are branch-and-bound and cutting plane algorithm (14). In the early development, a key drawback of the MILP algorithm was its high computation time and memory requirement. In recent years, efficient MILP softwares having ability to cope with large-scale UC problems have been developed and commercialized (15).

In generation scheduling, spinning reserve strategy has the considerable impact on the operating cost. The reserve capacity is generally scheduled to account for load forecast uncertainty and possible outage of generating units. The spinning reserve requirement set in most UC solving methodology is based on deterministic criteria e.g. a fraction of demand, largest generator/line contingency, or maximum online generator during a dispatch period. A probabilistic reserve criterion, even though is more complicated, can be applied to obtain a proper schedule of the spinning reserve capacity to meet acceptable risk, e.g. Expected Unserved Energy-EUE, unit commitment risk, etc. The level of risk index is usually specified by system operator based on social and economic requirement (16).

Another key factor having the significant impact on the UC decision is the load uncertainty. This uncertainty is embedded in the load forecast error due to two basic reasons i.e. inherent error in weather forecast, and inability to exactly predict load from the available information (17). Impact of the
weather temperature forecast uncertainty on the load forecast results has been investigated using Bayesian Load Forecasting method (17). A simple way to represent the load uncertainty is using load forecast distribution and variance.

Many approaches in the previous works dealt with the techniques to solve the impact of load uncertainty on the UC problem based on scenario analysis (18-20). In the scenario analysis method, the uncertainty about the future demand is modeled by a number of deterministic subproblems (20). In the other related paper, this method is also called decision tree analysis (21), which concludes that load uncertainty imposes additional risk on short-term planning, thereby increases Expected Cost of Uncertainty (ECOU). However all the mentioned papers did not take into account the cost of uncertainty resulting from generating unit unavailability.

This paper proposes a scenario based on decision analysis method to solve and obtain the best UC strategy which gives minimum total cost taking into account uncertainty from load forecast error and generating unit availability. Three spinning reserve strategies based on the familiar deterministic criteria, i.e. high, medium and low, are investigated to evaluate the reserve strategies based on the familiar deterministic criteria, forecast error and generating unit availability. Three spinning minimum total cost taking into account uncertainty from load forecast error and obtaining unit unavailability. A more detailed model (21) may be used if utilities may be forced out during operation. In this paper a two-state Markov model as shown in Fig. 1 is used to estimate its unavailability. A more detailed model (21) may be used if utilities have collected unit’s data accordingly.

In daily operational planning the considered lead time, L, is generally much smaller than the repair time of a unit. Thus the possibility of more than one repair during L can be neglected. For a single unit with exponential distribution, the probability of being in the fail state at the end of L is given by

\[ P_{\text{fail}} = \exp\left(-\frac{L}{\lambda}\right) \]

where \(\lambda\) is the failure rate.

In addition, there are generating unit constraints as described below.

- **Generation limit constraint**
  \[ P_{\text{min},i} \leq P_i^l \leq P_{\text{max},i}, \quad \forall i \in [1, N] \]  

- **Minimum up and down time constraint**
  \[ U_i = \begin{cases} 1, & \text{if } T_{\text{on}} < T_{\text{up}} \text{,} \\ 0, & \text{if } T_{\text{off}} < T_{\text{down}} \text{,} \\ 1 \text{ or } 0, & \text{otherwise} \end{cases} \]  

- **Start-up cost constraint**
  \[ ST_i = \begin{cases} \text{HST}, & \text{if } T_{\text{idown}} \leq T_{\text{cold}} + T_{\text{down}} \text{,} \\ \text{CST}, & \text{if } T_{\text{idown}} > T_{\text{cold}} + T_{\text{down}} \text{,} \end{cases} \]

### 2.2 Load Forecast Uncertainty

Load uncertainty, in general, results from forecast error. Consequently it is embedded in power system planning problems. In the short-term operation, if the actual demand is lower than the forecasted value, some unit may be unnecessary committed thereby resulting in higher operating cost than necessary. In contrast, if the actual demand is higher than the forecasted value, insufficient resources may be scheduled to meet reliability requirement.

Load uncertainty can be determined, based on historical forecasting performance, by a probability distribution function. In this paper a discrete normal distribution comprising three load levels, i.e. low, medium and high, will be used to represent the load uncertainty. Let’s assume that mean of the forecasted value is \(\hat{L}(t)\) and standard deviation is \(\sigma(t)\). In general, the longer lead time will be implicitly embedded with higher uncertainty in the forecasted value (17). Suppose that the predefined standard deviations in the first and last hours of the study horizon are denoted by \(\sigma(1)\) and \(\sigma(T)\) respectively. With the assumption that the standard deviation increases linearly with the considered lead time, the standard deviation in each considered hour, i.e. the first to the last, can be approximated by

\[ \sigma(t) = \sigma(1) + \frac{\sigma(T) - \sigma(1)}{T - 1}(t - 1), \quad \forall t \in [1, T] \]  

Based on Eq. (8), the low, medium, and high load levels can be generated as described in Eq. (9).
by Ref. (16)

$$P[\text{unit down at } L] \approx P[t_{\text{up}} \leq L] = 1 - e^{-\lambda L} \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdots \cdOTS
expected generation cost of scenario \( k \), called \( EGC_k \), by taking into account load uncertainty, which denoted by \( EGC_k \), is given by

\[
EGC_k = \sum_{j=1}^{9} PL_j GC_{jk} \quad \forall k \in [1,9] \] \hspace{2cm} (13)

where \( PL_j \) is the occurrence probability of load level \( j \). The flowchart of expected generation cost calculation is shown on the left side of Fig. 3.

### 3.2 Expected Risk Cost Calculation

Once a UC decision is obtained from the UC-MILP module, this information can be used to calculate the risk cost. The risk cost function is defined by the worth of damage cost on customer side due to electricity shortage. It can be obtained by multiplying the expected unserved energy and the predefined EUE price. The initial step for each time interval is setting up the capacity outage probability table (COPT)\(^{[10]}\) based on the ORR of the committed units. Suppose that the number of states in the developed COPT is NS. Each state represents an expected generation outage, the remained in-service capacity \( CR_s \) and the probability \( PR_s \) corresponding to the state. The EUE for each hour \( t \) can be calculated by

\[
EUE_t = \sum_{j=1}^{3} EUE_{tj} PL_j \quad \forall t \in [1,T] \] \hspace{2cm} (16)

Therefore the total EUE for the scheduling time horizon of scenario \( k \) is given by

\[
EUE_k = \sum_{t=1}^{T} EUE_t \quad \forall k \in [1,9] \] \hspace{2cm} (17)

Finally, based on the obtained total EUE and the predefined EUE price (\$/MWh), the expected risk cost of scenario \( k \), denoted by \( ERC_k \), can be calculated by

\[
ERC_k = EUE_k \times EUE_{price} \quad \forall k \in [1,9] \] \hspace{2cm} (18)

The expected risk cost calculation is presented on the right side of flowchart in Fig. 3.

Since the calculation of COPT which involves a large number of units generally requires long computation time, a modified generating unit using efficient round-off model as proposed in Ref. (24) is implemented in this work. The further reduction of computation time requirement can be achieved by omitting the outage levels for which the cumulative probability is less than a predefined limit, e.g., \( 10^{-7} \).

### 3.3 Expected Total Cost Calculation

As explained in the previous section, we can obtain the expected total cost, of scenario \( k \), called \( ETC_k \), as shown in Eq. (19).

\[
ETC_k = EGC_k + ERC_k \quad \forall k \in [1,9] \] \hspace{2cm} (19)

To obtain the best expected total cost among developed scenarios, the above procedure is repeated for other scenarios. The best scenario taking into account uncertainty on both generation and demand side can be determined by selecting the scenario which provides minimum total cost as defined in Eq. (20).

\[
\text{The best cost} = \min \{ETC_1, \ldots, ETC_9\} \] \hspace{2cm} (20)

---

*Fig. 3. Flowchart of the proposed method*
4. Numerical Results

The proposed method has been implemented to solve a modified IEEE 24-bus system comprising 26 generating units as shown in Fig. 4. The reliability data used in the paper is based on the modified actual information from a utility in Thailand. The details of generating unit’s data are shown in Appendix. A base case demand of 24 hour period is shown in Table 2. Three spinning reserve strategies based on deterministic criteria are set for each hour at 8%, 10%, and 12% of the load demand, representing low, medium and high spinning reserve strategy respectively. The quadratic fuel cost function has been linearized to two segments approximation. A fixed start-up cost, i.e. cold and hot start-up, is applied in our analysis. Meanwhile, the demand uncertainty is modeled by low, medium, and high load level with its associated probability. The load forecast uncertainty is represented by the standard deviation (SD), i.e. x% of the expected values.

The UC-MILP and economic dispatch model has been developed using TOMLAB/CPLEX v10.0 and implemented on Intel Pentium M 1.4 GHz processor and 2 GB of memory RAM. The optimality of the solution in the TOMLAB/CPLEX is reflected by MIPGAP parameter which represents the absolute relative distance between the best integer solution and the best LP solution. In this paper, the execution of CPLEX was terminated if the MIPGAP of the objective function is within 0.5% of the optimal solution.

Several test cases have been conducted on the base system, with varied system size, standard deviation, EUE price, and probability of each possible load, to verify the impact from each parameter on the investigating strategy.

4.1 Impact of Number of Units

In this section, the IEEE test system is duplicated to be 26-unit, 78-unit and 130-unit system representing small, medium, and large-scale system. The load forecast error represented by SD is assumed to be 1% of the forecast value in the first hour and linearly increased to 4% in the last hour. The EUE is priced at 2000 $/MWh, which is close to the result of study based on the actual data as reported in Ref. (25). The simulation results are presented in Fig. 5.

It can be seen from Fig. 5 that the generation cost for each scenario is a little bit different whereas the risk cost is rather
different from each other. It clearly shows that the risk cost plays an important role especially in case of small systems. The details of the EUE result which implies risk cost of each scenario is depicted in Fig. 6.

For the system with low spinning reserve strategy, the risk costs are 37.4%, 28.1%, and 15.4% of the total cost for the cases of scenario# 1st–3rd, respectively. Since different load levels require different number of units to be committed, therefore it creates different risk or EUE even though the same percentage of the spinning reserve strategy is applied. At higher spinning reserve strategy, the percentage of the risk cost compared to the total cost tends to decrease. For example, scenario# 7th to 9th, the contribution of risk cost to the total cost decreases to 26%, 16% and 8% respectively. However as higher SR strategy is employed the generation cost tends to increase since more units will be committed. Therefore the balance between the decrease of risk cost and the increase of generation cost will determine the best strategy to be used. It is found from the results shown in Fig. 6 that the best strategy for the small 26-unit system is the 9th scenario, i.e. scheduling high spinning reserve to meet the expected high load.

In cases of 78-unit and 130-unit system, scenario# 6th and 7th provide the best strategies respectively. It shows that the best strategy tends to require lower percentage of spinning reserve as the system becomes larger.

4.2 Impact of Load Forecast Error

As mentioned in section 2.2, the impact of the load forecast error is analyzed through the variation of standard deviation (SD) values. In this analysis, it is supposed that the SD is assumed to be 1% of the forecasted value in the first hour, and is treated as either a constant value for the whole lead time of 24 hours or linearly increased to 2–4% in the last hour. The simulation results are shown in Fig. 7.

It can be seen from Fig. 7(a) that for a small 26-unit system scenario# 9th, i.e. high spinning reserve strategy, is always the most appropriated strategy. It can be clearly understood that since the high SR will diminish the EUE which contributes fairly high percentage of the total cost for a small system, the high SR as of scenario # 9th therefore provides the best strategy. With higher forecast error, i.e. higher SD, the total cost obtained from the best strategy tends to decrease. However, as the system becomes larger, lower reserve strategy tends to be more appropriated, since the risk cost contribution to the total cost is relatively small. It can be seen in Fig. 7(b) that the 78-unit system should applies either medium or high spinning reserve strategy, i.e. scenarios# 6th and 8th, whereas in

the case of 130-unit system, Fig. 7(c), the low and medium spinning reserve strategies, i.e. scenarios# 3rd and 4th, should be applied.

4.3 Impact of EUE Price  

EUE price is varied to verify its impact on the operating strategy. The results are shown in Fig. 8. Unsurprisingly, higher EUE price causes the higher total cost. As is seen from Fig. 8(a), the selected scenario is sensitive to the change of EUE price at a relatively low price up to 130 $/MWh. After that value, the best scenario is always found at scenario# 9th, which requires high spinning reserve to keep the risk cost at a reasonable level.

For the larger 78-unit system, the best strategy tends to require higher spinning reserve for higher EUE prices. For the large system of 130 units, the results of the EUE are very small as shown in Fig. 6, even for low and medium spinning reserve strategies.

It can be noticed that if the risk cost is neglected from our consideration, i.e. EUE price is set at zero, the lower spinning reserve strategy will be preferred. However, if the higher EUE price is employed, the higher spinning reserve strategy will be more appropriate in the UC decision.

4.4 Impact of Load Uncertainty

In this sensitivity analysis, the probability of the future demand is varied meanwhile other parameters such as standard deviation in the first and last hour is fixed at 1% and 4% respectively, and EUE
price is defined as 2000 $/MWh. Since the medium load level is the forecasted load value, the probability of the medium load occurrence will be varied to reflect the accuracy of the forecasted load. In this test the probability of the medium load occurrence will be varied from 0.33–0.98, whereas the probability of the other two load levels will be adjusted accordingly. The sets of the probability for the occurrence of low, medium, and high load levels to be analysed in this section are (0.01, 0.98, 0.01), (0.05, 0.90, 0.05), (0.10, 0.80, 0.10), (0.20, 0.60, 0.20), (0.30, 0.40, 0.30), and (0.33, 0.33, 0.33). The simulation results are depicted in Fig. 9. It can be obviously seen that the rise of the probability of the medium load level, better accuracy of the forecasted values, leads to the decrease of the expected total cost. In these cases, the reduction of the total costs of the best accurate forecasted load, with the probability of 0.98, compared to the least accurate forecasted load, probability of 0.33, for the 26-unit, 78-unit, and 130-unit systems are 1.90%, 0.40%, and 0.29% respectively. It was found that risk cost play an important role on the total cost difference especially in the smaller systems.

It can be found from the results that the accuracy of the load forecast has the impact on the expected total cost. The better load forecast accuracy will result in the lower expected total cost.

5. Conclusion

An approach to incorporate the load forecast uncertainty and generating unit unavailability in the determination of the best short-term operating strategy has been presented in this paper. The best strategy is selected among the developed scenarios which are created based on decision analysis method. The effectiveness of the proposed method has been tested using a modified of IEEE 24-bus system and its replication. The sensitivity analysis has been conducted, which shows that the degree of sensitivity to the evaluated parameter is different among the investigated system sizes, hence the determination of the best strategy should be suited correspondingly. The results prove that the proposed method has a capability to solve a realistic short-term planning problem taking into account system uncertainties. Utilities may simulate in the same way as presented in this paper to define the best spinning reserve strategy for their systems, according to their specified conditions, e.g. system size, load forecast error in the past, EUE price.

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Appendix

Table 1. Generating unit data for IEEE 24-bus system

<table>
<thead>
<tr>
<th>Unit</th>
<th>$P_{max}$ (MW)</th>
<th>$P_{min}$ (MW)</th>
<th>$c_1$ ($k$/MW$^2$)</th>
<th>$b_1$ ($k$/MW)</th>
<th>$a_1$ ($k$)</th>
<th>Bus No.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2.4</td>
<td>12.0</td>
<td>0.0253</td>
<td>25.5472</td>
<td>24.3891</td>
<td>15</td>
</tr>
<tr>
<td>2</td>
<td>2.4</td>
<td>12.0</td>
<td>0.0265</td>
<td>25.6753</td>
<td>24.4110</td>
<td>15</td>
</tr>
<tr>
<td>3</td>
<td>2.4</td>
<td>12.0</td>
<td>0.0280</td>
<td>25.8027</td>
<td>24.6382</td>
<td>15</td>
</tr>
<tr>
<td>4</td>
<td>2.4</td>
<td>12.0</td>
<td>0.0284</td>
<td>25.9312</td>
<td>24.7605</td>
<td>15</td>
</tr>
<tr>
<td>5</td>
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<td>12.0</td>
<td>0.0286</td>
<td>26.0611</td>
<td>24.8882</td>
<td>15</td>
</tr>
<tr>
<td>6</td>
<td>4.0</td>
<td>20.0</td>
<td>0.0120</td>
<td>37.5510</td>
<td>117.7551</td>
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</tr>
<tr>
<td>7</td>
<td>4.0</td>
<td>20.0</td>
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<td>37.6037</td>
<td>118.1083</td>
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</tr>
<tr>
<td>8</td>
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<td>0.0136</td>
<td>37.7770</td>
<td>118.4576</td>
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<td>9</td>
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<td>20.0</td>
<td>0.0143</td>
<td>37.8896</td>
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<td>10</td>
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<td>12</td>
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Table 2. Generating unit operating parameter and reliability data

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HST: Hot start-up cost of unit i; CST: Cold start-up cost of unit i
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