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Research paper

Proposed New Conceptual and Economic-Based Flexibility Index in Real-Time Operation Incorporating Wind Farms

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Abstract

Background and Objectives: Uncertainty and variability are two main specifications of wind generation and the ability of the power system to overcome these challenges is called flexibility. The flexibility index is a measure to evaluate the flexibility level of the power system mainly to achieve the best level system flexibility.
Methods: Flexibility index should show a good view of the ability of the power system and also be easily converted to an equivalent cost to be combined with the operation cost function. So, in this paper by using economic dispatch simulation for the economic trade-off between the generation cost and the cost of flexibility, the best level of system flexibility in the presence of wind farms considering unit constraints and system loss is achieved. Where the difference between flexibility index in the no wind base case and the flexibility index in each time zone with wind incorporation is defined as the flexibility penalty by the suitable penalty factor. The combination of generation cost and flexibility cost makes the main part of objective function.
Results: The results on the test system verify the proposed method where by increasing penalty factor, improvement in flexibility index is achieved but the generation cost will be increased. So, it shows a good economic trade-off between generation cost and flexibility value. Also the desired flexibility level can be obtained by changing the penalty factor in each wind power penetration. So, the result of the sensitivity analysis shows the best level of flexibility regarding operation cost.
Conclusion: In this paper a new flexibility index is introduced especially for wind power incorporation and for real time operation purpose. This index can be combined by economic dispatch objective function as the penalty (cost) for economic trade-off analysis and to show the best flexibility level of generation system in each operation point.

Introduction

Nowadays, renewable energies especially wind and solar have a wide penetration in the power systems because of their attractive benefits such as low cost, environmental aspects, and availability. However, in addition to all these advantages, two main challenges of integration of these energies in the power system are their uncertainty and variability characteristics. The ability of the power system to overcome these two challenges is called flexibility. One of the well-known definitions of flexibility can be mentioned as "The term flexibility describes the ability of a power system to cope with variability and uncertainty in both generation and demand, while maintaining a satisfactory level of reliability at a reasonable cost over different time horizons." [1]. Four main concepts of flexibility are underlined in this definition. Another definition of power system flexibility is presented in [2] as "The ability to adapt to a wide range of possible demand conditions in the short run at little additional cost." However, it seems that the first definition is more complete and comprehensive than the second one. Due to the importance of the power system flexibility and the main challenges come from the shortage of needed flexibility in power system, wide researches can be found in this field and each of them focuses on a special subject. Flexibility evaluation, flexibility metrics, the role and challenges of flexibility in power system planning and operation, and the effect of variable generation (VG) such as renewable sources (mainly wind and solar) are the main subjects of power system flexibility studies. Herein, a brief literature review of the power system flexibility using some articles related to one or more mentioned fields are presented. A stepwise methodology based on a set of indicators for future power system flexibility analysis through assessing (i) flexibility requirements, (ii) available flexibility resources, and (iii) power system adequacy is the goal of [3]. The proposed methodology is applied to a European case for 2020 and 2025 scenarios. The insights gained from this study can be used as input in distributing power balancing resources and to introduce new balancing products in a power market. A comprehensive overview of power system flexibility as an effective way to maintain the power balance at every moment is presented in [4]. Also, the effects of the high penetration of variable energy resources on power systems and the evolution of flexibility in response to renewables are studied in the above-mentioned paper.

Based on the insights of the nature of flexibility, [5] proposes a unified framework for defining and measuring flexibility in the power system. Under the proposed framework, this paper suggests a flexibility metric that evaluates the largest variation range of uncertainty that the system can accommodate.

A new approach in power system flexibility is presented in [6] as the flexibility tracker. This concept is an assessment methodology developed to monitor and compare the readiness of power systems for high variable renewable energy (VRE) shares. The flexibility tracker builds 14 flexibility assessment domains, by screening systems across the possible flexibility sources (supply, demand, energy storage) and enablers (grid, markets), via 80 standardized key performance indicators (KPIs) scanning the potential, deployment, research activities, policies and barriers regarding flexibility. Also, some of the papers are related to power system flexibility evaluation and metrics. In this way, a comprehensive review of different flexibility measures is presented in [7]. Following, using suitable measures, several sources for power system flexibility with different variable generation (VG) cost levels are compared. A novel framework to develop a composite metric that provides an accurate assessment of flexibility within conventional generators of a power system is introduced in [8]. This assessment is performed using eight technical characteristics of generating units as indicators. An analytic hierarchy process (AHP) is applied to assign weights to these indicators to reflect their relative importance in the supply of flexibility. The survey in the literature on the concepts of power system flexibility, indices of flexibility and implementation of the concept of flexibility in power system security is done in [9]. Moreover, the review of the origin of the reserve problem, the meaning of reserve, its technical classification and related economic aspects are presented by highlighting the effect of renewables on these aspects, and finally, it suggests new research directions. Finally, in [10], by considering the economics and flexibility of the system, an optimal scheduling method is presented that takes the flexibility of each thermal power unit into account. This method includes a multi-objective optimization scheduling model involving the overall flexibility of the unit and the total power generation cost. The main goal of this paper is to introduce a new flexibility index for real-time operation purposes. The next sections of the paper are prepared as follows. In Section 2, a brief survey of the main flexibility metrics are explained. Section 3 describes the main concept of the proposed flexibility index. In Section 4, the calculation of the proposed flexibility index is illustrated. Section 5 presents the basic formulation for the economic dispatch. In Section 6, the wind power stochastic model is described. An objective function is also introduced by considering the flexibility index which is used for the trade-off between operation cost and suitable flexibility index. Simulation and analyses are presented in Section 7 and finally, Section 8 presents the conclusion.

Flexibility Evaluation

Similar to many other concepts in the power systems such as reliability, security, stability and so on, we need to quantify the flexibility by a suitable index. This index should determine the level of flexibility by using four main concepts illustrated in the first definition in the previous section. By this index, the level of flexibility of two systems or two operating points of one system can be compared and in the next step, the improvement of flexibility level can be shown by the corrective actions.

The value of flexibility is also another important concept which allocates the cost to the flexibility index suitably to be compared with the other system costs mainly the operation cost. Using the value of flexibility concept, the trade-off between the generation cost and the flexibility cost can be done as mentioned "reliability at a reasonable cost" in the first definition.

Based on the above explanation, a flexibility index is proposed as an insufficient ramping resource expectation (IRRE), which shows the power system's inability to overcome the variability in both generation and demand sides in a certain time interval [2]. A schematic diagram to explain the concept of IRRE with a concentration on wind penetration is shown in Fig. 1 [11].

It is clear that by increasing wind penetration, IRRE will go up. The IRRE can be used to identify the key time horizon (e.g., 2 hours in 15% wind penetration case and 7 hours in 30% case) where flexibility is an issue and additional flexibility is required.

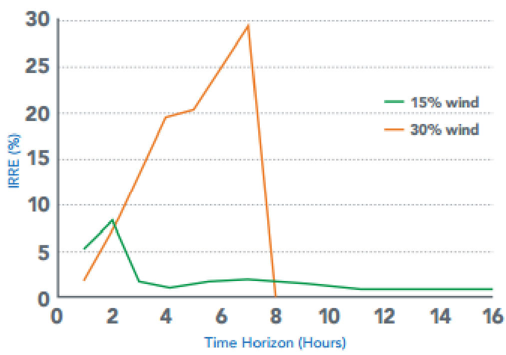


Fig. 1: Description of IRRE.

Another famous flexibility index is introduced for each generation unit as (1) [12]:

$$flex_i = \frac{0.5 * \left(P_i^{max} - P_i^{min}\right) + 0.5 * Ramp\Delta t}{P_i^{max}} \quad (1)$$

where Ramp is the mean of Rampup and Rampdn. Then, the system total flexibility is the combination of all the unit flexibility indices as:

$$Flex = \frac{\sum_{i=1}^{n} flex_i P_i^{max}}{\sum_{i=1}^{n} P_i^{max}} \quad (2)$$

This index is suitable for flexibility evaluation in power system planning and cannot be used for operational purposes. The main reason is no relation of this index to the operation point. In [13], a development to this idea is made and the modified index is suggested to use for operation purposes.

In [14], a conceptual flexibility index is defined which is based on four main system operation criteria as the minimum power of generation unit, the ramp rate capability, start-up time and controllability nature of the generation unit. In the next step, these criteria are assigned to the system elements which are responsible for providing these criteria. Then, the flexibility measurement technique is determined by using the analytical hierarchy process (AHP) method based on these criteria. In [15], another index is introduced as a lack of ramp probability (LORP) in each up and down ramp rate characteristic. LORP can be calculated both in ramping up or ramping down situations as suggested in (3) and (4).

$$LORP^{up} = \Pr(\sum_{i=1}^{n}\{P_{t,i} + \min(Rampup\,\Delta t, (P_i^{max} - P_{t,i})\} < PD_t) \quad (3)$$

$$LORP^{dn} = Pr(\sum_{i=1}^{n}\{P_{t,i} - min(Rampdn_i\,\Delta t, (P_{t,i} - P_i^{min})\} > PD_t) \quad (4)$$

Another index is defined in [16] as a system capability ramp (SCR). The ramping capability of a generator is defined as the ability to change its output during a specific period.

The next concept which is near the previous index is ramping capability shortage expectation (RSE); which represents the possibility of a ramping capability shortage due to major system uncertainties in a particular period [17]. The RSE is used as a criterion in the evaluation of Variable Generation (VG) acceptability.

A flexibility index named the ramping capability shortage probability (RSP) is defined in [18] which is used to quantify the extent to which the variability and uncertainty affect the flexibility.

One of the best conceptual flexibility indices is defined in [19]. The main concept of this index is shown in Fig. 2. As can be observed, this index depends on four main components as storage energy (ε), power capacity (π), ramp rate (ρ) and ramp duration (δ). The area limited by its boundaries is the permitted area for an operating point but it is also limited by the energy storage capability.

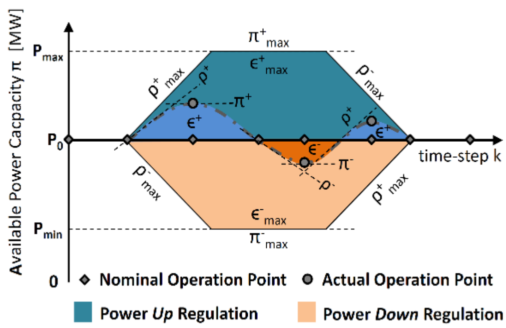


Fig 2: Concept of flexibility index.

In this paper, by getting the idea of permitted area for an operating point from time (t) to time (t+1), a new approach is introduced which can lead to a suitable flexibility index. The value of flexibility is added to the economic dispatch objective function which facilities the trade-off between operation cost and suitable flexibility. This approach can lead to a new concept of power system flexibility cost.

Based on the first definition for power system flexibility and the four key concepts mentioned in it, in this study, the system operation of incorporated wind farms is considered and we notice the variability and uncertainty generated by wind speed. Only the generation side is modeled and the economic trade-off between generation cost and flexibility is done. On the other hand, real-time up to the operational planning time zone will be considered as the time horizon.

Description

In this paper, the concept of flexibility area is introduced. In this concept, a permitted area is presented corresponding to each unit operation point and in each time step. The amount of this area is considered as the flexibility index for each unit. The larger amount of area corresponds to the greater flexibility of the unit and vice versa. Then, by combining all the unit flexibility indices, the total system flexibility index is calculated and can be used as the flexibility term in the economic dispatch objective function.

To start this concept, suppose $P_{i,t}$ is the unit generation i at time t (Fig. 3). Then, at time t+1 we have the triangle shown by $P_{i,t}$, $P_{i,rampup}$ and $P_{i,rampdn}$ where $P_{i,rampup}$ and $P_{i,rampdn}$ are the permitted up and down unit generation boundary points at time t+1 which are limited by the ramp up and ramp down unit constraints. It is clear that the points inside this triangle are the permitted operating points for the unit generation i in [t,t+1] time interval by the ramp up and ramp down constraints.

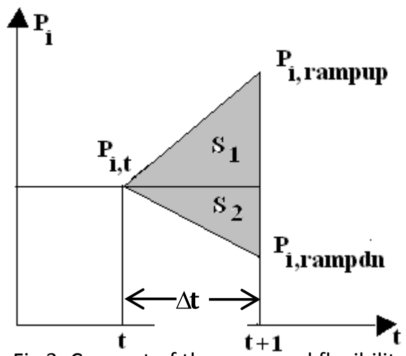


Fig 3: Concept of the proposed flexibility index.

Now, two other limitations should be added to this triangle as up and down unit generation limitations. All cases which are caused by the intersection of these two main constraints are shown in Fig. 4.

By the intersection of these limitations, the mentioned triangle is limited and the area corresponding to the unit flexibility index becomes smaller.

The gray area in each case in Fig. 4 shows the flexibility index. However, it should be noted that the difference between P^{max} and P^{min} is normally much bigger than the maximum increase/decrease of power generation in the time interval Δt (Rampup*Δt or Rampdn*Δt). So, the fourth case in Fig. 4, where both up and down sides are limited, will not occur.

In this paper, the flexibility area corresponding to each case concerning the unit limitations is selected as the unit flexibility index. The total system flexibility index can be found by combining the unit flexibility indices. This can be done using the unit capacity as the weighting factor to combine the unit flexibility indices as shown in (2) [12].

Flexibility Index Calculation

As mentioned before, the area corresponding to the permitted generation unit point in the [t, t+1] time interval is an index to show the unit flexibility at time t. At first, the area of the triangle shown in Fig. 3 is calculated.

$$S = \frac{1}{2}(Rampup + Rampdn)(\Delta t^2) \triangleq S_1 + S_2 \qquad (5)$$

Now, if this triangle is cut by the unit generation up limit, S_1 is converted to

$$S_1 = \frac{(P^{max} - P_t)}{2}(2\Delta t - Dt_1) \qquad (6)$$

where Dt_1 is shown in Fig. 4. Similarly, if the mentioned triangle is cut by the unit generation down limit, S_2 is converted to

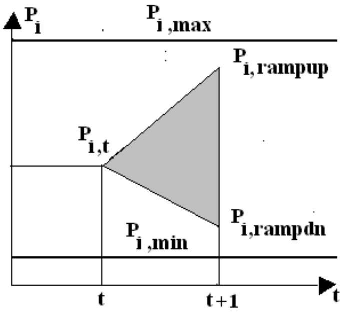
$$S_2 = \frac{(P_t - P^{min})}{2}(2\Delta t - Dt_2) \qquad (7)$$

Again Dt_2 is shown in Fig. 4. By this simple approach, the permitted area (S) can be found and used as the flexibility index of each unit at time t concerning its operating point (P_t), which is called $flex_i$.

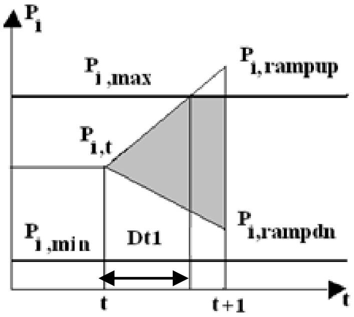
In the last step, the system flexibility index can be found by combining the flexibility indices of all units. As mentioned before, this is done by combining these indices using the unit capacity weighting factor. In this way, the system flexibility index can be found as:

$$Flex = \frac{\sum_{i=1}^{n} flex_i P_i^{max}}{\sum_{i=1}^{n} P_i^{max}} \qquad (8)$$

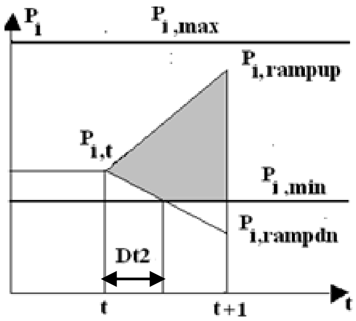
where no limitation in the flexibility triangle occurs, the maximum flexibility index is achieved. However, due to uncertainty and variability in both the generation and demand side, the operation point of each unit can approach the limits and so the flexibility index reduced concerning the maximum flexibility index. Also, it is clear that the proposed index is completely related to the operation point and can be used for real-time operation analysis.



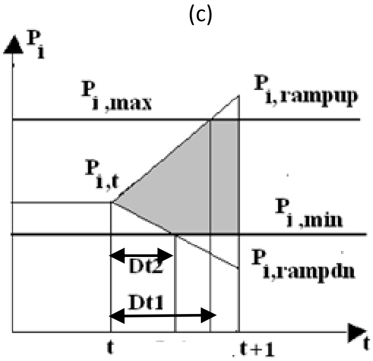
(a)



(b)



(c)



(d)

Fig 4: Different shapes of flexibility area.

Economic Dispatch Main Formulation

Economic dispatch (ED) solution is a well-known tool for the optimal power system operation. The simplest objective function for ED in the presence of wind farms can be written as:

$$Cost = \sum_{i=1}^{n} \alpha_i P_{t,i}^2 + \beta_i P_{t,i} + \gamma_i + \sum_{i=1}^{m} d_i P_{wi,t} \tag{9}$$

Subject to:

$$\sum_{i=1}^{n} P_{t,i} + \sum_{i=1}^{m} P_{wi,t} = PD_t + P_{loss,t} \tag{10-1}$$

$$P_i^{min} \le P_{t,i} \le P_i^{max} \tag{10-2}$$

$$\left|P_{(t+1),i} - P_{t,i}\right| \le Rampup_i \Delta t \tag{10-3}$$

$$\left|P_{(t+1),i} - P_{i,t}\right| \le Rampdn_i \Delta t \tag{10-4}$$

$$0 \le P_{wi,t} \le P_{rated,i} \tag{10-5}$$

The power system loss can be found by the B loss coefficient method as [20]

$$P_{loss,t} = \sum_{i=1}^{n}\sum_{j=1}^{n} P_{t,i} B_{ij} P_{t,j} + \sum_{i=1}^{n} B0_i P_{t,i} + B00 \tag{11}$$

As $P_{loss,t}$ depends on the $P_{i,t}$'s, then ED solution needs an iterative method. On the other hand, due to limitations on up and down unit generation and up and down ramp rates, the well-known algorithm to solve ED is λ coefficients. So, at first, the Lagrange function is formed as:

$$LG = \sum_{i=1}^{n} \alpha_i P_{t,i}^2 + \beta_i P_{t,i} + \gamma_i + \sum_{i=1}^{m} d_i P_{wi,t} - \lambda\left(\sum_{i=1}^{n} P_{t,i} + \sum_{i=1}^{m} P_{wi,t} - PD_t - P_{loss,t}\right) \tag{12}$$

Partial derivatives of LG with respect to $P_{t,i}$'s yields:

$$\frac{\partial LG}{\partial P_{t,i}} = 2\alpha_i P_{t,i} + \beta_i - \lambda\left(1 - \frac{\partial P_{loss,t}}{\partial P_{t,i}}\right) = 0 \tag{13}$$

where,

$$\frac{\partial P_{loss,t}}{\partial P_{t,i}} = 2B_{ii} P_{t,i} + \sum_{j \ne i} B_{ij}\, P_{t,j} + B0_i \triangleq \gamma_{t,i} \tag{14}$$

So, λ_i corresponding to $P_{t,i}$ can be found as

$$\lambda_i = \frac{2\alpha_i P_{t,i} + \beta_i}{(1 - \gamma_{t,i})} \tag{15}$$

Now, the minimum and maximum of λ_i should be calculated with respect to the unit limitations. Up and down limits of the generation unit i are

$$P_{t,i}^{max} = \min(P_i^{max}, P_{t,i} + Rampup_i \Delta t) \tag{16-1}$$

$$P_{t,i}^{min} = \max(P_i^{min}, P_{t,i} - Rampdn_i \Delta t) \tag{16-2}$$

So, by the substitution of (16-1) and (16-2) in (15), we have

$$\lambda_i^{max} = \frac{2\alpha_i P_{t,i}^{max} + \beta_i}{(1 - \gamma_{t,i})} \tag{17-1}$$

$$\lambda_i^{min} = \frac{2\alpha_i P_{t,i}^{min} + \beta_i}{(1 - \gamma_{t,i})} \tag{17-2}$$

Now, the calculated λ in each iteration is compared by the minimum and maximum limits of each unit as shown by (17-1) and (17-2). If each of these limits are violated, $P_{t,i}$ is fixed to the corresponding limit ((16-1) or (16-2)) and the limited generation is subtracted by PD_t. Thus, the remaining PD_t is re-dispatched among the other units.

Wind Stochastic Model and Economic Dispatch Incorporating Flexibility

Wind power has a stochastic behavior due to the stochastic behavior of wind speed. At first, the relation of wind power concerning the wind speed is determined by a third-order polynomial function as shown below [21]:

$$P_w = \begin{cases} 0 & v_{cut-in} > v, v > v_{cut-out} \\ k_w v^3 & v_{cut-in} \leq v \leq v_{rated} \\ P_{rated} & v_{rated} \leq v \leq v_{cut-out} \end{cases} \tag{18}$$

where k_w is defined as

$$k_w = 0.5 n_t \, C_p \eta \, A\rho \tag{19}$$

One of the most popular stochastic models for wind speed is the Weibull probability function. The Weibull PDF and CDF are:

$$f(v) = (\frac{k}{c})(\frac{v}{c})^{(k-1)} \exp[-(\frac{v}{c})^k] \tag{20}$$

$$F(v) = 1 - \exp[-(\frac{v}{c})^k] \tag{21}$$

So, by combining the wind speed stochastic model and wind-power relation, the stochastic behavior of wind power is found. Now, the objective function (9) is extended to include the flexibility value of the system generation. In this paper, the flexibility value is added to (9) as:

$$Cost = \sum_{i=1}^{n} \alpha_i P_{t,i}^2 + \beta_i P_{t,i} + \gamma_i + \sum_{i=1}^{m} d_i P_{wi,t} + K_F(Flex_{base} - Flex) \tag{22}$$

where $Flex_{base}$ indicates the base of the system flexibility in the case of no wind farm incorporation. In (22), wind power is a stochastic variable and also the main source of uncertainty and variability in the generation side. Thus, it needs a suitable system flexibility to overcome this challenge. If the system flexibility is not adequate, then wind power curtailment or load shedding may occur.

On the other hand, it is clear that by increasing flexibility, the term flexibility cost is reduced and vice versa. However, increasing the flexibility and consequently decreasing the corresponding cost results in going far from the optimum generation point which yields an increase in the generation cost. The global optimum point will be found by a trade-off between these two costs. It is obvious that by changing K_F, the value of flexibility is changed and the sensitivity analysis can be done.

Also, by extending the objective function (22) by including the penalty of wind power curtailment and load shedding cost, a global trade-off can be done to achieve the economic flexibility level of the generation system.

Simulation and Analysis

Here a test system is considered which consists of four thermal units and one wind farm for flexibility evaluation. Thermal units cost functions are as [22]:

$C_1=0.0010P_{g1}^2+1.1P_{g1}+100$ (£/h)

$C_2=0.0020P_{g2}^2+1.6P_{g2}+220$ (£/h)

$C_3=0.0030P_{g3}^2+2.5P_{g3}+150$ (£/h)

$C_4=0.0025P_{g4}^2+2.0P_{g4}+210$ (£/h)

The unit constraints are as Table 1.

Table 1: Unit constraints

Unit No.	P^{max} (MW)	P^{min} (MW)	Rampup (MW/h)	Rampdn (MW/h)
1	80	25	50	75
2	250	60	80	120
3	300	75	100	150
4	60	20	80	120

Δt is 10 minutes. Demand is 500 MW which is constant in all the time intervals. The wind farm parameters are as follows:

$A=4000\ m^2$, $\rho=1.255\ Kg/m^3$, $Cp=0.4$, $\eta=0.8$, $n_t=40$

Likewise, the wind speed parameters and Weibull probability function parameters are as:

$v_{cut-in}=4$ m/s, $v_{rated}=12$ m/s, $v_{cut-out}=25$ m/s, c=8, k=1

Also d is considered as one for wind power cost. Finally, the loss function coefficients are as:

$$B = 0.0001 \times \begin{bmatrix} 0.1700 & 0.1200 & 0.0700 & -0.0100 \\ 0.1200 & 0.1400 & 0.0900 & 0.0100 \\ 0.0700 & 0.0900 & 0.3100 & 0.0000 \\ -0.0100 & 0.0100 & 0.0000 & 0.2400 \end{bmatrix}$$

B_0 and B_{00} are disregarded in this simulation. Now, at first, the economic dispatch is run without the wind farm to reach the base unit dispatch and follow the base of the flexibility index. The results are as follows

Pg_1=80.0000 MW Pg_2=250.0000 MW

Pg_3=112.5963 MW Pg_4=60.0000 MW

P_{loss} is equal to 2.5963 MW and the total cost is 41950 (£) for 24 hours. Finally, the flexibility index is equal to 2.3792 which will be considered as the base. It should be noted that the flexibility index with no up and down generation constraint is 2.9589. Fig. 3 which shows maximum flexibility area, demonstrates the flexibility area is cut by up or down generation constraints in some generation units. The optimal operating point is also considered as the initial state for real-time simulation. To start the simulation incorporating wind farm, a sampling wind power is assumed every 10 minutes. In this way, the 144 stochastic samples for wind speed corresponding to 24 hours are derived from the Weibull PDF by the parameters mentioned before and then the corresponding wind power is calculated by using (18).

At first, the cost of flexibility is ignored (K_F=0). By solution the ED incorporated wind farm as said before, the generation of each unit is presented in Fig. 5. Horizontal axes shows the sampling number (1-144).

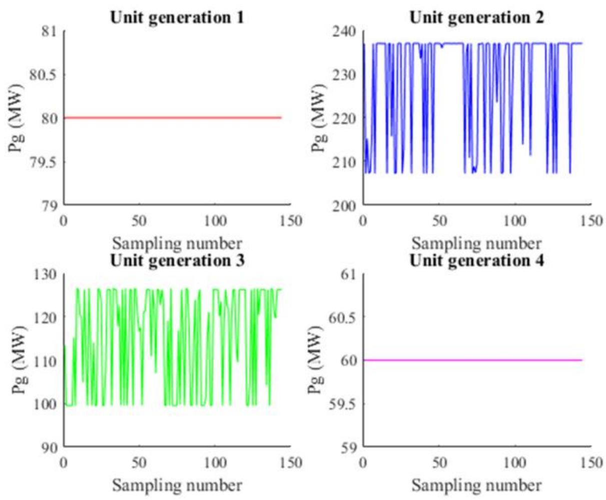


Fig 5: Unit generations with wind power.

Also, the flexibility index and total cost in the 24 hours interval are shown in Fig. 6. The red line shows the base level of flexibility/total cost.

As it is clear, the flexibility index with the wind farm is always less than the base case and the reduction in flexibility index occurs by incorporating the wind farm resulting from its uncertainty and variability characteristics.

The total cost of incorporating the wind farm is higher than base case in a few time intervals. But, in general, it is less than the base case cost. The total cost incorporating the wind farm for 24 hours is reduced to 41143 (£) because of the low cost of wind farm generation and ignoring flexibility cost. The average flexibility index is 2.2249 lower than the base index (2.3792). Now, the main simulation is done by including the flexibility cost in the objective function.

Due to the small amount of the flexibility index concerning the other terms in the objective function, K_F should be big enough to show the role of flexibility in the cost function. Thus, by considering K_F=50, the flexibility index and total cost are shown in Fig. 7.

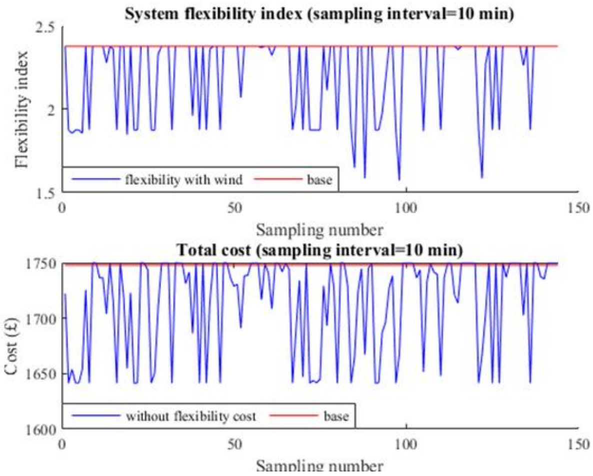


Fig 6: Flexibility index and total cost: K_F=0.

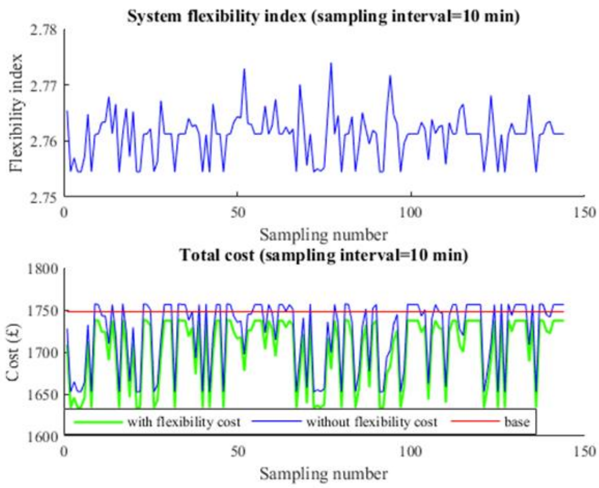


Fig 7: Flexibility index and total cost: K_F=50.

Again the red line shows the operation cost in the base case. Also, the total cost with/without flexibility cost is shown by the green/blue curves. The green curve is always less than the blue curve indicating that the flexibility index is always bigger than the corresponding base case index.

Total cost in this case by ignoring flexibility cost is 41329 (£) which is higher than the previous case (41143 (£)) and shows the flexibility index has a small effect in the optimal generation point displacement because of the low amount of K_F.

In other words, it shows that the value of flexibility is much lower concerning the generation cost. The average flexibility index is 2.7610, higher than the previous case flexibility index and also higher than the flexibility index with no wind incorporation. Again, this shows the flexibility term in cost function forces the ED solution to achieve greater flexibility. By this approach, it is expected to get more amount of flexibility index by increasing K_F. The total cost function (including flexibility cost term) is equal to 40870 (£) less than the total cost ignoring the flexibility cost. This is because of the negative flexibility cost for a higher flexibility index concerning the base case. Now, by increasing K_F, the value of flexibility increases and a higher total cost with incorporating wind farm is expected. This is done by K_F=300 and 500 and the results are shown in Fig. 8 and Fig. 9 respectively.

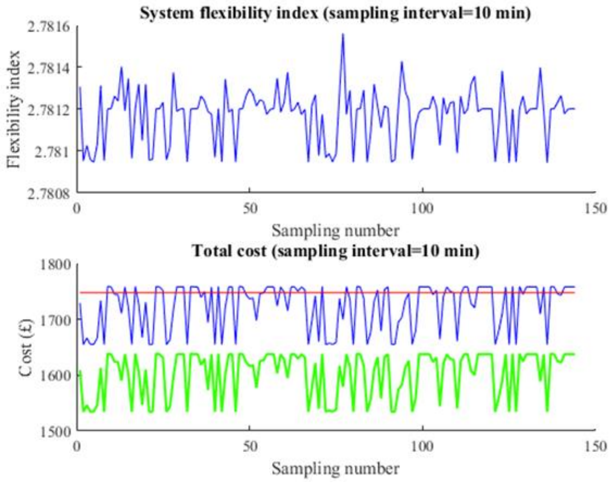


Fig 8: Flexibility index and total cost: K_F=300.

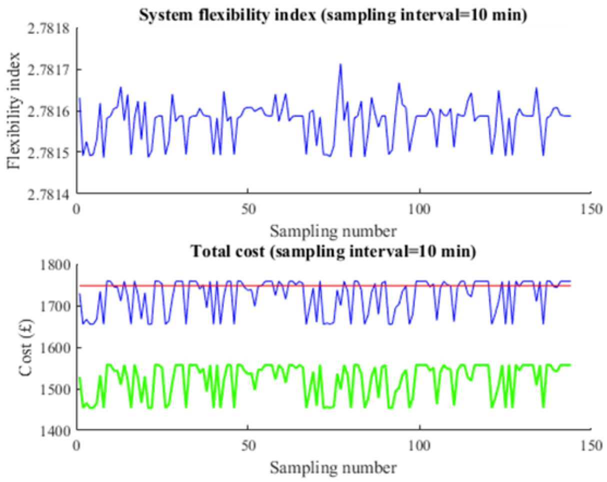


Fig 9: Flexibility index and total cost: K_F=500.

Again, the red lines show the corresponding parameters in the base case and the total costs with/without flexibility cost are shown by green/blue curves. The increase of flexibility index is considerable and also the total cost with flexibility cost (green cure) is completely far from total cost ignoring flexibility cost (blue curve). The total cost by ignoring flexibility cost is 41372 (£) for K_F=300 and 41376 (£) for K_F=500 respectively. Also, the total cost by including flexibility cost is 38478 (£) for K_F=300 and 36548 (£) for K_F=500, respectively. The difference between the total costs with/without flexibility cost is considerable in each case which shows the increase of flexibility value by increasing K_F. The average flexibility index is also 2.7812 for K_F=300 and 2.7816 for K_F=500 respectively. As can be seen, the flexibility index is almost equal in both cases.

This shows the high effect of flexibility in the optimal solution once more. The increase in cost concerning the base case is considered in each case and also by increasing the value of flexibility, the generation cost is increased. In other words, by increasing K_F, the ED solution is forced to prepare much flexibility to overcome uncertainty and variability and leads to more generation costs. Thus, one can select the desired level of flexibility (may be no less than the base case) by changing the K_F and get the best ED solution by a trade-off between the generation cost and flexibility cost.

Now the sensitivity is presented by showing the variation of total cost and flexibility index concerning K_F. The sensitivity analysis can be done by increasing K_F from 0 to 500 and calculating the corresponding value for the total cost with/without flexibility cost and also the average flexibility index. The results are shown in Table 2.

Table 2: Sensitivity analysis

K_F	Cost (No Flex.)(£)	Cost (Flex.) (£)	Ave. Flex. Index
0	41143	41143	2.2249
1	41143	41147	2.2249
5	41146	41161	2.2509
9	41169	41169	2.3803
10	41180	41169	2.4253
20	41263	41123	2.6703
50	41329	40870	2.7610
300	41372	38478	2.7812
500	41376	36548	2.7816

The variation of the flexibility index is shown in Fig. 10.

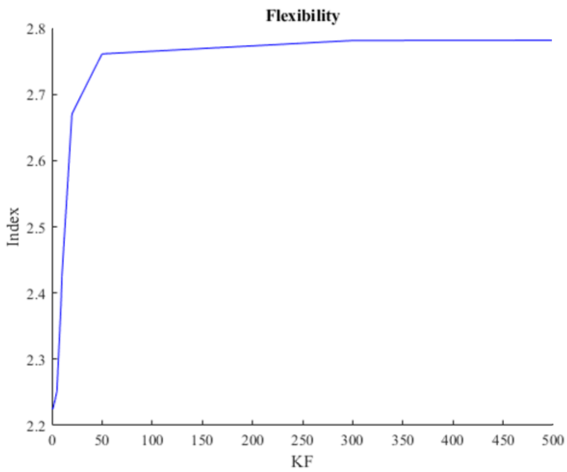


Fig 10: Flexibility index variation vs. K_F.

As can be seen, the greatest increase in flexibility index occurs in the first part of the flexibility curve with a relatively low amount of K_F, and then by increasing K_F the flexibility index is saturated and limited to the maximum flexibility index (2.9589 in this test).

The results of the total cost with/without flexibility cost are shown in Fig. 11. Again, green/blue curves correspond to with/without flexibility cost.

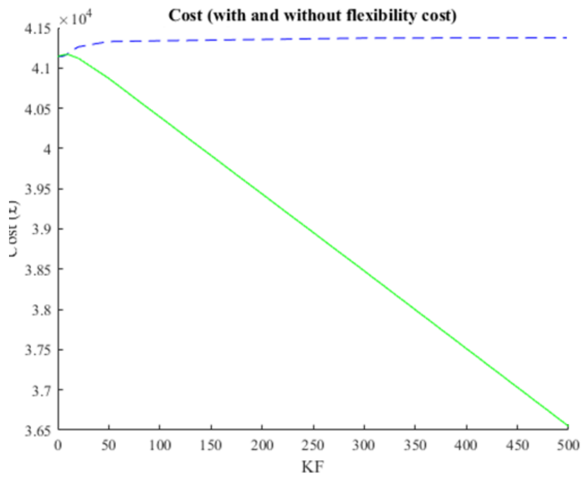


Fig 11: Total cost variation vs. K_F

The first sections of these two curves are shown in Fig 12, for better understanding.

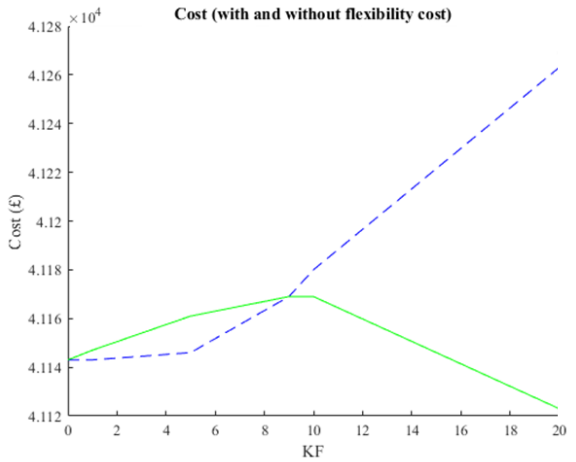


Fig 12: Total cost vs. K_F (high resolution).

The flexibility index is equal to the base case index in the intersection point (in this test, K_F=9). Before the intersection point of the two cost curves, the total cost without flexibility cost is less than the total cost with flexibility cost. This shows that the flexibility term (Flexbase-Flex) in the objective function is positive and the flexibility index is less than the base index. But after the intersection point, the flexibility term (Flexbase-Flex) is negative and the total cost without flexibility cost is more than the total cost with flexibility cost. This again shows the concept of flexibility value by which a good trade-off between operation cost and flexibility cost can be done.

Conclusion

By increasing the wind and solar energy penetration factor in the power system, reduction of system flexibility is the main challenge in power system operation. Thus, it is necessary to compensate for the flexibility to the desired level. This needs the system flexibility evaluation at first by a suitable index to measure the flexibility level and then prepare the adequate flexibility and improve the flexibility index to an economical level. In this paper, a new flexibility index was introduced which has a simple concept and easy calculation routine that can be included in the economic dispatch objective function. The solution of ED including flexibility cost based on the proposed index leads to the global optimum generation point both in generation cost and flexibility cost, simultaneously. By simple sensitivity analysis, the desired value of flexibility can be found and as stated in the main definition, suitable reliability can be obtained at a reasonable cost. As it is observed by increasing the weight of the flexibility index, the solution is to prepare more flexibility which causes more operation costs. Thus, an economic trade-off can be easily done between operation cost and flexibility level. In the next step, the wind power curtailment cost and load shedding penalty can be added to the objective function for a comprehensive analysis.

Author Contributions

This research paper is a part of the first author Ph.D thesis research work which is done under supervision of the second and third authors.

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Conflict of Interest

The author declares that there is no conflict of interests regarding the publication of this manuscript. In addition, the ethical issues, including plagiarism, informed consent, misconduct, data fabrication and/or falsification, double publication and/or submission, and redundancy have been completely observed by the authors.

Abbreviations

A	Turbine area
B, B0, B00	Power loss coefficients
c	Scale factor of Weibull function
Cost	Total cost function
C_p	Power coefficient for wind turbine
d	Wind power operation cost

Dt_1	Time to P^{max} and Rampup Intersection
Dt_2	Time to P^{min} and Rampdn Intersection
$flex$	Unit flexibility index
$Flex$	System flexibility index
i	Counter
k	Shape factor of Weibull function
k_w	Nonlinear wind power coefficient
m	Number of wind farms
n	Number of thermal units
n_t	Number of wind turbines
P	Unit generation power
PD	System demand
P_{loss}	System power loss
P^{max}	Maximum unit generation
P^{min}	Minimum unit generation
P_{rated}	Wind farm nominal power
P_t	Unit generation at time t
P_w	Wind farm power
$Rampup$	Unit ramp up rate constraint
$Rampdn$	Unit ramp down rate constraint
S	Area corresponds to flexibility
S_1	Upper side of flexibility area
S_2	Downer side of flexibility area
t	Time
v	Wind speed
$v_{cut\text{-}in}$	Starting wind speed
$v_{cut\text{-}out}$	Shut down wind speed
v_{rated}	Nominal wind speed
α, β, γ	Unit operation cost coefficients
Δt	Time step
η	Wind turbine-generator efficiency
ρ	Air density
λ	Lagrange multiplier

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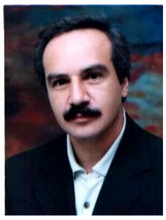

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