Security Constrained Unit Commitment Problem with Operational, Power Flow and Environmental Constraints

S. PRABHAKAR KARTHIKEYAN[1], K.PALANISAMY[1], C.RANI[1], I. JACOB RAGLEND[2], D. P. KOTHARI[3]

[1]Assistant Professor (Senior), School of Electrical Sciences, Vellore Institute of Technology, Vellore- 632014, INDIA.

[2]Principal, Christian College of Engineering and Technology, Oddanchatram, Dindigul District, Tamil Nadu, INDIA.

[3]Vice Chancellor, Vellore Institute of Technology, Vellore-632014. INDIA

e-mail: spk25in@yahoo.co.in, kpalanisamy79@gmail.com, crani@vit.ac.in,

jacobraglend@rediffmail.com, vc@vit.ac.in , http://www.vit.ac.in/vc

Abstract — An algorithm to solve unit commitment problem (UCP) with operational, power flow and environmental constraints under contingencies has been developed to plan an economic and secure generation schedule. The unit commitment (UC) solution for the environmental constrained problem has been formulated as a multi-objective problem by considering both Economic load dispatch (ELD) and Economic emission dispatch (EED) simultaneously. The combined economic emission dispatch (CEED) bi-objective problem is converted to single objective function by adding a modified price penalty factor. The UCP solutions without operational and power flow constraints are not practical due to secure operation of the power system network. This proposed algorithm introduces an efficient UC approach that obtains the minimum operating cost satisfying both unit and network constraints when contingencies are included. Repeated OPF for the satisfactory unit combinations for every line removal under the given study period has been carried out to obtain UC solutions with both operational, power flow and environmental constraints. This proposed algorithm has been tested on IEEE 14, 30, 57, 118 buses and practical Indian utility systems. The solutions obtained are quite encouraging and useful in the economic emission environment. The algorithm and simulation are carried through Matlab environment.

Key-Words: - Combined economic emission dispatch, Contingency Analysis, Dynamic Programming, Economic dispatch, Lagrangian multiplier, Newton Raphson, Optimal power flow, Price penalty factor, Unit commitment.

1. Introduction

The main objective of Unit Commitment Problem (UCP) is to minimize the system production cost during the period while simultaneously satisfying the load demand, spinning reserve, ramp constraints and the operational constraints of the individual unit. To achieve an accurate unit commitment (UC) schedule for either utilities or companies with more number of generating units and unpredicted market behavior becomes a challenge for the researchers in the recent times. There are a number of factors that affect the economic decisions of power generators. These include operating and maintenance costs, output control, start-up costs and emission caps etc. In addition to these, appropriate dispatch of generators also based upon the physical characteristics and limitations of the plant. These can include ramp-up rates, ramp-down rates and minimum and maximum run times. Unit commitment is an operation scheduling function and covers the scope of hourly power system operation decisions with a one-day to one week horizon. Scheduling the on and off times of the generating units and minimizing the cost for the hourly generation schedule is the economics to save great deal of money by turning units off (decommiting) when they are not needed. By incorporating UC schedule, the electric utilities may save millions of Dollars per year in the production cost. The system security is still the most important aspect of power system operation and cannot be compromised. UCP is an important optimization task in the daily operation planning of modern power systems [1] - [3]. A survey of literature on the UC methods reveals that various numerical optimization techniques have been employed to approach the UC Problem. Traditional and conventional methodologies such as exhaustive enumeration, priority listing, dynamic programming, integer and linear programming, branch and bound method, Lagrangian relaxation, interior point optimization etc. are able to solve UCP with success in varying degree [4] – [12].

Researchers taught the environmental constraints may also play an important role in the production cost. Gent and Lamont have started the early work on minimum emission dispatch [13]. Optimal power dispatch problem considering practical constraints has been solved by Fletcher's quadratic programming method [14]. Nanda, Hari and Kothari explore the feasibility of developing a classical technique based on co-ordination equations to solve Economic Emission load dispatch with line flow constraints [15]. Researchers proposed a price penalty factor for solving the CEED problem which blends the emission costs with the normal fuel costs [16]. Carlos E. Murillo-Sanchez and Robert J. Thomas describe a parallel implementation of the Lagrangian relaxation algorithm with variable duplication for the thermal UCP with AC power flow constraints [17]. Esteban Gil, Julian Bustos and Hugh Rudnick propose the short term generation scheduling problem for hydrothermal systems [18]. N.P. Padhy made a comparative study for UCP using hybrid models [19]. Researchers introduced a new UCP by adapting extended priority list method [20]. Walsh and Malley designed a Hopfield network to the economic dispatch problem [21]. Finardi and Silva proposes a model for solving the UCP of hydroelectric generating units [22]. Wei Fan, Xiao Hong Guan and Qiaozhu Zhai proposed a new method for scheduling units with ramping constraints [23]. Xiao Hong Guan, Sangang Guo and Qiaozhu Zhai discovered how to obtain feasible solution for the security constrained UCP within the Lagrangian relaxation framework [24]. Researchers proposed the optimization problem of unit commitment and economic dispatch with security constraints can be decomposed into two sub problems, one with integer variables and the other with continuous variables [25]. Yong Fu, Mohammad Shahidehpour and Zuyi Li proposes an efficient security constrained UC approach with ac constraints that obtains the minimum system operating cost while maintaining the security of power systems [26]. Bo Lu and Mohammad Shahidehpour consider network constraints in security constrained unit commitment and decomposed the problem into master problem for optimizing unit commitment and sub problem for minimizing network violations [27]. Zuyi Li and Mohammad Shahidehpour introduce a security constrained unit commitment model with emphases on the simultaneous optimization of energy and ancillary services markets [28]. A modified price penalty factor is introduced to find the exact economic emission fuel cost with respect to the load demand [29] - [30]. In this paper, the UCP is solved by considering both EED and ELD with operational, power flow constraints. The UC schedule for the generating units considering only the unit constraints may not satisfy the power flow constraints and leads to insecure operation of the network. To obtain the practical UC solutions the model must consider both the operational and power flow constraints. In this model, contingency analysis has been done by removing one line from the system and performs optimal power flow (OPF) and this continues until all the lines are removed once for each possible state. The state which converges for optimal power flow for every line removal is selected. Repeated OPF for the satisfactory unit combinations for every line removal under the given study period has been carried out to obtain UC solutions with both operational, power flow and environmental constraints including contingencies. The results obtained using contingency analysis gives a secure UC schedule because they are converged for OPF when any line from the system is removed during the operation. This paper presents the UC schedule for different IEEE bus systems and Indian utility practical system when contingency analysis are done on the system with environmental and power flow (PF) constraints scheduled for 24 hours.

2. Problem Formulation

Unit commitment is an optimization problem of determining the schedule of generating units within a power system with a number of constraints [2, 26]. For a given power system network, the optimization cost of generation is given by the following equation.

$$TC = Min \sum_{i=1}^{N_G} \sum_{t=1}^{T} f_i(FC, EC) + ST_{it} + SD_{it} \quad (1)$$

TC is the total production cost for the UC schedules.

N_G is the total number of generator units in the network.

FC and EC are total fuel cost and total emission of generators respectively.

Total fuel cost of generation FC in terms of control variables generator powers can be expressed as

$$FC_{it}(P_{Gi}) = \sum_{i=1}^{N_G} c_i + b_i P_{Gi} + a_i P_{Gi}^2 \quad \$/hr \quad (2)$$

a_i, b_i, c_i are the cost coefficients of generator

P_{Gi} - Real Power generated by the ith generator

Total emission of generation EC can be expressed as

$$EC_{it}(P_{Gi}) = \sum_{i=1}^{N_G} \alpha_i + \beta_i P_{Gi} + \gamma_i P_{Gi}^2 \quad lb/hr \quad (3)$$

$\gamma_i, \beta_i, \alpha_i$ are the emission coefficients.

ST_{it}, SD_{it} - Start-up cost, Start down cost at t^{th} hour ($/h)

The start up cost

$$ST_{it} = TS_{it}F_{it} + (1 - e^{(D_{ti}AS_{it})}BS_{it}F_{it} + MS_{it} \quad (4)$$

TS_{it} - Turbines start-up energy at i^{th} hour (MBTu)

F_{it} - Fuel input to the i^{th} generator

D_{it} - Number of hours down at tth hour

AS_{it} - Boiler cool-down coefficient at tth hour

BS_{it} - Boiler start-up energy at tth hour ($/h)

MS_{it} - Start-up maintenance cost at tth hour ($/h)

Similarly the start down cost $SD_{it} = kP_{Gi}$ (5)

k is the proportional constant and the total production cost is optimized with the following constraints.

Equality constraints: Power balance

$$\sum_{i=1}^{N_G} P_{Gi} = P_{Dt} + P_{Rt} + P_{Lt} \quad (6)$$

Inequality Constraints: System spinning reserve constraint

$$\sum_{i=1}^{N_G} P_{Gi}^{\max} I_{it} \geq P_{Dt} + P_{Rt} \quad (7)$$

Minimum up time

$$0 < T_{iu} \leq No.of\ hours\ units\ G_i\ has\ been\ on \quad (8)$$

Minimum down time

$$0 < T_{id} \leq No.of\ hours\ units\ G_i\ has\ been\ off \quad (9)$$

Maximum and minimum output limits on generators $P_{Gi}^{\min} \leq P_{Gi} \leq P_{Gi}^{\max}$ (10)

Ramp rate limits for unit generation changes

$$P_{Git} - P_{Gi(t-1)} \leq UR_i \quad as\ generation\ increases \quad (11)$$

$$P_{Gi(t-1)} - P_{Git} \leq DR_i \quad as\ generation\ decreases \quad (12)$$

P_{Dt}, P_{Rt}, P_{Lt} - Demand, Spinning reserve and Total system losses at t^{th} hour

T_{iu}, T_{id} - Minimum up-time and Minimum down time in hours

UR_i, DR_i - Ramp-up rate limit and Ramp-down rate limit of unit *i* (MW/h)

Power Flow Equality Constraints:

Power balance equations

$$P_{Gi} - P_{Li} - \sum_{j=1}^{N_b} |\bar{V}_i| |\bar{V}_j| |Y_{ij}| \cos(\theta_{ij} - \delta_i + \delta_j) = 0 \quad (13)$$

$$Q_{Gi} - Q_{Li} + \sum_{j=1}^{N_b} |\bar{V}_i| |\bar{V}_j| |Y_{ij}| \sin(\theta_{ij} - \delta_i + \delta_j) = 0 \quad (14)$$

Power Flow Inequality Constraints:

$$P_{Gi}^{\min} \leq P_{Gi} \leq P_{Gi}^{\max}, i = 1,\ldots\ldots, N_G \quad (15)$$

$$Q_{Gi}^{\min} \leq Q_{Gi} \leq Q_{Gi}^{\max}, i = 1,\ldots\ldots, N_G \quad (16)$$

$$|\bar{V}_i|^{\min} \leq |\bar{V}_i| \leq |\bar{V}_i|^{\max}, i = 1,\ldots\ldots, N_L \quad (17)$$

$$\phi_i^{\min} \leq \phi_i \leq \phi_i^{\max} \quad (18)$$

$$MVA\ f_{ij} \leq MVA\ f_{ij}^{\max}, i = 1,\ldots\ldots, N_{TL} \quad (19)$$

N_b, N_G - Number of total buses, number of generator buses

N_L, N_{TL} - Number of load buses, number of transmission lines

$P_{Gi}^{\min}, P_{Gi}^{\max}$ - Limits of real power allowed at generator i.

$Q_{Gi}^{\min}, Q_{Gi}^{\max}$ - Limits of reactive power allowed at generator i.

P_{Gi}, Q_{Gi} - Real and reactive power generation at bus *i*

P_{Li}, Q_{Li} - Active and reactive power loss at bus *i*

$|V_i|$, δ_i - Voltage magnitude, Voltage angle at bus *i*

Y_{ij} - ij^{th} elements of Y-bus matrix

MVA f_{ij} - Apparent power flow from bus *i* to bus *j*

MVA $f_{ij}^{\max}$ - Maximum rating of transmission line connecting bus *i* and *j*.

The bi-objective combined economic emission dispatch problem is converted into single optimization problem by introducing the penalty factor h [16] as follows

$$TC = Min \sum_{i=1}^{N_G} \sum_{t=1}^{T} FC_{it}\left(P_{Gi}\right) + h * EC_{it}(P_{Gi}) + ST_{it} + SD_{it} \$/hr \qquad (20)$$

subject to the power flow constraints using (7)-(19). The price penalty factor h blends the emission with fuel cost and TC the total production cost in \$/hr [29, 30]. The price penalty factor h_i is the ratio between maximum fuel cost and maximum emission of corresponding generator.

$$h_i = \frac{FC\left(P_{Gi}^{\max}\right)}{EC\left(P_{Gi}^{\max}\right)} \quad , i = 1,2, \cdots N_G \qquad (21)$$

To determine the price penalty factor for a particular load demand use the following steps

1. Find the ratio between maximum fuel cost and maximum emission of each generator.
2. Arrange the values of price penalty factor in ascending order.
3. Add the maximum capacity of each unit $\left(P_{Gi}^{\max}\right)$ one at a time, starting from the smallest h_i unit until $\sum P_{Gi}^{\max} \geq P_D$
4. At this stage, h_i associated with the last unit in the process is the price penalty factor h for the given load.

This method gives the appropriate value of price penalty factor for the corresponding load demand. Hence a modified price penalty factor h_m is introduced to give the exact minimum dispatch solution. The first two steps for computing the modified price penalty factor also remains the same as above. Then the modified price penalty factor is computed by interpolating the values of h_i for the last two units by satisfying the corresponding load demand. The introduction of price penalty factor gives the environmental constrained UCP solution with PFC including the contingencies in the network. Dynamic programming is used to compute the minimum running cost for a given combination of units according to the enumeration technique for a given load [2]. The UC schedule for the generating units considering only the unit constraints may not satisfy the PFC and leads to insecure operation of the network. For secure operation and to obtain the practical UC solutions the model must consider both the operational, power flow and environmental constraints including contingencies in the network. In every hour all the possible combination of units that satisfies the unit and network constraints are checked by removing one line at a time and if it converges remove the next line and proceed until all the lines are removed once and select the state which converges for every line removal. The state which converges for OPF for every line removal is stored and the best combination which gives minimum production cost are selected and stored. Proceed further until the UC schedule for the entire time horizon is obtained and the total production cost is obtained and minimized respectively. In a power system, the objective is to find the real and reactive power scheduling for each generating unit to meet a particular load in such a way to minimize the total production cost. This is called the OPF problem. The OPF optimizes a power system operating objective function, while satisfying a set of network constraints. The UC solution for a system can be obtained with repeated OPF algorithms. Repeated OPF for the satisfactory unit combinations under given study period be carried out to obtain UC solutions with unit and network constraints including contingencies.

2.1 Implementation of Security Constrained UCP with Operational, Power Flow, Environmental Constraints

- Initialize the unit characteristics for the N unit system with system constraints.
- Find all the available states that satisfy the load demand for 24 hours. Each state corresponds to the “ON” and “OFF” conditions of the generator units and represented as 1 and 0.
- Calculate the transitional generation cost for the states satisfying the system constraints on their transit from the present stage to the succeeding stage with the help of following steps
- For each satisfying state perform contingency analysis by removing one line from the system and carry out the optimal power flow solution using a hybrid Lagrangian multiplier and Newton Raphson power flow algorithms. Perform contingency analysis for each satisfying state repeatedly until all the lines are removed once except the lines which are connected only either to the load bus or generator bus and carry out optimal power flow for every contingency for that state. Prepare the data base for

the system including line data, bus data, generator data and tap setting of the transformers.

- Form Y_{bus} using line resistance, reactance, and shunt elements [31].
- Compute P_{Gi} and Q_{Gi} for each load bus using (13, 14).
- Compute the Scheduled errors $\Delta P_{Gi}^{(k)}$ and $\Delta Q_{Gi}^{(k)}$ for each load from the following relation

$$\Delta P_{Gi}^{(k)} = P_{Gi}^{Sch} - P_{Gi}^{(k)} \quad \text{and} \quad \Delta Q_{Gi}^{(k)} = Q_{Gi}^{Sch} - Q_{Gi}^{(k)} \qquad (22)$$

- Using (12, 13) compute the elements of the Jacobian matrix obtained from the partial derivatives with respect to $\Delta\delta_i^{(k)}$ and $\Delta\left|V_i^{(k)}\right|$.

$$\begin{bmatrix}\Delta P\\ \Delta Q\end{bmatrix} = \begin{bmatrix}J1 & J2\\ J3 & J4\end{bmatrix}\begin{bmatrix}\Delta\delta\\ \Delta|V|\end{bmatrix} \qquad (23)$$

- The new voltage magnitudes and phase angles are computed using

$$\delta_i^{(k+1)} = \delta_i^{(k)} + \Delta\delta_i^{(k)} \text{ and } \left|V_i^{(k+1)}\right| = \left|V_i^{(k)}\right| + \Delta\left|V_i^{(k)}\right| \qquad (24)$$

- The process is continued until the residuals $\Delta P_{Gi}^{(k)}$ and $\Delta Q_{Gi}^{(k)}$ for all load buses are less than the specified tolerance ε.
- Calculate the loss co-efficient using the following steps.
- From the power flow solution, the voltage magnitude and phase angle of all buses are determined. The total injected power at bus 'i' is given by $S_i = P_i + jQ_i = V_i I_i^*$ (25)
- The summation of powers over all buses gives the total system loss

$$P_L + jQ_L = \sum_{i=1}^{N_b} V_i I_i^* = V_{bus}^T I_{bus}^* \qquad (26)$$

P_L and Q_L are real and reactive power loss of the system.

V_{bus}, I_{bus} - Column vector of nodal bus voltages and injected bus currents.

- Obtain Z_{bus} matrix by taking the inverse of the Y_{bus} matrix.
- The real power loss becomes

$$P_L = \sum_{i=1}^{N_b}\sum_{j=1}^{N_b} I_i R_{ij} I_j^* \qquad (27)$$

In matrix form, (27) can be written as

$$P_L = I_{bus}^T \, R_{bus} \, I_{bus}^* \qquad (28)$$

R_{bus} - Real part of the bus impedance matrix.

- The total load current I_D and the individual load current I_{LK} and individual bus currents l_k are calculated.

Total load current $I_D = I_{L1} + I_{L2} + \cdots + I_{LN_L}$ (29)

Individual bus currents $l_k = I_{LK} / I_D$ (30)

Voltage at the reference bus (say bus 1) can be written in terms of load currents I_L and generator currents I_g.

$$V_1 = \sum_{i=1}^{N_G} Z_{1i} I_{gi} + \sum_{k=1}^{N_L} Z_{1k} I_{LK} \qquad (31)$$

$$V_1 = \sum_{i=1}^{N_G} Z_{1i}\, I_{gi} + I_D T \qquad (32)$$

$$V_1 = -Z_{11} I_0 \qquad (33)$$

I_0 - Current flowing away from reference bus (say 1) with other load currents set to zero.

Substitute V_1 in (33) and solve I_D

$$I_D = -\frac{1}{T}\sum_{i=1}^{N_G} Z_{1i} I_{gi} - \frac{1}{T} Z_{11} I_0$$

$$where \quad T = \sum_{k=1}^{N_L} l_k Z_{1k} \ and \ \rho = -l_k / T \text{(24)} \qquad (34)$$

$$I_{LK} = \rho_k \sum_{i=1}^{N_G} Z_{1i} I_{gi} + \rho_k Z_{11} I_0 \qquad (35)$$

Augmenting the generator currents with the above relation in matrix form gives

$$\begin{bmatrix} I_{g1}\\ I_{g2}\\ \vdots\\ I_{gN_G}\\ I_{L1}\\ I_{L2}\\ \vdots\\ I_{LN_L}\end{bmatrix} = \begin{bmatrix} 1 & 0 & \cdots & 0 & 0\\ 0 & 1 & \cdots & 0 & 0\\ \vdots & \vdots & \ddots & \vdots & \vdots\\ 0 & 0 & \cdots & 1 & 0\\ \rho_1 Z_{11} & \rho_1 Z_{12} & \cdots & \rho_1 Z_{1N_G} & \rho_1 Z_{11}\\ \rho_2 Z_{11} & \rho_2 Z_{12} & \cdots & \rho_2 Z_{1N_G} & \rho_2 Z_{11}\\ \vdots & \vdots & \ddots & \vdots & \vdots\\ \rho_k Z_{11} & \rho_k Z_{12} & \cdots & \rho_k Z_{1N_G} & \rho_k Z_{11}\end{bmatrix}\begin{bmatrix} I_{g1}\\ I_{g2}\\ \vdots\\ I_{gN_G}\\ \\ I_0\end{bmatrix} \qquad (36)$$

The generator current $I_{gi} = \psi_i \, P_{gi}$, where

$$\psi_i = \left(\frac{1 - j\frac{Q_{Gi}}{P_{Gi}}}{V_i^*}\right) \qquad (37)$$

$$\begin{bmatrix} I_{g1}\\ I_{g2}\\ \vdots\\ I_{gN_G}\\ I_0\end{bmatrix} = \begin{bmatrix} \psi_1 & 0 & \cdots & 0 & 0\\ 0 & \psi_2 & \cdots & 0 & 0\\ \vdots & \vdots & \ddots & \vdots & \vdots\\ 0 & 0 & \cdots & \psi_{N_G} & 0\\ 0 & 0 & \cdots & 0 & I_0\end{bmatrix}\begin{bmatrix} P_{g1}\\ P_{g2}\\ \vdots\\ P_{gN_G}\\ 1\end{bmatrix} \qquad (38)$$

- The total transmission power loss including B_{mn} is $P_L = \sum_{i=1}^{N_G}\sum_{j=1}^{N_G} P_i B_{ij} P_j + \sum_{i=1}^{N_G} B_{0i} P_i + B_{00}$ (39)
- After getting the loss coefficient perform economic dispatch and emission dispatch i.e., the power generated in each 'ON' generator unit using Lagrangian multiplier method.
- Read the total demand, cost characteristics and MW limits along with loss co-efficient. The condition for optimum dispatch

$$\frac{dC_i}{dP_{Gi}} + \lambda \frac{\partial P_L}{\partial P_{Gi}} = \lambda, \quad i = 1 \ldots N_G \tag{40}$$

$$\left(\frac{1}{1 - \frac{\partial P_L}{\partial P_{Gi}}}\right) \frac{dC_i}{dP_{Gi}} = \lambda, \quad i = 1, \ldots, N_G \tag{41}$$

$$L_i \frac{dC_i}{dP_{Gi}} = \lambda, \quad i = 1, \ldots, N_G \tag{42}$$

where L_i is the penalty factor of plant i.

- For an estimated value of λ, P_{Gi} are found from the cost quadratic function.

$$P_{Gi}^{(k)} = \frac{\left(\lambda^{(k)}(1 - B_{0i}) - \beta_i - 2\lambda^{(k)} \sum_{j \neq i} B_{ij} P_{Gj}^{(k)}\right)}{2\left(\gamma_i + \lambda^{(k)} B_{ii}\right)} \tag{43}$$

$$\Delta\lambda^{(k)} = \frac{\Delta P^{(k)}}{\sum \left(\frac{dP_{Gi}}{d\lambda}\right)^{(k)}} \tag{44}$$

$$\lambda^{(k+1)} = \lambda^{(k)} + \Delta\lambda^{(k)} \tag{45}$$

$$\Delta P^{(k)} = P_{Dt} + P_{Lt}^{(k)} - \sum_{i=1}^{N_G} P_{Gi}^{(k)} \tag{46}$$

2.2 Algorithm

- Check the slack bus power generated from the cost quadratic function and the slack bus power obtained from the power flow solution. If they lie with in a tolerance limit say 0.001, then find the generation cost using (2). If they are not with in the tolerance limit, then with the power generation obtained from economic dispatch using cost quadratic equation is given as the P specified in the load flow analysis for the next iteration.
- Similarly the emission dispatch is determined from (3). Losses can be obtained from the new power flow solution and repeat the economic dispatch.
- Check whether the slack bus power obtained from this economic dispatch and the slack bus power obtained from the power flow solution are within the tolerance limit.
- If they are within the tolerance limit, perform the load flow with P_{Gi} obtained from economic dispatch and determine the transitional cost by including the price penalty factor for the corresponding load demand.
- The state which converges for optimal power flow when all the lines are removed once from the system is selected. For that state perform optimal power flow and economic dispatch without any contingencies in the system and store the transitional cost.
- The same procedure is followed for all the states that satisfy the load demand and spinning reserve constraints for that hour and repeat the above steps for 24 hours with the generated load profile.
- Now tabulate all the transitional cost of the satisfying states for each stage and choose the minimum transitional cost for each stage that satisfy the unit constraints and repeat the above steps for 24 hours with the generated load profile.
- Calculate the total generation cost by adding all the minimum transitional cost obtained between each stage and print the results.

Table 1
Comparison of Power Flow and Security Constrained UC Schedule for IEEE 30 Bus System

Load	Price penalty factor	With PFC	Fuel Cost $/hr	Emission Output lb/hr	Minimum transitional cost $/hr	With Contingency Analysis	Fuel Cost $/hr	Emission Output lb/hr	Minimum transitiona l cost $/hr
166	2.7083	101100	383.1527	76.6078	690.6	111100	367.3222	90.1567	898.5
196	2.7985	101100	465.1614	107.2830	765.4	111100	443.8772	107.2528	744.0
229	2.9639	101100	561.6252	157.3960	1028.1	111000	531.1262	121.6174	976.6
267	3.3151	111100	640.7015	180.9583	1427.6	111001	642.9129	180.6902	1354.9
283.4	3.4797	111100	690.2637	209.4508	1419.1	111011	690.9253	214.7983	1618.4
272	3.3653	111100	655.7792	188.3548	1289.6	111010	655.2282	188.5274	1319.7
246	3.1044	111100	580.1208	154.1772	1058.7	111011	583.4589	168.1483	1218.5
213	2.8837	111100	488.9667	120.5906	836.7	111010	487.9908	120.6381	865.9
192	2.7847	111100	433.4472	104.5002	724.4	111010	432.3440	104.3893	723.0
161	2.6936	110100	374.2392	66.9930	584.7	110010	373.6654	67.2442	584.8
147	2.5692	110100	338.5361	59.2813	490.8	110010	337.8636	59.6661	491.2
160	2.6907	110100	371.6587	66.3749	550.3	110010	371.0775	66.6329	550.4
170	2.7200	110100	397.6675	73.0233	596.3	110010	397.1655	73.2314	596.4
185	2.7641	110100	437.5547	84.9648	672.4	110010	437.1916	85.1759	672.6
208	2.8586	110100	500.8114	107.9569	809.4	110010	501.3720	108.2307	810.8
232	2.9790	110100	570.4942	138.3123	982.5	110010	570.6891	138.6674	983.8
246	3.1044	111100	580.1257	154.1794	1171.8	110011	613.4932	168.5430	1249.7
241	3.0542	111100	565.9985	148.4276	1019.3	111000	565.4340	136.0159	1175.9
236	3.0040	111100	551.9839	142.9139	981.3	111001	553.6495	142.7544	1095.5
225	2.9439	111100	521.5529	131.6186	909.0	111000	519.8424	117.1410	894.7
204	2.8386	111100	464.9371	113.1967	786.3	111000	461.8304	96.2504	735.0
182	2.7553	111100	407.6775	98.2587	678.4	111000	402.9430	78.6167	619.6
161	2.6936	110100	374.2387	66.9929	584.7	110000	371.8882	48.7960	533.3
131	2.4198	110100	298.8239	52.9253	426.9	111000	275.1838	55.1816	521.7

CA- Contingency Analysis
PFC- Power Flow Constraints

Table 2
Comparison of Power Flow and Security Constrained UC Schedule for IEEE 14, 57, 118 Bus Systems

IEEE 14 bus				IEEE 57 bus				IEEE 118 bus			
Load	Price penalty factor	With PFC	With CA	Load	Price penalty factor	With PFC	With CA	Load	Price penalty factor	With PFC	With CA
148	1.9416	11110	11110	540	0.7972	1000101	1001011	3170	1.5212	1111101111111101101	1111101111111101100
173	1.9567	11110	11110	620	0.7987	1000101	1001011	3200	1.5215	1111101111111111110	1111101011111101100
220	1.9850	11110	11110	954	0.8047	1000101	1001110	3250	1.5222	1111101011111101110	1111111111111101110
244	1.9994	11100	11100	1026	0.8060	1000101	1001110	3300	1.5228	1111001011111101110	1111111111111101111
259	2.0084	11100	11101	1002	0.8055	1000101	1001110	3460	1.5248	1111001011111101110	1111101111111101110
248	2.0018	11100	11101	992	0.8054	1000101	1001110	3640	2.7013	1111001111111101111	1111101111111101111
227	1.9892	11001	11001	978	0.8051	1000101	1001110	3686	2.7638	1111001111111101110	1111111111111101111
202	1.9741	11001	11001	956	0.8047	1000101	1001110	3640	2.7013	1111001111111101111	1111111111111101111
176	1.9585	11000	11000	942	0.8045	1000101	1001110	3560	2.5926	1111001111111101111	1111111111111101111
134	1.9332	11001	11001	922	0.8041	1000101	1001110	3440	1.5245	1111001111111101101	1111101111111101101
100	1.9127	11001	10001	902	0.8037	1000101	1001110	3250	1.5222	1111001011111101101	1111101011111101100
130	1.9308	11001	10001	751	0.8010	1000101	1001110	3200	1.5215	1111101111111111110	1111101111111111110
157	1.9470	10001	10001	651	0.7992	1000100	1001110	3175	1.5212	1111101111111101110	1111101111111101110
168	1.9537	11001	10101	588	0.7981	1000100	1001011	3210	1.5217	1111101111111111110	1111101111111111110
195	1.9699	11001	10101	602	0.7984	1000100	1001011	3420	1.5243	1111101111111101110	1111101111111101110
225	1.9880	11101	11101	768	0.8013	1000100	1001011	3620	2.6741	1111001111111101110	1111101111111101111
244	1.9994	11100	11100	876	0.8033	1000101	1001110	3620	2.6741	1111001111111101110	1111101111111101111
241	1.9976	11100	11100	863	0.8030	1000101	1001110	3580	2.6198	1111011111111101110	1111101111111101111
230	1.9910	11000	11001	843	0.8027	1000101	1001110	3460	1.5248	1111001111111101110	1111101111111101101
210	1.9789	11000	11001	802	0.8019	1010001	1001110	3270	1.5224	1111001111111101100	1111101011111101100
176	1.9585	11000	11000	784	0.8016	1010001	1001110	3210	1.5217	1111101111111111110	1111101111111111110
157	1.9470	10000	10000	702	0.8002	1000001	1001110	3153	1.5209	1111001111111101111	1111001111111101111
138	1.9356	10000	10000	692	0.8000	1000011	1001110	3148	1.5209	1111001111111101111	1111001111111101111
103	1.9145	10100	10100	645	0.7991	1000100	1001110	3166	1.5211	1111101111111101101	1111101111111101101

Table 3
Comparison of Power Flow and Security Constrained UC Schedule for Indian Utility System

Demand	Penalty factor	Unit status With PFC	Fuel cost $/hr	Emission output lb/hr	Minimum total operating cost $/hr	Unit status with CA	Fuel cost $/hr	Emission output lb/hr	Minimum total operating cost $/hr
3352	1.0154	111111111111111	4060.1	4330.6	8458	111110111111111	4060.9	4305.8	8463
3384	1.0183	111111111111111	4116.4	4374.9	8571	111110001111111	4116.9	4321.6	8628
3437	1.0230	111111111111111	4209.6	4436.1	8748	111110101111111	4211.1	4406.7	8789
3489	1.0277	111111111111111	4303.0	4514.9	8943	111110101111111	4304.3	4486.2	8915
3659	1.0428	111111111111111	4606.2	4682.8	9490	111110101111111	4611.2	4710.0	9523
3849	1.0598	111111111111111	4954.9	4875.0	10122	111110101111111	4964.2	4937.5	10197
3898	1.0642	111111111111111	5046.4	4940.6	10304	111110101111111	5057.1	5014.4	10393
3849	1.0598	111111111111111	4954.9	4875.0	10122	111110101111111	4964.2	4937.5	10197
3764	1.0522	111111111111111	4809.8	4798.9	9859	111110101111111	4804.9	4810.0	9866
3637	1.0409	111111111111111	4566.4	4656.7	9413	111110101111111	4570.9	4677.9	9440
3437	1.0230	111111111111111	4209.6	4436.1	8748	111110101111111	4211.1	4406.7	8719
3384	1.0183	111111111111111	4116.4	4374.9	8571	111110001111111	4116.9	4321.6	8568
3357	1.0159	111111111111111	4069.3	4345.0	8483	111110001111111	4069.7	4292.4	8430
3394	1.0192	111111111111111	4133.9	4386.2	8604	111110001111111	4134.5	4332.7	8550
3616	1.0390	111111011111111	4527.7	4610.6	9368	111110001111111	4531.3	4619.9	9331
3828	1.0579	111111011111111	4915.1	4821.0	10015	111110001111111	4923.5	4875.6	10082
3828	1.0579	111111011111111	4915.1	4821.0	10015	111110001111111	4923.5	4875.6	10082
3786	1.0542	111111011111111	4848.6	4798.5	9907	111110001111111	4844.8	4812.8	9918
3659	1.0428	111111011111111	4605.4	4660.6	9466	111110001111111	4609.9	4681.8	9492
3458	1.0249	111111011111111	4247.1	4452.6	8811	111110001111111	4248.0	4422.4	8780
3394	1.0192	111111011111111	4133.3	4362.9	8580	111110001111111	4134.5	4332.7	8550
3334	1.0138	111111011111111	4028.0	4282.1	8369	111111001111111	4027.9	4279.0	8479
3329	1.0134	111111011111111	4019.3	4275.9	8352	111111001111111	4019.2	4272.6	8349
3348	1.0151	111111011111111	4052.4	4299.6	8417	111110001111111	4054.0	4282.9	8431

Table 4
Comparison of Total Production Cost for different Cases

Cases	Total production cost with PFC in $/day	Solution Time (Sec)	Total production cost with CA in $/day	Solution Time (Sec)
IEEE 14 bus	15863.08	229	16281.26	1124
IEEE 30 bus	20484.48	391	21234.6	4968
IEEE 57 bus	73483.95	5,846	88133.68	122,121
IEEE 118 bus	704417.35	124,404	705057.7	514,230
Indian Utility System	219736.0	28,206	220173.8	313,998

3 Simulation and Results

Five case studies consisting of an IEEE 14, 30, 57, 118 bus systems and Indian utility 75 bus system have been considered to illustrate the performance of UC schedule with operational, power flow and environmental constraints along with contingencies in the network. The UC schedule obtained considering contingency analysis is very realistic as it has the capability to withstand when contingency exists in a particular line. The contingency analysis is not performed on the lines which are completely dedicated for generating and supplying the loads. The unit combination which satisfies the load demand and spinning reserve are allowed to perform OPF for every contingency and the unit combination for which OPF converges for every line removal is selected. For that unit combination OPF is performed without considering any contingencies, store the dispatch, emission output, fuel and transitional cost. The commitment schedules with contingency analysis and with power flow constraints (PFC) for the above case studies have been tabulated from Table I to III.

Loads at different buses are assumed to be variable and have been generated using Gaussian random noise function for the twenty four hours during power flow simulations because in practice the loads do not vary uniformly. In the proposed approach, the UCP schedule with minimum generation and cost of the generating units were obtained in CEED with operational and power flow constraints. The UC schedules and the transitional cost, fuel cost and emission output at each stage with power flow constraints and with contingency analysis for IEEE 30 bus and Indian utility systems are given in Table I and III. Table II gives only the UC schedules with power flow constraints and with contingency analysis for IEEE 14, 57, 118 bus systems. The characteristics of generators, unit constraints and the emission coefficients are given in Appendix. The network topology and test data for the IEEE systems are given in www.ee.washington.edu/research/pstca.

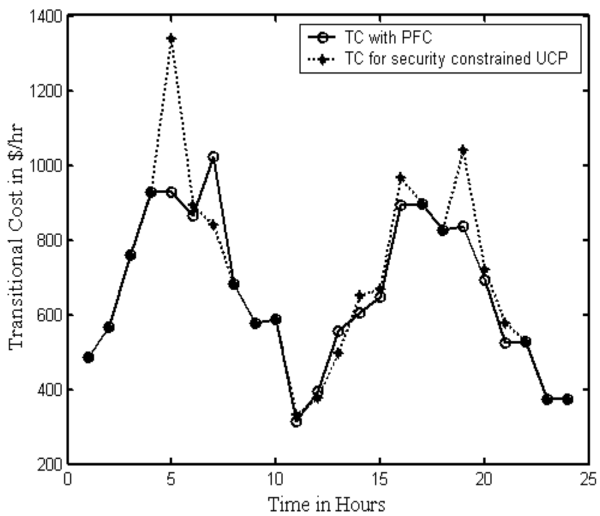

Fig. 1. Transitional cost for IEEE 14 bus system

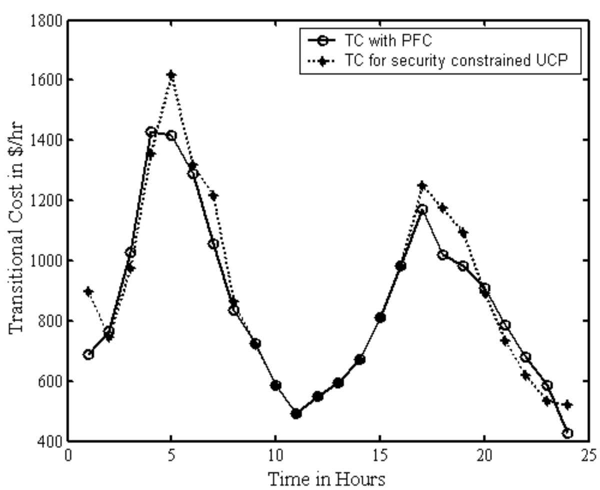

Fig. 2. Transitional cost for IEEE 30 bus system

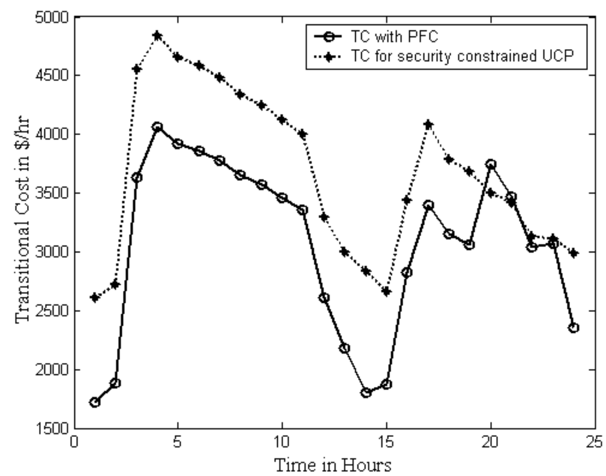

Fig. 3. Transitional cost for IEEE 57 bus system

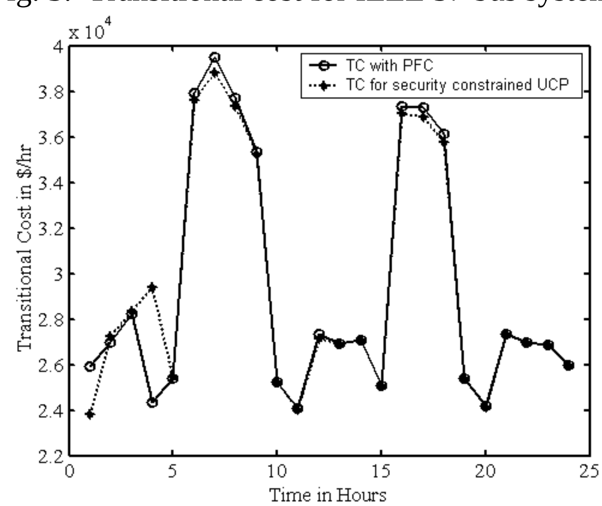

Fig. 4. Transitional cost for IEEE 118 bus system

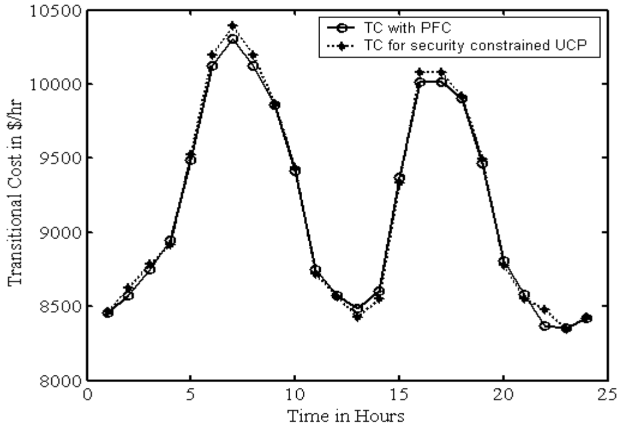

Fig. 5. Transitional cost for Indian Utility system

From Table IV, comparing the results of security and emission constrained UCP (SEUCP) and UCP with OC, PFC and EC, the total generation cost requirement for SEUCP increases by a percentage of 2.56%, 3.53%, 16.62%, 0.09% and 0.20% respectively for IEEE 14, 30, 57, 118 bus systems and Indian utility system with respect to the total generation cost obtained using operational, power flow and environmental constraints. In a similar way, the solution time also increases with the inclusion of additional constraints.

The total generation cost obtained by modified penalty price factor h_m gives accurate results. The minimum total generation cost under different IEEE systems and Indian utility system including operational, power flow and environmental constraints with contingencies is given in Table IV.

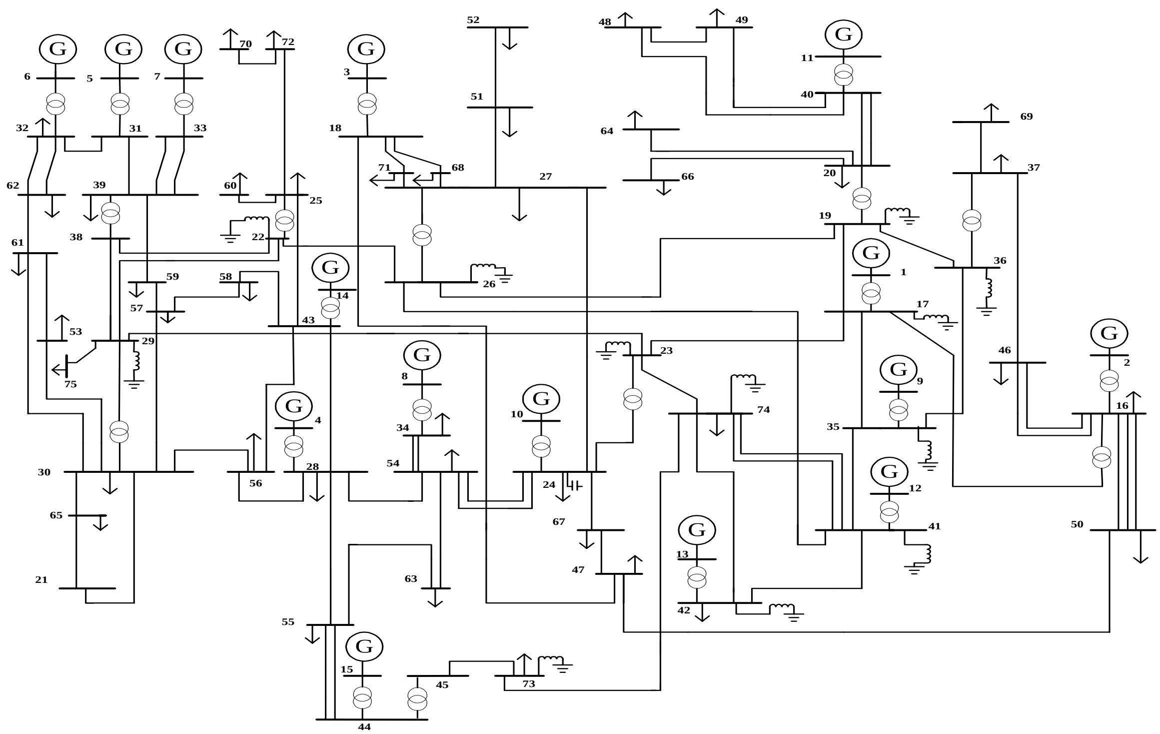

Fig. 6. One line diagram for Indian Utility system

The 75-bus Uttar Pradesh State Electricity Board (UPSEB) Indian Utility system with fifteen generating units is shown in Fig.6. For every hour, all the possible combinations that satisfy the load demand and spinning reserve constraints are selected and these states are allowed to perform OPF for all the possible contingencies that can happen in that network. If the state converges for OPF for every line removal, then select that state and perform OPF without any contingencies and store that state. Similarly all the states that satisfy OPF for every contingency in the system and demand on that hour are stored.

This procedure has to continue for the specified time horizon. Now select the state that possess minimum cost and satisfies the unit constraints for the entire time horizon. Finally the complete unit commitment schedule with total minimum production cost including the emission constraint has been obtained. Unit commitment schedule without power flow constraints may not be practical, since the states must include the system network losses and also converge for optimal power flow. Fig 1 to 5 shows the transitional generation cost for every hour with power flow constraints and with security constraints based on the price penalty factor (PPF) for different IEEE bus systems and Indian utility system. The solution results in this study indicate that the proposed algorithm is applicable to the day-ahead UC calculation of large scale power systems.

The platform used for the implementation of this proposed approach is on INTEL[R], Pentium [R] 4 CPU 1.8 GHz, 256 MB of RAM and simulated in the MATLAB environment. The solution obtained using modified price penalty factor gives exact solution. Large amount of saving is possible by applying modified price penalty factor. The solution results in this study indicate that the proposed algorithm is applicable to the day-ahead UC calculation of large scale power systems.

4 Conclusion

This paper presents an approach to perform contingency analysis in the network and solve UCP by accommodating operational, power flow and environmental constraints. This algorithm would give realistic results as the entire unit and network constraints are included. The commitment schedule holds well even if there is any contingency in any of the lines in the network as the selected unit combination has been converged for OPF for every contingency occurred in the system. The commitment schedule obtained by performing contingency analysis has been compared with the commitment schedule obtained by incorporating both network and unit constraints.

Since exhaustive enumeration technique is used, it guarantees the optimality of the solution. Modified price penalty factor has been applied to solve the UCP to get exact best solution for the corresponding load demands. The effectiveness of this method has been demonstrated on an IEEE 14, 30, 57, 118 buses and on Indian utility system and may also be extended to large systems. The results achieved are quite encouraging and indicate the viability of the proposed technique to deal with future unit commitment problems.

5 Appendix

Gen No	Max MW	Min. MW	Ramp Level (MW/Hr)	γ	β	α	a	b	c	Min Up Time (Hr)	Min Down Time (Hr)	Shut down Cost ($)	Cold Start (Hr)	Init. unit status	Startup costs	
															Hot ($)	
1	1500	100	300	0.0036	-0.81	24.300	0.0008	0.8140	0	3	2	50	3	4	70	1
2	300	100	100	0.0035	-0.10	27.023	0.0014	1.3804	0	3	1	60	2	5	74	2
3	200	40	100	0.0330	-0.50	27.023	0.0016	1.5662	0	3	2	30	3	5	50	3
4	170	40	110	0.0034	-0.30	22.070	0.0016	1.6069	0	4	2	85	1	7	110	4
5	240	2	150	0.0380	-0.81	24.300	0.0016	1.5662	0	1	1	52	1	5	72	5
6	120	1	120	0.0330	-0.50	27.023	0.0018	1.7422	0	1	1	30	1	3	40	6
7	100	1	50	0.0034	-0.03	29.040	0.0018	1.7755	0	1	1	50	2	4	70	7
8	100	20	80	0.0039	-0.02	29.030	0.0018	1.7422	0	1	1	60	1	5	74	8
9	570	60	214	0.0030	-0.20	27.050	0.0012	1.1792	0	4	2	30	3	5	50	9
10	250	30	140	0.0034	-0.30	22.070	0.0017	1.6947	0	2	1	85	1	7	110	10
11	200	40	400	0.0034	-0.25	23.010	0.0016	1.6208	0	1	1	52	2	5	72	11
12	1300	80	260	0.0035	-0.03	21.090	0.0004	0.4091	0	3	1	30	1	3	40	12
13	900	50	380	0.0038	-0.41	24.300	0.0007	0.6770	0	3	2	50	2	10	70	13
14	150	10	80	0.0034	-0.20	23.060	0.0015	1.4910	0	2	1	60	1	5	74	14
15	454	20	160	0.0036	-0.10	29.000	0.0010	1.0025	0	1	1	30	0	5	50	15

Table 5. Cost, Emission Coefficients, Unit Characteristics of Indian Utility System

Table 6. Cost, Emission Coefficients, Unit Characteristics of IEEE 57 Bus system

Gen No	Max MW	Min. MW	Ramp Level (MW/ Hr)	γ	β	α	a	b	c	Min Up Time (Hr)	Min Down Time (Hr)	Shut down Cost ($)	Cold Start (Hr)	Init. unit status	Startup costs	
															Hot ($)	Cold ($)
1	576	50	120	0.0126	-0.90	22.983	0.0017	1.7365	0	3	2	50	3	4	70	176
2	100	10	50	0.0210	-0.10	26.313	0.0100	10.0	0	3	1	60	2	5	74	187
3	140	20	50	0.0194	-0.20	25.888	0.0071	7.1429	0	2	1	30	3	5	50	113
4	100	10	50	0.0210	-0.10	26.313	0.0100	10.0	0	4	2	85	1	7	110	267
5	550	40	350	0.0134	-0.82	23.104	0.0018	1.81	0	1	1	52	1	5	72	180
6	100	10	25	0.0210	-0.10	26.313	0.0100	10.0	0	1	1	30	1	3	40	113
7	410	30	105	0.0152	-0.76	23.736	0.0024	2.4390	0	2	1	50	2	4	70	176

Table 7. Cost, Emission Coefficients, Unit Characteristics of IEEE 14 Bus system

Gen No	Max MW	Min. MW	Ramp Level (MW/ Hr)	γ	β	α	a	b	c	Min Up Time (Hr)	Min Down Time (Hr)	Shut down Cost ($)	Cold Start (Hr)	Init. unit status	Startup costs	
															Hot ($)	Cold ($)
1	250	10	70	0.0126	-0.90	22.983	0.00375	2.0	0	1	1	50	2	1	70	176
2	140	20	28	0.0200	-0.10	25.313	0.01750	1.75	0	2	1	60	2	3	74	187
3	100	15	20	0.0270	-0.01	25.505	0.06250	1.0	0	1	1	30	1	2	50	113
4	120	10	44	0.0291	-0.005	24.900	0.00834	3.25	0	1	2	85	1	3	110	267
5	45	10	9	0.0290	-0.004	24.700	0.02500	3.0	0	1	1	52	1	-2	72	180

Table 8. Cost, Emission Coefficients, Unit Characteristics of IEEE 30 Bus system

Gen No	Max MW	Min. MW	Ramp Level (MW/ Hr)	γ	β	α	a	b	c	Min Up Time (Hr)	Min Down Time (Hr)	Shut down Cost ($)	Cold Start (Hr)	Init. unit status	Startup costs	
															Hot ($)	Cold ($)
1	200	50	50	0.0126	-0.90	22.983	0.00375	2.0	0	1	1	50	2	-1	70	176
2	80	20	20	0.0200	-0.10	25.313	0.01750	1.7	0	2	2	60	1	-3	74	187
3	50	15	13	0.0270	-0.01	25.505	0.06250	1.0	0	1	1	30	1	2	50	113
4	35	10	9	0.0291	-0.005	24.900	0.00834	3.25	0	1	2	85	1	3	110	267
5	30	10	8	0.0290	-0.004	24.700	0.02500	3.0	0	2	1	52	1	-2	72	180
6	40	12	10	0.0271	-0.0055	25.300	0.02500	3.0	0	1	1	30	1	2	40	113

Table 9. Cost, Emission Coefficients, Unit Characteristics of IEEE 118 Bus system

Gen No	Max MW	Min. MW	Ramp Level (MW/Hr)	γ	β	α	a	b	c	Min Up Time (Hr)	Min Down Time (Hr)	Shut down Cost ($)	Cold Start (Hr)	Init. unit status	Startup costs	
															Hot ($)	Cold ($)
1	500	50	200	0.016	-1.500	23.333	0.0018	1.8180	0	3	2	50	3	4	70	176
2	90	10	18	0.011	-1.040	68.828	0.0054	5.4050	0	3	1	60	2	5	74	187
3	300	30	60	0.013	-1.249	22.050	0.0031	3.1250	0	3	2	30	3	5	50	113
4	400	40	80	0.012	-1.355	22.983	0.0024	2.4150	0	4	2	85	1	7	110	267
5	10	1	2	0.009	-1.100	20.001	0.0093	9.3460	0	1	1	52	1	5	72	180
6	23	3	5	0.010	-1.110	40.313	0.0084	8.4030	0	1	1	30	1	3	40	113
7	240	30	48	0.020	-1.900	21.313	0.0033	3.2890	0	2	1	50	2	4	70	176
8	50	5	10	0.011	-1.140	60.828	0.0068	6.7570	0	3	1	60	1	5	74	187
9	200	20	40	0.015	-1.401	23.001	0.0039	3.9220	0	4	5	30	4	5	50	113
10	200	20	40	0.015	-1.401	23.001	0.0038	3.8460	0	2	1	85	1	7	110	267
11	400	90	130	0.018	-1.800	24.003	0.0020	2.0370	0	3	2	52	2	5	72	180
12	400	90	130	0.019	-2.000	25.121	0.0020	2.0320	0	3	1	30	1	3	40	113
13	900	100	305	0.012	-1.360	22.990	0.0012	1.2420	0	3	2	50	2	10	70	176
14	600	50	120	0.033	-2.100	27.010	0.0017	1.7330	0	2	1	60	1	5	74	187
15	5	1	1	0.006	-0.094	19.584	0.0096	9.6150	0	1	1	30	0	5	50	113
16	700	50	150	0.018	-1.800	25.101	0.0014	1.4140	0	2	2	85	1	7	110	267
17	300	30	60	0.018	-1.810	24.313	0.0028	2.8410	0	3	1	52	2	5	72	180
18	50	5	10	0.011	-1.140	60.828	0.0071	7.1430	0	3	1	30	1	3	40	113
19	40	4	8	0.011	-1.140	60.828	0.0074	7.3530	0	1	1	50	0	4	70	176

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