On-Line Detection of Loss of Synchronism Using Locally Measurable Quantities

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Abstract— **Maintaining dynamic security of a power system subjected to large disturbances is of utmost importance. Fast and accurate on-line detection of instability is essential in initiating certain emergency control measures. The techniques reported in the literature involve mainly application of global phasor measurements and heuristic algorithms. In this paper, an accurate technique for the on-line detection of loss of synchronism based on voltage and current measurements in a line is presented. The technique makes use of the concept of potential energy in a line. The conditions for the system instability are derived from energy function analysis. However no assumptions are made regarding the power-angle relationship in a line, nor any data on the system equivalents are necessary in implementing the detection scheme which is simple and requires only local measurements.**

Keywords— **on-line detection of loss of synchronism, system protection, transient stability**

I. Introduction

The occurrence of a large disturbance in a power system may lead to uncontrolled tripping of generators and cascaded outage and may finally result in a black out, if proper actions are not taken. There are many discrete control measures [1,2] which can be initiated to maintain system stability. Some of the emergency measures like generator tripping and controlled system separation should be exercised only when there is an absolute necessity. Hence a fast and accurate method of distinguishing between stable and unstable swings is necessary.

The conventional out-of-step relaying based on impedance measurement on a transmission line has many limitations. The relay settings are normally made such that satisfactory operation is possible for different operating conditions and a number of pre-determined contingencies; hence the settings are not optimum for any single case. To overcome these limitations, an adaptive out-of-step relaying scheme was proposed [3]. In this scheme the relay settings are adapted to suit the prevailing system conditions. The system is represented by an equivalent generator on either side of the line and the relay uses the equal area criterion in performing the transient stability computation. The system angle is obtained using phasor measurements on the interconnection.

Most of the techniques proposed for the detection of instability use global phasor measurements. In [4,5], a small-size equivalent of the system is obtained in real time from the post-fault phasor measurements and the equivalent model is solved to predict future behaviour. In [6], system instability condition is detected by identifying the characteristic (concave or convex) of the post-fault trajectory; the method uses global phasor measurements. In [7,8], intelligent techniques like decision trees and artificial neural networks are used to distinguish between stable and unstable swings; the inputs used are obtained from global phasor measurements. In [9], a method for detecting loss of synchronism using power and current measurements on a tie-line, is proposed.

In this paper, a method of on-line detection of loss of synchronism based on voltage and current measurements in a line is presented. The conditions for system instability are derived from energy function analysis. The potential energy with generators represented by classical model can be expressed as sum of energies in the series elements (transmission lines, transformers and generator reactances) [10]. In this paper, it is shown that such an expression is applicable even for detailed (1.1) generator model. Under certain assumptions, it is possible to express the potential energy as sum of energies in the lines belonging to a cutset. The technique proposed in this paper makes use of the potential energy in a line belonging to the cutset. The technique has been tested extensively by simulation studies on the New England 10 generator system and the IEEE 17 generator (benchmark) system. The paper reports on these studies along with methods of speeding up the detection of instability based on prediction of system trajectories.

II. Energy Function

A power system with n buses and m generators represented by detailed (1.1) model is considered. The system is assumed to be lossless. The equations governing the system are [2]

$$\frac{d\theta_i}{dt} = \omega_i \tag{1}$$

$$\frac{d\omega_i}{dt} = \frac{1}{M_i}(P_{mi} - P_{gi} - \frac{M_i}{M_T}P_{COI}) \tag{2}$$

$$\frac{dE'_{qi}}{dt} = \frac{1}{T'_{doi}}[-E'_{qi} + (x_{di} - x'_{di})i_{di} + E_{fdi}] \tag{3}$$

$$\frac{dE'_{di}}{dt} = \frac{1}{T'_{qoi}}[-E'_{di} - (x_{qi} - x'_{qi})i_{qi}] \tag{4}$$

$$E'_{qi} + x'_{di}i_{di} = V_i cos(\phi_i - \theta_i) \tag{5}$$

$$E'_{di} - x'_{qi}i_{qi} = V_i sin(\phi_i - \theta_i) \tag{6}$$

$$i = 1, 2, ...m$$

$$P_{gi} - P_{Li} = \sum_{j=1}^{n} B_{ij}V_iV_j sin\phi_{ij} \tag{7}$$

$$Q_{gi} - Q_{Li} = -\sum_{j=1}^{n} B_{ij} V_i V_j cos\phi_{ij} \quad (8)$$
$$i = 1, 2, ...n$$

$$\begin{aligned} P_{gi} &= \frac{E'_{di} V_i cos(\theta_i - \phi_i)}{x'_{qi}} + \frac{E'_{qi} V_i sin(\theta_i - \phi_i)}{x'_{di}} \\ &+ \frac{V_i^2 sin\{2(\theta_i - \phi_i)\}}{2} \left(\frac{1}{x'_{qi}} - \frac{1}{x'_{di}} \right) \quad (9) \\ Q_{gi} &= -\frac{E'_{di} V_i sin(\theta_i - \phi_i)}{x'_{qi}} + \frac{E'_{qi} V_i cos(\theta_i - \phi_i)}{x'_{di}} \\ &+ \frac{V_i^2 cos\{2(\theta_i - \phi_i)\}}{2} \left(\frac{1}{x'_{qi}} - \frac{1}{x'_{di}} \right) \\ &- \frac{V_i^2}{2} \left(\frac{1}{x'_{qi}} + \frac{1}{x'_{di}} \right) \quad (10) \\ P_{COI} &= \sum_{i=1}^{m} (P_{mi} - P_{gi}) \\ M_T &= \sum_{i=1}^{m} M_i \\ \phi_{ij} &= \phi_i - \phi_j \end{aligned}$$

where,

- θ_i : rotor angle in centre of inertia reference
- ω_i : rotor speed in centre of inertia reference
- M_i : inertia constant
- P_{mi} : mechanical power input to generator
- P_{gi} : electrical power output of generator
- E'_{qi} : generator quadrature axis voltage
- T'_{doi} : direct axis open circuit transient time constant
- x_{di} : direct axis reactance
- x'_{di} : direct axis transient reactance
- i_{di} : generator direct axis current
- E_{fdi} : generator field voltage
- E'_{di} : generator direct axis voltage
- T'_{qoi} : quadrature axis open circuit transient time constant
- x_{qi} : quadrature axis reactance
- x'_{qi} : quadrature axis transient reactance
- i_{qi} : generator quadrature axis current
- P_{Li} : static active power load, assumed to be constant
- Q_{gi} : reactive power output at generator terminal
- Q_{Li} : static reactive power load, assumed to be a function of bus voltage
- B_{ij} : ij^{th} element of the network admittance matrix
- V_i : bus voltage
- ϕ_i : bus angle in centre of inertia reference

An energy function W for this system [2] is defined as

$$W = W_1 + W_2 \quad (11)$$

W_1 is kinetic energy and W_2 is potential energy given by

$$\begin{aligned} W_1 &= \frac{1}{2} \sum_{i=1}^{m} M_i \omega_i^2 \\ W_2 &= \sum_{i=1}^{6} W_{2i} \\ W_{21} &= -\sum_{i=1}^{m} P_{mi} (\theta_i - \theta_{io}) \\ W_{22} &= \sum_{i=1}^{n} P_{Li} (\phi_i - \phi_{io}) \\ W_{23} &= \sum_{i=1}^{n} \int_{V_{io}}^{V_i} \frac{Q_{Li}}{V_i} dV_i \\ W_{24} &= \frac{1}{2} \sum_{i=1}^{m} \{(Q_{gi}^{in} - Q_{gio}^{in}) - (Q_{Li} - Q_{Lio})\} \\ W_{25} &= \sum_{i=1}^{m} \int_{t_o}^{t} i_{di} \frac{dE'_{qi}}{dt} dt \\ W_{26} &= -\sum_{i=1}^{m} \int_{t_o}^{t} i_{qi} \frac{dE'_{di}}{dt} dt \end{aligned}$$

where Q_{gi}^{in} is the reactive power output at the internal bus of generator i. The energy function is defined for the postfault system and the time derivative of W is zero along a postfault trajectory. The subscript 'o' in the above expressions indicates quantities at time t_o.

The potential energy W_2 is equivalent to (proof is given in the appendix)

$$W_2 = \sum_{k=1}^{ns} \int_{t_o}^{t} (P_k - P_{ks}) \frac{d\delta_k}{dt} dt \quad (12)$$

where P_k is the power flow in the series element k, P_{ks} is the steady state value of P_k, δ_k is the phase angle difference across the element and ns is the total number of series elements.

III. Detection of Instability

When a power system becomes unstable, it initially splits into two groups. There is usually a unique cutset consisting of series elements (connecting the two groups) across which the angle becomes unbounded. This is illustrated in Fig. 1 in which the angle across all series elements (transmission lines, transformers and generator reactances) are plotted for a three phase fault at bus #14 (of New England 10 generator system) cleared after 0.28 s. The angle across the lines 18-19 and 11-12 become unbounded. Hence for this case, these two lines form the critical cutset across which the system separates into two areas.

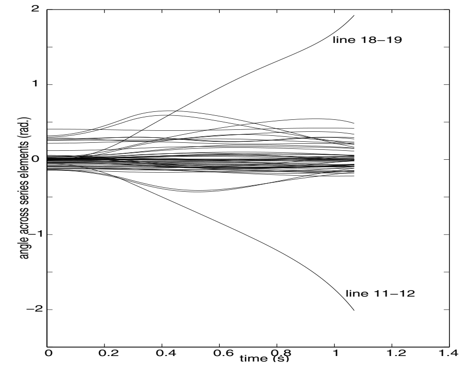

Fig. 1. Angle across series elements for an unstable case

The potential energy can be decomposed into the energy within the two areas and the energy along the critical cutset [10]. Assuming coherent areas, the potential energy within an area is zero as all the buses in that area have the same frequency ($\frac{d\delta_k}{dt}$ is zero for all series elements within an area). Hence

$$W_2 = \sum_{k=1}^{nc} \int_{t_o}^{t} (P_k - P_{ks}) \frac{d\delta_k}{dt} dt \tag{13}$$

where nc is the number of elements in the critical cutset. It can be shown that the variation of potential energy in all the lines in the critical cutset is similar. If a series element (line or transformer) k in the critical cutset connects buses i and j,

$$P_k = V_i V_j b_k sin\delta_k \tag{14}$$

$$\delta_k = \phi_i - \phi_j \tag{15}$$

where V_i and V_j are the voltage magnitudes at buses i (in area I) and j (in area II) respectively and b_k is the susceptance of the series element. Due to the assumption of coherency, the variations of V_i and ϕ_i are similar for all the elements in the cutset. This is also true of the variations of V_j and ϕ_j. Hence the variation of potential energy can be monitored from the energy in the individual lines in the cutset. Hence

$$W_2 = A_k W_{2k} \tag{16}$$

where A_k is a constant and subscript k refers to any element in the cutset, and

$$W_{2k} = \int_{t_o}^{t} (P_k - P_{ks}) \frac{d\delta_k}{dt} dt \tag{17}$$

The corrected kinetic energy W_1' to properly account for the portion of the kinetic energy that contributes to system separation [11] is given by

$$W_1' = \frac{1}{2} M_{eq} \omega_{eq}^2 \tag{18}$$

where

$$M_{eq} = \frac{M_I M_{II}}{M_I + M_{II}}, \qquad \omega_{eq} = \omega_I - \omega_{II}$$

$$M_I = \sum_{i\epsilon area\, I} M_i, \qquad M_{II} = \sum_{i\epsilon area\, II} M_i$$

$$\omega_I = \frac{1}{M_I} \sum_{i\epsilon area\, I} M_i \omega_i, \qquad \omega_{II} = \frac{1}{M_{II}} \sum_{i\epsilon area\, II} M_i \omega_i$$

By assumption of coherency, the rotor speeds of all the generators in an area are equal and the derivative of the angle across all the elements in the critical cutset are same. Hence

$$\omega_{eq} = \frac{d\delta_k}{dt} \tag{19}$$

where δ_k is the angle across any line in the critical cutset. The corrected kinetic energy is given by

$$W_1' = \frac{1}{2} M_{eq} \left(\frac{d\delta_k}{dt} \right)^2 \tag{20}$$

The criterion derived for the detection of instability is based on energy function analysis. The power system gains kinetic and potential energy due to a disturbance. For transient stability, the system must be capable of absorbing the kinetic energy completely. If the kinetic energy is not completely converted to potential energy, the system becomes unstable. Therefore for a stable swing, kinetic energy is zero when potential energy attains a maximum, and for an unstable swing, kinetic energy is not zero (positive) when potential energy attains a maximum. This criterion is used for the detection of instability, with kinetic and potential energy given by (20) and (16) respectively. Since the criterion checks whether kinetic energy is zero or positive when potential energy is maximum, it is adequate to monitor $\frac{d\delta_k}{dt}$ instead of the kinetic energy given by (20), and the potential energy given by (17) can be used instead of (16).

IV. Case Studies

The potential energy attains a maximum value when P_k=P_{ks} or $\frac{d\delta_k}{dt}$=0. For stable cases, $\frac{d\delta_k}{dt}$=0 (δ_k reaches a maximum value) when potential energy attains the first maximum; for unstable cases, $P_k = P_{ks}$ when potential energy attains the first maximum. Hence stability is dependent on whether $\frac{d\delta_k}{dt}$ becomes zero (δ_k reaches a maximum) before P_k drops to P_{ks} or vice versa. Figs. 2 and 3 show the variation of P_k and $\frac{d\delta_k}{dt}$ in the line 11-12 for fault at bus #14 (of 10 generator system) for stable (fault cleared after 0.27 s) and unstable (fault cleared after 0.28 s) cases. The detection criterion requires P_k and δ_k. These two quantities can be obtained by local measurements at one end of a line. δ_k is obtained from the measurement of voltage and current phasors (in each cycle) at one end of a line with the knowledge of line reactance.

For faster detection of instability, the variation of P_k and δ_k is predicted by fitting a polynomial curve to the sampled measurements. The sampling period τ is chosen as 1 or 2 cycles. The algorithm for prediction is as follows:

1. δ_k is measured at $t_s - 3\tau$, $t_s - 2\tau$, $t_s - \tau$ and t_s ($t_s \geq t_{cl} + 3\tau$), where t_s is the current sampling instant and

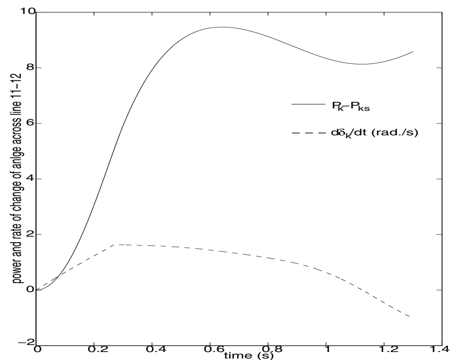

Fig. 2. Variation of power and rate of change of angle (Stable case)

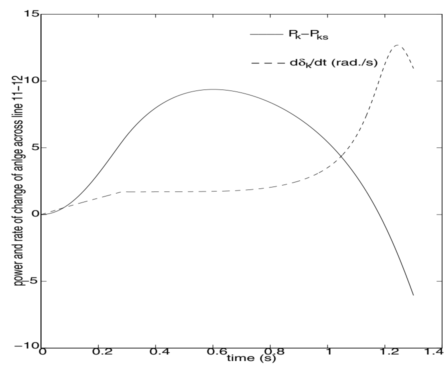

Fig. 3. Variation of power and rate of change of angle (Unstable case)

t_{cl} is the fault clearing time; P_k is measured at $t_s - 2\tau$, $t_s - \tau$ and t_s; P_{k1}, P_{k2} and P_{k3} are the sampled measurements of P_k at these instants respectively.

2. If $P_{k3} < P_{k2}$, a quadratic curve is fit to the three sampled measurements of P_k and a cubic curve is fit to the four sampled measurements of δ_k.

$$P_k - P_{ks} = a_1t^2 + b_1t + c_1 \quad (21)$$
$$\delta_k = a_2t^3 + b_2t^2 + c_2t + d_2 \quad (22)$$

3. The following two equations are solved for real positive values to obtain the instant t_1 at which $P_k = P_{ks}$ and the intant t_2 at which $\frac{d\delta_k}{dt}$=0.

$$a_1t^2 + b_1t + c_1 = 0 \quad (23)$$
$$3a_2t^2 + 2b_2t + c_2 = 0 \quad (24)$$

4. If $t_1 < t_2$ or if (23) has a real positive solution and (24) does not have a real positive solution, system is unstable; otherwise a new set of measurements are obtained and the procedure from step 2 is repeated.

The proposed detection criterion is tested on the New England 10 generator system and the IEEE 17 generator system. The network and generator losses are neglected. The loads are treated as constant impedances. The proposed detection criterion is tested by simulating three phase faults at different locations. Sample results are given in table I. The simulations in all the cases studies are for critically unstable fault clearing time. The results (the last 4 columns in table I) given are for the lines in which instability is first detected/predicted (a 'd' or'p' in the brackets indicates the lines in which instability is detected or predicted first). The average value of the angle between the centres of inertia (COI) of the two separating areas at the instant of detection is 176.0^o; the corresponding value with prediction is 114.8^o.

V. Discussion

The main objective of the detection criterion proposed is system protection as distinct from equipment protection. If instability is detected, corrective actions need to be taken in order to maintain system integrity.

Most of the techniques reported in the literature involve global phasor measurements. The adaptive out-of -step relaying requires phasor measurements for all the buses on the interconnection [3]. The relaying scheme also requires the knowledge of the equivalent system parameters that have to be reasonably accurate particularly with changing system conditions.

For a given mode of instability, there are many possible cutsets connecting the two separating areas; but there is usually a unique cutset across which the angle becomes unbounded in case of instability. For the 10 generator system, there are few critical cutsets. For many contingencies, generator #2 separates from the rest of the system since its inertia constant is high compared to other generators. For this mode of instability the critical cutset consists of lines 18-19 and 11-12. In the case of 17 generator system, the critical cutsets are different for faults at different locations.

For the 17 generator system, when there are many lines in the critical cutset, a false alarm is generated in few lines belonging to the critical cutset, for critically stable cases. In these lines P_k drops to P_{ks} immediately after the fault is cleared, reaches a minimum and again starts increasing. When the system is critically stable, P_k increases as the angle between the two separating areas increase. With further increase in angle, power decreases (as shown in fig. 2) due to dip in the voltage. In stable cases, the angle reaches a maximum and starts decreasing, thereby voltage recovers and P_k agains increases. Hence P_k reaches a minimum and starts increasing for critically stable cases whereas it monotically decreases (as shown in fig. 3) for unstable cases. The misjudgement can be avoided by predicting whether P_k reaches a minimum, only in those lines in which $P_k - P_{ks} < 0$ at the instant of fault clearing or within 0.05 s from the instant of fault clearing. It was observed that if the predicted time at which P_k reaches a minimum is less than 0.4 s, the system is stable. Hence if $a_1 > 0$ and $-\frac{b_1}{2a_1} < 0.4$ s, the system is stable.

It is interesting to observe that for the fault at bus #129 in the 17 generator system, there are 19 lines in the cutset

TABLE I

Angle between the Two Areas at the Instant of Instability Detection/Prediction

faulted bus #	line cleared	fault clearing time (s)	lines/transformers belonging to the critical cutset	angle between COI of two areas at the instant of instability detection/prediction (deg.)		instant of instability detection/prediction (s)	
				detection	prediction	detection	prediction
10 generator system (generators represented by classical model)							
37	37-27	0.21	11-12,18-19(d,p)	179.9	123.1	1.860	0.610
27	37-27	0.17	26-29(d,p),26-28	157.1	105.5	1.104	0.437
33	33-34	0.24	20-31(p),32-31(p),16-1(d,p)	115.5	81.0	0.573	0.340
26	26-29	0.07	26-28	148.9	102.8	1.037	0.604
10 generator system (generators represented by 1.1 model with excitation system)							
14	14-34	0.35	11-12(d),18-19(p)	203.4	126.2	1.000	0.450
37	37-27	0.30	11-12,18-19(d,p)	189.4	145.5	1.117	0.500
26	26-29	0.15	26-28	178.4	129.5	0.767	0.383
17 generator system (generators represented by classical model)							
112	4-112	0.24	112-121	182.1	155.4	0.423	0.340
120	5-120	0.26	110-114(d,p),112-121(p)	167.5	146.5	0.427	0.360
72	14-72	0.45	110-114	193.0	177.6	0.650	0.583
129	5-129	0.31	1-3,1-4(d,p),2-13,3-14,4-112 8-10,8-13,8-15,12-13,25-26, 26-74(d,p),51-141,53-55,20-53, 55-57(d,p),71-85(d,p),111-115, 143-144(d,p),144-146(d,p)	91.2	91.2	0.360	0.360

which separates the system into two groups. For this case the detection takes only 3 cycles after fault clearing which is not improved by prediction.

The detection criterion derived from energy function analysis is based on the assumptions of coherent areas and constant power loads. The coherency assumption is made to neglect the oscillations within the areas and account only for interarea oscillations which contribute to system separation. The detection criterion is effective even when the loads are modelled as constant impedances.

The main requirements of a method to detect instability are accuracy (no false alarms and false dismissals) and speed. The proposed method is capable of distinguishing between stable and unstable swings accurately. In all the cases studied, the unique cutset separating the two groups of generators is identified exactly. It is observed that for a given fault, the cutset is not altered by the generator modelling. The detection is speeded up by extrapolation.

When a fault is cleared by opening the line, the steady state value of power in the elements belonging to the critical cutset P_{ks} is different from the pre-fault steady state value. P_{ks} can be obtained from the results of on-line static security assessment.

The proposed method for detection of transient instability can also be used for dynamic security assessment. The method requires monitoring the variation of power and angle in a cutset instead of the swing curves. The use of the proposed prediction stategy can result in considerable savings in computation time.

VI. Conclusion

The paper presents a method of detection of instability based on energy function analysis. The detection criterion requires powerflow in a line and the angle across the line. Since these quantities can be obtained from local measurements, it is easy to implement the detection scheme. The method is accurate and the detection can be speeded up by predicting the variation of power and angle. The proposed detection criterion can be useful in initiating emergency control measures like controlled system separation.

VII. Appendix

Proof of (12):

$$\sum_{k=1}^{ns}\int_{t_o}^{t}(P_k - P_{ks})\frac{d\delta_k}{dt}dt = \sum_{i=1}^{ns}\int_{t_o}^{t}P_k\frac{d\delta_k}{dt}dt - \sum_{k=1}^{ns}P_{ks}(\delta_k - \delta_{ko}) \quad (25)$$

In a lossless system, power flows satisfy Kirchhoff's current law and deviation in bus angles from the initial value satisfy

Kirchhoff's voltage law. Hence an equivalent network can be obtained for the power system as shown in fig. 4, with power being considered analogous to current and deviation in bus angles to voltage. For any electric network, where the branch voltages and currents satisfy Kirchhoff's laws, Tellegen's theorem can be applied, which states that "at any time, the sum of the power delivered to each branch of the network is zero" [12]. Under steady state, P_{gi} is equal to P_{mi} and P_k is equal to P_{ks}. Tellegen's theorem is also

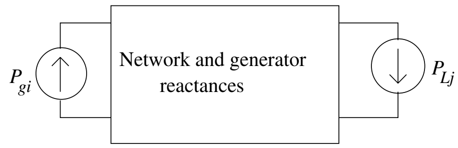

Fig. 4. Equivalent network of power system

valid when branch voltages of one network and the branch currents of another network are considered, provided the networks have the same graph. Applying Tellegen's theorem to the powers in steady state and deviation in bus angles at any instant, the second term on the RHS of (25) can be expressed as

$$\begin{aligned} -\sum_{k=1}^{ns} P_{ks}(\delta_k - \delta_{ko}) &= -\sum_{i=1}^{m} P_{mi}(\theta_i - \theta_{io}) \\ &\quad + \sum_{j=1}^{n} P_{Lj}(\phi_j - \phi_{jo}) \\ &= W_{21} + W_{22} \end{aligned} \tag{26}$$

The first term on the RHS of (25) can be separated into terms corresponding to power flows in the generator reactances and those corresponding to power flows in the transmission lines/transformers as follows:

$$\begin{aligned} \sum_{k=1}^{ns} \int_{t_o}^{t} P_k \frac{d\delta_k}{dt} dt &= \sum_{i=1}^{m} \int_{t_o}^{t} P_{gi} \frac{d(\theta_i - \phi_i)}{dt} dt \\ &+ \sum_{l=1}^{nl} \int_{t_o}^{t} P_l \frac{d\phi_{pq}}{dt} dt \end{aligned} \tag{27}$$

where nl is the number of lines and transformers, P_l is the power flow in the series element l connecting buses p and q. The first term on the RHS of (27) is evaluated by integrating the expression for P_{gi} (given by (9)) w.r.t. $(\theta_i - \phi_i)$ by parts. It can be shown that

$$\begin{aligned} \sum_{i=1}^{m} \int_{t_o}^{t} P_{gi} \frac{d(\theta_i - \phi_i)}{dt} dt = W_{25} + W_{26} + \sum_{i=1}^{m} \int_{t_o}^{t} \frac{Q_{gi}}{V_i} \frac{dV_i}{dt} dt \\ + \frac{1}{2} \sum_{i=1}^{m} [(i_{di}^2 - i_{dio}^2) x'_{di} + (i_{qi}^2 - i_{qio}^2) x'_{qi}] \end{aligned} \tag{28}$$

The second term on the RHS of (27) is evaluated by integrating the expression for P_l (given by (14)) w.r.t. ϕ_{pq} by parts. It can be shown that

$$\begin{aligned} \sum_{l=1}^{nl} \int_{t_o}^{t} P_l \frac{d\phi_{pq}}{dt} dt = W_{23} - \sum_{i=1}^{m} \int_{t_o}^{t} \frac{Q_{gi}}{V_i} \frac{dV_i}{dt} dt \\ - \frac{1}{2} \sum_{p=1}^{n} \sum_{q=1}^{n} B_{pq} (V_p V_q cos\phi_{pq} - V_{po} V_{qo} cos\phi_{pqo}) \end{aligned} \tag{29}$$

The sum of the last terms on the RHS of (28) and (29) gives half the reactive power losses in the generator reactances and the network. Substituting (28) and (29) in (27),

$$\sum_{k=1}^{ns} \int_{t_o}^{t} P_k \frac{d\delta_k}{dt} dt = W_{23} + W_{24} + W_{25} + W_{26} \tag{30}$$

(12) follows from (25), (26) and (30).

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