Any generator operating with a low power factor (for example units connected primarily for var support) would be very susceptible to high loss factor calculations. Assuming the power factor to be constant implies that with every increment in generator output there is a corresponding increase in generator var output. As actual transmission losses are not only a function of MW but also Mvar, the small change in generator output could have a significant impact on total system losses associated with the assumption of a constant '**R**' matrix. The net result is that low power factor generators could be assessed excessively large loss factor penalties or credits.

A second undesirable effect of this assumption is that some generators could be penalized in terms of increased loss factors for supplying vars to the system under conditions when vars are needed on the system. It is also conceivable that some generators and associated loads could receive credits for taking vars from the system under var shortage conditions.

One method of circumventing this issue is to treat all var injections, from both loads and generators as equivalent constant admittance shunt devices. The nodal admittance matrix must be adjusted to include this effect, before the '**R**' matrix is established.

The implication of this treatment of load and generator vars is that the load and generator var injections are treated as being constant. Since bus voltages are assumed to be constant, the vars generated by the equivalent shunt devices are also constant. This is again a reasonable approximation for small changes in generator output.

If the power market evolves to include equivalent var loss factors for both generators and loads, these assumptions would need to be revisited.

3.5 Area Load Methodology Using Uncorrected Loss Matrix

Equation (5) above also can be used to determine the change in losses for a small change in swing bus generation and total system load. If all of the loads in the system are increased by a small percentage (say δ), the total change in system losses can be approximated by the following expression for a given network configuration defined by "**R**" and linearized around a fixed operating condition defined by "**Pg**" and "**Pl**".

$$\Delta \text{Losses} = 2(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}} \cdot \mathbf{R} \cdot \mathbf{\Delta Pg} + \delta \cdot 2(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}} \cdot \mathbf{R} \cdot \mathbf{Pl} \qquad \text{Equation (13)}$$

$$\Delta \text{Losses} = \sum_i \Delta Pg_i + \delta \cdot \sum_i Pl_i \qquad \text{Equation (14)}$$

If only the generation at the loss factor bus "j" changes, then again the above equations can be reduced to two simultaneous equations with three unknowns (ΔLosses, ΔPg_j, δ).

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The simultaneous equations can be combined to again calculate the ratio:

$$\frac{\Delta \mathrm{Losses}}{\Delta \mathrm{Pg}_j} = \frac{2(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}} \cdot \mathbf{R} \cdot \left(\begin{pmatrix} 0 \\ 1_j \\ 0 \end{pmatrix} - \frac{\mathbf{Pl}}{\sum_i \mathrm{Pl}_i} \right)}{1 - \frac{2(\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}} \cdot \mathbf{R} \cdot \mathbf{Pl}}{\sum_i \mathrm{Pl}_i}}$$

at the generator bus "j" for which the loss factor is being determined. By linearizing the equations, the above ratio is independent of the magnitude of δ.

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For this methodology, the generator for which the loss factor is calculated effectively becomes the swing machine for the system. Hence the loss factors calculated are independent of an arbitrary selection of a swing bus in the system.

3.6 Area Load Methodology Using Corrected Loss Matrix

The calculation method discussed in 3.5 above was repeated using the corrected loss matrix. This method is again subject to the limitations introduced by the assumptions regarding the constant '**R**' matrix discussed in Section 3.4. Generator and load vars are treated as equivalent shunt devices and hence are indirectly assumed to be constant, by the assumption of constant voltages.

As the main function of generator loss factors is to define the relationship between generator power output and transmission losses, it is reasonable to assume that the variation in system load is related only to the active power component, i.e., the change in load vars is zero. The assumption of constant load vars in this corrected '**R**' matrix methodology is therefore reasonable.

3.7 Gradient Methodology Using Uncorrected Loss Matrix

The partial derivative of Equation (5) above with respect to individual generator output can be determined for each generator as follows:

$$\frac{\partial \mathrm{Losses}}{\partial \mathrm{Pg}_i} = 2 \cdot (\mathbf{Pg}+\mathbf{Pl})^{\mathbf{T}} \cdot \mathbf{R} \cdot \mathbf{S(i)} \qquad \text{Equation (15)}$$

where $\mathbf{S(i)}$ is a vector in which the i^{th} element is 1.0 and all other elements are zero.

A vector of all the gradients is simply:

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