A power system must be able to meet reasonable power demands by large and small customers of domestic, commercial and industrial type. It must withstand with reasonable security the capricious forces of nature. In an age of high energy costs it is called upon to transform the prime energy resources into electric form with an optimum overall efficiency. The control functions are obviously many and varied.

Some control and decision processes, exemplified by the optimal utilization of the controlled flow of river systems involve dynamics with month-long time constants. Other phenomena, like the transients on the transmission lines following lightning strikes, run their course in a few milliseconds.

The slower control processes are normally handled by computer-assisted human operators. The faster control functions are trusted to fully automatic control systems of either open or closed-loop nature.

The objective of this article is first to outline briefly the basic functional features of a power system and, secondly, describe some of the more important controls required for its satisfactory operation. Finally some of the more relevant research and development areas are identified and discussed.

1. The Power Grid

Fig. 1 shows a one-line diagram of a section of a larger system. The electric power is produced in the generators, transformed to an appropriate voltage level in the transformers and then via the buses sent out on the transmission lines for final distribution to the loads. Via tie-lines the system is connected to neighboring systems belonging to the same pool.

Fig. 1 does not show the low-voltage distribution portion of the system, which contains the majority of the load objects. For most important system studies it is sufficient to use lumped or composite representations of the loads. The load symbols in Fig. 1 are of the latter type.

The circuit breakers permit the tripping of faulty components and also sectionalizing of the system. High voltage dc (HVDC) is being used in special cases. However, the vast majority of the world's electric power is being generated, transformed, transmitted and distributed as high voltage ac (HVAC) of the three-phase variety. Collectively the generators, transformers, buses, lines and loads constitute the power network or grid.

2. Load Characteristics and Generator Mix

The loads vary widely over daily, weekly and seasonal cycles. Fig. 2 shows a typical daily fluctuation. Electric power travels on the lines at a speed close to that of light. In addition, the lines themselves (unlike gas transmission lines) have no energy storage capacity, and as a consequence the electric power must be generated at the instant it is being demanded by the loads. The installed generating capacity of the system must thus equal the peak demand plus a spinning reserve of 10–20 percent, the latter consisting of partially loaded generators.

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The power demand in Fig. 2 is met by a generator mix consisting of:

1. **Baseloaded units**, running fullloaded on a 24 hour basis. Nuclear and large fossilfired units fall in this category. Reactor cores and huge boilers do not tolerate fast power changes once thermal balance has been reached.

2. **Controllable units**, consisting of hydrogenerators and smaller fossil units. All such units have rate limits giving the fastest rates (MW/sec) with which their loads can be changed.

3. **Peak loaders**, which can pick up load relatively fast. Gasturbine-driven generators are common, but also generators driven from short-time energy storage facilities like pumped hydro, compressed gas or thermal storage (ref's. 1 and 2).

### 3. The Power Flow Equations (PFE)

Central to all analysis of power systems are the physical laws that determine the flow of the electric power throughout the system. We give a brief presentation of this important topic. (For more details see ref. 3.)

Consider an N-bus system. For a typical US power system \( N > 100 \). For very large systems \( N > 1000 \), Fig. 3 details bus \( #i \) of such a system, containing generation, load and \( n_i \) outgoing lines. For typical systems

\[
 n_i \ll N \tag{1}
\]

The bus is characterized by the bus voltage phasor \( V_i \), measured between the reference phase and ground. \( V_i \) has magnitude and phase defined by

\[
 V_i = |V_i| e^{j\delta_i} \tag{2}
\]

We choose bus \( #1 \) as reference bus and assign to it the voltage

\[
 V_1 = |V_1| e^{j0^0} \tag{3}
\]

All other voltage and current phasors are measured relative to \( V_1 \).

The bus current, \( I_i \), is defined as the difference between the generator current \( I_{Gi} \) and the load current \( I_Li \), i.e.

\[
 I_i = I_{Gi} - I_{Li} = |I_i| e^{j\alpha_i} \tag{4}
\]

The bus power consists of two components, the real and reactive powers, \( P_i \) and \( Q_i \) respectively, defined as follows:

\[
 P_i = |V_i||I_i| \cos \phi_i \tag{5}
\]

\[
 Q_i = |V_i||I_i| \sin \phi_i \tag{6}
\]

where \( \phi_i \) is the relative phase between \( V_i \) and \( I_i \), i.e.,

\[
 \phi_i = \delta_i - \alpha_i \tag{7}
\]

\( P_i \) and \( Q_i \) represent the generated minus the load power at bus \( i \), measured in MW and Mvar par phase resp. It can be readily shown that \( P_i \) and \( Q_i \) satisfy the complex equation

\[
 P_i - jQ_i = V_i^* I_i \tag{8}
\]

where \( ( \ )^* \) denotes "conjugate."

As the network is linear, electric circuit theory tells us that the following linear relationship exists between the \( V_i \)'s and \( I_i \)'s:

\[
 I_{bus} = Y_{bus} V_{bus} \tag{9}
\]

The N-dimensional vectors \( I_{bus} \) and \( V_{bus} \) are defined by

\[
 I_{bus} \triangleq \begin{bmatrix} I_1 \\ \vdots \\ I_N \end{bmatrix} \quad \text{and} \quad V_{bus} \triangleq \begin{bmatrix} V_1 \\ \vdots \\ V_N \end{bmatrix} \tag{10}
\]

The \( N \times N \) busadmittance matrix

\[
 Y_{bus} \triangleq \begin{bmatrix} y_{11} & \cdots & y_{1N} \\ \vdots & \ddots & \vdots \\ y_{N1} & \cdots & y_{NN} \end{bmatrix} \tag{11}
\]

is symmetric and contains the elements \( y_{ij} \) which are complex of the form

\[
 y_{ij} = |y_{ij}| e^{j\gamma_{ij}} \tag{12}
\]

As a result of the nonequality (1), \( Y_{bus} \) is a sparse matrix, i.e., most of its off-diagonal elements are zero. (A nonexisting line between buses \( i \) and \( j \) means that \( y_{ij} \) is zero.) Upon substitution of the ith of equations (9) into eq. (8) we obtain

\[
 P_i - jQ_i = V_i^* \sum_{j=1}^{N} y_{ij} V_j \quad \text{for} \quad i = 1, \ldots, N \tag{13}
\]
Separation of the real and imaginary parts of eq. (13) yields the $2N$ real equations:

$$f_{pi} = P_i - \sum_{j=1}^{N} |y_{ij}| |V_i| |V_j| \cos (\gamma_{ij} + \delta_j - \delta_i) = 0$$

$$f_{qi} = Q_i + \sum_{j=1}^{N} |y_{ij}| |V_i| |V_j| \sin (\gamma_{ij} + \delta_j - \delta_i) = 0$$

(14)

for $i = 1, \cdots, N$

These are the famous power flow equations (PFE). In contrast to eq’s (9) they are highly nonlinear. Physically they express real and reactive power balance at the $N$ buses.

We can view the bus powers $P_i$ and $Q_i$ as control inputs. By their manipulation we can affect or control the voltage safe variables $I_i$ and $\delta_i$. In accepted control lingo we thus have the state and control vectors

$$x = \left[ \begin{array}{c} \delta_1 \\ \vdots \\ \delta_N \\ |V_1| \end{array} \right], \quad u = \left[ \begin{array}{c} P_1 \\ \vdots \\ P_N \\ Q_1 \\ \vdots \\ Q_N \end{array} \right]$$

(15)

and

$$x \in \mathbb{R}^{2N}, \quad u \in \mathbb{R}^{2N}$$

The vectors $x$ and $u$ each are of dimension $2N$. The subvectors $\delta, |V|, P$ and $Q$ each are of dimension $N$.

### 4. Normal Operating State

A power system operates in a normal state if the following conditions are met:

1. All the load demands are met and the PFE’s are satisfied.
2. The frequency, $f$, is constant (60 Hz in USA)
3. The bus voltage magnitudes $|V_i|$ are within prescribed limits.
4. No components are overloaded.

According to Fig. 2 the demands vary slowly with time. Thus, in order to track the loads to meet requirement #1 the normal state is “drifting” as the hours wear on.

Frequency constancy is required for a number of reasons; electric clocks must be accurate, steamturbines must not be subjects to blade resonance, motor speeds must be kept constant. However, the most important reason for keeping $f$ constant is that its constancy indicates that total system powerbalance is maintained (Sect. 9).

Voltage constancy is required because all load objects from lightbulbs to giant motors are voltage rated.

Component overload must be avoided as it results in elevated temperatures and risk for damage. For a transmission line thermal damage is only half the problem. It can be shown (ref. 3) that the real power, $P_{kl}$, transmitted on the line connecting buses $k$ and $l$ follows the formula

$$P_{kl} \approx \frac{|V_k||V_l|}{X_{kl}} \sin (\delta_k - \delta_l)$$

(17)

where $X_{kl}$ is the line reactance. As this power increases, the line power angle, $\delta_k - \delta_l$, may reach $90^\circ$ in which case we have reached the static power limit

$$P_{kl\max} \approx \frac{|V_k||V_l|}{X_{kl}}$$

(18)

Any attempt to further increase the power would result in the loss of synchronism and transmission collapse. For relatively short lines (less than 200 miles) the thermal limit typically determines the line loading. For long lines the situation is reversed and the static power limit now becomes the critical concern.

### 5. The State Transition Diagram

Dy Liacco (ref. 4) defined the various “states” in which a power system may be found. Fink and Carlsen (ref. 5) went further and suggested the state transition diagram shown in Fig. 4. This diagram provides a good conceptual picture of the overall control requirements of a power system.

```
E,I
NORMAL

Restarts
Load pickup

Preventive
Control

E,I
RESTORATIVE

Resynchron-
ization

Alert

E,I
EMERGENCY

E,I
EXTREMIS

'E' = Equality Constraint
'I' = Inequality Constraint
'-' = Negation
```

Fig. 4. State transition diagram.

For more than 99 percent of the time we find the system in its normal state as defined in the previous section. In sect. 7 we shall discuss the normal state controls required to keep the system in this state. The symbol “E” refers to “equality” and means that the PFE’s are satisfied and frequency and voltage constancy observed. The symbol “I” refers to “inequality” and means that we are operating within rated component limits.

Assume now that the system would suffer the sudden loss of a generator or experience some other event that would reduce the security level. The system would now enter the alert state. The “E” and “I” would still be satisfied and,
with luck, we could operate in this state indefinitely. However, by preventive controls (for example start-up of reserve generators) we would seek to return the system to its normal state.

With the system still in the alert state some additional disturbance may occur, for example the tripping of a tie-line or the loss of an additional generator. The resulting power shift may then overload a line. The system remains intact, i.e., “E” is still satisfied but “I” is negated. The system now enters the extremis state. By means of emergency controls, we would now try to relieve the overload situation. For example, by lowering the bus voltages, one would force a reduction in the loads (“brownouts”).

Should the emergency controls fail then the overloaded line must be tripped. We may then see a series of cascading events which may lead to the extremis state. Typically, the system would now break up into islands, each of which would be operating at their own frequencies. Both “E” and “I” are now negated. Each island would typically be characterized by severe power imbalance and “heroic” control measures like load shedding or generator tripping would be tried to save as much as possible of the system. On rare occasions, however, the efforts might fail and the system would end up in a total “blackout.”

The restorative state involves generator restarts, re-synchronization and gradual load pickup. This is a slow process and can in severe cases last for hours and days.

6. Normal State Control—A Noninteraction Property

Maintaining a power system in its normal state is a high priority control function. The job is made relatively simple by a noninteraction property characterizing all power systems. We presently discuss this property.

Consider a system operating in its normal state. Small changes $\Delta P$ and $\Delta Q$ are now made in the control vectors $P$ and $Q$. As a result the state vectors $\delta$ and $|V|$ will undergo small changes $\Delta \delta$ and $|\Delta V|$ respectively. Eq's (14) yield the following relationships between the control and state changes:

$$\Delta P = \frac{\partial f_p}{\partial \delta} \Delta \delta_1 + \frac{\partial f_p}{\partial \delta_2} \Delta \delta_2 + \ldots$$

$$+ \frac{\partial f_p}{\partial |V_1|} \Delta |V_1| + \frac{\partial f_p}{\partial |V_2|} \Delta |V_2| + \ldots \approx 0$$

$$\Delta Q = \frac{\partial f_q}{\partial \delta_1} + \frac{\partial f_q}{\partial \delta_2} \Delta \delta_2 + \ldots$$

$$+ \frac{\partial f_q}{\partial |V_1|} \Delta |V_1| + \frac{\partial f_q}{\partial |V_2|} \Delta |V_2| + \ldots \approx 0$$

for $i = 1, \ldots, N$

We can write these linear relationships in the compact vector-matrix form

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \approx \begin{bmatrix} J_1 & J_2 \\ J_3 & J_4 \end{bmatrix} \begin{bmatrix} \Delta \delta \\ \Delta \Delta V \end{bmatrix}$$

(20)

The four Jacobian submatrices $J_1 \cdots J_4$ have as elements the partial derivatives computed in the normal state. The matrices are sparse.

We can write eq (20) in “component” form:

$$\Delta P \approx J_1 \Delta \delta + J_2 \Delta |V|$$

$$\Delta Q \approx J_3 \Delta \delta + J_4 \Delta |V|$$

(21)

In a typical power network the impedance elements are almost purely reactive which means that the angles $\gamma_{ij}$ of the $Y_{bus}$ elements are close to $\pm 90^\circ$. In addition we seldom operate with line power angles, $\delta_j - \delta_i$, above $30^\circ$. Under these circumstances it is easy to show that the submatrices $J_1$ and $J_4$ dominate over $J_2$ and $J_3$ and in a first approximation eq's (21) thus can be written in simpler form:

$$\Delta P \approx J_1 \Delta \delta$$

$$\Delta Q \approx J_4 \Delta |V|$$

(22)

In words: A change in the reactive bus power components will result in changes in the bus voltage magnitudes with only minor effects on the bus voltage phase angles. Similarly, changes in the real bus power components bring about changes in bus voltage phase angles with very minor effects on the voltage magnitudes.

We make mass additional important observations:

1. Assume that we manipulate the buspower at one bus, #k, only. As a result the voltages of all buses will change. The changes will be largest at bus k and diminish with the distance from this bus. However, all changes $\Delta |V_i|$ and $\Delta \delta_i$ will be of the same polarity as $\Delta Q_k$ and $\Delta P_k$ respectively. For example, if we increase $\Delta Q_k$ then the voltage magnitudes of all buses will increase with the largest increase measured at bus k.

2. The increments $\Delta P_k$ and $\Delta Q_k$ added at bus $k$ will divide and flow out on the $n_k$ lines terminating in bus $k$. At the ends of these lines there will be a further subdivision, etc. Powerinjection at a bus thus dissipates as it flows out in the network. This “dissipation effect” makes it possible to analyze phenomena in power systems by modeling only the local portion of the network. For example, the Florida and California grids are electrically interconnected, but a network disturbance in Florida, even a major one, will have no measurable effects in California.

7. The Normal State Controllers

In sect. 4 we stated the four conditions that must be met for the system to remain in its normal state. The obvious way to maintain a perfect power balance at each bus would be to continuously keep the generated powers, $P_{Gi}$ and $Q_{Gi}$, in balance with the changing load powers $P_{Li}$ and $Q_{Li}$. This then would maintain all $\Delta P_i$ and $\Delta Q_i$ at zero levels and thus all busvoltages and line powers at constant values.

This, of course, is neither desirable nor possible. It is undesirable because constant line powers would defeat the real purpose of transmission lines which is to make possible
at each moment the most economical transfer of power. Neither would it be possible since most buses lack both real and reactive power sources.

The most important power sources are the synchronous generators. Typically, generators are available only at less than five percent of the network buses. At these “generator buses” both $P_i$ and $Q_i$ can be controlled. The real power is controlled via the turbine torque, the reactive power via the “exciter” and field winding.

Generators obviously represent the most important means for system control. Each generator is equipped with two separate automatic feedback control loops both depicted in Fig. 5. The Automatic Voltage Regulator (AVR) loop maintains control of the bus voltage by means of manipulation of the reactive power output. The Automatic Load-Frequency Control (ALFC) loop maintains a constant frequency by manipulation of the real power output. Both these loops are designed to operate around the normal state with small variable excursions. Thus the loops may be modeled with linear, constant coefficient differential equations and represented with linear transfer functions. We look separately at the two loops.

8. The Automatic Voltage Regulator Loop

Depending upon size and type of the generator, excitation systems come in several different models. Ref. 6 gives a detailed classification. Here we briefly point out some of the more important features, that are typical of most AVR loops.

As shown in Fig. 5 the bus voltage is measured via a potential transformer (PT). After rectification and filtering the output is compared with a reference. The resulting error voltage, after amplification serves as input to an exciter which feeds directly into the generator field. A drop in the terminal voltage causes a boost in the field current. This increases the reactive power output of the machine thus tending to offset the initiating voltage drop.

The analysis of the loop is not difficult (ref. 3). The amplifier, exciter and field circuit each represent separate time constants the latter reaching values as high as 5-10 sec’s. The three time constants add the three real and negative open-loop poles marked $a$, $b$ and $c$ in Fig. 6. There will be three closed-loop root loci and three closed-loop poles the latter marked $A$, $B$ and $C$ in the same figure.

Normally, the closed loop should respond in less than 0.1 seconds. To overcome the slow field circuit and also for purposes of achieving sufficient static accuracy we obviously require very high loop gain. But this gain would push the conjugate complex pole pair ($A$, $B$) into the unstable s-plane. The AVR loop is clearly in need of effective stabilization if speed and accuracy requirements both have to be met. Ref. 6 describes various practical means for achieving stability compensation.

The AVR loop maintains reactive power balance at a generator bus by indirectly maintaining a constant voltage level. The generator buses thus can be considered “voltage fix points” in the network. One normally needs additional such fix points to assure an overall good voltage profile. This can be achieved by installing banks of shunt capacitors at certain key buses. A capacitor delivers reactive power and constitutes thus a “Q-source.” If negative bus power generation also is required banks of shunt reactors must also be installed. By controlling these capacitor and/or reactor banks from an error voltage similar to that of the AVR loop, automatic closed-loop voltage control can be achieved. The control itself can be done in on-off fashion by means of circuit breakers. Modern installations utilize thyristor control which permits continuous variation of the reactive power.
9. The Automatic Load-Frequency Control

Actually there is not one ALFC loop but two, designated "primary" and "secondary" in fig. 5. The purpose of both these loops is to achieve real power balance, or "load tracking," in the system. Just as the AVR loop achieves Q-balance by maintaining a constant voltage, the ALFC loops achieve P-balance by maintaining a constant frequency.

There is an important difference, however. The AVR loop is able to maintain perfect Q-balance only at those buses that are voltage controlled. The ALFC loops maintain primarily P-balance at the generator buses but because the frequency is the same throughout the system they thus collectively, achieve P-balance on a system wide-basis.

To understand the functioning of the ALFC loops we need to briefly review the mechanism whereby the generator supplies power to the network. Consider thus the generator in Fig. 5 to operate in its normal state. It delivers the constant electrical power, \( P_G \) megawatts, to the network. Through a rather intricate mechanism (ref. 3, chap. 4) the generator currents and the rotor magnetic field create a constant electro-mechanical decelerating torque \( T_G^0 \) which is related to the generator power through the equation

\[
T_G^0 = \frac{P_G^0}{\omega_m^0}
\]

(22)

\( \omega_m^0 \) is the mechanical rotational speed of the turbine-generator expressed in rad/sec.

The turbine delivers a constant accelerating torque, \( T_T^0 \), which if expressed in turbine power, amounts to

\[
p_T^0 = \omega_m^0 T_T^0
\]

(24)

The torques \( T_G^0 \) and \( T_T^0 \) (and the powers \( P_G^0 \) and \( P_T^0 \)) are in complete balance and the speed and frequency, \( \omega^0 \), are thus constant.

This equilibrium is suddenly upset by an electrical load change, \( \Delta P_G \), (fig. 5) due either to a change, \( \Delta P_L \), in the local load or a change, \( \Delta P_T \), in the line* power or both. The load increment \( \Delta P_L \), due, for example, to an added motor will be referred to as "new" load, in contrast to changes in already connected or "old" loads (see also Sect. 11C). As a result of these load changes the generator power changes instantaneously with the amount of \( \Delta P_G \). Electrical power balance requires that

\[
\Delta P_G = \Delta P_L + \Delta P_T
\]

(25)

*For simplicity we assume only one outgoing line in Fig. 5.

decrease will accelerate the unit. In either case the generator frequency will undergo a change, \( \Delta f \), which thus becomes an indicator of the existing power unbalance.

The ALFC loops are designed to maintain power balance by an appropriate adjustment of the turbine torque. By means of the "primary" loop a relatively fast but coarse frequency control is achieved. The response time of this loop is limited by the inherent speed of the turbine and is typically measured in seconds.

The "secondary" ALFC loop works in a slow reset mode to eliminate the small frequency errors which still remain after the actions of the primary loop. This loop also controls the power interchange between poolmembers. We now look at these two loops in more detail.

10. The Primary ALFC Loop—Mathematical Modeling

The purpose of this loop is to achieve the fastest possible adjustment of the turbine power in response to a change in frequency. To this end the speed governor measures continuously the frequency (or speed) and produces a power command, \( P_c \), of the linear form

\[
\Delta P_c = \Delta P_{ref} - K_q \Delta f
\]

(26)

(Ref. 3 gives hardware details)

\( P_{ref} \) is a reference power setting. The constant \( K_q \) has dimension MW/Hz. Its inverse value (Hz/MW) is referred to as "regulation" and informs of the static drop in frequency as caused by increased power output. In USA the regulation is typically set at 5% meaning that the frequency would drop 5% (=3 Hz) for a change in power between zero and full load.

The command, \( \Delta P_c \), is fed into a hydraulic amplifier which causes a position change, \( \Delta \theta \), of the steam control valve (or control gate in the case of a hydrogenerator). The hydraulic amplifier typically has a transfer function

\[
G_H = \frac{1}{1 + sT_H}
\]

(27)

where the time constant \( T_H \) lies in the range 0.1–0.2 sec's. The change in valve (or gate) opening translates in the turbine into a power increment, \( \Delta P_T \).

We can now readily assemble the block diagram shown in Fig. 7. (Disregard for the time being the dotted portion.) The portions labeled "network" and "turbine" require further elaboration.

11. Network Dynamic Representation

The turbine power, \( \Delta P_T \), will be used for four different purposes:

1. To supply the demanded "new" load \( \Delta P_L \).
2. To accelerate the turbine-generator, thus increasing the kinetic energy, \( W_{kin} \), of the unit.
3. To increase the powers in outgoing lines, i.e., \( \Delta P_T \).
4. To meet the increase in the "old" load.

We discuss briefly the three last power components.

A. Kinetic Power Increment, $\Delta P_{\text{kin}}$

The kinetic energy serves as a buffer storage. For example when a customer suddenly connects a 100 kW motor to the system it obviously cannot be met by a corresponding increase in the slow-changing turbine power. Instead, the generator will supply it by "borrowing" from the kinetic energy. Since the latter varies as the square of the speed this power component can be expressed as follows:

$$\Delta P_{\text{kin}} = \frac{d}{dt} (W_{\text{kin}}) = \frac{d}{dt} \left[ W_{\text{kin}} \left( \frac{f}{f_0} \right)^2 \right]$$

$$= \frac{d}{dt} \left[ W_{\text{kin}} \left( \frac{f^0 + \Delta f}{f_0} \right)^2 \right]$$

$$\approx \frac{2 W_{\text{kin}}}{f^0} \frac{d}{dt} (\Delta f)$$

(28)

where $W_{\text{kin}}^0$ represents the kinetic energy as measured at normal speed.
B. Line Power Increment, $\Delta P_I$

For simplicity we assume there is only one outgoing line connecting our generator bus, $#i$, with another generator bus, $#j$.

From eq (17) we obtain

$$\Delta P_I \approx \frac{|V_i||V_j|}{X_{ij}} \cos(\delta_i^0 - \delta_j^0)(\Delta \delta_i - \Delta \delta_j)$$  \hspace{1cm} (29)

As $\Delta \delta = 2\pi \int \Delta f dt$ we can write

$$\Delta P_I \approx 2\pi T_{ij} \int \Delta f dt$$  \hspace{1cm} (30)

where the parameter, $T_{ij}$, the synchronizing coefficient of the line, is defined by

$$T_{ij} \equiv \frac{|V_i||V_j|}{X_{ij}} \cos(\delta_i^0 - \delta_j^0)$$  \hspace{1cm} (31)

C. Frequency Dependency of “Old” Load

As the frequency increases so will the speed of all motors fed from the bus. Added speed means added torque and power. One may express this frequency dependency of existing load by an empirical parameter, $D$, having the unit MW/Hz. Thus the increase in the “old” load equals $D \Delta f$.

By Laplace transforming all the above power components and adding them the dynamic power balance at the bus reads:

$$\Delta P_L = \Delta P_{LV} + \frac{2W_{kin}^0}{J^0} s \Delta f + \frac{2\pi T_{ij}^0}{s^2} (\Delta f - \Delta f_i^0) + D \Delta f$$  \hspace{1cm} (32)

We can rearrange this equation as follows:

$$\Delta f = \left[ \frac{\Delta P_T - \Delta P_L}{1 + sT_N} - \frac{2\pi T_{ij}^0}{s} (\Delta f - \Delta f_i^0) \right] \frac{K_N}{1 + sT_N}$$  \hspace{1cm} (33)

where

$$K_N^0 \equiv \frac{1}{D}$$  \hspace{1cm} (34)

$$T_N \equiv \frac{2W_{kin}^0}{D^0}$$

Putting eq (33) in block diagram form yields the part labelled “network” in Fig. 7.

12. Turbine Representation

The turbine dynamics is of central importance. It will vary widely depending upon type of turbine used. We give the transfer function representation for three different turbine types. (More details can be obtained from ref. 7.)

A. Non-Reheat Steam Turbine

This turbine type (Fig. 8a) has a simple design. After passing the control valve the high pressure steam enters the turbine via the steamchest. The chest introduces a delay, $T_{CH}$, in the steamflow resulting in the transfer function

$$G_T \equiv \frac{\Delta P_T}{\Delta P_V} = \frac{1}{1 + sT_{CH}}$$  \hspace{1cm} (35)

Typical values for $T_{CH}$ lie in the range 0.2–0.5 sec’s.

B. Reheat Steam Turbine

This type of turbine has several turbine stages, between which the steam is led via reheaters. The design increases efficiency and is always used for large units.

Assume that the two stages in Fig. 8b are rated at half total power each. If we also assume that the reheater can be
represented by a timeconstant, $T_{RH}$, then the total turbine power equals (neglecting the delay in the chest):

$$\Delta P_T = \left( 0.5 + 0.5 \frac{1}{1 + sT_{RH}} \right) \Delta P_V$$

(36)

The overall transfer function would be

$$G_T \triangleq \frac{\Delta P_T}{\Delta P_V} = \frac{1 + 0.5sT_RH}{1 + sT_{RH}}$$

(37)

$T_{RH}$ has typical values in the range 4–10 sec's thus resulting in slow overall response times.

C. Hydro Turbine

Depending upon the magnitude of water "head" (fig. 8c) this type of turbine is of varying design. Without proof (see ref. 7) we give the following transfer function

$$G_T = \frac{1 - 2sT_p}{1 + sT_p}$$

(38)

$T_p$ is the time it takes for the water to pass through the penstock.

Fig. 9 shows a comparison between the three turbine types in regards to the time response to a stepchange in the valve position. It is interesting to note the momentary power decrease for a hydroturbine. (Electrical engineers refer to this type of behavior as "non-minimum-phase.")

13. The Secondary ALFC Loop

The primary ALFC loop would yield a frequency drop of about 3 Hz between zero and full-load of the generator. This poor accuracy is entirely unsatisfactory. This is where the "secondary" loop enters the picture. It performs slow "reset" adjustments of the frequency by changing the reference power command $P_{ref}$.

The dotted portion of Fig. 7 shows how this can be best accomplished by a low-gain integrator loop.

Following a sudden load increase, $\Delta P_L$, the turbine output, $\Delta P_T$, is increased to a new value as rapidly as the primary ALFC loop will permit. As we noted, the turbine response sets the pace. However, we are left with a considerable negative frequency error, which now causes a slowly growing positive integrator output and a corresponding increase in power reference setting. Whereas the primary loop response is over in seconds, the secondary fine adjustment may take of the order of one minute and will not stop until the frequency error is zero.

14. Extension to "Multi-Area" Systems

The loop model in Fig. 7 is in strictest sense valid for a single generator only. We have noted, that the frequency dynamics is relatively slow. This tends to make a whole group of generators move in unison, or coherently, thus permitting us to represent them all with the same $\Delta f$. For this reason it is common to let the model in Fig. 7 represent a whole "area" which in practice typically can embrace a whole power system.

If this "area" via tie-lines is connected to neighboring "areas" then we talk about multi-area dynamics. In such situations all the power commands are executed in unison among all generators that are under control. If each generator in the area has the same percentage "regulation" then each generator will participate in proportion to its rating.

The secondary ALFC loops in multi-area systems contain control signals, now referred to as "area control errors" (ACE), which in addition to frequency error, $\Delta f$, also contain the errors in the contracted tie-line powers. A typical such ACE would be of the form

$$ACE = \Delta P_{tie} + B\Delta f$$

(39)

15. Optimal LQR Design

The AVR and ALFC loops were derived on the assumption of total noninteraction. There is, however, cross-coupling between the channels, which under certain circumstances will have noticeable effects, sometimes of very deleterious nature (ref. 3, chap. 9). For example, sometimes whole areas will start to oscillate at frequencies around 1 Hz. The oscillations show up in frequency and tie-line powers and can grow to levels when desynchronization occurs.

In principle it is not difficult to expand the mathematical models to account for these phenomena. However, the models become of high dimensionality and classic control design becomes difficult.

In situations like this optimum LQR design becomes attractive. Following initial attempts by Yu, Elgerd and Fosha (ref. 8, 9) many additional contributions have been reported (ref. 10). Space does not permit a discussion here, but the reader is referred to ref. 3 for more detailed coverage.

16. Emergency Controls

All previous discussions have concerned control loops which are intended to maintain the power system in its normal state. In sect. 5 we indicated how cascading events, or multicontingencies, can bring the power system into an emergency state, which if not properly controlled can deteriorate into an extremis state. Due to the slow turbine response the ALFC loops are ineffective in emergencies. The AVR loops are faster but the limited exciter power renders even these loops essentially useless.

Power system components, especially generators, are very expensive and the primary objective of emergency controls is to prevent damage to the equipment. For this reason one always finds a first line of defence consisting of protective devices organized into unit protective systems. For example, generators, transformers, lines and buses have their own specialized fastacting protective devices, which mostly are set to operate in preset or openloop mode. Typically a relay detects the fault and initiates a circuit breaker trip. It is important that tripping involves only those
components that are subject to damage and the relays must thus have high selectivity. Microprocessors are finding increased use in modern relay design.

The second objective of the emergency controls is to perform automatic re-energizing of components. For example, following the tripping of a line in most instances the shortcircuit will “heal” in a fraction of a second and the line after reclosure can function normally. The reclosing must take place fast and automatically to be successful.

The third objective of emergency control is to prevent the system from desynchronization, i.e., breaking up into parts. A system is said to be transient stable for a particular disturbance if the generator rotors, following the initial transient angular swings, tend to stick together. The system may not in itself have a sufficiently strong synchronizing “glue” and it will then be necessary to insert on a temporary basis components designed to enhance the stability.

The fourth and final objective of emergency controls is to save a deteriorating frequency.

17. Transient Stability Control—Classical Approach

Under normal conditions the turbine power, \( P_T \), and generator power, \( P_G \), are in balance and the turbine-generator unit is running at constant speed. During major fault disturbances \( P_T \) remains approximately constant whereas \( P_G \) undergoes sudden and large changes. The postfault difference power \( P_T - P_G \), depending upon sign, will either accelerate or decelerate the unit. The accelerations of the generator units follow from the swing equations

\[
P_{TI} - P_{GI} = M_i \frac{d^2 \delta_i}{dt^2}
\]

(40)

where \( \delta \) is the angular rotor coordinate and \( M = \frac{W_{\text{kin}}}{\pi f^0} \) is the rotor inertia constant.

The name “swing equation” implies that power systems are oscillatory in nature. When brought out of balance the machine rotors tend to perform torsional oscillations which are quite undamped. As the electrical restoring, or synchronizing, powers of the lines (eq’s 17, 29) are nonlinear functions of the angular coordinates the oscillations become nonlinear of the limit-cycle type.

A transient stability study involves the integration of the coupled swing equations (40). The coupling takes place via the network. In such a simulated study it is, of course, necessary to make contingency assumptions.

Classically, transient stability control has centered on use of fast-acting circuit breakers. For example, consider the two-machine system in Fig. 10. Initially the system is in its normal state characterized by the powerflows shown (disregard the dotted portion).

A sudden short on the line causes the circuit breakers 1 and 4 to open. At that instant the generator powers \( P_{G1} \) and \( P_{G2} \) change to match the local loads which will remain at their prefault values*. Unit #1 thus finds itself with a power surplus of 300 MW causing an acceleration. Unit #2 will have a power deficiency of 300 MW and will thus decelerate. The angles \( \delta_1 \) and \( \delta_2 \) will thus move apart at an accelerating rate. If line reclosure can be accomplished fast enough the two machines will regain synchronization.

18. Transient Stability Control—New Approaches

Consider now the following alternative chain of events. At the moment of line tripping the circuit breaker #2 inserts a 300 MW “brake” resistor R. At the same instant 300 MW of the load at bus #2 is disconnected in a “fast load-shed.” These breaker operations will in effect restore power balance at each rotating unit, thus avoiding severe angular accelerations. At the later moment when line reclosure takes place the brake resistor is disconnected and the load is restored at bus 2.

The combined use of breaker resistor and “load-skipping” obviously is a more active approach to preserving transient stability. It has lately received considerable attention (refs 11, 12). For this type of control to be effective the control decisions must be arrived at fast. The controllers must also be robust as they must function under vastly different fault conditions.

*The bus voltages will change (in spite of the best efforts by the AVR loops) and as the voltages change so will the loads. We neglect this in our discussion.
19. Frequency Control and Longterm Dynamics

Following a major fault the transient stability is typically determined within one or several seconds. Even if the system remains initially synchronized, fault-induced problems often occur which make themselves known within several seconds or possibly minutes and which will give rise to longterm frequency dynamics.

For example, the line trip in the above example may cause voltage swings so severe that a feedwater pumpmotor will trip making it necessary to take G2 out of service, thus creating a systemwide generation shortage of 200 MW. If the system were part of a power pool, support power would immediately flow in over the tie-lines. If the system is operating alone the 200 megawatts will be taken from the kinetic storage resulting in a rapid frequency deterioration. Power balance must be rapidly restored and permanent loadshedding will often be the last resort. It can be done manually by the operator or automatically upon command from underfrequency relays.

Simulation of the frequency dynamics could, theoretically, be performed by extending the integration of the swing equations (40), now rewritten in the frequency form

$$P_{TI} - P_{G_I} = 2\pi M_i \frac{df_i}{dt}$$

(41)

As some of the generators are performing relatively fast intermachine swings this integration procedure requires small integration steps (≈0.01 s). A considerably more practical approach is to turn the attention to the average frequency of all the area generators.

We thus define a lumped area generator having the inertia

$$M_a = \sum M_i$$

(42)

and its rotor position ("center of inertia") defined by

$$\delta_a = \frac{\sum M_i \delta_i}{M_a}$$

(43)

The frequency of this imaginary machine then equals

$$f_a = \frac{1}{2\pi} \delta_a$$

(44)

and can be integrated from a "lumped" swing equation

$$\sum P_{TI} - \sum P_{G_I} = 2\pi M_a \frac{df_a}{dt}$$

(45)

As the frequency, $f_a$, is a fairly slowly changing variable the integration steps can now be chosen fairly large (≈ 1 s).

20. Future Trends

In this brief exposition of power system control we have focused on the normal and emergency state control problems as being the most relevant ones from the operator's point of view. Other important control problems related to resource optimization, security enhancement and environmental protection have been excluded due to space limitation. Due to the enormous capital investments, changes in power systems technology tend to be of evolutionary rather than revolutionary nature. We presently identify some of the areas that probably will be subject to increased future attention by control and systems researchers.

The graph in Fig. 2 depicts one of the basic problems facing the power systems planner—disparity between maximum and minimum loading—which results, on the average, in poor utilization of generating equipment. In an earlier and more plentiful energy era the electric utilities never attempted to interfere with the customer's power use habits. However, adding new generating capacity is exceedingly expensive in both monetary and environmental terms. By shaving the demand peaks it is possible to either cancel or at least postpone for several years the construction of new plants and/or the installation of expensive peaking units. Controlling the power demand, or load management, has thus today become a very high priority item on the engineering agenda of most utility industries.

Load control can in principle be achieved in a number of ways ranging from the totally voluntary approach to compulsory shutoff (refs. 13, 14). Using microprocessors in combination with novel rate schedules (ref. 15) offers new possibilities. The industry is looking urgently for new and imaginative ideas in this field.

Areawide blackouts although rare have dramatic impacts and often serious consequences. Increased operating security thus is high on the industry priority list. Finding improved methods for predicting transient and frequency stability and developing new emergency control methods are tasks singularly suited to the control specialist.

Determination of transient stability has classically been performed indirectly by integration of the swing equations. Time-domain simulation is computationally costly and places a constraint upon the number of contingencies that can be studied. Direct stability analysis methods seem to offer better promise in this regard. These methods are known under the acronym TESA (Transient Energy Stability Analysis). Direct stability assessment methods exemplified by the famous "equal area criterion" (ref. 3) have been used by power engineers for many years. The TESA methods based as they all are upon Lyapunov theory are not new either. However, recent contributors (ref. 16) claim a "breakthrough" in the use of these methods as a result of physically based energy functions and a more intuitive interpretation of computer results. An ultimate goal in TESA research would be to develop a method whereby the system operator could assess in real time the degree of stability characterizing the system at a certain operating time and in a certain operating configuration.

In sect. 18 we briefly mentioned the new emergency control schemes the theory of which has been recently studied by Zaborszky and Meisel (refs. 11, 12). Those methods represent a distinct departure from existing
practice of emergency control since they would require extensive addition of control hardware to the system at every generating bus. The proposed control schemes would function as follows:

A few critical state variables would be locally monitored at each control point. When the variables would indicate a major disturbance a local microprocessor would determine the best control strategy for applying the locally available control forces in an attempt to achieve optimal power balance in the overall system.

The authors demonstrate impressive success with their respective control strategies during fault situations in large scale systems. Of course, at this early stage only simulated data is available. Extensive follow-up work is needed before the utility industry will gain confidence in these methods. The authors limit their studies to symmetrical network faults. Extensive simulation seems required to check the robustness for all the various types of unbalanced faults that can befall power systems. Most importantly, hardware studies—performed first at reduced power levels—must confirm beyond any doubts that the added equipment does not in fact introduce more security problems than it is intended to cure. At this stage the work represents an exciting new development in power systems control which deserves the attention by more investigators.

In recent years control of "large-scale" systems has become a popular research area of control theoreticians. It is not surprising that power systems in particular have become the focus of much attention, since typical largescale system topics like aggregation and decentralized control have been of great concern (under different names) by power systems engineers. The "dissipation effect" (sect. 6) manifesting itself in localization of even major disturbances has long been known and been the basic reason why so-called "area control" has historically emerged as an unquestioned natural feature of power systems control. The division into "areas" was often performed on a political basis.

The intuitive use of decentralized control did not always turn successful. The classical example was the emergence of the "tie-line frequency-bias" control law described by equation (39). Originally the attempt was made to delegate regulation of the tie-line powers to the individual power companies but let the frequency control be handled by one (usually the largest) company. It turned out that this pool member experienced unacceptably large power swings. Sharing the control of both the frequency and tie-line power as implied by eq. (39) was suggested by Cohn (ref. 17) and proved a radical improvement.

The powerful analysis tools of modern linear control have later confirmed the soundness of the empirically found formula (39). For example, it was pointed out in ref. 9 how use of only local state variables in the optimal control of a two-area system added only insignificantly to the optimum integral index. This has been confirmed by later researchers working with much larger systems and using more extensive models. A good discussion is given in ref. 18 which also contains a substantial bibliography on related topics.

"Aggregation" is the one large-scale system technique that may possibly offer the best payoffs in future power systems control. It is a well-known fact that all power system dynamics, both of the small and large magnitude varieties, is characterized by "coherency," i.e., groups of generators tending to swing in unison. For example, it is intuitively felt that the new emergency control methods discussed above could be greatly simplified by taking advantage of this feature. Rather than installing the control devices at each generator bus they may prove equally effective if lumped together into a few "switching centers."

References

IEEE Professional Activities and the Control Systems Society

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This is the first in a series of short articles about IEEE professional activities as they relate to the Control Systems Society member. In this article, we look at IEEE professional activities and examine their relationship to the primarily technical activities of the Control Systems Society. Future installments will deal with organization and financing of professional activities, program plans and performance assessment, specific program areas relevant to the control engineer, and future activities which can be pursued through the Control Systems Society.

Significant growth in IEEE professional activities has occurred mostly over the last decade and has involved primarily U.S. Members of the Institute. Some of the factors which led to the institutionalization of IEEE professional activities—represented by the establishment of the United States Activities Board (USAB)—arose from the social activism of the 1960’s. With the space program and the rapid evolution of computer technology, many members recognized that engineering developments unavoidably have a profound effect on the sociopolitical system and on individual lifestyles and employment. For the engineer to maintain his traditional detached and objective viewpoint on such matters would be irresponsible to society and moreover suicidal to the profession. A large number of laws, including social legislation and R&D funding, appeared to be “dealing-out” engineering and science. Not enough attention was being paid to engineering and science enrollments and much less attention and support was being voiced for education. In some instances, engineers were victimized by wage-squeezes, flawed pension programs, or management pressures to overlook public safety. Under these circumstances, the consequences of inactivity were clear: government, society, big business and even big education would be free to push engineers around at will. Without any form of organization, the efforts of individuals to counteract such influences would be largely in vain. In spite of the engineer’s traditionally conservative and individualistic image, the cost of doing nothing had become so high that organization, planning, and a financial commitment had become inescapable.

Suffice it to say that these have all come about within the decade, and some of the details will be described in future articles in this series. Our present purpose is to develop a framework in which to view IEEE professional activities and by which the relationship of our technical and professional activities as control and systems engineers can be understood. These considerations apply more or less equally to U.S. and to international members of the Control Systems Society. The fact that IEEE professional activities are currently financed by, and for the benefit of, the U.S. membership should be regarded as largely a pragmatic development; it happens that there is no other significantly large professional organization to represent electrical engineers in the United States, and at the same time there are probably too few IEEE members in most other countries to warrant such a substantial investment in professional activities through the IEEE. Such developments are occurring independently, in some instances, through other appropriate national engineering organizations abroad.

Fitting enough, feedback is a concept central to the understanding of IEEE professional activities. Society may be viewed as a complex interconnection of socioeconomic groups, some of which are institutionalized. Any student of in-